RISK FACTORS

An investment in the partnership involves a high degree of risk and is suitable only if you have substantial financial means and no need of liquidity in your investment.

SPECIAL RISKS OF THE PARTNERSHIP

NO GUARANTEE OF RETURN OF INVESTMENT OR RATE OF RETURN ON INVESTMENT BECAUSE OF SPECULATIVE NATURE OF DRILLING NATURAL GAS AND OIL WELLS. Natural gas and oil exploration is an inherently speculative activity. Before the drilling of a well the managing general partner cannot predict with any certainty:

- the volume of natural gas and oil recoverable from the well; or

- the time it will take to recover the natural gas and oil.

There is a risk that you will not recover all of your investment or if you do recover your investment that you will not receive a rate of return on your investment which is competitive with other types of investment.

You will be able to recover your investment only through the partnership's distributions of the sales proceeds from the production of natural gas and oil from productive wells. The quantity of natural gas and oil in a well, which is referred to as its reserves, decreases over time as the natural gas and oil is produced until the well is no longer economical to operate. All of these distributions to you will be considered a return of capital until you have received 100% of your investment.

RISK THAT A WELL DOES NOT RETURN THE AMOUNT PAID TO DRILL AND COMPLETE IT. There is a risk that even if a well is completed by the partnership and produces natural gas and oil in commercial quantities it will not produce enough natural gas and oil to pay for the costs of drilling and completing the well, even if tax benefits are considered. For example, the managing general partner has formed 38 partnerships since 1985, 33 of which were formed in 1990 or subsequent years. All the partnerships are continuing to make cash distributions, however, 32 of the 38 partnerships have not yet returned to the investor 100% of his capital contributions without taking tax savings into account.

RISK OF NONPRODUCTIVE WELLS IN DEVELOPMENT DRILLING. Although drilling development wells reduces the risk of drilling nonproductive wells, there is a risk that the partnership will drill some wells which are nonproductive and must be plugged and abandoned. If one or more of the partnership's wells are nonproductive, then the partnership's productive wells may not produce enough revenues to offset the loss of investment in the nonproductive wells.

RISK OF REDUCED PARTNERSHIP DISTRIBUTIONS BECAUSE OF DECREASE IN THE PRICE OF NATURAL GAS AND OIL. There is no assurance of the price at which the partnership's natural gas and oil will be sold and if natural gas and oil prices decrease, then your partnership distributions will decrease accordingly. Although there were significant increases in the price of natural gas at the end of 2000 and the first quarter of 2001, natural gas and oil prices have declined and remain volatile. The price of natural gas and oil will depend on supply and demand factors largely beyond the control of the partnership and there is a risk that natural gas and oil prices could decrease in the future.

There is a further risk that the price of natural gas and oil may decrease during the first years of production when the wells achieve their greatest level of production. This would have the greatest adverse affect on your partnership distributions.

RISKS REGARDING THE PARTNERSHIP'S NATURAL GAS MARKET WHICH COULD REDUCE PARTNERSHIP DISTRIBUTIONS. In addition to the risk of decreased natural gas and oil prices described above, there are risks associated with marketing natural gas which could reduce partnership distributions to you and the other investors. These risks are set forth below.

- Competition from other natural gas producers and marketers may make it more difficult to market the partnership's natural gas.

- The managing general partner anticipates that a portion of the partnership's natural gas production will be sold directly to industrial end-users situated in the areas where the wells will be drilled. Selling natural gas to industrial end-users creates a risk that the partnership may not be paid or may experience delays in receiving payment for natural gas that has already been delivered.

- There can be no assurance that the terms of a natural gas supply agreement will be favorable over the life of the wells. A substantial portion of the partnership's natural gas will be sold under a 10-year agreement which began on April 11, 1999, and provides that the price may be adjusted upward or downward in accordance with the spot market price and market conditions. The managing general partner anticipates that the remainder of the partnership's natural gas will be sold under similar contracts. Thus, there is no assurance of a specific natural gas price for the term of the agreement, and there is a risk that the price for the partnership's natural gas will be decreased because of market conditions. Furthermore, even if the natural gas supply contract did not provide for price and other adjustments, in the past low natural gas prices or other difficulties in marketing natural gas have resulted in some purchasers renegotiating existing agreements to reduce the contract price for natural gas and the volume of natural gas to be purchased.

- Partnership revenues may be less the farther the natural gas is transported because of increased transportation costs.

- Production from the wells may be reduced due to seasonal marketing demands since the demand for natural gas is usually greater in the winter months because of residential heating requirements than the summer months.

- Production from wells drilled in certain areas may be delayed until construction of the necessary pipelines and production facilities is completed.

IF YOU CHOOSE TO INVEST AS A GENERAL PARTNER FOR THE TAX BENEFITS, THEN YOU HAVE GREATER RISK THAN A LIMITED PARTNER. If you invest as an investor general partner for the tax benefits instead of as a limited partner, then under Pennsylvania law you will have unlimited liability for the partnership's activities. This could result in you being required to make payments, in addition to your original investment, in amounts that are impossible to predict because of their uncertain nature. Under the terms of the partnership agreement, if you are an investor general partner you agree to pay only your proportionate share of the partnership's obligations and liabilities. This agreement, however, does not eliminate your liability to third-parties if another investor general partner does not pay his proportionate share of the partnership's obligations and liabilities.

Also, the partnership may own less than 100% of the interest in some of the wells. If a court holds you and the other third-party owners of the well liable for the development and operation of a well and the third-party well owner does not pay its proportionate share of the costs and liabilities associated with the well, then the partnership and you and the other investor general partners would be liable to third-parties for those costs and liabilities.

The partnership will have the benefit of the managing general partner's general and excess liability insurance of $50 million during drilling operations and $11 million thereafter, per occurrence and in the aggregate. Nevertheless, as an investor general partner you may become subject to the following:

- contract liability which is not covered by insurance;

- liability for pollution, abuses of the environment and other environmental damages against which the managing general partner cannot insure because coverage is not available or against which it may elect not to insure because of high premium costs or other reasons; and

- liability for drilling hazards which result in property damage or personal injury or death to third-parties in amounts greater than the insurance coverage. The drilling hazards include, but are not limited to well blowouts, fires and explosions.

If the partnership's insurance proceeds and assets and the managing general partner's indemnification of you and the other investor general partners, were not sufficient to satisfy the liability, then the managing general partner would call for additional funds from you to satisfy the liability.

RISK THAT THE MANAGING GENERAL PARTNER CANNOT MEET ITS INDEMNIFICATION AND REPURCHASE OBLIGATIONS BECAUSE ITS LIQUID NET WORTH IS NOT GUARANTEED. The managing general partner has made commitments to you and the other investors regarding the following:

- the payment of equipment costs and organization costs;

- indemnification of the investor general partners for liabilities in excess of their pro rata share of partnership assets; and

- repurchasing the units.

A significant financial reversal for the managing general partner could adversely affect its ability to honor these obligations.

The managing general partner's net worth is based primarily on the estimated value of its producing natural gas properties and is not available in cash without borrowings or a sale of the properties. Also, if natural gas prices decrease the estimated value of the properties and the managing general partner's net worth will be reduced. There is no assurance that the managing general partner will have the necessary net worth, either currently or in the future, to meet its financial commitments under the partnership agreement. These risks are increased because the managing general partner has made and will make similar financial commitments in other partnerships.

RISKS OF A LONG-TERM INVESTMENT BECAUSE THE UNITS ARE ILLIQUID AND NOT READILY TRANSFERABLE. If you invest in the partnership, then you must assume the risks of an illiquid investment. The transferability of the units is limited by the federal securities laws, tax laws and the partnership agreement. The units cannot be readily liquidated, and there is no market for the sale of the units. Also, a sale of your units could create adverse tax and economic consequences for you.

THE NUMBER OF PARTNERSHIP WELLS DRILLED DEPENDS ON THE AMOUNT OF SUBSCRIPTION PROCEEDS. If all of the units offered are not sold, then fewer wells will be drilled which decreases the partnership's ability to spread the risks of drilling. The managing general partner anticipates that approximately 5 wells will be drilled if the minimum required subscriptions of $1 million are received, and approximately 124 wells will be drilled if subscription proceeds of $25 million are received.

On the other hand, to the extent more than the minimum subscriptions are received and the number of wells drilled increases, the partnership's overall investment return may decrease if the managing general partner is unable to find enough suitable wells to be drilled. Also, in a large partnership greater demands will be placed on the managing general partner's management capabilities.

There is also a risk of cost overruns in drilling and completing the wells because the wells will not be drilled and completed on a turnkey basis for a fixed price which would shift the risk of loss to the managing general partner as drilling contractor. The majority of the equipment costs of the partnership's wells, including any equipment costs in excess of 10% of the partnership's subscription proceeds, will be paid by the managing general partner. However, all of the intangible drilling costs will be charged to you and the other investors. If there is a cost overrun for the intangible drilling costs of a well or wells, then the managing general partner anticipates that it would use the partnership's subscription proceeds, if available, to pay the cost overrun or advance the necessary funds to the partnership. However, using subscription proceeds to pay cost overruns will result in the partnership drilling fewer wells.

RISK REGARDING LACK OF INFORMATION FOR A PORTION OF THE WELLS. The wells currently proposed to be drilled represent approximately 65% of the wells that will be drilled if all 2,500 units are sold. The managing general partner has also reserved the right to substitute wells and to drill in other areas. Thus, not all of the wells are specified and you do not have any geological or production information to evaluate any additional and/or substituted wells. Instead, you must rely entirely on the managing general partner to select those wells.

The partnership does not have the right of first refusal in the selection of well locations from the inventory of the managing general partner and its affiliates, and they may sell their well locations to other partnerships, companies, joint ventures or other persons at any time.

THERE IS A RISK THAT THE DATA REGARDING CURRENTLY PROPOSED WELLS IS INCOMPLETE OR INCORRECT. The information in this prospectus regarding wells previously drilled in the areas where the wells currently proposed to be drilled are located has been prepared by the managing general partner from sources which it believes are reliable. However, there is a risk that the data does not show:

- all the wells drilled in the area; or

- the correct volume of natural gas and oil produced from the wells.

Also, the production information for some of the wells may be incomplete:

- if there is or was a third-party operator and the information is unavailable to the managing general partner; or

- if the managing general partner is the operator and the wells are not yet completed, on-line to sell production or have been producing for only a short period of time.

RISK OF BIAS REGARDING GEOLOGICAL REPORTS PREPARED BY MANAGING GENERAL PARTNER. The geological report for the currently proposed wells in Fayette County, Pennsylvania and the geological report for the Clinton/Medina geological formation in southern Ohio were prepared by the managing general partner which is not independent. This lack of independence in the preparation of the reports may affect their reliability since the managing general partner has an incentive to prepare a more positive report than an independent geologist.

MANAGING GENERAL PARTNER'S SUBORDINATION IS NOT A GUARANTEE OF THE RETURN OF ANY OF YOUR INVESTMENT. If your cash distributions are less than a 10% return for each of the first five 12-month periods beginning with the partnership's first cash distributions from operations, then the managing general partner has agreed to subordinate a portion of its share of the partnership's net production revenues. However, if the wells produce only a small natural gas and oil volume, and/or natural gas and oil prices decrease, then even with subordination you may not receive the 10% return for each of the first five years as described above or a return of your investment. Also, at any time during the subordination period the managing general partner is entitled to an additional share of partnership revenues to recoup previous subordination distributions to the extent your cash distributions from the partnership exceed the 10% return described above.

RISK THAT BORROWINGS BY THE MANAGING GENERAL PARTNER COULD REDUCE FUNDS AVAILABLE FOR ITS SUBORDINATION OBLIGATION. The managing general partner will pledge either its partnership interest and/or an undivided interest in the assets of the partnership to secure borrowings for its own corporate purposes. There is a risk that if there was a default to the lender under this pledge arrangement, then this would reduce the amount of the partnership's net production revenues available to the managing general partner for its subordination obligation to you and the other investors.

COMPENSATION AND FEES TO THE MANAGING GENERAL PARTNER REGARDLESS OF SUCCESS OF THE PARTNERSHIP'S ACTIVITIES. The managing general partner and its affiliates will profit from their services in drilling, completing and operating the partnership's wells and will receive the other fees described in "Compensation" regardless of the success of the partnership's wells.

RISK OF REDUCED OR DELAYED DISTRIBUTIONS TO INVESTORS . There is a risk that you will not receive cash distributions every quarter. Although the managing general partner intends to distribute the cash quarterly, distributions may be deferred to the extent partnership revenues are used for any of the following:

- repayment of borrowings;

- cost overruns;

- remedial work to improve a well's producing capability;

- reserves, including a reserve for the estimated costs of eventually plugging and abandoning the wells; or

- indemnification of the managing general partner and its affiliates by the partnership for losses or liabilities incurred in connection with the partnership's activities.

RISKS ARISING FROM CONFLICTS OF INTEREST BETWEEN MANAGING GENERAL PARTNER AND THE INVESTORS. There are conflicts of interest between you and the managing general partner and its affiliates. Other than certain guidelines set forth in "Conflicts of Interest," the managing general partner has no established procedures to resolve a conflict of interest.

RISKS THAT PRESENTMENT OBLIGATION MAY NOT BE FUNDED AND REPURCHASE PRICE MAY NOT REFLECT FULL VALUE. Subject to certain conditions, beginning in 2006 you may present your units to the managing general partner for purchase. There is a risk that the managing general partner will determine, in its sole discretion, that it does not have the necessary cash flow or cannot arrange financing for this purpose on reasonable terms. In either event the managing general partner may suspend the presentment feature. This risk is increased because the managing general partner has and will incur similar presentment obligations in other partnerships.

Further, there is a risk that the presentment price may not reflect the full value of the partnership's property or your units because of the difficulty in accurately estimating natural gas and oil reserves. The estimates are merely appraisals of value and may not correspond to realizable value. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way, and the accuracy of the reserve estimate is a function of the quality of the available data and of engineering and geological interpretation and judgment. There can be no assurance that the presentment price paid for your units and any revenues received by you before the presentment will be equal to the purchase price of the units. On the other hand, you might realize a greater return if you retain the units, which you may elect, rather than selling the units to the managing general partner.

RISK REGARDING PARTICIPATION WITH THIRD-PARTIES IN DRILLING WELLS. The managing general partner anticipates that the partnership will own 25% to 100% of the interest in its wells subject to royalties and any other burdens on the leases. Thus, third-parties may participate with the partnership in drilling some of the wells. Additional financial risks exist when the cost of drilling, equipping, completing and operating wells is shared by more than one person. If the partnership pays its share of the costs but another interest owner does not, then the partnership would have to pay the costs of the defaulting party.

If the managing general partner were not the actual operator of the well, then there is a risk that the managing general partner cannot supervise the third-party operator closely enough. Also, decisions concerning how the well is operated and expenditures related to the well will be made by a third-party operator and may not be in the best interests of the partnership and you and the other investors. There is a further risk that a third-party operator will have financial difficulties and fail to pay for materials or services on the wells it drills or operates and, in that event, the partnership could incur extra costs in discharging materialmen's and workmen's liens. The managing general partner may not be the operator of the well if the partnership owns less than a 50% interest in the well or if the managing general partner acquired the interest in the well from a third-party which required that it be named operator.

RISK THAT THE MANAGING GENERAL PARTNER WILL NOT DEVOTE THE NECESSARY TIME TO THE PARTNERSHIP BECAUSE ITS MANAGEMENT OBLIGATIONS ARE NOT EXCLUSIVE. The managing general partner must devote the amount of time to the partnership's affairs that it determines is reasonably necessary. However, the managing general partner and its affiliates will be engaged in other oil and gas activities and unrelated business ventures for their own account or for the account of others during the term of the partnership, including other partnerships. Thus, there is a risk that the managing general partner will not devote the necessary time to the partnership.

RISK OF PREPAYING SUBSCRIPTION PROCEEDS TO MANAGING GENERAL PARTNER. Under the drilling and operating agreement the partnership will be required to immediately pay the managing general partner the investors' share of the entire estimated price for drilling and completing the partnership's wells. Thus, these funds could be subject to claims of the managing general partner's creditors.

RISKS ASSOCIATED WITH MANAGING GENERAL PARTNER'S BENEFIT FROM DEVELOPMENT OF PARTNERSHIP PROSPECTS. There is a risk that the managing general partner may choose well locations along the natural gas gathering system owned by its affiliate, Atlas Pipeline Partners, which would benefit the managing general partner's parent company by providing more gathering fees to Atlas Pipeline

Partners, even if there are other well locations available in the area or other areas which offer the partnership a greater potential return.

RISK ASSOCIATED WITH LEASES IN SOUTHERN OHIO. The managing general partner anticipates that many of the leases in southern Ohio, which is one of the three primary areas for the partnership's drilling activities as discussed in "Proposed Activities - Primary Areas of Operations," will have been originally acquired from a coal company and are subject to a provision that the well must be abandoned if it hinders the development of the coal. Consequently, the managing general partner will not drill a well on any lease subject to this provision unless it covers lands which were previously mined. Although this does not totally eliminate the risk because the leases may cover other coal deposits that might be mined during the life of a well, the managing general partner believes that drilling wells on these previously mined leases would be in the best interests of the partnership.

TAX RISKS

CHANGES IN THE LAW. Your investment in the partnership will be adversely affected by changes in the tax laws. For example, under the Economic Growth and Tax Relief Reconciliation Act of 2001 the federal income tax rates are being reduced between 2001 and 2006, including reducing the top rate in stages from 39.6% for the first half of 2001 to 35% by 2006. This will reduce to some degree the amount of taxes you save by virtue of your share of the partnership's deductions for intangible drilling costs, depletion and depreciation.

YOU MAY OWE TAXES IN EXCESS OF YOUR CASH DISTRIBUTIONS FROM THE PARTNERSHIP. There is a risk that you may become subject to income tax liability for partnership income in excess of the cash you actually receive from the partnership. For example:

- if the partnership borrows money your share of partnership revenues used to pay principal on the loan will be included in your taxable income from the partnership and will not be deductible;

- taxable income or gain may be allocated to you if there is a deficit in your capital account even though you do not receive a corresponding distribution of partnership revenues;

- partnership revenues may be expended by the managing general partner for non-deductible costs or retained to establish a reserve for future estimated costs, including a reserve for the estimated costs of eventually plugging and abandoning the wells; and

- the taxable disposition of partnership property or your units may result in income tax liability in excess of cash distributions.

YOUR DEDUCTION FOR INTANGIBLE DRILLING COSTS MAY BE LIMITED FOR PURPOSES OF THE ALTERNATIVE MINIMUM TAX. You will be allocated a share of the partnership's deduction for intangible drilling costs. However, under current tax law alternative minimum taxable income of most investors cannot be reduced by more than 40% by the deduction for intangible drilling costs.

INVESTMENT INTEREST DEDUCTIONS OF INVESTOR GENERAL PARTNERS MAY BE LIMITED. An investor general partner's share of the partnership's deduction for intangible drilling costs will reduce his investment income and may adversely affect the deductibility of his investment interest expense, if any.

LACK OF TAX SHELTER REGISTRATION. The managing general partner believes that the partnership is not a tax shelter required to register with the IRS. If it is subsequently determined by the IRS or the courts that the partnership was required to be registered with the IRS as a tax shelter, then you would be liable for a $250 penalty for failure to include a tax registration number of the partnership on your tax return, unless this failure was due to reasonable cause.

ADDITIONAL INFORMATION

The partnership currently is not required to file reports with the SEC. However, a registration statement on Form SB-2 has been filed on behalf of the partnership with the SEC. Certain portions of the registration statement have been deleted from this prospectus under SEC rules and regulations. Also, statements in this prospectus concerning the contents of any document are incomplete. You are urged to refer to the registration statement and exhibits for further information concerning the provisions of certain documents referred to in this prospectus.

You may read and copy any materials filed as a part of the registration statement, including the tax opinion included as Exhibit 8, at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The SEC maintains an internet world wide web site that contains registration statements, reports, proxy statements and other information about issuers who file electronically with the SEC, including the partnership. The address of that site is HTTP://WWW.SEC.GOV. Also, you may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, a copy of the tax

opinion may be obtained by you or your advisors from the managing general partner at no cost. The delivery of this prospectus does not imply that its information is correct as of any time after its date.

FORWARD LOOKING STATEMENTS AND ASSOCIATED RISKS

Statements, other than statements of historical facts, included in this prospectus and its exhibits address activities, events or developments that the managing general partner and the partnership anticipate will or may occur in the future. These forward-looking statements include such things as:

- investment objectives;
- business strategy;
- estimated future capital expenditures;
- competitive strengths and goals;
- references to future success; and
- other similar matters.

These statements are based on certain assumptions and analyses made by the partnership and the managing general partner in light of their experience and their perception of historical trends, current conditions and expected future developments. However, whether actual results will conform with these expectations is subject to a number of risks and uncertainties, many of which are beyond the control of the partnership, including:

- general economic, market or business conditions;
- changes in laws or regulations;

- the risk that the wells are productive but do not produce enough revenue to return the investment made;

- the risk that the wells are dry holes;

- uncertainties concerning the price of natural gas and oil; and

- other risks.

Thus, all of the forward-looking statements made in this prospectus and its exhibits are qualified by these cautionary statements. There can be no assurance that actual results will conform with the managing general partner's and the partnership's expectations.

INVESTMENT OBJECTIVES

The partnership's principal investment objectives are to invest the subscription proceeds in natural gas development wells which will:

- Provide quarterly cash distributions to you until the wells are depleted, historically 20+ years, with a preferred annual cash flow of 10% during the first five years beginning with the partnership's first revenue distribution based on $10,000 per unit for all units sold. A reserve and economic report effective October 2000 which was prepared by Wright & Company, Inc., petroleum consultants, and reviewed by the managing general partner, evaluated the past history and estimated future production of 1,114 wells drilled to the Clinton/Medina geological formation in western Pennsylvania which is one of the partnership's primary drilling areas. Based on data in that report, approximately 1,054 of those wells are expected by the managing general partner to produce more than 20 years. The Clinton/Medina geological formation is also the objective formation in southern Ohio which is another one of the partnership's primary drilling areas as well as western New York which is one of the partnership's secondary drilling areas.

- Obtain tax deductions in 2001 from intangible drilling costs to offset a portion of your taxable income, subject to the passive activity rules if you invest as a limited partner. For example, if you pay $10,000 for a unit your investment will produce a 2001 tax deduction of approximately $9,000 per unit, 90% against:

- ordinary income if you invest as an investor general partner; and

- passive income if you invest as a limited partner.

If you are in either the new 39.1% or 35.5% tax bracket for 2001, then one unit will save you up to approximately $3,519 or $3,195 per unit respectively in federal taxes this year. Most states also allow this type of a deduction against the state income tax.

- Offset a portion of any taxable income generated by the partnership with tax deductions from percentage depletion, which is 15% in 2001 and estimated by the managing general partner to be 17% on net revenue. The managing general partner estimates that in 2001 this feature would reduce your effective tax rate from 39.1% to approximately 32.5%, which is 83% of 39.1%, on partnership net revenues. The percentage depletion rate fluctuates from year to year depending on the price of oil, but will not be less than the statutory rate of 15% nor more than 25%.

- Obtain tax deductions of the remaining 10% of the initial investment of you and the other investors in the partnership from 2001 through 2008. For example, if you pay $10,000 for a unit, you will receive an additional tax deduction of approximately $1,000 per unit for depreciation over a seven-year cost recovery period of the partnership's equipment costs for the wells.

Attainment of the partnership's investment objectives will depend on many factors, including the ability of the managing general partner to select suitable wells which will be productive and produce enough revenue to return the investment made. The success of the partnership depends largely on future economic conditions, especially the future price of natural gas and oil which is volatile and may decrease. There can be no guarantee that the foregoing objectives will be attained.

ACTIONS TO BE TAKEN BY MANAGING GENERAL

PARTNER TO REDUCE RISKS OF ADDITIONAL

PAYMENTS BY INVESTOR GENERAL PARTNERS

You may choose to invest as an investor general partner so that you can receive an immediate tax deduction against any type of income. To help reduce the risk that you and other investor general partners could be required to make additional payments to the partnership, the managing general partner will take the actions set forth below.

- INSURANCE. The partnership will have the benefit of $50 million of liability coverage during drilling operations and $11 million after drilling operations cease.

- CONVERSION OF INVESTOR GENERAL PARTNER UNITS TO LIMITED PARTNER INTERESTS. Your investor general partner units will be automatically converted by the managing general partner to limited partner units after

substantially all of the partnership wells have been drilled and completed. The managing general partner anticipates conversion in late summer of 2002.

Once your units are converted you will have the lesser liability of a limited partner under Pennsylvania law for obligations and liabilities arising after the conversion. However, you will continue to have the responsibilities of a general partner for partnership liabilities and obligations incurred before the effective date of the conversion. For example, you might become liable for partnership liabilities in excess of your subscription during the time the partnership is engaged in drilling activities and for environmental claims that arose during drilling activities but were not discovered until after conversion.

- NONRECOURSE DEBT. The partnership does not anticipate that it will borrow funds. However, if borrowings are required, then the partnership will be permitted to borrow funds only from the managing general partner or its affiliates without recourse against your non-partnership assets. Thus, if there is a default under this loan arrangement you cannot be required to contribute funds to the partnership. Any borrowings will be repaid from partnership revenues.

The amount that may be borrowed at any one time may not exceed an amount equal to 5% of the investors' subscriptions. However, because you do not bear the risk of repaying these borrowings with non-partnership assets, the borrowings will not increase the extent to which you are allowed to deduct your individual shares of partnership losses.

To further protect you, during producing operations all third party goods and services will be acquired by the managing general partner and its affiliates, and the partnership will then acquire the goods and services from the managing general partner and its affiliates at their cost.

- INDEMNIFICATION. The managing general partner will indemnify you from any liability incurred in connection with the partnership which is in excess of your interest in the partnership's:

- undistributed net assets; and

- insurance proceeds, if any.

The managing general partner's indemnification obligation, however, will not eliminate your potential liability if the insurance is not sufficient or available to cover a liability and the managing general partner's assets are insufficient to satisfy its indemnification obligation. There can be no assurance that the managing general partner's assets, including its liquid assets, will be sufficient to satisfy its indemnification obligation.

CAPITALIZATION AND SOURCE OF FUNDS AND USE OF PROCEEDS

SOURCE OF FUNDS

On completion of the offering the partnership's source of funds will be as follows assuming each unit is sold for $10,000:

- the subscription proceeds of you and the other investors will range from $1 million if 100 units are sold to $25 million if 2,500 units are sold; and

- the managing general partner estimates its capital contributions, which include its credit for contributing the leases, will range from approximately $360,600 if 100 units are sold, to approximately $8,972,400 if 2,500 units are sold.

USE OF PROCEEDS

The subscription proceeds received from you and the other investors will be used to pay:

- 100% of the intangible drilling costs of drilling and completing the partnership's wells; and

- 34% of the equipment costs of drilling and completing the partnership's wells, but not to exceed 10% of the partnership's subscription proceeds.

The managing general partner will:

- contribute all of the leases to the partnership covering the acreage on which the wells will be drilled; and

- pay 100% of the organization and offering costs and 66% of the equipment costs of drilling and completing the partnership's wells, plus any equipment costs that exceed 10% of the partnership's subscription proceeds which would otherwise be charged to you and the other investors.

The following tables present information concerning the partnership's use of the proceeds provided by both you and the other investors and the managing general partner. Substantially all of the proceeds available to the partnership will be expended for the following purposes and in the following manner:

INVESTOR CAPITAL

ENTITY RECEIVING PAYMENT	NATURE OF PAYMENT	100 UNITS SOLD	% (1)	2,500 UNITS SOLD	% (1)
ORGANIZATION AND OFFERING EXPENSES					
Broker/Dealers	Dealer-manager fee, sales commissions, .5% reimbursement of marketing expenses, and .5% reimbursement for bona fide accountable due diligence expenses	- 0 -	- 0 -	- 0 -	- 0 -

Various Organization costs -
0 - - 0 - - 0 - - 0 -

AMOUNT AVAILABLE FOR INVESTMENT:
Managing General Partner Intangible drilling costs
(2) $900,000 90% $22,500,000 90%

Managing General Partner Equipment
costs $100,000 10% $2,500,000 10%

Managing General Partner Leases -
0 - - 0 - - 0 - - 0 -
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TOTAL INVESTOR
CAPITAL $1,000,000
100% $25,000,000 100%
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(1) The percentage is based on total investor subscriptions and excludes the managing general partner's capital contribution.

(2) These costs will vary depending on the actual cost of drilling and completing the wells, but not less than 90% of the subscription proceeds provided by you and the other investors will be used to pay intangible drilling costs.

MANAGING GENERAL PARTNER CAPITAL

ENTITY RECEIVING PAYMENT	NATURE OF PAYMENT	100 UNITS SOLD	% (1)	2,500 UNITS SOLD	% (1)
ORGANIZATION AND OFFERING EXPENSES					
Broker-Dealers	Dealer-manager fee, sales commissions, .5% reimbursement of marketing expenses and .5% reimbursement for bona fide accountable due diligence expenses (2)	$105,000	29.1%	$2,625,000	29.3%
Various	Organization costs (2)	$45,000	12.5%	$1,125,000	12.5%
AMOUNT AVAILABLE FOR INVESTMENT:					
Managing General Partner	Intangible drilling costs	-0-	-0-	-0-	-0-
Managing General Partner	Equipment costs (3)	$193,925	53.8%	$4,808,860	53.6%
Managing General Partner	Leases (4)	$16,675	4.6%	$413,540	4.6%
TOTAL MANAGING GENERAL PARTNER CAPITAL		$360,600	100%	$8,972,400	100%

(1) The percentage is based upon the managing general partner's capital contribution and excludes the investors' subscriptions.

(2) If these fees, commissions, reimbursements and organization costs exceed 15% of the investors' subscription proceeds, the excess will be paid by the managing general partner but will not be included as part of its capital contribution.

(3) These costs will vary depending on the actual costs of drilling and completing the wells.

(4) Instead of contributing cash for the leases, the managing general partner will assign to the partnership the leases covering the acreage on which the partnership's wells will be drilled. However, as described in "Compensation," the managing general partner's lease cost is approximately $3,335 per prospect and for purposes of this table has been quantified based on the managing general partner's estimate of the number of wells that will be drilled as set forth in "Proposed Activities - Overview of Drilling Activities".

TOTAL PARTNERSHIP CAPITAL

NATURE OF 100 UNITS 2,500 UNITS
ENTITY RECEIVING PAYMENT
PAYMENT SOLD %
(1) SOLD % (1)

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----- ---- -----
ORGANIZATION AND OFFERING EXPENSES

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Broker-Dealers                Dealer-manager fee, sales
commissions,        $105,000      7.7%         $2,625,000        7.7%
.5% reimbursement of marketing expenses
and .5% reimbursement for bona fide
accountable due diligence expenses (2)



Various                       Organization costs
(2)                         $45,000      3.3%         $1,125,000        3.3%



AMOUNT AVAILABLE FOR INVESTMENT:
Managing General Partner      Intangible drilling costs
(3)                 $900,000     66.2%        $22,500,000       66.2%



Managing General Partner      Equipment costs
(3)                           $293,925     21.6%         $7,308,860       21.6%



Managing General Partner      Leases
(4)                                     $16,675      1.2%
$413,540        1.2%
-------      ----          --------        ----
TOTAL PARTNERSHIP
CAPITAL                                                 $1,360,600
100%        $33,972,400        100%
==========      ====        ===========        ====



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(1) The percentage is based on total investor subscriptions and the managing general partner's estimate of its capital contributions.

(2) If these fees, commissions, reimbursements and organization costs exceed 15% of the investors' subscription proceeds, the excess will be paid by the managing general partner but will not be included as part of its capital contribution.

(3) These costs will vary depending on the actual cost of drilling and completing the wells, but not less than 90% of the subscription proceeds provided by you and the other investors will be used to pay intangible drilling costs.

(4) Instead of contributing cash for the leases, the managing general partner will assign to the partnership the leases covering the acreage on which the partnership's wells will be drilled. However, as described in "Compensation," the managing general partner's lease cost is approximately $3,335 per prospect and for purposes of the table has been quantified based on the managing general partner's estimate of the number of wells that will be drilled as set forth in "Proposed Activities - Overview of Drilling Activities".

SUBSEQUENT SOURCE OF FUNDS AND BORROWINGS

Substantially all the subscription proceeds of you and the other investors will be committed or expended after the partnership offering closes. If the partnership requires additional funds for cost overruns or additional development or remedial work is required for a well after it begins producing, then these funds may be provided by:

- subscription proceeds, if available, by drilling fewer wells or acquiring a lesser interest in one or more wells;

- borrowings from the managing general partner or its affiliates; or

- retaining partnership revenues.

There will be no borrowings from third parties.

The amount that may be borrowed by the partnership from the managing general partner and its affiliates may not at any time exceed 5% of the partnership's subscription proceeds from you and the other investors and must be without recourse to you and the other investors. The partnership's repayment of any borrowings would be from partnership production revenues and would reduce or delay your cash distributions.

If the managing general partner loans money to the partnership, which it is not required to do, then:

- the interest charged to the partnership must not exceed the managing general partner's interest cost or the interest that would be charged to the partnership without reference to the managing general partner's financial abilities or guarantees by unrelated lenders, on comparable loans for the same purpose; and

- the managing general partner may not receive points or other financing charges or fees although the actual amount of the charges incurred from third-party lenders may be reimbursed to the managing general partner.

Currently, the managing general partner, together with affiliates Resource Energy, Inc. and Viking Resources Corporation, participate in a $40 million revolving credit facility with a group of banks with PNC Bank as the agent bank. A portion of the credit facility, approximately $5.1 million, supports an irrevocable letter of credit in favor of Atlas Pipeline Partners, L.P., in connection with a distribution support agreement between Atlas Pipeline Partners and its general partner. The letter of credit will reduce each quarter as the distribution support obligation reduces. Borrowings under the facility are collateralized by substantially all the natural gas and oil properties of the borrowers, which includes the managing general partner's interests in its partnerships but does not include any investor's interest in the partnership, and has a term ending in June 2003. As of June 30, 2001, the managing general partner had no balance under the revolving credit facility.

COMPENSATION

The items of compensation paid to the managing general partner and its affiliates from the partnership are set forth below.

NATURAL GAS AND OIL REVENUES

You and the other investors and the managing general partner will share in partnership revenues in the same percentages as your respective capital contributions bear to the total partnership capital contributions except that the managing general partner will receive an additional 7% of partnership revenues.

LEASE COSTS

Under the partnership agreement the managing general partner will contribute to the partnership all the undeveloped leases necessary to drill the partnership's wells. The managing general partner will receive a credit to its capital account equal to:

- the cost of the leases; or

- the fair market value of the leases if the managing general partner has reason to believe that cost is materially more than the fair market value.

The cost of the leases will include a portion of the managing general partner's reasonable, necessary and actual expenses for services allocated to the partnership's leases determined using industry guidelines.

In the partnership's primary areas of interest, the managing general partner's lease cost is approximately $3,335 per prospect. Assuming all the leases are situated in these areas and the partnership acquires 100% of the interest, the managing general partner estimates that its credit for lease costs will be:

- $16,675 if $1 million is received, which is 5 wells at $3,335 per prospect; and

- $413,540 if $25 million is received, which is 124 wells at $3,335 per prospect.

Drilling the partnership's wells may also provide the managing general partner with offset prospects to be drilled by allowing it to determine at the partnership's expense the value of adjacent acreage in which the partnership would not have any interest.

DRILLING CONTRACTS

The partnership will enter into the drilling and operating agreement with the managing general partner to drill and complete the partnership wells at cost plus 15%. The managing general partner has determined that this is a competitive rate compared with the estimated costs of non-affiliated persons to drill and equip wells in the Appalachian Basin as reported by an independent industry association which surveyed other non-affiliated operators in the area. If this rate subsequently exceeds competitive rates available from other non-affiliated persons in the area engaged in the business of rendering or providing comparable services or equipment, then the rate will be adjusted to the competitive rate. The managing general partner expects to subcontract some of the actual drilling and completion of the partnership's wells to third-parties selected by it. However, the managing general partner may not benefit by interpositioning itself between the partnership and the actual provider of drilling contractor services.

Cost when used with respect to services, generally means the reasonable, necessary and actual expense incurred in providing the services, determined in accordance with generally accepted accounting principles. The cost of the well includes all ordinary costs of drilling, testing and completing the well such as the following for a natural gas well which will be the classification of the majority of the wells:

- a second completion and frac which means, in general, treating a second potentially productive geological formation in an attempt to enhance the gas production from the well;

- installing gathering lines for the natural gas of up to 2,500 feet; and

- the necessary facilities for the production of natural gas.

The amount of compensation which the managing general partner could earn as a result of these arrangements depends on many factors, including the number of wells drilled. The managing general partner anticipates that on average over all of the wells drilled and completed by the partnership that the average well cost, excluding lease costs, will be $240,580. This anticipated average cost per well consists of intangible drilling costs of approximately $181,820 (75.6%) and equipment costs of approximately $58,760 (24.4%). In this regard, the managing general partner further anticipates that the cost of drilling and completing any given well, excluding lease costs, may range from as low as $190,000 to as high as $340,000, depending primarily on the area.

To the extent that the partnership acquires less than a 100% interest in a well, its drilling and completion costs of that well will be proportionately decreased. On an average per well basis the managing general partner will have reimbursement of general and administrative overhead of approximately $14,975 per well and a profit of 15% (approximately $29,120) per well with respect to the intangible drilling costs and the portion of equipment costs paid by you and the other investors. Assuming the partnership acquires 100% of the interest in the wells, the managing general partner estimates that its general and administrative overhead reimbursement and profit will be:

- $220,475 if $1 million is received, which is 5 wells at $44,095 profit and overhead per well; and

- $5,467,780 if $25 million is received, which is 124 wells at $44,095 profit and overhead per well.

PER WELL CHARGES

Under the drilling and operating agreement when the wells begin producing the managing general partner, as operator of the wells, will receive the following:

- reimbursement at actual cost for all direct expenses incurred on behalf of the partnership; and

- well supervision fees for operating and maintaining the wells during producing operations at a competitive rate.

Currently the competitive rate is $275 per well per month. The well supervision fees will be proportionately reduced to the extent the partnership acquires less than 100% of the interest in the well, and may be adjusted for inflation annually beginning January 1, 2003. If the foregoing rates exceed competitive rates available from other non-affiliated persons in the area engaged in the business of providing comparable services or equipment, then the rates will be adjusted to the competitive rate. The managing general partner may not benefit by interpositioning itself between the partnership and the actual provider of operator services. In no event will any consideration received for operator services be duplicative of any consideration or reimbursement received under the partnership agreement.

The well supervision fee covers all normal and regularly recurring operating expenses for the production, delivery and sale of natural gas and oil, such as:

- well tending, routine maintenance and adjustment;

- reading meters, recording production, pumping, maintaining appropriate books and records; and

- preparing reports to the partnership and to government agencies.

The well supervision fees do not include costs and expenses related to:

- the purchase of equipment, materials or third-party services;

- brine disposal; and

- rebuilding of access roads.

These costs will be charged at the invoice cost of the materials purchased, or the third-party services performed.

Assuming the partnership acquires 100% of the interest in the wells, the managing general partner estimates that it will receive well supervision fees for the partnership's first 12 months of operation after all of the wells have been placed in production of:

- $16,500 if $1 million is received, which is 5 wells at $275 per well per month; and

- $409,200 if $25 million is received, which is 124 wells at $275 per well per month.

GATHERING FEES

Atlas Pipeline Partners, L.P. is a master limited partnership which acquired the gathering system owned by the managing general partner's parent company, Atlas America, and its affiliates in February 2000. Approximately 53% of Atlas Pipeline Partners is owned by Atlas America and its affiliates. The managing general partner anticipates that Atlas Pipeline Partners will gather and deliver the majority of the natural gas produced by the partnership to interstate pipeline systems, local distribution companies, or industrial end-users in the area,. The partnership will pay a gathering charge at a competitive rate which may change from time to time. Currently the managing general partner anticipates that the partnership will pay the following gathering fees to Atlas Pipeline Partners in its primary and secondary areas.

AREA
GATHERING FEE

Clinton/Medina Geological Formation in Western Pennsylvania and Eastern Ohio
In Stark, Mahoning and
Trumbull Counties ....$.29 per mcf(1)
Clinton/Medina Geological Formation in

Southern Ohio...$.35 per mcf(1)
Mississippian/Upper Devonian Sandstone Reservoirs in
Fayette and Greene
Counties, Pennsylvania..$.35 per mcf(1)
Clinton/Medina Geological Formation in
New York..$.35 per mcf(1)
Mississippian Berea Sandstone Geological Formation in
Columbiana
County, Ohio...$.35
per mcf(1)
Devonian Oriskany Sandstone Geological Formation in
Tuscarawas
County, Ohio...$.35
per mcf(1)
Big Lime, Weir, and Devonian Shale Geological Formation
in Kentucky
and
Virginia..(2)

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(1) The managing general partner and its affiliates will pay the difference between the amounts set forth above and the greater of $.35 per mcf or 16% of the gross sales price for natural gas delivered by Atlas Pipeline Partners. This arrangement is described in "Proposed Activities -Sale of Natural Gas and Oil Production - Gathering of Natural Gas."

(2) The partnership will use a third-party gathering system.

The actual amount to be paid to Atlas Pipeline Partners cannot be quantified because the volume of natural gas that will be produced from the wells and transported by Atlas Pipeline Partners cannot be predicted.

DEALER-MANAGER FEES

Subject to certain exceptions described in "Plan of Distribution," Anthem Securities, the dealer-manager and an affiliate of the managing general partner, will receive on each unit sold to an investor a 2.5% dealer-manager fee, a 7%

sales commission, a

.5% reimbursement of marketing expenses, and a .5% reimbursement of the selling agents' bona fide accountable due diligence expenses. The dealer-manager will receive:

- $105,000 if $1 million is received; and

- $2,625,000 if $25 million is received.

All or a portion of the sales commissions, reimbursement of marketing expenses, and reimbursement of the selling agents' bona fide accountable due diligence expenses will be reallowed to the selling agents. The 2.5% dealer-manager fee generally will be reallowed to the wholesalers who are associated with Anthem Securities for subscriptions obtained through the wholesalers' effort.

INTEREST AND OTHER COMPENSATION

The managing general partner or an affiliate will have the right to charge a competitive rate of interest on any loan it may make to or on behalf of the partnership. If the managing general partner provides equipment, supplies and other services to the partnership, then it may do so at competitive industry rates.

ESTIMATE OF ADMINISTRATIVE COSTS AND DIRECT COSTS TO BE BORNE BY THE PARTNERSHIP
The managing general partner and its affiliates will receive an unaccountable, fixed payment reimbursement for their administrative costs which has been determined by the managing general partner to be $75 per well per month. This

fee will be proportionately reduced to the extent the partnership acquires less than 100% of the interest in the well, and will not be received for plugged and abandoned wells. The managing general partner estimates that the unaccountable, fixed payment reimbursement for administrative costs allocable to the partnership's first 12 months of operation after all of its wells have been placed into production will not exceed approximately:

- $4,500 if $1 million is received, which is 5 wells at $75 per well per month; and

- $111,600 if $25 million is received, which is 124 wells at $75 per well per month.

Direct costs will be billed directly to and paid by the partnership to the extent practicable. The anticipated direct costs set forth below for the partnership's first 12 months of operation after all of its wells have been placed into production may vary from the estimates shown for numerous reasons which cannot accurately be predicted. These reasons include:

- the number of investors;

- the number of wells drilled;

- the partnership's degree of success in its activities;

- the extent of any production problems;

- inflation; and

- various other factors involving the administration of the partnership.

	MINIMUM SUBSCRIPTIONS OF $1 MILLION	MAXIMUM SUBSCRIPTIONS OF $25 MILLION
DIRECT COSTS		
External Legal..	$ 6,000	$ 7,000
Accounting Fees..	2,500	13,000
Independent Engineering Reports.....................................	1,500	5,000
TOTAL	$10,000	$25,000

TERMS OF THE OFFERING

SUBSCRIPTION TO THE PARTNERSHIP

The partnership will offer a minimum of 100 units, which is $1 million, and a maximum of 2,500 units, which is $25 million. Units are offered at a subscription price of $10,000 per unit, subject to certain exceptions which are described in "Plan of Distribution," and must be paid 100% in cash at the time of subscribing. Your minimum subscription is one unit; however, the managing general partner, in its discretion, may accept one-half unit ($5,000) subscriptions from you at any time. Larger subscriptions will be accepted in $1,000 increments.

The managing general partner will have exclusive management authority for the partnership. You will have the election to purchase units as either an investor general partner or a limited partner.

PARTNERSHIP CLOSINGS AND ESCROW

The offering period will begin on the date of this prospectus, and will end on or before December 31, 2001, as determined by the managing general partner, in its sole discretion, which will not be extended. Also, subject to the receipt of the minimum subscriptions of $1 million, the managing general partner may close the offering period before this date. No subscriptions to the partnership will be accepted after either:

- the receipt of the maximum subscriptions, or

- the close of the offering by the managing general partner.

If subscriptions for $1 million are not received by the offering termination date, then the sums deposited in the escrow account will be promptly returned to you and the other subscribers with interest and without deduction for any fees. Although the managing general partner and its affiliates may buy up to 10% of the units, they do not currently anticipate purchasing any units. If they do buy units, then those units will not be applied towards the minimum subscriptions required for the partnership to begin operations.

Subscription proceeds will be held in a separate interest bearing escrow account at National City Bank of Pennsylvania until receipt of the minimum subscriptions. On receipt of the minimum subscriptions, the partnership may break escrow. The partnership will begin all activities, including drilling, after receipt of the minimum subscriptions, although the managing general partner does not anticipate that there will be any production before the offering closes. After breaking escrow the partnership funds and additional subscription payments will be paid directly to the partnership account and will continue to earn interest until the offering closes.

You will receive interest on your subscription proceeds from the time they are deposited in the escrow account, or the partnership account if you subscribe after the minimum subscriptions have been received and escrow has been broken, until the final closing of the partnership. The interest will be paid to you approximately eight weeks after the offering closes.

Subscription proceeds will be invested during the escrow period only in institutional investments comprised of or secured by securities of the United States government. After the funds are transferred to the partnership account and before their use in partnership operations, they may be temporarily invested in income producing short-term, highly liquid investments, in which there is appropriate safety of principal, such as U.S. Treasury Bills. If the managing general partner determines that the partnership may be deemed an investment company under the Investment Company Act of 1940, then the investment activity will cease. Subscriptions will not be commingled with the funds of the managing general partner or its affiliates nor will subscriptions be subject to their creditors' claims before they are paid to the managing general partner under the drilling and operating agreement.

ACCEPTANCE OF SUBSCRIPTIONS

Your execution of the subscription agreement constitutes your offer to buy units and hold the offer open until either:

- your subscription is accepted or rejected by the managing general partner; or

- you withdraw your offer.

To withdraw your offer, you must give written notice to the managing general partner before your offer is accepted by the managing general partner. Your subscription will be accepted or rejected by the partnership within 30 days of its receipt. The managing general partner's acceptance of your subscription is discretionary and the managing general partner may reject your subscription for any reason without incurring any liability to you for this decision. If your subscription is rejected, then all of your funds will be promptly returned to you together with any interest earned on your subscription proceeds.

When you will be admitted to the partnership depends on whether your subscription is accepted before or after breaking escrow. If your subscription is accepted:

- before breaking escrow you will be admitted to the partnership not later than 15 days after the release from escrow of the investors' funds to the partnership; and

- after breaking escrow you will be admitted to the partnership not later than the last day of the calendar month in which your subscription was accepted by the partnership.

Your execution of the subscription agreement and the managing general partner's acceptance also constitutes your:

- execution of the partnership agreement and agreement to be bound by its terms as a partner; and

- grant of a special power of attorney to the managing general partner to file amended certificates of limited partnership, governmental reports, and other matters.

SUITABILITY STANDARDS

IN GENERAL. It is the obligation of persons selling the units to make every reasonable effort to assure that the units are suitable for you based on your investment objectives and financial situation, regardless of your income or net worth. You, however, should invest in the partnership only if you are willing to assume the risk of a speculative, illiquid, and long-term investment. Also, subscriptions to the partnership will not be accepted from IRAs, Keogh plans and qualified retirement plans because the partnership's income would be unrelated business taxable income.

The decision to accept or reject your subscription will be made by the managing general partner, in its sole discretion, and is final. The managing general partner will not accept your subscription until it has reviewed your apparent qualifications and the suitability determination must be maintained by the managing general partner during the partnership's term and for at least six years thereafter.

Units will be sold to you only if you have:

- a minimum net worth of $225,000, exclusive of home, home furnishings and automobiles; or

- a minimum net worth of $60,000, exclusive of home, home furnishings and automobiles, and had during the last tax year or estimate that you will have during the current tax year "taxable income" as defined in Section 63 of the Internal Revenue Code of at least $60,000 without regard to an investment in the partnership.

However, if you are a resident of the states set forth below, then additional suitability requirements apply to you.

PURCHASERS OF LIMITED PARTNER UNITS. If you are a resident of CALIFORNIA and you purchase limited partner units, then you must:

- have a net worth of not less than $250,000, exclusive of home, furnishings, and automobiles, and expect to have gross income in the current tax year of $65,000 or more; or

- have a net worth of not less than $500,000, exclusive of home, furnishings, and automobiles; or

- have a net worth of not less than $1 million; or

- expect to have gross income in the current tax year of not less than $200,000.

If you are a resident of MICHIGAN or NORTH CAROLINA and you purchase limited partner units, then you must:

- have a net worth of not less than $225,000, exclusive of home, furnishings, and automobiles; or

- have a net worth of not less than $60,000, exclusive of home, furnishings, and automobiles, and estimated current tax year taxable income as defined in Section 63 of the Internal Revenue Code of $60,000 or more without regard to an investment in the partnership.

If you are a resident of NEW HAMPSHIRE and you purchase limited partner units, then you must:

- have a net worth of not less than $250,000, exclusive of home, home furnishings, and automobiles, or

- have a net worth of not less than $125,000, exclusive of home, home furnishings, and automobiles and $50,000 of taxable income.

In addition, if you are a resident of MICHIGAN, OHIO or PENNSYLVANIA, then you must not make an investment in the partnership in excess of 10% of your net worth, exclusive of home, furnishings and automobiles.

PURCHASERS OF INVESTOR GENERAL PARTNER UNITS. If you are a resident of ALABAMA, MAINE, MASSACHUSETTS, MINNESOTA, NORTH CAROLINA, OHIO, PENNSYLVANIA, TENNESSEE or TEXAS and you purchase investor general partner units, then you must:

- have an individual or joint net worth with your spouse of $225,000 or more, without regard to the investment in the partnership, exclusive of home, furnishings, and automobiles, and a combined gross income of $100,000 or more for the current year and for the two previous years; or

- have an individual or joint net worth with your spouse in excess of $1 million, inclusive of home, home furnishings and automobiles; or

- have an individual or joint net worth with your spouse in excess of $500,000, exclusive of home, home furnishings, and automobiles; or

- have a combined "gross income" as defined in Internal Revenue Code

Section 61 in excess of $200,000 in the current year and the two previous years.

If you are a resident of ARIZONA, INDIANA, IOWA, KANSAS, KENTUCKY, MICHIGAN, MISSISSIPPI, MISSOURI, NEW MEXICO, OKLAHOMA, OREGON, SOUTH DAKOTA, VERMONT or WASHINGTON and you purchase investor general partner units, then you must:

- have an individual or joint net worth with your spouse of $225,000 or more, without regard to the investment in the partnership, exclusive of home, furnishings, and automobiles, and a combined "taxable income" of $60,000 or more for the previous year and expect to have a combined "taxable income" of $60,000 or more for the current year and for the succeeding year; or

- have an individual or joint net worth with your spouse in excess of $1 million, inclusive of home, home furnishings and automobiles; or

- have an individual or joint net worth with your spouse in excess of $500,000, exclusive of home, home furnishings, and automobiles; or

- have a combined "gross income" as defined in Internal Revenue Code

Section 61 in excess of $200,000 in the current year and the two previous years.

If you are a resident of NEW HAMPSHIRE and you purchase investor general partner units, then you must:

- have a net worth, exclusive of home, home furnishings, and automobiles, of $250,000; or

- have a net worth, exclusive of home, home furnishings, and automobiles, of $125,000 and $50,000 of taxable income.

In addition, if you are a resident of MICHIGAN, OHIO or PENNSYLVANIA, then you must not make an investment in the partnership in excess of 10% of your net worth, exclusive of home, furnishings and automobiles.

If you are a resident of CALIFORNIA and you purchase investor general partner units, then you must:

- have a net worth of not less than $250,000, exclusive of home, furnishings, and automobiles, and expect to have gross income in the current tax year of $120,000 or more; or

- have a net worth of not less than $500,000, exclusive of home, furnishings, and automobiles; or

- have a net worth of not less than $1 million; or

- expect to have gross income in the current tax year of not less than $200,000.

FIDUCIARY ACCOUNTS AND CONFIRMATIONS. If there is a sale of a unit to a fiduciary account, then all the suitability standards set forth above must be met by:

- the beneficiary;

- the fiduciary account; or

- the donor or grantor who directly or indirectly supplies the funds to purchase the units if the donor or grantor is the fiduciary.

Generally, you are required to execute your own subscription agreement, and the managing general partner will not accept any subscription agreement that has been executed by someone other than you. The only exception is if you have given someone else the legal power of attorney to sign on your behalf and you meet all of the conditions in this prospectus. Also, the managing general partner will:

- not complete a sale of units to you until at least five business days after the date you receive a final prospectus; and

- send you a confirmation of purchase.

PRIOR ACTIVITIES

The following tables, other than Table 6, reflect certain historical data with respect to 27 private drilling partnerships which raised a total of $110,670,536, and 9 public drilling partnerships which raised a total of $74,980,035, which the managing general partner has sponsored. The tables, other than Table 6, also reflect certain historical data with respect to 1999 Viking Resources LP, a private drilling program which raised $4,555,210 and is the only drilling program sponsored by Viking Resources after it was acquired by Resource America in August 1999. Information concerning other programs sponsored by Viking Resources before it was acquired by Resource America will be provided to you on written request to the managing general partner. The tables also do not include information concerning wells acquired by Atlas through merger or other form of acquisition.

IT SHOULD NOT BE ASSUMED THAT YOU AND THE OTHER INVESTORS WILL EXPERIENCE RETURNS, IF ANY, COMPARABLE TO THOSE EXPERIENCED BY INVESTORS IN THE PRIOR DRILLING PARTNERSHIPS FOR SEVERAL REASONS, INCLUDING, BUT NOT LIMITED TO:

- DIFFERENCES IN PARTNERSHIP TERMS,

- PROPERTY LOCATIONS,

- PARTNERSHIP SIZE, AND

- ECONOMIC CONSIDERATIONS,

THE RESULTS OF THE PRIOR DRILLING PARTNERSHIPS SHOULD BE VIEWED ONLY AS A MEASURE OF THE LEVEL OF ACTIVITY AND EXPERIENCE OF THE MANAGING GENERAL PARTNER WITH RESPECT TO DRILLING PARTNERSHIPS.

Table 1 sets forth certain sales information of previous development drilling partnerships sponsored by the managing general partner and its affiliates.

TABLE 1

EXPERIENCE IN RAISING FUNDS

AS OF JANUARY 15, 2001

PARTNERSHIP	NUMBER OF INVESTORS	INVESTOR CAPITAL	MANAGING GENERAL PARTNER CAPITAL	TOTAL CAPITAL	DATE OPERATIONS BEGAN	DATE OF FIRST DISTRIBUTIONS	YEARS WELLS IN PRODUCTION	PREVIOUS ASSESSMENTS
Atlas L.P. #1 - 1985	19	$600,000	$114,800	$714,800	12/31/85	07/02/86	15.05	-0-
A.E. Partners 1986	24	631,250	120,400	751,650	12/31/86	04/02/87	14.05	-0-
A.E. Partners 1987	17	721,000	158,269	879,269	12/31/87	04/02/88	13.05	-0-
A.E. Partners 1988	21	617,050	135,450	752,500	12/31/88	04/02/89	12.05	-0-
A.E. Partners 1989	21	550,000	120,731	670,731	12/31/89	04/02/90	11.05	-0-
A.E. Partners 1990	27	887,500	244,622	1,132,122	12/31/90	04/02/91	10.05	-0-
A.E. Nineties-10	60	2,200,000	484,380	2,684,380	12/31/90	03/31/91	9.83	-0-
A.E. Nineties-11	25	750,000	268,003	1,018,003	09/30/91	01/31/92	9.00	-0-
A.E. Partners 1991	26	868,750	318,063	1,186,813	12/31/91	04/02/92	8.83	-0-
A.E. Nineties-12	87	2,212,500	791,833	3,004,333	12/31/91	04/30/92	8.75	-0-
A.E. Nineties-JV 92	155	4,004,813	1,414,917	5,419,730	10/28/92	04/05/93	8.08	-0-
A.E. Partners 1992	21	600,000	176,100					

776,100	12/14/92	07/02/93	7.58	-0-
A.E. Nineties-Public #1	221	2,988,960	528,934	
3,517,894	12/31/92	07/15/93	7.33	-0-
A.E. Nineties-1993 Ltd.	125	3,753,937	1,264,183	
5,018,120	10/08/93	02/10/94	7.00	-0-
A.E. Partners 1993	21	700,000	219,600	
919,600	12/31/93	07/02/94	6.75	-0-
A.E. Nineties-Public #2	269	3,323,920	587,340	
3,911,260	12/31/93	06/15/94	6.50	-0-
A.E. Nineties-14	263	9,940,045	3,584,027	
13,524,072	08/11/94	01/10/95	6.00	-0-
A.E. Partners 1994	23	892,500	231,500	
1,124,000	12/31/94	07/02/95	5.75	-0-
A.E. Nineties-Public #3	391	5,799,750	928,546	
6,728,296	12/31/94	06/05/95	5.75	-0-
A.E. Nineties-15	244	10,954,715	3,435,936	
14,390,651	09/12/95	02/07/96	4.92	-0-
A.E. Partners 1995	23	600,000	244,725	
844,725	12/31/95	10/02/96	4.50	-0-
A.E. Nineties-Public #4	324	6,991,350	1,287,752	
8,279,102	12/31/95	07/08/96	4.75	-0-
A.E. Nineties-16	274	10,955,465	1,643,320	
12,598,785	07/31/96	01/12/97	4.08	-0-
A.E. Partners 1996	21	800,000	367,416	
1,167,416	12/31/96	07/02/97	3.75	-0-
A.E. Nineties-Public #5	378	7,992,240	1,654,740	
9,646,980	12/31/96	06/08/97	3.75	-0-
A.E. Nineties-17	217	8,813,488	2,113,947	
10,927,435	08/29/97	12/12/97	3.17	-0-
A.E. Nineties-Public #6	393	9,901,025	1,950,345	
11,851,370	12/31/97	06/08/98	2.75	-0-
A.E. Partners 1997	13	506,250	231,050	
737,300	12/31/97	07/02/98	2.58	-0-
A.E. Nineties-18	225	11,391,673	3,448,751	
14,840,424	07/31/98	01/07/99	2.08	-0-
A.E. Nineties-Public #7	366	11,988,350	3,812,150	
15,800,500	12/31/98	07/10/99	1.75	-0-
A.E. Partners 1998	26	1,740,000	756,360	
2,496,360	12/31/98	07/02/99	1.75	-0-
A.E. Nineties-19	288	15,720,450	4,776,598	
20,497,048	09/30/99	01/14/00	1.25	-0-
A.E. Nineties-Public #8	380	11,088,975	3,148,181	
14,237,156	12/31/99	06/09/00	0.75	-0-
A.E. Partners 1999	8	450,000	196,500	
646,500	12/31/99	10/02/00	0.50	-0-
1999 Viking Resources LP	131	4,555,210	1,678,038	
6,233,248	12/31/99	06/01/00	0.50	-0-
Atlas America - Series 20	361	18,809,150	6,297,945	
25,107,095	09/30/00	01/30/01	0.25	-0-
Atlas America - Public #9	530	14,905,465	5,563,527	

20,468,992	12/31/00	(1)	(1)	-0-

(1) This program closed December 31, 2000, and its first distribution is expected in the summer of 2001.

Table 2 reflects the drilling activity of previous development drilling partnerships sponsored by the managing general partner and its affiliates. All the wells were development wells. You should not assume that the past performance of prior partnerships is indicative of the future results of the partnership.

TABLE 2

WELL STATISTICS - DEVELOPMENT WELLS

AS OF JANUARY 15, 2001

GROSS WELLS (1) NET WELLS (2)

PARTNERSHIP	OIL	GAS	DRY (3)	OIL	GAS	DRY(3)
Atlas L.P. #1 - 1985 (4)	0	7	1	0	3.15	0.25
A.E. Partners 1986	0	8	0	0	3.50	0.00
A.E. Partners 1987	0	9	0	0	4.10	0.00
A.E. Partners 1988	0	9	0	0	3.80	0.00
A.E. Partners 1989	0	10	0	0	3.30	0.00
A.E. Partners 1990	0	12	0	0	5.00	0.00
A.E. Nineties-10	0	12	0	0	11.50	0.00
A.E. Nineties-11	0	14	0	0	4.30	0.00
A.E. Partners 1991	0	12	0	0	4.95	0.00
A.E. Nineties-12	0	14	0	0	12.50	0.00
A.E. Nineties-JV 92	0	52	0	0	24.44	0.00
A.E. Partners 1992	0	7	0	0	3.50	0.00
A.E. Nineties-Public #1	0	14	0	0	14.00	0.00
A.E. Nineties-1993 Ltd. (4)	0	20	2	0	19.40	2.00
A.E. Partners 1993	0	8	0	0	4.00	0.00
A.E. Nineties-Public #2	0	16	0	0	15.31	0.00
A.E. Nineties-14 (4)	0	55	1	0	55.00	1.00
A.E. Partners 1994 (4)	0	12	0	0	5.00	0.00
A.E. Nineties-Public #3	0	27	0	0	26.00	0.00
A.E. Nineties-15 (4)	0	61	0	0	55.50	0.00
A.E. Partners 1995	0	6	0	0	3.00	0.00
A.E. Nineties-Public #4	0	31	0	0	30.50	0.00
A.E. Nineties-16 (4)	0					

57	0	0	47.50	0.00
A.E. Partners 1996		0		
13	0	0	4.84	0.00
A.E. Nineties-Public #5		0		
36	0	0	35.91	0.00
A.E. Nineties-17 (4)		0		
52	2	0	42.00	1.50
A.E. Nineties-Public #6		0		
55	0	0	44.45	0.00
A.E. Partners 1997		0		
6	0	0	2.81	0.00
A.E. Nineties-18		0		
63	0	0	58.00	0.00
A.E. Nineties-Public #7		0		
64	0	0	57.50	0.00
A.E. Partners 1998		0		
19	0	0	9.50	0.00
A.E. Nineties-19 (4)		0		
86	4	0	79.75	4.00
A.E. Nineties-Public #8		0		
58	0	0	54.66	0.00
A.E. Partners 1999		0		
5	0	0	2.50	0.00
1999 Viking Resources LP		0		
25	2	0	23.00	2.00
Atlas America - Series 20		7		
99	1	0	93.25	1.00
Atlas America - Public #9		0		
19	0	0	18.00	0.00
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7	1073	13	0.00	
885.42	11.75			
===	====	===	====	
======	=====			

(1) A "gross well" is one in which a leasehold interest is owned.

(2) A "net well" equals the actual leasehold interest owned in one gross well divided by one hundred. For example, a 50% leasehold interest in a well is one gross well, but a .50 net well.

(3) For purposes of this Table only, a "Dry Hole" means a well which is plugged and abandoned without a completion attempt because the operator has determined that it will not be productive of gas and/or oil in commercial quantities.

(4) - Atlas L.P. #1-1985 had 1 gross well (.25 net well) which was completed but non-commercial;

- A.E. Nineties-1993 Ltd. had 1 gross well (1 net well) which was completed but non-commercial;

- A.E. Nineties-14 had 2 gross wells (2 net wells) which were completed but non-commercial;

- A.E. Partners-1994 had 1 gross well (.25 net well) which was completed but non-commercial;

- A.E. Nineties-15 had 1 gross well (1 net well) which was completed but non-commercial;

- A.E. Nineties-16 had 5 gross wells (4.5 net wells) which were completed but non-commercial;

- A.E. Nineties-17 had 3 gross wells (2.5 net wells) which were completed but non-commercial; and

- A.E. Nineties-19 had 4 gross wells (4 net wells) which were completed but non-commercial.

Table 3 provides information concerning the operating results of previous development drilling partnerships sponsored by the managing general partner and its affiliates. You should not assume that the past performance of prior partnerships is indicative of the future results of the partnership.

TABLE 3

INVESTOR OPERATING RESULTS - INCLUDING EXPENSES

AS OF JANUARY 15, 2001

		TOTAL COSTS				
PARTNERSHIP	INVESTOR CAPITAL(1)	ADMIN	DIRECT	OPERATING	CASH DISTRIBUTION(2)	CASH ON CASH RETURN
Atlas L.P. #1 - 1985	$600,000	$160,079	$36,960	$8,335	$1,364,553	227%
A.E. Partners LP - 1986	631,250	125,526	55,384	7,102	653,459	104%
A.E. Partners LP - 1987	721,000	121,709	49,082	7,177	530,108	74%
A.E. Partners LP - 1988	617,050	99,247	45,760	6,691	486,539	79%
A.E. Partners LP - 1989	550,000	96,095	49,035	5,650	642,164	117%
A.E. Partners LP - 1990	887,500	136,903	67,616	6,687	846,314	95%
A.E. Nineties - 10	2,200,000	310,288	66,471	22,640	1,495,495	68%
A.E. Nineties - 11	750,000	115,898	72,765	40,960	900,572	120%
A.E. Partners LP - 1991	868,750	115,705	87,989	14,698	913,228	105%
A.E. Nineties - 12	2,212,500	322,014	70,301	109,481	1,695,177	77%
A.E. Nineties - JV 92	4,004,813	493,817	109,678	198,344	3,454,713(3)	86%
A.E. Partners LP - 1992	600,000	67,348	42,975	4,775	631,452	105%
A.E. Nineties - Public #1	2,988,960	282,606	66,691	84,250	1,859,960	62%
A.E. Nineties - 1993 Ltd.	3,753,937	364,859	74,744	37,186	1,935,720	52%
A.E. Partners LP - 1993	700,000	79,639	31,538	4,398	722,088	103%
A.E. Nineties - Public #2	3,323,920	289,715				

57,383 43,323 1,645,801 50%
A.E. Nineties - 14 9,940,045 867,914
176,466 41,524 4,742,397 48%
A.E. Partners LP - 1994 892,500
60,048 34,874 3,438 705,390 79%
A.E. Nineties - Public #3 5,799,750 414,207
87,574 47,557 2,833,713 49%
A.E. Nineties - 15 10,954,715 752,411
160,826 24,684 5,133,367 47%
A.E. Partners LP - 1995 600,000
41,072 11,996 2,838 269,018 45%
A.E. Nineties - Public #4 6,991,350 451,189
89,550 37,629 2,256,963 32%
A.E. Nineties - 16 10,955,465 592,557
107,909 39,945 3,297,696 30%
A.E. Partners LP - 1996 800,000 47,808
13,660 39,878 270,448 34%
A.E. Nineties - Public #5 7,992,240 399,574
79,084 28,218 2,371,986 30%
A.E. Nineties - 17 8,813,488 357,432
67,002 97,339 2,735,379 31%
A.E. Nineties - Public #6 9,901,025 411,808
75,946 27,223 2,718,244 27%
A.E. Partners LP - 1997 506,250 19,220
5,705 25,965 150,236 30%
A.E. Nineties - 18 11,391,673 377,691
61,137 260,131 2,580,366 23%
A.E. Nineties - Public #7 11,988,350 292,578
44,535 18,251 1,825,350 15%
A.E. Partners LP - 1998 1,740,000 53,958
12,181 40,743 450,085 26%
A.E. Nineties - 19 15,720,450
256,806 31,938 4,641 1,965,283 13%
A.E. Nineties - Public #8 11,088,975 111,342
15,800 13,733 1,100,738 10%
A.E. Partners LP - 1999 450,000
3,739 619 650 81,389 18%
1999 Viking Resources LP 4,555,210
191,369 9,056 0 1,211,221 27%
Atlas America - Series 20 18,809,150
8,407 2,601 0 539,101 3%
Atlas America - Public # 9 14,905,465
0 0 0 0 0%

LATEST QUARTERLY
AVERAGE CASH DISTRIBUTION AS
PARTNERSHIP YEARLY RETURN OF DATE OF TABLE
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Atlas L.P. #1 - 1985	15%	$20,410
A.E. Partners LP - 1986	7%	7,342
A.E. Partners LP - 1987	6%	10,551
A.E. Partners LP - 1988	7%	10,420
A.E. Partners LP - 1989	11%	8,968
A.E. Partners LP - 1990	9%	24,908
A.E. Nineties - 10	7%	40,809
A.E. Nineties - 11	13%	17,340
A.E. Partners LP - 1991	12%	21,372
A.E. Nineties - 12	9%	32,644
A.E. Nineties - JV 92	11%	99,156
A.E. Partners LP - 1992	14%	12,746
A.E. Nineties - Public #1	8%	41,245
A.E. Nineties - 1993 Ltd.	7%	28,592
A.E. Partners LP - 1993	15%	19,577
A.E. Nineties - Public #2	8%	40,269
A.E. Nineties - 14	8%	131,573
A.E. Partners LP - 1994	14%	33,125
A.E. Nineties - Public #3	8%	81,587
A.E. Nineties - 15	10%	237,936
A.E. Partners LP - 1995	10%	8,317
A.E. Nineties - Public #4	7%	93,235
A.E. Nineties - 16	7%	182,165
A.E. Partners LP - 1996	9%	20,481
A.E. Nineties - Public #5	8%	136,655
A.E. Nineties - 17	10%	234,646
A.E. Nineties - Public #6	10%	262,421
A.E. Partners LP - 1997	12%	24,024
A.E. Nineties - 18	11%	282,738
A.E. Nineties - Public #7	9%	269,599
A.E. Partners LP - 1998	15%	59,028
A.E. Nineties - 19	10%	472,543
A.E. Nineties - Public #8	13%	553,761
A.E. Partners LP - 1999	36%	43,125
1999 Viking Resources LP	53%	664,687
Atlas America - Series 20	36%	539,101
Atlas America - Public # 9	0%	0

(1) There have been no partnership borrowings other than from the managing general partner. The approximate principal amounts of such borrowings were as follows:

- A.E. Nineties-10 - $330,000;

- A.E. Nineties-11 - $112,500; and

- A.E. Nineties-12 - $331,875.

A portion of each partnership's cash distributions was used to repay that partnership's loan.

(2) All cash distributions were from the sale of gas, and not sales of properties.

(3) A portion of the cash distributions was used to drill three reinvestment wells at a cost of $333,860 in accordance with the terms of the offering.

Table 3A provides information concerning the operating results of previous development drilling partnerships sponsored by the managing general partner and its affiliates.

TABLE 3A

MANAGING GENERAL PARTNER

OPERATING RESULTS - INCLUDING EXPENSES

AS OF JANUARY 15, 2001

PARTNERSHIP	MANAGING GENERAL PARTNER CAPITAL(1)	COSTS OPERATING	COSTS ADMIN	COSTS DIRECT	TOTAL CASH DISTRIBUTIONS(2)	CASH ON CASH RETURN	LATEST QUARTERLY CASH DISTRIBUTION AS OF DATE OF TABLE
Atlas L.P. #1 - 1985	$114,800	$30,491	$7,040	$1,588	$258,464	225%	$3,888
A.E. Partners LP - 1986	120,400	23,910	10,549	1,353	124,797	104%	1,399
A.E. Partners LP - 1987	158,269	35,092	14,152	2,069	135,108	85%	3,042
A.E. Partners LP - 1988	135,450	31,963	14,737	2,155	122,431	90%	3,356
A.E. Partners LP - 1989	120,731	21,094	10,764	1,240	146,594	121%	1,969
A.E. Partners LP - 1990	244,622	45,634	0	0	325,918	133%	8,886
A.E. Nineties - 10	484,380	103,429	0	0	528,202	109%	14,153
A.E. Nineties - 11	268,003	49,671	31,185	12,496	379,234	142%	7,432
A.E. Partners LP - 1991	318,063	38,568	0	0	392,486	123%	7,949
A.E. Nineties - 12	791,833	138,006	30,129	21,413	726,504	92%	13,990
A.E. Nineties - JV 92	1,414,917	243,223	54,020	16,152	912,816	65%	0
A.E. Partners LP - 1992	176,100	22,449	0	0	295,155	168%	4,699
A.E. Nineties - Public #1	528,934	89,244	21,060	14,799	519,536	98%	13,025
A.E. Nineties - 1993 Ltd.	1,264,183	156,368	32,033	12,355	351,355	28%	12,254
A.E. Partners LP - 1993	219,600	26,546	0	0	265,140	121%	6,826
A.E. Nineties - Public #2	587,340	91,489	18,121	13,681	354,695	60%	12,717
A.E. Nineties - 14	3,584,027	427,480	86,916	13,273	1,148,039	32%	21,722
A.E. Partners LP - 1994	231,500	20,016	0	0	248,471	107%	11,510
A.E. Nineties - Public #3	928,546	138,069	29,191	15,852	883,384	95%	27,196
A.E. Nineties - 15	3,435,936	322,462	68,925	10,579	1,758,123	51%	3,623
A.E. Partners LP - 1995	244,725	13,691	0	0	80,497	33%	2,997

A.E. Nineties - Public #4	1,287,752	150,396	29,850	12,543	594,968	46%	16,453
A.E. Nineties - 16	1,643,320	162,293	29,555	6,135	577,779	35%	25,430
A.E. Partners LP - 1996	367,416	15,936	0	0	107,995	29%	7,131
A.E. Nineties - Public #5	1,654,740	133,191	26,361	9,406	552,508	33%	24,116
A.E. Nineties - 17	2,113,947	128,870	24,157	5,750	841,791	40%	40,599
A.E. Nineties - Public #6	1,950,345	137,269	25,315	9,074	818,016	42%	46,310
A.E. Partners LP - 1997	231,050	6,407	0	0	60,635	26%	8,229
A.E. Nineties - 18	3,448,751	173,683	28,114	6,751	1,176,471	34%	130,018
A.E. Nineties - Public #7	3,812,150	131,448	20,008	8,200	417,095	11%	61,604
A.E. Partners LP - 1998	756,360	17,986	0	0	167,670	22%	20,032
A.E. Nineties - 19	4,776,598	118,093	14,687	2,134	905,960	19%	219,518
A.E. Nineties - Public #8	3,148,181	45,478	6,453	5,609	341,407	11%	226,184
A.E. Partners LP - 1999	196,500	1,246	0	0	27,553	14%	14,469
1999 Viking Resources LP	1,678,038	63,790	3,019	0	302,805	18%	221,562
Atlas America - Series 20	6,297,945	3,109	962	0	199,394	3%	199,394
Atlas America - Public #9	5,563,527	0	0	0	0	0%	0

(1) All cash distributions were from the sale of gas and not sales of properties.

Table 4 sets forth the aggregate cash distributions and estimated federal tax savings to investors in the managing general partner's prior development drilling partnerships, based on the maximum marginal tax rate in each year, as reported in the partnerships' tax returns and such share of tax deductions as a percentage of their subscriptions. You are urged to consult with your own tax advisors concerning your specific tax situation and should not assume that the past performance of prior partnerships is indicative of the future results of the partnership.

TABLE 4

SUMMARY OF INVESTOR TAX BENEFITS AND CASH DISTRIBUTION RETURNS

AS OF JANUARY 15, 200

ESTIMATED FEDERAL TAX SAVINGS FROM(1)

PARTNERSHIP	INVESTOR CAPITAL	1ST YEAR TAX DEDUCT(2)	EFF. TAX RATE	1ST YEAR D. C. DEDUCT (3)	DEPLETION ALLOWANCE(3)	DEPRECIATION(3)	SECTION 29 TAX CREDIT(4)
Atlas L.P. #1 - 1985	$600,000	99%	50.0%	$298,337	$118,077	N/A	$55,915
A.E. Partners LP - 1986	631,250	99%	50.0%	312,889	65,568	N/A	13,507
A.E. Partners LP - 1987	721,000	99%	38.5%	356,895	47,909	N/A	N/A
A.E. Partners LP - 1988	617,050	99%	33.0%	244,351	44,321	N/A	N/A
A.E. Partners LP - 1989	550,000	99%	33.0%	179,685	61,114	N/A	N/A
A.E. Partners LP - 1990	887,500	99%	33.0%	275,125	80,302	N/A	247,346
A.E. Nineties - 10	2,200,000	100%	33.0%	726,000	154,329	N/A	457,350

A.E. Nineties - 11	750,000	100%	31.0%	232,500	90,334	N/A	295,392
A.E. Partners LP - 1991	868,750	100%	31.0%	269,313	96,674	N/A	278,094
A.E. Nineties - 12	2,212,500	100%	31.0%	685,875	182,440	N/A	552,060
A.E. Nineties - JV 92	4,004,813	92.5%	31.0%	1,322,905	315,863	N/A	883,588
A.E. Partners LP - 1992	600,000	100%	31.0%	186,000	70,771	N/A	189,428
A.E. Nineties - Public #1	2,988,960	80.5%	36.0%	877,511	191,272	251,828	N/A
A.E. Nineties - 1993 Ltd.	3,753,937	92.5%	39.6%	1,378,377	192,636	N/A	N/A
A.E. Partners LP - 1993	700,000	100%	39.6%	273,216	71,797	N/A	N/A
A.E. Nineties - Public #2	3,323,920	78.7%	39.6%	1,036,343	162,871	262,565	N/A
A.E. Nineties - 14	9,940,045	95%	39.6%	3,739,445	441,852	N/A	N/A
A.E. Partners LP - 1994	892,500	100%	39.6%	353,430	64,844	N/A	N/A
A.E. Nineties - Public #3	5,799,750	76.2%	39.6%	1,752,761	284,986	444,636	N/A
A.E. Nineties - 15	10,954,715	90.0%	39.6%	3,904,261	511,294	N/A	N/A
A.E. Partners LP - 1995	600,000	100%	39.6%	237,600	21,077	N/A	N/A
A.E. Nineties - Public #4	6,991,350	80.0%	39.6%	2,214,860	206,582	429,246	N/A
A.E. Nineties - 16	10,955,465	86.8%	39.6%	3,361,289	309,157	676,716	N/A
A.E. Partners LP - 1996	800,000	100%	39.6%	316,800	29,007	N/A	N/A
A.E. Nineties - Public #5	7,992,240	84.9%	39.6%	2,530,954	244,661	435,255	N/A
A.E. Nineties - 17	8,813,488	85.2%	39.6%	2,966,366	291,358	273,387	N/A
A.E. Nineties - Public #6	9,901,025	80.0%	39.6%	3,166,406	326,003	444,116	N/A
A.E. Partners LP - 1997	506,250	100%	39.6%	200,475	17,965	N/A	N/A
A.E. Nineties - 18	11,391,673	90.0%	39.6%	4,030,884	96,985	249,293	N/A
A.E. Nineties - Public #7	11,988,350	85.0%	39.6%	4,043,670	175,520	177,785	N/A
A.E. Partners LP - 1998	1,740,000	100.0%	39.6%	689,040	46,090	N/A	N/A
A.E. Nineties - 19	15,720,450	90.0%	39.6%	5,602,767	194,381	18,537	N/A

A.E. Nineties - Public #8	11,088,975	85.0%					
39.6%	3,734,654	111,637		0	N/A		
A.E. Partners LP - 1999	450,000	100.0%					
39.6%	178,200	3,235		N/A	N/A		
1999 Viking Resources LP	4,555,210	92.0%					
39.6%	1,678,038	77,291		N/A	N/A		
Atlas America - Series 20	18,809,150	90.0%					
39.6%	6,712,802	0		0	N/A		
Atlas America - Public #9	14,905,465	90.0%					
39.6%	4,272,996	0		N/A	N/A		

CUMULATIVE
CASH % OF CASH
DISTRIBUTION TOTAL CASH DIST. AND TAX
AS OF DATE DIST. AND SAVINGS TO

PARTNERSHIP	TOTAL	OF TABLE(5)	TAX SAVINGS	DATE
Atlas L.P. #1 - 1985	$472,328	$1,364,553	$1,836,881	306%
A.E. Partners LP - 1986	391,964	653,459	1,045,423	166%
A.E. Partners LP - 1987	404,804	530,108	934,911	130%
A.E. Partners LP - 1988	288,672	486,539	775,212	126%
A.E. Partners LP - 1989	240,799	642,164	882,963	161%
A.E. Partners LP - 1990	602,772	846,314	1,449,087	163%
A.E. Nineties - 10	1,337,679	1,495,495	2,833,174	129%
A.E. Nineties - 11	618,226	900,572	1,518,798	203%
A.E. Partners LP - 1991	644,081	913,228	1,557,309	179%
A.E. Nineties - 12	1,420,375	1,695,177	3,115,552	141%
A.E. Nineties - JV 92	2,522,356	3,454,713	5,977,069	149%
A.E. Partners LP - 1992	446,199	631,452	1,077,652	180%
A.E. Nineties - Public #1	1,320,611	1,859,960	3,180,571	106%
A.E. Nineties - 1993 Ltd.	1,571,013	1,935,720	3,506,733	93%
A.E. Partners LP - 1993	345,013	722,088	1,067,101	152%
A.E. Nineties - Public #2	1,461,779	1,645,801	3,107,580	93%
A.E. Nineties - 14	4,181,297	4,742,397	8,923,695	90%
A.E. Partners LP - 1994	418,274	705,390	1,123,663	126%
A.E. Nineties - Public #3	2,482,382	2,833,713	5,316,095	92%
A.E. Nineties - 15	4,415,555	5,133,367	9,548,922	87%
A.E. Partners LP - 1995	258,677	269,018	527,695	88%
A.E. Nineties - Public #4	2,850,689	2,256,963	5,107,651	73%
A.E. Nineties - 16	4,347,162	3,297,696	7,644,858	70%
A.E. Partners LP - 1996	345,807	270,448	616,254	77%
A.E. Nineties - Public #5	3,210,870	2,371,986	5,582,856	70%
A.E. Nineties - 17	3,531,110	2,735,379	6,266,490	71%
A.E. Nineties - Public #6	3,936,525	2,718,244	6,654,770	67%
A.E. Partners LP - 1997	218,440	150,236	368,676	73%
A.E. Nineties - 18	4,377,162	2,580,366	6,957,528	61%
A.E. Nineties - Public #7	4,396,975	1,825,350	6,222,325	52%
A.E. Partners LP - 1998	735,130	450,085	1,185,215	68%

A.E. Nineties - 19	5,815,685	1,965,283	7,780,968	49%
A.E. Nineties - Public #8	3,846,291	1,100,738	4,947,028	45%
A.E. Partners LP - 1999	181,435	81,389	262,824	58%
1999 Viking Resources LP	1,755,329	1,211,221	2,966,550	65%
Atlas America - Series 20	6,712,802	539,101	7,251,903	39%
Atlas America - Public #9	4,272,996	0	4,272,996	29%

(1) These columns reflect the savings in taxes which would have been paid by an investor, assuming full use of deductions available to the investor.

(2) The managing general partner anticipates that approximately 90% of an investor general partner's subscription to the partnership will be deductible in 2001.

(3) The I.D.C. Deductions, Depletion Allowance and MACRS depreciation deductions have been reduced to credit equivalents.

(4) The Section 29 tax credit is not available with respect to wells drilled after December 31, 1992. N/A means not applicable.

(5) These distributions were all from production revenues. See footnotes 1 and 3 of Table 3.

Table 5 sets forth payments made to the managing general partner and its affiliates from its previous partnerships.

TABLE 5

SUMMARY OF PAYMENTS TO THE MANAGING GENERAL PARTNER AND AFFILIATES

FROM PRIOR PARTNERSHIPS

AS OF JANUARY 15, 2001

Cumulative

CUMULATIVE
LEASEHOLD
DRILLING AND
INVESTOR
OPERATOR'S
PARTNERSHIP
COSTS(1)

	REIMBURSEMENT OF GENERAL AND					
	CUMULATIVE NON-RECURRING ADMINISTRATIVE CHARGES	COMPLETION CAPITAL OVERHEAD	MANAGEMENT FEE			
Atlas L.P. #1 - 1985	$600,000	-	0-	$600,000	$190,571	$44,000
A.E. Partners 1986	631,250	-	0-	631,250	149,436	65,933
A.E. Partners 1987	721,000	-	0-	721,000	156,801	63,233
A.E. Partners 1988	617,050	-	0-	617,050	131,210	60,498
A.E. Partners 1989	550,000	-	0-	550,000	117,189	59,799
A.E. Partners 1990	887,500	-	0-	887,500	182,538	67,616
A.E. Nineties-10	2,200,000	-	0-	2,200,000	413,717	66,471

A.E. Nineties-11	750,000	-	0-	761,802 (2)	165,569	103,950
A.E. Partners 1991	868,750	-	0-	867,500	154,273	87,989
A.E. Nineties-12	2,212,500	-	0-	2,272,017 (2)	460,020	100,430
A.E. Nineties-JV 92	4,004,813	-	0-	4,157,700	737,041	163,698
A.E. Partners 1992	600,000	-	0-	600,000	89,797	42,975
A.E. Nineties-Public #1	2,988,960	-	0-	3,026,348 (2)	371,850	87,751
A.E. Nineties-1993 Ltd.	3,753,937	-	0-	3,480,656 (2)	521,227	106,778
A.E. Nineties-Public #2	3,323,920	-	0-	3,324,668 (2)	381,204	75,504
A.E. Partners 1993	700,000	-	0-	689,940	106,186	31,538
A.E. Nineties-14	9,940,045	-	0-	9,512,015 (2)	1,295,395	263,382
A.E. Partners 1994	892,500	-	0-	892,500	80,064	34,874
A.E. Nineties-Public #3	5,799,750	-	0-	5,799,750	552,276	116,766
A.E. Nineties-15	10,954,715	-	0-	9,859,244 (2)	1,074,873	229,751
A.E. Partners 1995	600,000	-	0-	600,000	54,763	11,996
A.E. Nineties-Public #4	6,991,350	-	0-	6,991,350	601,586	119,400
A.E. Nineties-16	10,955,465	-	0-	10,955,465	754,850	137,464
A.E. Partners 1996	800,000	-	0-	800,000	63,745	13,660
A.E. Nineties-Public #5	7,992,240	-	0-	7,992,240	532,765	105,445
A.E. Nineties-17	8,813,488	-	0-	8,813,488	486,302	91,160
A.E. Nineties-Public #6	9,901,025	-	0-	9,901,025	549,077	101,261
A.E. Partners 1997	506,250	-	0-	506,250	25,626	5,705
A.E. Nineties-18	11,391,673	-	0-	11,391,673	551,374	89,252
A.E. Nineties-Public #7	11,988,350	-	0-	11,988,350	424,026	64,543
A.E. Partners 1998	1,740,000	-	0-	1,740,000	71,944	12,181
A.E. Nineties-19	15,720,450	-	0-	15,720,450	374,900	46,625

A.E. Nineties-Public #8	11,088,975	-0-	11,088,975	156,820	22,253
A.E. Partners 1999	450,000	-0-	450,000	4,986	619
1999 Viking Resources LP	4,555,210	-0-	4,555,210	255,159	12,074
Atlas America-Series 20	18,809,150	-0-	18,809,150	11,516	3,563
Atlas America-Public #9	14,905,465	-0-	14,905,465	0	0

(1) Excluding the managing general partner's capital contributions.

(2) Includes additional drilling costs paid with production revenues.

Table 6 sets forth partnerships in which Atlas, the managing general partner, and/or Atlas Energy served as operator and/or drilling contractor for third party general partners as well as the partnerships in which Atlas served as managing general partner. The table does not include those wells acquired by acquisitions and/or through mergers. The table includes the managing general partner's share of costs and revenues set forth in Table 3A, above.

TABLE 6

ATLAS RESOURCES, INC. AND ITS AFFILIATES' HISTORICAL PRODUCTION RECORD

AS OF JANUARY 15, 2001

YEAR WELLS WERE PLACED INTO PRODUCTION	TOTAL WELLS(1)	TOTAL MCF'S PRODUCED	TOTAL AMOUNT INVESTED IN WELLS(2)	TOTAL AMOUNT RETURNED(2)	CUM % RETURN CASH-ON-CASH(3)	LAST 3 MO. DISTRIBUTION ENDING AS OF DATE OF TABLES
1973	6	2,589,593	$576,000	$4,149,050	720%	$21,516
1974	18	3,065,767	2,387,200	4,084,856	171%	33,092
1975	21	4,390,008	2,814,200	6,867,818	244%	29,410
1976	14	2,963,008	1,819,200	4,473,952	246%	18,229
1977	26	9,578,612	3,912,600	16,831,860	430%	87,894
1978	78	8,215,611	12,399,900	19,677,828	159%	98,174
1979	46	9,618,840	7,404,000	20,305,330	274%	88,199
1980	41	6,040,673	6,561,100	14,073,548	214%	63,683
1981	77	6,616,864	15,382,850	17,551,189	114%	87,933
1982	63	2,567,752	12,438,500	5,940,103	48%	19,528
1983	22	1,385,645	6,733,480	3,224,671	48%	48,524
1984	47	4,987,812	10,663,250	10,797,577	101%	82,476
1985	39	5,208,125	8,971,200	10,762,313	120%	100,173
1986	45	6,047,078	9,649,100	11,401,663	118%	101,597
1987	12	1,658,725	2,425,800	2,856,635	118%	39,308

1988	37	4,011,088	7,688,386	7,387,200	96%	75,253
1989	48	3,982,881	9,280,448	7,309,484	79%	473,063
1990	46	5,167,394	9,038,238	9,666,792	107%	71,110
1991	79	9,599,316	16,034,382	17,485,134	109%	345,057
1992	64	8,963,488	14,250,032	16,134,103	113%	497,068
1993	107	11,674,657	21,958,681	19,425,220	88%	1,419,044
1994	94	7,715,299	20,418,366	12,600,207	62%	339,592
1995	105	8,108,099	22,350,889	13,846,745	62%	463,412
1996	114	6,535,468	25,396,708	11,155,624	44%	480,530
1997	103	5,026,136	20,908,334	9,057,752	43%	621,296
1998	128	4,932,180	26,092,000	9,176,937	35%	816,675
1999	117	3,089,783	29,091,538	6,245,663	21%	2,627,879
2000	100	836,171	18,798,285	2,289,653	12%	1,156,996
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TOTAL	1697	154,576,073	$345,444,667	$294,778,906	85%	$10,306,711
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(1) The above numbers do not include information for:

- 87 wells drilled for General Motors from 1971 to 1973 which were subsequently purchased by General Motors;

- 25 wells successfully drilled in 1981 and 1982 for an industrial customer which requested that the wells be capped and not placed into production;

- 127 wells drilled from 1980 to 1985 which were sold in 1993 and are no longer operated by the managing general partner; and

- wells which were drilled recently but are not yet in production.

(2) - The column "Total Amount Invested in Wells" only includes funds paid to the managing general partner or its affiliates as operator and/or drilling contractor for drilling and completing the designated wells. This column does not include all of the costs paid by investors to the third party managing general partner and/or sponsor of the program because such information is generally not available to the managing general partner or its affiliates.

- Similarly, the column "Total Amount Returned" only includes amounts paid by the managing general partner or its affiliates as operator of the wells to the third party managing general partner and/or sponsor of the program. This column does not set forth the revenues which were actually received by the investors from the third party managing general partner and/or sponsor because such information is generally not available to the managing general partner or its affiliates. Notwithstanding, the columns "Total Amount Invested in Wells" and "Total Amount Returned" also include the partnerships in which Atlas serves as managing general partner and are presented on the same basis as the third party partnerships.

(3) This column reflects total cash distributions beginning with the first production from the well, as a percentage of the total amount invested in the well, and includes the return of the investors' capital.

THE RESULTS OF TABLE 6 SHOULD BE VIEWED ONLY AS A MEASURE OF THE LEVEL OF ACTIVITY AND EXPERIENCE OF THE MANAGING GENERAL PARTNER WITH RESPECT TO DEVELOPMENT DRILLING PARTNERSHIPS.

MANAGEMENT

MANAGING GENERAL PARTNER AND OPERATOR

The managing general partner, Atlas Resources, Inc., a Pennsylvania corporation, was incorporated in 1979, and its affiliate, Atlas Energy Group, Inc., an Ohio corporation which was the first of the Atlas group of companies, was incorporated in 1973. Atlas Energy Group will serve as the partnership's general drilling contractor and operator in Ohio. The managing general partner and its affiliates have acted as the operator and the general drilling contractor on over 4,100 gas wells, approximately 3,875 of which were capable of production in commercial quantities. As of December 31, 2000, the managing general partner and its affiliates operated approximately 3,500 natural gas and oil wells located in Ohio, Pennsylvania and New York.

Since 1985 the managing general partner has sponsored 9 public and 29 private partnerships to conduct natural gas drilling and development activities in Pennsylvania, Ohio and New York. In these partnerships the managing general partner and its affiliates acted as the operator and the general drilling contractor and were responsible for drilling, completing and operating the wells.

In September 1998, Atlas Group, the former parent company of the managing general partner, merged into Atlas America, Inc., a newly formed wholly-owned subsidiary of Resource America, Inc. Resource America is a publicly-traded company principally engaged in energy, energy finance, and real estate finance.

Atlas America has and is continuing the existing business of Atlas Group. It is headquartered at 311 Rouser Road, Moon Township, Pennsylvania 15108, near the Pittsburgh International Airport which is also the managing general partner's primary office. As of March 1, 2001, the Board of Directors for Atlas America includes the following:

NAME	AGE	POSITION OR OFFICE
Edward E. Cohen	62	Chairman of the Board
James R. O'Mara	57	Director
Tony C. Banks	46	Director
Michael L. Staines	51	Director
Jonathan Z. Cohen	30	Director
John S. White	60	Director
JoAnn Bagnell	72	Director
James C. Eigel	66	Director

See " - Officers, Directors and Key Personnel," below, for biographical information on certain of these individuals who are also officers and/or directors of the managing general partner. Biographical information on the other directors will be provided by the managing general partner on request.

The managing general partner and its affiliates under Atlas America employ a total of approximately one hundred fifty-seven persons, consisting of four geologists, five landmen, three engineers, eighty-seven drilling/production personnel and thirty-seven accounting/information technology/gas marketing personnel. The balance of the personnel are administrative.

Atlas America and its Affiliates have been leading participants in the energy finance industry for more than 28 years, providing drilling, operating and supervisory services for more than $380 million of independent investment now under Atlas America's management.

ORGANIZATIONAL DIAGRAM(1)(2)

This organizational diagram does not include all of the subsidiaries of Resource America.

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Resource America, Inc.
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Atlas Energy Holdings, Inc.
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Atlas America, Inc. (DE)
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Viking Resources,             AIC, Inc.            Atlas America,
Inc.           Resource Energy,        Atlas Noble Corp.
Corporation
(PA)                         Inc.
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|                        |                   |
|                 |                  |
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-----------------    ---------------    -------------    --------------------
Atlas Resources,         Atlas Energy
Transatco,           Pennsylvania       Opitron,         Atlas Energy Group,
Inc., managing           Corporation,           Inc.,
which          Industrial         Inc.,            Inc., driller and
general partner,         managing general       owns 50% of
Energy, Inc.       technology       operator in Ohio
driller and              partner
of             Topico,                                services
operator in              exploratory            operates
Pennsylvania             drilling               pipeline in Ohio
partnerships and
driller and
operator
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ARD
Investments,
AED Investments,
Inc.                                                                                                         Inc.
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(1) Resource Energy, Viking Resources, and Atlas Noble Corporation are also engaged in the oil and gas business. Resource Energy has been an energy subsidiary of Resource America since 1973. Resource America acquired Viking Resources in August 1999, and Atlas Noble was formed in October

2000 after Resource America acquired all of the assets of Kingston Oil Corporation. In the near term Resource Energy, Viking Resources, and Atlas Noble will retain their separate corporate existence, however, Atlas America will manage their assets and employees including sharing common employees. Also, many of the officers and directors of the managing general partner serve as officers and directors of those entities.

(2) Atlas Pipeline Partners, L.P. (and Atlas Pipeline Operating Partnership) is a master limited partnership formed by a subsidiary of Atlas America as managing general partner using Atlas America and Viking Resources personnel who act as its officers and employees. It has acquired the natural gas gathering system and related facilities from Atlas America, Resource Energy, and Viking Resources. The gathering system consists of approximately 1,000 miles of intrastate pipelines located in Pennsylvania, Ohio, and New York. It is anticipated that this master limited partnership will gather and deliver the majority of the natural gas produced by the partnership to industrial end-users in the area, local distribution companies, or interstate pipeline systems.

OFFICERS, DIRECTORS AND KEY PERSONNEL

The officers and directors of the managing general partner will serve until their successors are elected. The officers, directors and key personnel of the managing general partner are as follows:

NAME	AGE	POSITION OR OFFICE
James R. O'Mara	57	President, Chief Executive Officer and a Director
Frank P. Carolas	41	Executive Vice President - Land and Geology and a Director
Jeffrey C. Simmons	42	Executive Vice President - Operations and a Director
Michael L. Staines	51	Senior Vice President, Secretary and a Director
Nancy J. McGurk	45	Vice President, Chief Financial Officer and Chief Accounting Officer
Jack L. Hollander	45	Vice President - Direct Participation Programs
Louis Tierno, Jr.	38	Controller and Assistant Secretary

JAMES R. O'MARA. President, Chief Executive Officer and a Director. Mr. O'Mara also serves as Vice Chairman and a Director of Atlas America. Mr. O'Mara served with the United States Army Security Agency (ASA) and is a Vietnam veteran. Mr. O'Mara is a Certified Public Accountant and had been associated with Coopers and Lybrand, a national accounting firm, and Teledyne, Inc., a large conglomerate, before joining Atlas Energy in 1975. He is a member of the Pennsylvania Institute of Certified Public Accountants, and received a Bachelor of Science Degree in Accounting from Gannon University in 1968.

FRANK P. CAROLAS. Executive Vice President-Land and Geology and a Director. Mr. Carolas also serves as Executive Vice President-Land and Geology of Atlas America and Viking Resources. Mr. Carolas is a certified petroleum geologist and has been with Atlas Energy since 1981. He received a Bachelor of Science Degree in Geology from Pennsylvania State University in 1981 and is an active member of the American Association of Petroleum Geologists.

JEFFREY C. SIMMONS. Executive Vice President-Operations and a Director. Mr. Simmons also serves as Executive Vice President-Operations of Atlas America and Viking Resources. Mr. Simmons joined Resource America in 1986 as senior petroleum engineer. From 1988 through 1994 he served as director of production and as president of Resource Well Services, Inc., a subsidiary of Resource America. He was then promoted to vice president of Resource Energy, the energy subsidiary of Resource America formed in 1993. In 1997 he was promoted to executive vice president, chief operating officer and director of Resource Energy, a position he currently holds. Before Mr. Simmons' career with Resource America, he had worked with Core Laboratories, Inc., of Dallas, Texas, and PNC Bank of Pittsburgh. Mr. Simmons received his Petroleum Engineering degree from Marietta College and his Masters Degree in Business Administration from Ashland University. He is a Board Member of the Ohio Oil and Gas Association, the Independent Oil and Gas Association of New York and the Ohio Section of the Society of Petroleum Engineers.

MICHAEL L. STAINES. Senior Vice President, Secretary and a Director. Mr. Staines is also Executive Vice President, Secretary and Managing Director, Business Development of Atlas America and Atlas Pipeline Partners, and a Director of Atlas America since 1998, Senior Vice President and a Director of Resource America since 1998 and 1989, respectively, Secretary of Resource America from 1989 to 1998, and President, Chief Executive Officer and a Director of Resource

Energy, the energy subsidiary of Resource America, since 1997. Mr. Staines is a member of the Ohio Oil and Gas Association and the Independent Oil and Gas Association of New York. Mr. Staines received a Bachelor of Science Degree from Cornell University in 1971 and a Master of Business Degree from Drexel University in 1977.

NANCY J. MCGURK. Vice President, Chief Financial Officer and Chief Accounting Officer. Ms. McGurk also serves as Vice President, Chief Financial Officer and Chief Accounting Officer of Atlas America and has been Vice President of Resource America since 1992. Before that she had served as Treasurer and Chief Accounting Officer of Resource America since 1989. Also, since 1995 Ms. McGurk has served as Vice President - Finance of Resource Energy.

JACK L. HOLLANDER. Vice President - Direct Participation Programs. Mr. Hollander also serves as Vice President - Direct Participation Programs of Atlas America. Mr. Hollander began his career serving as in house tax counsel for a large diversified financial services company from 1982 to 1990. He then went on to practice law with a concentration in tax matters, real estate transactions and consulted with and assisted technology companies in raising capital until joining the managing general partner in January 2001. Mr. Hollander earned a Bachelor of Science Degree from the University of Rhode Island in 1978, his law degree from Brooklyn Law School in 1981 and a Master of Law Degree in Taxation from New York University School of Law Graduate Division in 1982. Mr. Hollander is a member of the New York State bar, the Investment Program Association and the Financial Planning Association.

LOUIS TIERNO, JR. Controller and Assistant Secretary. Mr. Tierno also serves as Controller of Atlas America. Mr. Tierno has over 15 years of finance, accounting, tax and administrative experience in the oil and gas industry with Angerman Associates, Inc. before joining Atlas America and the managing general partner in April 2001. He received a Bachelor of Science Degree in Business Administration from Duquesne University and holds a Masters Degree in Industrial Administration from Carnegie Mellon University. He also passed the Pennsylvania Certified Public Accountant examination in 1990.

KEY PERSONNEL.

JOHN S. COFFEY. President, Secretary, Treasurer and Director of Anthem Securities, Inc. Mr. Coffey joined Anthem Securities, Inc. in May 2000. He was previously associated with Financial Investment Analysts, Inc. from November

1984 to May 2000, where he served as a Financial Planner, Principal and Registered Investment Advisor. Mr. Coffey received a Bachelor of Science Degree in Industrial Management from Gannon University in 1970, and is a member of The Institute of Industrial Engineers and The Financial Planning Association.

The officers and directors of AIC, Inc., which owns 100% of the common stock of the managing general partner, are Tony C. Banks, Jonathan Z. Cohen and Michael L. Staines. The biography of Mr. Staines is set forth above.

REMUNERATION

No officer or director of the managing general partner will receive any direct remuneration or other compensation from the partnership. These persons will receive compensation solely from affiliated companies of the managing general partner.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

Resource America owns 100% of the common stock of Atlas America, which owns 100% of the common stock of AIC, Inc., which owns 100% of the common stock of the managing general partner.

TRANSACTIONS WITH MANAGEMENT AND AFFILIATES

Atlas Group shareholders are eligible to receive incentive compensation should Atlas Group's post-acquisition earnings exceed a specified amount during the five years following the merger. The incentive compensation is equal to 10% of Atlas Group's aggregate earnings in excess of that amount equal to an annual, but uncompounded, return of 15% on $63 million which is increased to include any amount paid by Resource America for any post-merger energy acquisitions. Incentive compensation is payable, at Resource America's option, in cash or in shares of Resource America's common stock, valued at the average closing price of Resource America's common stock for the 10 trading days before September 30, 2003.

The managing general partner and its officers, directors and affiliates have in the past invested, and may in the future invest, in partnerships sponsored by the managing general partner. They may also subscribe for units in the partnership as described in "Plan of Distribution."

PROPOSED ACTIVITIES

OVERVIEW OF DRILLING ACTIVITIES

The managing general partner anticipates that all the partnership's wells will be development wells, which means a well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive. Also, the majority of the wells will be classified as natural gas wells, which may produce a small amount of oil, although some of the wells may be classified as oil wells. Assuming the partnership acquires 100% of the interest in the wells, the managing general partner anticipates that the partnership will drill approximately:

- 5 wells if the minimum subscriptions of $1 million are received; and

- 124 wells if the maximum subscriptions of $25 million are received.

The actual number of wells drilled by the partnership, however, may vary from these estimates and will depend on the following:

- the amount of subscriptions proceeds received;

- where the wells are drilled; and

- the partnership's percentage of interest owned in the wells, which could range from 25% to 100%.

Before the managing general partner selects a prospect on which a well will be drilled by the partnership, the managing general partner will review all available geologic and production data for wells located in the vicinity of the proposed well including, but not limited to:

- various well logs;

- completion reports;

- plugging reports; and

- production reports.

PRIMARY AREAS OF OPERATIONS

As discussed below, the three primary areas for the partnership's drilling activities are the Clinton/Medina Geological Formation in western Pennsylvania, the Clinton/Medina geological formation in southern Ohio and the Mississippian/Upper Devonian Sandstone reservoirs in Fayette County, Pennsylvania, which is also in western Pennsylvania. The Clinton/Medina geological formation in Pennsylvania and Ohio is the same geological formation, although in Pennsylvania it is often referred to as the Medina/Whirlpool geological formation. For purposes of this prospectus, the term Clinton/Medina geological formation is used for both Ohio and Pennsylvania. The wells drilled to the Clinton/Medina geological formation, regardless of whether they are situated in western Pennsylvania, eastern Ohio, southern Ohio or western New York, and the Mississippian/Upper Devonian Sandstone reservoirs have the following similarities:

- geological features such as structure and faulting are not generally factors used in finding commercial production from a well drilled to this formation or these reservoirs and the governing factors appear to be sand quality in terms of net pay zone thickness, porosity, and the effectiveness of fracture stimulation;

- a well drilled to this formation or these reservoirs usually requires hydraulic fracturing of the formation to stimulate productive capacity;

- generally, natural gas from a well drilled to this formation or these reservoirs is produced at rates which decline rapidly during the first few years of operations, and although the well can produce for many years, a proportionately larger amount of production can be expected within the first several years; and

- it has been the managing general partner's experience that natural gas production from wells drilled to this formation or these reservoirs is reasonably consistent with nearby wells, although from time to time there can be great differences in the natural gas volumes and performance of wells located close together.

The managing general partner anticipates that the majority of the subscription proceeds of the partnership will be expended in the primary areas.

CLINTON/MEDINA GEOLOGICAL FORMATION IN WESTERN PENNSYLVANIA. The Clinton/Medina geological formation is a blanket sandstone found throughout most of the northwestern edge of the Appalachian Basin. The Clinton/Medina is described in petroleum industry terms as a "tight" sandstone with porosity ranging from 6% to 12% and with very low permeability. Porosity is the percentage of void space between sand grains that is available for occupancy by either liquids or gases, and permeability is the property of porous rock that allows fluids or gas to flow through it. Based on the managing general partner's experience, it anticipates that all the natural gas wells will be completed and fraced in two different zones of the Clinton/Medina geological feature. See the geologic evaluation and the model decline curve prepared by United Energy Development Consultants, Inc., an independent geological and engineering firm for a discussion of the development of the Clinton/Medina Geological Formation in western Pennsylvania, which also covers a small area in eastern Ohio primarily in Stark, Mahoning and Trumbull Counties.

The wells in the Clinton/Medina geological formation in western Pennsylvania will be:

- primarily situated in Mercer, Lawrence, Warren, Venango, and Crawford Counties;

- situated on approximately 50 acres, subject to adjustment to take into account lease boundaries;

- drilled at least 1,650 feet from each other in Pennsylvania, which is greater than the 660 feet minimum distance allowed by state law or local practice to protect against drainage from adjacent wells, and drilled at least 1,000 feet from each other in Ohio;

- drilled from approximately 5,100 to 6,300 feet in depth;

- classified as natural gas wells which may produce a small amount of oil, although the wells in eastern Ohio may be classified as oil wells; and

- connected to the gathering system owned by Atlas Pipeline Partners and have their natural gas production marketed to First Energy Services Corporation as described below, although a portion of the natural gas production may be gathered by and sold to third parties if there is a third-party operator.

Also, see "Secondary Areas" below, for a discussion of the Clinton/Medina geological formation in western New York.

CLINTON/MEDINA GEOLOGICAL FORMATION IN SOUTHERN OHIO. The geological characteristics of the Clinton/Medina geological formation in southern Ohio are substantially the same as western Pennsylvania. See the managing general partner's geological evaluation for a discussion of the development of the Clinton/Medina geological formation in southern Ohio.

Wells located in southern Ohio and drilled to the Clinton/Medina geological formation will be:

- primarily situated in Noble, Washington, Guernsey and Muskingum Counties;

- situated on approximately 40 acres, subject to adjustment to take into account lease boundaries;

- drilled at least 1,000 feet from each other;

- drilled from approximately 4,900 to 6,500 feet in depth;

- classified as either natural gas wells or oil wells; and

- connected to the gathering system owned by Atlas Pipeline Partners if classified as a natural gas well and have their natural gas production marketed to First Energy Services Corporation as described below, although a portion of the natural gas production may be gathered by and sold to third parties if there were a third-party operator.

MISSISSIPPIAN/UPPER DEVONIAN SANDSTONE RESERVOIRS, FAYETTE COUNTY, PENNSYLVANIA. The Mississippian/Upper Devonian Sandstone reservoirs are discontinuous lens-shaped accumulations found throughout most of the Appalachian Basin. The Mississippian/Upper Devonian Sandstone reservoirs have porosities ranging from 5% to 20% with attendant permeabilities. See the managing general partner's geologic evaluation for a discussion of the development of the Mississippian/Upper Devonian Sandstone reservoirs in Fayette and Greene Counties, Pennsylvania.

The wells in the Mississippian/Upper Devonian Sandstone reservoirs will be:

- situated on approximately 20 acres, subject to adjustment to take into account lease boundaries;

- drilled at least 1,000 feet from each other, although existing wells may be re-entered by parties other than the partnership even though they are not 1,000 feet from each other;

- drilled from approximately 1,900 to 4,500 feet in depth;

- classified as natural gas wells which may produce a small amount of oil; and

- connected to the gathering system owned by Atlas Pipeline Partners and have their natural gas production marketed to First Energy Services Corporation as described below.

SECONDARY AREAS OF OPERATIONS

The managing general partner also has reserved the right to use a portion of the subscription proceeds to drill development wells in other areas of the United States primarily in the Appalachian Basin. The secondary areas anticipated by the managing general partner are discussed below.

CLINTON/MEDINA GEOLOGICAL FORMATION IN WESTERN NEW YORK. Wells located in

western New York and drilled to the Clinton/Medina geological formation will be:

- primarily situated in Chautauqua County;

- situated on approximately 40 acres, subject to adjustment to take into account lease boundaries;

- drilled from approximately 3,800 to 4,000 feet in depth;

- drilled on leases with a net revenue interest of approximately 84.375% to 87.5%;

- classified as natural gas wells which may produce a small amount of oil; and

- connected to the gathering system owned by Atlas Pipeline Partners and have their natural gas production marketed to First Energy Services Corporation as described below.

MISSISSIPPIAN BEREA SANDSTONE IN EASTERN OHIO. Wells located in eastern Ohio and drilled to the Mississippian Berea Sandstone will be:

- primarily situated in Columbiana County;

- situated on approximately 5 acres, subject to adjustment to take into account lease boundaries;

- drilled from 850 to 950 feet in depth;

- drilled on leases with a net revenue interest of approximately 84.375% to 87.5%;

- classified as natural gas wells which may produce a small amount of oil; and

- connected to the gathering system owned by Atlas Pipeline Partners and have their natural gas production marketed to First Energy Services Corporation as described below.

DEVONIAN ORISKANY SANDSTONE IN EASTERN OHIO. Wells located in eastern Ohio and drilled to the Devonian Oriskany Sandstone will be:

- primarily situated in Tuscarawas County;

- situated on approximately 40 acres, subject to adjustment to take into account lease boundaries;

- drilled from approximately 3,800 to 4,200 feet in depth;

- drilled on leases with a net revenue interest of approximately 84.375% to 87.5%;

- classified as natural gas wells which may produce a small amount of oil; and

- connected to the gathering system owned by Atlas Pipeline Partners and have their natural gas production marketed to First Energy Services Corporation as described below.

KENTUCKY AND VIRGINIA. Wells in Kentucky and Virginia will be drilled to the following formations in descending order: Big Lime Limestone; Weir Sandstone; and the Cleveland, Upper Huron and Lower Huron members of the Devonian Shale. These wells will be:

- primarily situated in Harlan County, Kentucky and Lee County, Virginia;

- situated on approximately 70 acres, subject to adjustment to take into account lease boundaries;

- drilled from 5,000 to 6,600 feet in depth;

- drilled on leases with a net revenue interest of approximately 81.25%;

- classified as natural gas wells which may produce a small amount of oil; and

- connected to a third-party gathering system in the area since Atlas Pipeline Partners is not situated in the area, and have their natural gas production marketed to Duke Energy Marketing.

ACQUISITION OF LEASES

The managing general partner will have the right, in its sole discretion, to select the prospects which the partnership will drill. Currently, the managing general partner has proposed approximately 65% of the prospects to be drilled if all 2,500 units are sold. The leases covering each prospect on which a well will be drilled will be acquired by the partnership from the managing general partner or its affiliates and credited to the managing general partner as a part of its required capital contribution to the partnership. Neither the managing general partner nor its affiliates will receive any royalty or overriding royalty interest on any well.

The managing general partner may substitute the prospects depending on various considerations. The managing general partner anticipates that it will select any additional and/or substituted prospects from the following:

- leases in its and its affiliates' existing leasehold inventory;

- leases which are subsequently acquired by it or its affiliates; or

- leases owned by independent third-parties which may participate with the partnership in drilling wells.

Most of the additional and/or substituted prospects will be in areas where the managing general partner or its affiliates have previously conducted drilling operations and will meet the same general criteria for drilling potential as the currently proposed prospects. The managing general partner believes that its and its affiliates' leasehold inventory and leases acquired from third parties will be sufficient to provide all the prospects to be drilled by the partnership.

The managing general partner and its affiliates are continually engaged in acquiring additional leasehold acreage in Pennsylvania, Ohio and other areas of the United States. As of the date of this prospectus, the managing general partner and its affiliates owned approximately:

- 94,009 net acres of undeveloped lease acreage in Pennsylvania;

- 46,973 net acres of undeveloped lease acreage in Ohio;

- 8,652 net acres of undeveloped lease acreage in West Virginia;

- 2,356 net acres of undeveloped lease acreage in Kentucky; and

- 13,379 net acres of undeveloped lease acreage in New York.

Because the managing general partner will assign to the partnership only the number of prospects which it believes are necessary for the partnership's drilling operations, the partnership will not farmout any acreage. Generally, a farmout is an agreement where the owner of the lease agrees to assign his interest in certain acreage to an assignee subject to the assignee drilling one or more wells. The owner would retain some interest in the assigned acreage such as an overriding royalty interest which reverts to a working interest when the assignee has recovered its drilling costs.

DEEP DRILLING RIGHTS RETAINED BY MANAGING GENERAL PARTNER. In the areas where the Clinton/Medina is the primary geological formation, the lease assignments to the partnership will be limited to a depth of from the surface to the top of the Queenston geological formation. In the areas where the Mississippian/Upper Devonian Sandstone reservoirs are the primary targets, the lease assignments to the partnership will be limited to a depth of from the surface through the completion total depth of the well.

In these areas the managing general partner will retain the deeper drilling rights because the partnership's objective is to conduct development drilling which would not be the case with the deeper formations. The managing general partner, however, believes that the partnership's development drilling in these areas will not provide any geological information that would assist it in evaluating drilling to deeper formations. Also, the amount of the credit the managing general partner receives for the leases does not include any value allocable to the deeper drilling rights retained by it. If in the future the managing general partner undertakes any activities with respect to the deeper formations, including drilling an exploratory well, then the partnership would not share in the profits from these activities, nor would it pay any of the associated costs.

INTERESTS OF PARTIES

Generally, production and revenues from a well drilled by the partnership will be net of the applicable landowner's royalty interest, which is typically 1/8th (12.5%) of gross production, and any interest in favor of third parties such as an overriding royalty interest. Landowner's royalty interest generally means an interest which is created in favor of the landowner when an oil and gas lease is obtained, and overriding royalty interest generally means an interest which is created in favor of someone other than the landowner. In either case, the owner of the interest receives a specific percentage of the natural gas and oil production free and clear of all costs of development, operation, or maintenance of the well.

The managing general partner anticipates that the partnership generally will have a net revenue interest in its leases in its primary drilling areas as set forth in the charts below. Net revenue interest generally means the percentage of revenues the owner of an interest in a well is entitled to receive under the lease. The following charts express the percentage of production revenues that the managing general partner, the landowner, other third-parties, and you and the other investors will share in from the wells in two of the three primary proposed areas. The third primary proposed area is discussed following the chart. If the partnership acquires a lesser percentage ownership interest in a well, then the partnership's net revenue interest will decrease proportionately.

PRIMARY AREAS.

CLINTON/MEDINA GEOLOGICAL FORMATION IN WESTERN PENNSYLVANIA AND MISSISSIPPIAN/UPPER DEVONIAN SANDSTONE RESERVOIRS IN FAYETTE COUNTY, PENNSYLVANIA:

ENTITY	PARTNERSHIP INTEREST	THIRD PARTY ROYALTY INTEREST	87.5% PARTNERSHIP NET REVENUE INTEREST(2)
Managing General Partner	32% partnership interest(1)		28.0%
Investors	68% partnership interest(1)		59.5%
Third Party			12.5%
Landowner Royalty Interest		12.5%	
			100.0%

(1) These percentages are for illustration purposes only and are based on the managing general partner's minimum required capital contribution of 25% and assume capital contributions of 75% from you and the other investors. The actual percentages are likely to be different because they will be based on the actual capital contributions of the managing general partner, which will not exceed 28%, and you and the other investors.

(2) It is possible that substituted or additional wells could have a net revenue interest to the partnership as low as 84.375% which would reduce the investors' interest to 57.375%.

CLINTON/MEDINA GEOLOGICAL FORMATION IN SOUTHERN OHIO:

The managing general partner anticipates that the majority of the wells in southern Ohio will have a net revenue interest of 85% which would reduce the investors' interest in the above chart to 57.8%. The other currently proposed wells have an 87.5% net revenue interest, except one well which has an 82.5% net revenue interest which would reduce the investors' interest in the above chart to 56.1% for that well. The managing general partner also anticipates that many of the leases in southern Ohio will have been originally acquired from a coal company and are subject to a provision that the well must be abandoned if it hinders the development of the coal. Consequently, the managing general partner will not drill a well on any lease subject to this provision unless it covers lands which were previously mined. Although this does not totally eliminate the risk because the leases may cover other coal deposits that might be mined during the life of a well, the managing general partner believes that drilling wells on these previously mined leases would be in the best interests of the partnership.

SECONDARY AREAS. Although the managing general partner anticipates the partnership will have a net revenue interest ranging from 81% to 87.5% in the secondary areas described above, there is no minimum net revenue interest which the partnership is required to own before drilling a well in other areas of the Appalachian Basin or the United States. The leases in these other areas may be subject to interests in favor of third parties which are not currently known such as:

- overriding royalty interests;

- net profits interests;

- carried interests;

- production payments;

- reversionary interests pursuant to farmouts or non-consent elections under joint operating agreements; or

- other retained or carried interests.

TITLE TO PROPERTIES

Title to all leases acquired by the partnership will be held in the name of the partnership. However, to facilitate the acquisition of the leases title to the leases may initially be held in the name of:

- the managing general partner;

- its affiliates; or

- any nominee designated by the managing general partner.

Title to the leases will be transferred to the partnership from time to time after the minimum subscriptions are received and released from escrow. After drilling, the title to the leases will be filed for record.

The managing general partner will take the steps it deems necessary to assure that the partnership has acceptable title for its purposes. However, it is not the practice in the natural gas and oil industry to warrant title or obtain title insurance on leases and the managing general partner will provide neither for the leases it assigns to the partnership. The managing general partner will obtain a favorable formal title opinion for the leases before each well is drilled, but the managing general partner may use its own

judgment in waiving title requirements and will not be liable for any failure of title of leases transferred to the partnership. Also, there is no assurance that the partnership will not experience losses from title defects excluded from or not disclosed by the formal title opinion.

DRILLING AND COMPLETION ACTIVITIES; OPERATION OF PRODUCING WELLS

Under the drilling and operating agreement the responsibility for drilling and completing, or plugging, partnership wells will be on the managing general partner or an affiliate as the operator and the general drilling contractor. During drilling operations the managing general partner's duties as operator and general drilling contractor will include:

- making the necessary arrangements for drilling and completing partnership wells and related facilities for which it has responsibility under the drilling and operating agreement;

- managing and conducting all field operations in connection with drilling, testing and equipping the wells; and

- making the technical decisions required in drilling and completing the wells.

Under the drilling and operating agreement all partnership wells will be drilled to a sufficient depth to test thoroughly the objective geological formation.

If there is a co-owner of the well which serves as the actual operator and the general drilling contractor, then the managing general partner will still enter into the drilling and operating agreement with the partnership to drill and complete the wells on the terms described in "Compensation." This may include a few of the wells drilled in the Clinton/Medina geological formation in western Pennsylvania, eastern and southern Ohio, and the Devonian Shale geological formation in Kentucky and Virginia. The managing general partner would review the performance of the third-party operator and general drilling contractor which would include monitoring:

- all field operations in connection with drilling, testing and equipping the wells;

- the technical decisions required in drilling and completing the wells;

- the costs and expenses charged by the third party operator; and

- the accounting and production records for the partnership.

If the partnership is the largest interest owner in the well, then it is likely that even in these circumstances the managing general partner would control the operations through its ownership interest in the well.

Under the drilling and operating agreement the managing general partner, as operator and general drilling contractor, will complete each well if there is a reasonable probability of obtaining commercial quantities of natural gas or oil. However, based on its past experience, the managing general partner anticipates that most of the partnership's wells drilled to the Clinton/Medina geological formation and the Mississippian/Upper Devonian Sandstone reservoirs will have to be completed before it can determine the well's productivity. If the managing general partner, as operator and general drilling contractor, determines that a well should not be completed, then the well will be plugged and abandoned.

During producing operations the managing general partner's duties as operator will include:

- managing and conducting all field operations in connection with operating and producing the wells;

- making the technical decisions required in operating the wells; and

- maintaining the wells, equipment and facilities in good working order during their useful life.

The managing general partner as operator will be reimbursed for its direct expenses and will receive well supervision fees at competitive rates for operating and maintaining the wells during producing operations. The drilling and operating agreement contains a number of other material provisions which you should carefully review.

If the managing general partner or an affiliate is not the actual operator of the well during producing operations as described above, then the managing general partner will enter into the drilling and operating agreement and receive well supervision fees for reviewing the third-party operator's performance. This includes the following:

- reviewing the costs and expenses charged by the third-party operator; and

- monitoring the accounting and production records for the partnership.

The actual operator will perform services for each well which are customarily performed to operate a well in the general area where the well is located. The third-party operator will be reimbursed for its direct costs and will receive either reimbursement of its administrative overhead or well supervision fees under an operating agreement. In these cases these fees will be paid by the managing general partner from the well supervision fees it receives under the drilling and operating agreement entered into between the managing general partner and the partnership.

As described above, certain wells may be drilled with third-parties owning a portion of the interest in the wells. Any other interest owner in a well may have a separate agreement with the managing general partner for drilling and operating the well with differing terms and conditions from those contained in the partnership's drilling and operating agreement.

SALE OF NATURAL GAS AND OIL PRODUCTION

POLICY OF TREATING ALL WELLS EQUALLY IN A GEOGRAPHIC AREA. The managing general partner is responsible for selling the partnership's natural gas and oil production, and its policy is to treat all wells in a given geographic area equally. This reduces certain potential conflicts of interest among the owners of the various wells, including the partnership, concerning to whom and at what price the natural gas and oil will be sold. For example, the managing general partner calculates a weighted average selling price for all of the natural gas sold in the geographic area by dividing the money received from the sale of all of the natural gas sold to customers in the area by the volume of all natural gas sold from the wells in the area. For gas sold in western Pennsylvania the managing general partner received an average selling price after deducting all expenses, including transportation expenses, of approximately:

- $2.22 per mcf in 1998;

- $2.35 per mcf in 1999; and

- $3.30 per mcf in 2000.

Although on occasion the managing general partner has reduced the amount of natural gas production it normally sells on the spot market until the spot market price increased, the managing general partner has not voluntarily restricted its natural gas production in the past five years because of a lack of a profitable market price.

If the managing general partner should decide that reducing production would be in the best interests of its partnerships, then production will be reduced to the same degree in all the wells in the same geographic area. On the other hand, if the managing general partner has not decided to reduce production, but all the natural gas produced cannot be sold because of limited demand for the natural gas, which increases pipeline pressure, then the production that is sold will be from those wells which have the greatest well pressure and are able to feed into the pipeline, regardless of which partnerships own the wells.

GATHERING OF NATURAL GAS. Atlas Pipeline Partners, L.P., a limited partnership in which a subsidiary of Atlas America serves as managing general partner, will gather, compress and transport the majority of the partnership's natural gas production, including natural gas in the primary areas, to interstate pipeline systems, local distribution companies, or industrial end-users as discussed below. If the partnership's natural gas is not transported through the Atlas Pipeline Partners gathering system, then it is because there is a third-party operator or the gathering system has not been extended to the wells. In these cases the natural gas will be transported through a third-party gathering system and the partnership will pay a competitive gathering fee.

As a part of the sale of the gathering system to Atlas Pipeline Partners, Atlas America and its affiliates, Resource Energy and Viking Resources, made the commitments set forth below which to varying degrees may affect the partnership. The commitments were intended to maximize the use and expansion of the gathering system. These are continuing obligations of Atlas America, Resource Energy, and Viking Resources unless the managing general partner of Atlas Pipeline Partners is removed without cause in which case the obligations cease.

- They are required to pay a gathering fee equal to the greater of $0.35 per mcf or 16% of the gross sales price for each mcf transported for all partnerships in which their subsidiaries serve as managing general partner, which includes the partnership. Thus, if the partnership pays a lesser amount as is currently anticipated by the managing general partner as described in "Compensation - Gathering Fees," then Atlas America or one of the other parties must pay the difference to Atlas Pipeline Partners.

- They committed to adding 225 wells to the gathering system over a period from January 1, 1999, until December 31, 2002, which includes any well drilled in a partnership sponsored by them. The wells had to be drilled within 2,500 feet of the gathering system and the well owner had to construct up to 2,500 feet of small diameter sales or flow lines from the wellhead to the gathering system. This commitment has been satisfied.

- They have agreed to assist Atlas Pipeline Partners in identifying existing gathering systems for possible acquisition.

- They have agreed that a managing general partner's interests in a drilling program may not be transferred to a person unless it transfers its ownership in each of its other drilling programs to the same person.

- Atlas America has agreed to provide construction management and financing services to Atlas Pipeline Partners in the construction of additions or extensions to the gathering system. For a period of five years from January 28, 2000, to January 28, 2005, Atlas America has a standby commitment for a maximum of $1.5 million in any contract year.

NATURAL GAS CONTRACTS. The managing general partner, Resource Energy, Inc. and Atlas Energy Group, Inc. have a natural gas supply agreement with First Energy Services Corporation, for a 10-year term which began on April 1, 1999. Subject to certain exceptions, First Energy Services Corporation must buy all of the natural gas produced and delivered by the managing general partner and its affiliates, which includes the partnership, at certain delivery points with the facilities of:

- East Ohio Gas Company, National Fuel Gas Distribution, and Peoples Natural Gas Company, which are local distribution companies; and

- National Fuel Gas Supply, Columbia Gas Transmission Corporation, Tennessee Gas Pipeline Company, and Texas Eastern Transmission Company, which are interstate pipelines.

First Energy Services Corporation is the marketing affiliate of First Energy Corporation, which is an electric utility listed on the New York Stock Exchange which also provides natural gas to industry and retail consumers. First Energy Corporation has provided a guaranty of the monetary obligations of First Energy Services Corporation of an amount up to $10 million for a period until April 30, 2002, which will continue on a monthly basis thereafter unless terminated on 30 days notice.

Generally, all of the managing general partner's and its affiliates' natural gas is subject to the agreement with First Energy Services Corporation, with the following exceptions:

- natural gas being sold to Wheatland Tube Company, CSC Industries and Warren Consolidated, which are industrial end-users and direct delivery customers of the managing general partner and its affiliates;

- natural gas which at the time of the agreement was already dedicated for the life of the well to another buyer;

- natural gas which is produced by a company which was not an affiliate of the managing general partner at the time of the agreement;

- natural gas which is produced in areas where there is not a delivery point into any of the interstate pipelines or local distribution companies described above; or

- natural gas which is produced from well(s) operated by a third-party.

The agreement establishes a price formula for each of the delivery points for either the first one or two years of the agreement which is tied to the market indexes. If, at the end of the applicable period, the parties cannot agree to a new price for any delivery point, then the managing general partner and its affiliates may arrange a sale of their natural gas for that delivery point to a third-party. If First Energy Services Corporation does not match this price, then the natural gas will be sold to the third-party. This process will be repeated at the end of each contract period which is usually one year. For example, the managing general partner and its affiliates have entered into contracts to sell natural gas at certain delivery points to third-parties other than First Energy Services Corporation under this process, however, these contracts have expired. Since then, the managing general partner and First Energy Services Corporation have been able to agree to new pricing arrangements for these delivery points under their agreement.

The agreement may be suspended for force majeure which means generally such things as an act of God, fire, storm, flood, and explosion, but also includes the permanent closing of the factories of Carbide Graphite or Duferco Farrell Corporation during the term of First Energy Services Corporation's agreements to sell natural gas to them. If these factories were closed, however, the managing general partner believes that First Energy Services Corporation would be able to find alternative purchasers and would not invoke the force majeure.

The managing general partner anticipates that all of the natural gas produced by the partnership from wells drilled to the Mississippian/Upper Devonian Sandstone reservoirs in Fayette County, Pennsylvania and the Clinton/Medina geological formation in southern Ohio will be sold to First Energy Services Corporation. The managing general partner anticipates that 85% to 90% of the natural gas produced by the partnership from wells drilled to the Clinton/Medina geological formation in western Pennsylvania will be sold to First Energy Services Corporation, and approximately 10% to 15% of the natural gas will be sold to Wheatland Tube pursuant to an agreement that expires September, 2001. However, the managing general partner anticipates that it and Wheatland Tube will enter into a new agreement. If not, the natural gas will be sold to First Energy Services Corporation.

The marketing of natural gas production has been influenced by the availability of certain financial instruments which may be used as hedge instruments to lock in the price which will ultimately be paid for future deliveries of natural gas. The managing general partner enters into natural gas futures and options contracts, which may be pursuant to its agreement with First Energy Services Corporation, to hedge its exposure to changes in natural gas prices. At any point in time, these contracts may include regulated NYMEX futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties. The futures contracts employed by the managing general partner are commitments to purchase or sell natural gas at future dates and generally cover one-month periods for up to 18 months in the future. To assure that the financial instruments will be used solely for hedging price risks and not for speculative purposes, the managing general partner has established a committee to assure that all financial trading is done in compliance with hedging policies and procedures. The managing general partner does not intend to contract for positions that it cannot offset with actual production. Although hedging provides the partnership some protection against falling prices, these activities could also reduce the potential benefits of price increases, depending on the instrument.

MARKETING OF NATURAL GAS PRODUCTION FROM WELLS IN OTHER AREAS OF THE UNITED STATES. The managing general partner expects that natural gas produced from wells drilled in areas of the United States other than described above will be primarily tied to the spot market price and supplied to:

- gas marketers;
- local distribution companies;

- industrial end-users; and/or
- companies generating electricity.

CRUDE OIL. Crude oil produced from the wells will flow directly into storage tanks where it will be picked up by the oil company, a common carrier or pipeline companies acting for the oil company which is purchasing the crude oil. Unlike natural gas, crude oil does not present any transportation problem. The managing general partner anticipates selling any oil produced by the wells to regional oil refining companies at the prevailing spot market price for Appalachian crude oil in spot sales. The managing general partner was receiving an average selling price for oil of approximately:

- $13.00 per barrel in December, 1998;
- $16.20 per barrel in 1999; and

- $26.21 per barrel in 2000.

Over the past eight years, the price of oil has ranged from approximately $38 to as low as $8 per barrel. There can be no assurance as to the price of oil during the term of the partnership.

INSURANCE

Since 1972, the managing general partner and its affiliates, including its partnerships, have been involved in the drilling of approximately 4,000 wells in Ohio, Pennsylvania and other areas of the Appalachian Basin. They have not incurred a blow-out, fire or similar hazard with any of these wells, and thus have not made any insurance claims.

The managing general partner will obtain and maintain insurance coverage in amounts and for purposes which would be carried by a reasonable, prudent general contractor and operator in accordance with industry standards. The partnership will be named as an additional insured under these policies. In addition, the managing general partner requires all of its subcontractors to certify that they have acceptable insurance coverage for worker's compensation and general, auto and excess liability coverage. Major subcontractors are required to carry general and auto liability insurance with a minimum of $1 million combined single limit for bodily injury and property damage in any one occurrence or accident. The managing general partner's current insurance coverage satisfies the following specifications:

- worker's compensation insurance in full compliance with the laws of the Commonwealth of Pennsylvania and any other applicable state laws where the wells will be drilled;

- liability insurance, including automobile, which has a $1 million combined single limit for bodily injury and property damage in any one occurrence or accident and in the aggregate; and

- excess liability insurance as to bodily injury and property damage with combined limits of $50 million during drilling operations and $10 million thereafter, per occurrence or accident and in the aggregate.

- This includes $1 million of seepage, pollution and contamination insurance which protects the insured against bodily injury or property damage claims from third parties, other than a co-owner of the interest in the well, alleging seepage, pollution or contamination damage resulting from an accident.

The excess liability insurance will be effective no later than the date subscription proceeds are first released from escrow and drilling begins, and will insure the partnership and the managing general partner's other partnerships until the investor general partners are converted to limited partners. After conversion the partnership will have the benefit of the managing general partner's $11 million liability insurance on the same basis as the managing general partner and its affiliates, including other partnerships. Because the managing general partner is driller and operator of other

partnerships there is a risk that the insurance available to the partnership could be substantially less if there are claims with respect to the other partnerships.

These insurance policies will have terms, including exclusions and deductibles, which are standard for the natural gas and oil industry. On request the managing general partner will provide you or your representative a copy of its insurance policies. The managing general partner will use its best efforts to maintain insurance coverage which meets its current coverage, but may be unsuccessful if the coverage becomes unavailable or too expensive.

If you are an investor general partner and there is going to be an adverse material change in the partnership's insurance coverage, which the managing general partner does not anticipate, then the managing general partner must notify you at least 30 days before the effective date. If the insurance coverage is materially reduced, then you will have the right to convert your units into limited partner interests before the reduction by giving written notice to the managing general partner.

USE OF CONSULTANTS AND SUBCONTRACTORS

The partnership agreement authorizes the managing general partner to use the services of independent outside consultants and subcontractors. The services will normally be paid on a per diem or other cash fee basis and will be charged to the partnership as either a direct cost or as a direct expense under the drilling and operating agreement. These charges will be in addition to the unaccountable, fixed payment reimbursement paid to the managing general partner for administrative costs, and well supervision fees paid to the managing general partner as operator.

INFORMATION REGARDING CURRENTLY PROPOSED WELLS

Set forth below is information relating to 81 prospects and the wells which will be drilled on the prospects. One well will be drilled on each prospect. For purposes of this section the well and prospect are referred to together as the "well." These wells are currently proposed to be drilled when the subscription proceeds are released from escrow and from time to time thereafter subject to the managing general partner's right to withdraw the wells and to substitute other wells. The specified wells represent the necessary wells if approximately $16.3 million is raised and the partnership takes 100% of the interest in the wells. The managing general partner does not anticipate that the wells will be selected in the order in which they are set forth, and it has not proposed any other wells if:

- a greater amount is raised;
- the partnership takes a lesser interest in the wells; or
- the wells are substituted.

The managing general partner has not authorized any person to make any representations to you concerning the possible inclusion of any other wells which will be drilled by the partnership and you should rely only on the information in this prospectus.

The currently proposed wells will be assigned unless there are circumstances which, in the managing general partner's opinion, lessen the relative suitability of the wells. These considerations include:

- the amount of the subscription proceeds;
- the latest geological and production data available;
- potential title problems;
- approvals by federal and state departments or agencies;
- agreements with other interest owners in the wells; and
- continuing review of other properties which may be available.

Any substituted and/or additional wells will meet the same general criteria for development potential as the currently proposed wells and will generally be located in areas where the managing general partner or its affiliates have previously conducted drilling operations. You, however, will not have the opportunity to evaluate for yourself the relevant production and geological information for the substituted and/or additional wells.

The purpose of the information regarding the currently proposed wells is to help you evaluate the economic potential and risks of drilling the proposed wells. This includes production information for wells in the general area of the proposed well which the managing general partner believes is an important indicator in evaluating the economic potential of any well to be drilled. There, however, can be no assurance that a well drilled by the partnership will experience production comparable to the production experienced by wells in the surrounding area since the geological conditions in these areas can change in a short distance.

When reviewing production information for each well offsetting or in the general area of a well proposed to be drilled you should consider the factors set forth below.

- The length of time which the well has been on-line and the period for which production information is shown. Generally, the longer the period for which production is shown the more reliable the information.

- Production from a well declines throughout the life of the well but the rate of decline, the "decline curve," may be affected by the operation of the well. Decline curves also vary depending on the geological location of the well.

- The greatest volume of production from a well usually occurs in the early period of well operations and may indicate a greater reserve volume than the well actually has. This period of flush production can vary depending on the location of the well and how the well is operated.

- The production information for some wells is incomplete or very limited. The designation "N/A" means:

- the production information was not available to the managing general partner; or

- if the managing general partner was the operator, then the well was not completed or on-line as of the date the information was prepared.

- Production information for wells located close to a proposed well tends to be more relevant than production information for wells located farther away, although even with wells located close together well performance and the volume of production from the wells can be much different.

- Consistency in production among wells tends to confirm the reliability and predictability of the production.

To help you become familiar with the proposed wells the information set forth below is included.

- Western Pennsylvania (Clinton/Medina Geological Formation).

- A map of western Pennsylvania and eastern Ohio showing their counties.

- Lease information for western Pennsylvania.

- A Location and Production Map for western Pennsylvania showing the proposed wells and the wells in the area.

- Production data for western Pennsylvania.

- United Energy Development Consultants, Inc.'s geologic evaluation for western Pennsylvania.

- Fayette County, Pennsylvania (Mississippian/Upper Devonian Sandstone Reservoirs).

- A map of western Pennsylvania showing Fayette and Greene Counties.

- Lease information for Fayette and Greene Counties, Pennsylvania.

- A Location and Production Map for Fayette and Greene Counties, Pennsylvania showing the proposed wells and the wells in the area.

- Production data for Fayette and Greene Counties, Pennsylvania.

- The managing general partner's geologic evaluation for Fayette and Greene Counties.

- Southern Ohio (Clinton/Medina Geological Formation).

- A map of southern Ohio showing its counties.

- Lease information for southern Ohio.

- A Location and Production Map for southern Ohio showing the proposed wells and the wells in the area.

- Production data for southern Ohio.

- The managing general partner's geologic evaluation for southern Ohio.

MAP OF WESTERN PENNSYLVANIA

AND

EASTERN OHIO

[MAP]

LEASE INFORMATION

FOR

WESTERN PENNSYLVANIA

PROSPECT NAME	COUNTY	EFFECTIVE DATE*	EXPIRATION DATE*	LANDOWNER ROYALTY	OVERRIDING ROYALTY INTEREST TO THE MANAGING GENERAL PARTNER	OVERRIDING ROYALTY INTEREST TO 3RD PARTIES
1. Byler #88	Crawford	05/20/99	05/20/02	12.5%	0%	0%
2. Byler #89	Crawford	05/20/99	05/20/02	12.5%	0%	0%
3. Williams #11	Crawford	05/20/99	05/20/02	12.5%	0%	0%
4. Williams #12	Crawford	05/20/99	05/20/02	12.5%	0%	0%
5. Bielak #1	Lawrence	03/01/01	03/01/04	12.5%	0%	0%
6. Moore #4	Lawrence	03/30/00	03/30/03	12.5%	0%	0%
7. Sholler #1	Lawrence	08/16/00	08/16/03	12.5%	0%	0%
8. Sholler #2	Lawrence	08/16/00	08/16/03	12.5%	0%	0%
9. McFarland #20	Lawrence	10/19/98	10/19/04	12.5%	0%	0%
10. Moore #2	Lawrence	03/30/00	03/30/03	12.5%	0%	0%
11. Moore #3	Lawrence	03/30/00	03/30/03	12.5%	0%	0%
12. King #7	Mercer	09/23/98	HBP	12.5%	0%	0%
13. Graham #3	Mercer	05/08/91	HBP	12.5%	0%	0%
14. Wise #1	Mercer	09/07/00	09/07/03	12.5%	0%	0%
15. Wise #2	Mercer	09/07/00	09/07/03	12.5%	0%	0%
16. Yanak #2	Mercer	08/16/00	08/16/03	12.5%	0%	0%

17.	Davis #4	Mercer	07/15/87	HBP	12.5%	0%	0%
18.	Jewell #4	Mercer	03/17/87	HBP	12.5%	0%	0%
19.	McCullough #14	Mercer	10/03/88	HBP	12.5%	0%	0%
20.	Morrison #2	Mercer	05/15/89	HBP	12.5%	0%	0%
21.	Nickel #3	Mercer	01/07/88	HBP	12.5%	0%	0%
22.	Seidle #7	Mercer	09/04/90	HBP	12.5%	0%	0%
23.	Keck Unit #3	Mercer	09/13/00	09/13/03	12.5%	0%	0%
24.	Lutz #3	Mercer	06/25/97	06/25/03	12.5%	0%	0%
25.	Mogor #1	Mercer	08/11/00	08/11/03	12.5%	0%	0%
26.	Nych #4	Mercer	10/27/82	HBP	12.5%	0%	0%
27.	Pirka #3	Mercer	07/13/83	HBP	12.5%	0%	0%
28.	Sapala #5	Mercer	04/27/98	HBP	12.5%	0%	0%
29.	Dunhoff #1	Mercer	01/08/99	01/08/02	12.5%	0%	0%
30.	Novosel #1	Mercer	08/27/98	08/27/01	12.5%	0%	0%
31.	White #1	Mercer	09/02/87	HBP	12.5%	0%	0%

	PROSPECT NAME	NET REVENUE INTEREST	NET ACRES	ACRES TO BE ASSIGNED TO PARTNERSHIP
1.	Byler #88	87.5%	100.00	50.00
2.	Byler #89	87.5%	100.00	50.00
3.	Williams #11	87.5%	250.00	50.00
4.	Williams #12	87.5%	250.00	50.00
5.	Bielak #1	87.5%	60.00	50.00
6.	Moore #4	87.5%	234.00	50.00
7.	Sholler #1	87.5%	115.00	50.00
8.	Sholler #2	87.5%	115.00	50.00
9.	McFarland #20	87.5%	42.00	42.00
10.	Moore #2	87.5%	234.00	50.00
11.	Moore #3	87.5%	234.00	50.00
12.	King #7	87.5%	162.00	50.00
13.	Graham #3	87.5%	198.00	50.00

14.	Wise #1	87.5%	95.00	50.00
15.	Wise #2	87.5%	95.00	45.00
16.	Yanak #2	87.5%	47.00	47.00
17.	Davis #4	87.5%	67.96	50.00
18.	Jewell #4	87.5%	76.74	50.00
19.	McCullough #14	87.5%	137.74	50.00
20.	Morrison #2	87.5%	109.84	50.00
21.	Nickel #3	87.5%	138.63	50.00
22.	Seidle #7	87.5%	105.76	50.00
23.	Keck Unit #3	87.5%	9.00	9.00
24.	Lutz #3	87.5%	160.00	50.00
25.	Mogor #1	87.5%	65.00	50.00
26.	Nych #4	87.5%	284.51	50.00
27.	Pirka #3	87.5%	119.00	50.00
28.	Sapala #5	87.5%	185.00	50.00
29.	Dunhoff #1	87.5%	105.00	50.00
30.	Novosel #1	87.5%	42.00	42.00
31.	White #1	87.5%	169.00	50.00

*HBP - Held by Production

1.

LOCATION AND PRODUCTION MAP

FOR

WESTERN PENNSYLVANIA

[MAP]

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PRODUCTION DATA

FOR

WESTERN PENNSYLVANIA

The Production Data provided in the table below is not intended to imply that the wells to be drilled by the partnership will have the same results, although it is an important indicator in evaluating the economic potential of any well to be drilled by the partnership.

```
ID
DATE       MOS              TOTAL        TOTAL     LATEST
NUMBER       OPERATOR                    WELL NAME         COMPLT'D
ON LINE            MCF        LOGGERS    30 DAY
CLINTON/MEDINA   DEPTH      PROD.
-----------------------------------------------------------------------------------------------------------------------
20022  The Peoples Nat. Gas Co.  Sokevitz #1               12/14/79  Plugged
& Abandoned             4202      N/A
20026  The Peoples Nat. Gas Co.  Courtney, W.T.               N/A
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Shallow Well 640 N/A
20077 North Coast Energy Cimperman #1 03/10/94
N/A N/A 6453 N/A
20116 The Peoples Nat. Gas Co. Fleck #1 08/11/75
N/A N/A 9196 N/A
20185 Atlas Resources, Inc. Reed #4
08/03/98 30 35749 6144 574
20215 Atlas Resources, Inc. Mikolz #1
10/27/98 29 57343 6148 956
20230 Wainoco Oil & Gas Bell #1 06/23/81
N/A N/A 5180 N/A
20232 Wainoco Oil & Gas Kleinhans #2 05/21/81
N/A N/A 5293 N/A
20246 Wainoco Oil & Gas Kleinhans #3 05/29/81
N/A N/A 5198 N/A
20247 Wainoco Oil & Gas Thompson #10 06/14/81
N/A N/A 5220 N/A
20265 Wainoco Oil & Gas Newbold #1 07/08/81
N/A N/A 5275 N/A
20272 Atlas Resources, Inc. Best #3
11/01/99 12 16976 6292 926
20275 Atlas Resources, Inc. Shaffer Unit #6
01/04/00 12 26701 6337 1111
20280 Atlas Resources, Inc. Byler #72
01/12/00 13 2808 6283 154
20284 Atlas Resources, Inc. Kendall #1
12/10/00 4 19106 6254 8418
20285 Atlas Resources, Inc. Kendall #2
02/01/00 10 37578 6315 3695
20286 Atlas Resources, Inc. Clark #7
02/14/00 11 14158 6326 603
20287 Atlas Resources, Inc. Misco #1
09/25/00 6 8524 6300 1060
20289 Atlas Resources, Inc. Balog #1
02/06/00 6 8031 6193 1102
20292 Atlas Resources, Inc. Telesz #2
03/13/00 12 14759 6317 631
20299 Atlas Resources, Inc. Mitcheltree #2
09/09/00 6 13466 6332 2485
20301 Atlas Resources, Inc. Reeher #3
12/12/00 3 2354 6412 1121
20302 Atlas Resources, Inc. Telesz #3
12/06/00 3 364 6405 235
20310 Atlas Resources, Inc. Wilson #7
01/15/01 1 1086 6403 N/A
20311 Atlas Resources, Inc. McConnell #2
01/22/01 2 72 6309 61
20315 Atlas Resources, Inc. Griffith #2
02/16/01 1 242 6453 N/A
20316 Atlas Resources, Inc. Lahr #1

02/10/01 1 206 6385 N/A
20320 Atlas Resources, Inc. Telesz #5 03/16/01
N/A N/A 6405 N/A
20551 Atlas Resources, Inc. Bartholomew, P. #1
05/18/84 159 54940 5795 251
20604 Atlas Resources, Inc. Nych Unit #1
05/05/84 159 33762 5652 90
20612 Atlas Resources, Inc. Horvath, E. #2
07/07/84 200 32582 5755 171
20620 Atlas Resources, Inc. Hoagland-Hofius Unit #1
07/20/84 159 67770 5742 291
20624 Atlas Resources, Inc. Buchanan-Oris Unit #1
08/02/84 159 37861 5791 487
20625 Atlas Resources, Inc. Thompson Unit #1
08/13/84 159 26266 5768 105
20626 Atlas Resources, Inc. Plymire #1 11/03/84 Plugged
& Abandoned 5784 N/A
20629 Atlas Resources, Inc. Pirka, J. #2
11/14/84 159 91564 5703 364

The Production Data provided in the table below is not intended to imply that the wells to be drilled by the partnership will have the same results, although it is an important indicator in evaluating the economic potential of any well to be drilled by the partnership.

ID
DATE MOS TOTAL TOTAL LATEST
NUMBER OPERATOR WELL NAME COMPLT'D
ON LINE MCF LOGGERS 30 DAY
CLINTON/MEDINA DEPTH PROD.

20640 Atlas Resources, Inc. Tomko #1
11/27/84 159 54015 5724 192
20641 Atlas Resources, Inc. Horodnic #1
11/19/84 159 35622 5815 128
20645 Atlas Resources, Inc. Buchanan Unit #1
10/18/84 159 72606 5769 317
20655 Atlas Resources, Inc. Horvath #4
11/30/84 195 86315 5698 408

20711	Atlas Resources, Inc.	Smith, R. #1			
09/10/85	159		51932	5726	264
20712	Atlas Resources, Inc.	Grundy #1			
01/18/86	159		70494	5626	443
20713	Atlas Resources, Inc.	Tetrick #1			
09/19/85	159		57287	5704	219
20715	Atlas Resources, Inc.	Horvath-Erickson #1			
08/03/85	159		140647	5630	552
20721	Atlas Resources, Inc.	Root Unit #1			
08/15/85	159		44448	5739	231
20727	Atlas Resources, Inc.	Smith-Tetrick #1			
09/13/85	159		62410	5725	282
20739	Atlas Resources, Inc.	Clarke, B.D. #1			
11/13/85	182		158371	5495	425
20760	Atlas Resources, Inc.	Foltz, C. #1			
12/04/85	182		168545	5585	358
20761	Atlas Resources, Inc.	Foltz, C. #2			
01/04/86	182		173846	5555	523
20770	Atlas Resources, Inc.	Martuccio #1			
11/22/85	159		107649	5675	473
20779	Atlas Resources, Inc.	Greenwalt-Finzel Unit #1			
01/28/86	159		102542	5635	426
20780	Atlas Resources, Inc.	Senkosky #1			
12/15/85	159		207415	5587	837
20782	Atlas Resources, Inc.	Finzel-Johnson Unit #1			
12/04/85	159		122890	5618	378
20791	Atlas Resources, Inc.	Grundy-Whitman Unit #1			
02/10/86	159		84665	5581	406
20844	Atlas Resources, Inc.	Bronich #1			
02/09/87	169		105174	5557	318
20847	Atlas Resources, Inc.	Gaines #1			
01/04/88	158		102596	5645	313
20856	Atlas Resources, Inc.	Miller Unit #1			
02/01/88	158		112381	5565	328
20857	Atlas Resources, Inc.	Kovach #1			
01/06/88	158		177337	5432	544
20859	Atlas Resources, Inc.	Sperring #1			
02/16/88	159		111580	5580	439
20860	Atlas Resources, Inc.	Sperring #2			
02/06/88	158		90047	5580	261
20861	Atlas Resources, Inc.	Welch #1			
02/23/88	157		119943	5579	367
20868	Atlas Resources, Inc.	Leali #5			
03/01/88	157		46295	5565	54
20891	Atlas Resources, Inc.	Hayla #1			
04/06/88	156		69544	5996	N/A
20934	Atlas Resources, Inc.	McCullough #2			
03/19/89	144		128922	5409	322
20948	Atlas Resources, Inc.	Kutcher #1			
03/03/89	143		89977	5613	306

20957	Atlas Resources, Inc.	McCullough #5	02/15/89	144	101122	5508	193
20958	Atlas Resources, Inc.	Shaffer #1	03/16/89	145	131197	5653	450
20959	Atlas Resources, Inc.	Jewell #1	03/19/89	144	100009	5581	302
20965	Atlas Resources, Inc.	Edell Unit #1	02/23/89	145	133850	5623	403
20998	Atlas Resources, Inc.	McCullough #3	03/23/89	144	78268	5524	269
21000	Atlas Resources, Inc.	Davis #1	03/23/89	144	109605	5484	337
21004	Atlas Resources, Inc.	Minnick #1	03/30/89	143	105013	5469	360

The Production Data provided in the table below is not intended to imply that the wells to be drilled by the partnership will have the same results, although it is an important indicator in evaluating the economic potential of any well to be drilled by the partnership.

CLINTON/MEDINA

ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D	MOS ON LINE	TOTAL MCF	TOTAL LOGGERS DEPTH	LATEST 30 DAY PROD.
21005	Atlas Resources, Inc.	Stambaugh #1	03/14/90	133	130660	5751	357
21009	Atlas Resources, Inc.	Morrison #1	01/19/90	134	56847	5630	275
21010	Atlas Resources, Inc.	Magargee #1	01/31/90	134	116787	5736	355
21012	Atlas Resources, Inc.	Nickel #2	02/14/90	133	92520	5422	275
21013	Atlas Resources, Inc.	Sailar #1	01/25/90	134	110616	5676	464
21014	Atlas Resources, Inc.	Meade #1	01/16/90	135	137769	5541	504
21015	Atlas Resources, Inc.	Bagnall #1					

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02/03/90     134               188394       5648       568
21016  Atlas Resources, Inc.     Jefferson Twp. #1A
01/23/90     134               105498       5735       461
21017  Atlas Resources, Inc.     Babinka #1
01/13/90     135               151261       5450       377
21018  Atlas Resources, Inc.     McCullough Unit #7
01/10/90     135                69379       5588       252
21019  Atlas Resources, Inc.     O'Shany Unit #1
02/06/90     134               112556       5475       475
21021  Atlas Resources, Inc.     Jewell #3
01/29/90     134                96519       5523       367
21025  Atlas Resources, Inc.     Bukus #1
02/22/90     133               127128       5365       435
21027  Atlas Resources, Inc.     Jewell #2
03/06/90     132               114848       5629       391
21029  Atlas Resources, Inc.     Angermeier #1
01/19/90     134               122249       5518       356
21035  Atlas Resources, Inc.     Jewell #5                    02/23/90  Plugged
& Abandoned               5728       N/A
21038  Atlas Resources, Inc.     Stambaugh #5
02/08/90     134               204899       5602       761
21043  Atlas Resources, Inc.     Stambaugh #3
02/13/90     134               119357       5563       433
21058  Atlas Resources, Inc.     Besco #2
04/02/90     130               222549       5412       686
21108  Atlas Resources, Inc.     Besco #3
09/18/90     126                65460       5427       95
21123  Atlas Resources, Inc.     Angermeier Unit #2
01/15/91     123               118470       5567       N/A
21126  Atlas Resources, Inc.     Stambaugh #2
02/06/91     120                94704       5528       318
21133  Atlas Resources, Inc.     Stambaugh #4
01/31/91     122               234051       5589       433
21139  Atlas Resources, Inc.     Tralich #1
01/09/91     123               156170       5728       512
21154  Atlas Resources, Inc.     Babnis Unit #1
01/08/91     123                94268       5680       528
21163  Atlas Resources, Inc.     Ealy #1
03/20/91     119               115031       5439       427
21176  Atlas Resources, Inc.     Seidle #2A
12/14/90     123                45066       5388       54
21177  Atlas Resources, Inc.     Blank #1
02/01/91     122               114902       5504       445
21180  Atlas Resources, Inc.     Seidle Unit #3
01/28/91     122                77269       5412       352
21185  Atlas Resources, Inc.     Dunham #1
02/02/91     122                91066       5386       322
21192  Atlas Resources, Inc.     Murcko #2
02/12/91     112               117762       5579       N/A
21222  Everflow Eastern          Theofolis, G. Unit #1      02/14/91
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				N/A	N/A	5601	N/A	
21240	Capital Oil & Gas	Mann, J. & B. #1	N/A	N/A	N/A	5600	N/A	
21274	Atlas Resources, Inc.	Murcko #1		03/06/91	120	100146	5761	422
21369	Quaker State	Breese #1	09/22/91	N/A	N/A	5504	N/A	
21376	Atlas Resources, Inc.	Rollinson Unit #7		10/06/91	114	76075	5597	2

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ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D	DATE ON LINE	MOS	TOTAL MCF	TOTAL LOGGERS DEPTH CLINTON/MEDINA	LATEST 30 DAY PROD.
21525	Atlas Resources, Inc.	Sealand #3		12/07/92	98	145638	6136	394
21569	Tipka A.W. Oil & Gas	Byler, J. & K. #1	09/19/92	N/A	N/A	6036	N/A	
21580	Atlas Resources, Inc.	Mastarone #1		10/10/92	98	197901	6211	24
21586	Atlas Resources, Inc.	Howard #1		10/22/92	94	19262	6345	73
21599	Atlas Resources, Inc.	Diegan #2		10/17/92	100	15288	5748	6
21623	Atlas Resources, Inc.	Halansky #2		01/06/93	98	243207	6378	1129
21633	Atlas Resources, Inc.	Keck #1		12/09/92	97	84346	6334	375
21635	Atlas Resources, Inc.	Young #5		04/05/93	95	22248	6291	218
21654	Atlas Resources, Inc.	Schafer #4		11/01/93	88	125543	6356	170

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21662  Atlas Resources, Inc.     Lawrence #1
01/19/93     97               114806       6200       507
21671  Atlas Resources, Inc.     Clark #4
02/07/93     96                30403       6310       157
21717  Atlas Resources, Inc.     White #3
12/06/93     85                60958       6244       275
21736  Atlas Resources, Inc.     Lipaichan Unit #1
10/14/94     77                14818       6350       62
21743  Atlas Resources, Inc.     USX #2
10/26/93     89               225810       6410       903
21761  Atlas Resources, Inc.     Coyer #1
12/10/93     87                66857       6335       256
21811  Atlas Resources, Inc.     Nelson #2
02/09/94     85               119133       6095       664
21830  Atlas Resources, Inc.     Peters #2
11/30/93     86                48676       6023       330
21863  Atlas Resources, Inc.     Bartholomew #3
01/28/94     81               118941       5813       670
21866  Atlas Resources, Inc.     Winder #1
03/09/94     83                79391       6341       317
21873  Atlas Resources, Inc.     peter #3
02/15/94     85                57102       6020       364
21900  Atlas Resources, Inc.     Sealand Unit #2
02/20/94     85                36466       6078       234
21912  Atlas Resources, Inc.     Reed Unit #1
07/14/94     78               125065       6295       457
21913  Atlas Resources, Inc.     Roberts #1
06/26/94     78                18741       6015       122
21914  Atlas Resources, Inc.     Mills #3
10/11/94     77                56333       5891       301
21915  Atlas Resources, Inc.     Peters Unit #1
07/14/94     78                64333       5915       392
21917  Atlas Resources, Inc.     Coss #1
07/21/94     78                16686       6421       110
21919  Atlas Resources, Inc.     Heath #1
07/08/94     78               166711       6250       628
21921  Atlas Resources, Inc.     Graham #1
07/02/94     78                34998       5922       228
21923  Atlas Resources, Inc.     Winder #2
06/30/94     78                95308       6336       504
21927  Atlas Resources, Inc.     Mills #2
07/09/94     78               134716       6000       889
21933  Atlas Resources, Inc.     Igersheim #1
10/07/94     76                43985       6385       370
21941  Atlas Resources, Inc.     Bartholomew #4
08/16/94     78                78947       5791       397
21952  Atlas Resources, Inc.     Coyer #2
10/02/94     77                60913       6394       353
21957  Atlas Resources, Inc.     Coss #3
02/06/95     73                65899       6401       458
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21964	Atlas Resources, Inc.	Reynolds #1	08/27/94	78	172786	6365	N/A
21968	Atlas Resources, Inc.	Coss Unit #4	11/30/94	75	37630	6389	211

The Production Data provided in the table below is not intended to imply that the wells to be drilled by the partnership will have the same results, although it is an important indicator in evaluating the economic potential of any well to be drilled by the partnership.

ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D ON LINE	MOS CLINTON/MEDINA	TOTAL MCF	TOTAL LOGGERS DEPTH	LATEST 30 DAY PROD.
22013	Atlas Resources, Inc.	Andrusky #1	06/27/95	65	64539	5974	537
22016	Atlas Resources, Inc.	Andrusky #2	02/09/95	72	166368	5904	763
22037	Atlas Resources, Inc.	Kelly Unit #1	03/07/95	71	250405	6053	964
22060	Atlas Resources, Inc.	Williamson #1	02/09/95	72	80056	6305	659
22095	Atlas Resources, Inc.	Romain #3	07/23/95	65	71768	5842	338
22097	Atlas Resources, Inc.	Rambold #2	08/24/95	63	98137	5906	694
22111	Atlas Resources, Inc.	Romain #4	10/20/95	65	247100	5906	1050
22113	Atlas Resources, Inc.	Romain #5	08/18/95	62	41670	5879	372
22144	Atlas Resources, Inc.	Devonshire #1	11/17/95	62	69715	5989	535
22166	Atlas Resources, Inc.	Goebel #1	01/14/96	62	95974	5891	787
22167	Atlas Resources, Inc.	Smith Unit #5	01/07/96	62	104367	6016	870
22177	Atlas Resources, Inc.	Rambold #3					

```
01/25/96     62                 37686       5891        288
22179  Atlas Resources, Inc.     Thompson #4
01/21/96     62                111782       5921        817
22269  Atlas Resources, Inc.     Ealy #3
09/01/96     54                 61463       5451        480
22281  Atlas Resources, Inc.     Bartholomew #5
02/19/97     49                138657       5819       1461
22282  Atlas Resources, Inc.     Bartholomew #6
09/08/96     54                 56775       5824        634
22306  Atlas Resources, Inc.     McDowell #11
01/05/97     51                 65999       6067        622
22347  Atlas Resources, Inc.     Ealy Unit #5
03/03/97     48                 69690       5379        604
22352  Atlas Resources, Inc.     Rueberger Unit #1
02/26/97     47                 56331       5851        608
22358  Atlas Resources, Inc.     Carrier #1
03/08/97     48                 68288       5321        716
22401  Atlas Resources, Inc.     Beighley #1
08/25/97     43                 62362       5835        845
22403  Atlas Resources, Inc.     George #1
09/01/97     43                 64378       5880        618
22451  Atlas Resources, Inc.     Zrile #1
07/19/99     20                 26556       5825       1024
22469  Atlas Resources, Inc.     Seamans #1
07/19/98     30                 28505       5963        508
22472  Atlas Resources, Inc.     Ellis #1
09/04/98     30                 47034       6415        788
22475  Atlas Resources, Inc.     Root #2
03/01/98     35                 22487       5911        288
22483  Atlas Resources, Inc.     Seamans #3
03/14/98     34                 54410       5960        856
22484  Atlas Resources, Inc.     Seamans #2
03/31/98     34                 46892       5982        675
22492  Atlas Resources, Inc.     Byler #25
03/25/98     34                 37700       5848        609
22493  Atlas Resources, Inc.     Wes. Res. Sports #1
03/22/98     36                 15065       5756        268
22496  Atlas Resources, Inc.     Byers #2
03/19/98     34                 27338       5893        474
22524  Atlas Resources, Inc.     McFarland #3
09/11/98     30                 49190       5919        785
22530  Atlas Resources, Inc.     Hughes #2
08/23/98     30                 11415       5894        246
22535  Atlas Resources, Inc.     McFarland #4
08/15/98     30                 32093       5914        623
22538  Atlas Resources, Inc.     Book #1
03/31/99     23                 15302       5905        473
22550  Atlas Resources, Inc.     Wareham #1
08/22/98     30                 20132       5769        289
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The Production Data provided in the table below is not intended to imply that the wells to be drilled by the partnership will have the same results, although it is an important indicator in evaluating the economic potential of any well to be drilled by the partnership.

CLINTON/MEDINA

ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D	MOS ON LINE	TOTAL MCF	TOTAL LOGGERS DEPTH	LATEST 30 DAY PROD.
22560	Atlas Resources, Inc.	Thompson #9	10/22/98	28	23276	5781	455
22564	Atlas Resources, Inc.	Sharon Auto Wr. Unit #1A	09/29/98	28	43553	5809	826
22566	Atlas Resources, Inc.	Santelli #1	10/20/99	17	21724	5882	746
22568	Atlas Resources, Inc.	Byers #3	10/19/99	17	26492	5829	767
22570	Atlas Resources, Inc.	Donner #1	10/05/98	29	46748	5902	796
22580	Atlas Resources, Inc.	McFarland #5	02/02/99	26	17082	5900	471
22585	Atlas Resources, Inc.	Minner #1	03/10/99	24	11512	5795	318
22589	Atlas Resources, Inc.	Paglia #2	02/21/99	25	9759	5782	224
22590	Atlas Resources, Inc.	Thompson #8	10/26/99	17	39649	5805	1359
22595	Atlas Resources, Inc.	Thompson #7	02/19/99	25	31846	5750	659
22608	Atlas Resources, Inc.	Maranuk #1	03/09/99	24	13247	5543	204
22610	Atlas Resources, Inc.	Jovenall #1	03/02/99	24	18923	5889	390
22616	Atlas Resources, Inc.	Campbell #6	02/28/99	24	25146	5787	651
22617	Atlas Resources, Inc.	Cameron #2	03/10/99	24	18819	5843	482

22647 Atlas Resources, Inc.		Minner #2		
08/05/99	20	20673	5876	603
22653 Atlas Resources, Inc.		Buckwalter Unit #1		
07/31/99	19	56013	5834	2063
22663 Atlas Resources, Inc.		Thompson #10		
10/30/00	4	5308	5728	1110
22674 Atlas Resources, Inc.		Biros #1		
08/23/99	18	22914	5723	1178
22681 Atlas Resources, Inc.		Shardy #2		
09/24/99	8	5429	5482	375
22687 Atlas Resources, Inc.		Ammann #1		
09/19/99	9	6103	5513	407
22696 Atlas Resources, Inc.		King #4		
10/01/99	9	4694	5466	282
22714 Atlas Resources, Inc.		Combine #1		
12/19/99	14	60192	5811	1963
22732 Atlas Resources, Inc.		Gilliland #1		
12/03/99	8	9437	5893	1096
22733 Atlas Resources, Inc.		Jovenall #3		
12/09/99	8	3323	5883	349
22735 Atlas Resources, Inc.		Horodnic #2		
12/10/99	14	30171	5890	1488
22743 Atlas Resources, Inc.		Whalen #1		
12/21/99	14	22306	5890	973
22749 Atlas Resources, Inc.		Shardy #1		
01/12/00	8	3663	5535	174
22763 Atlas Resources, Inc.		Racketa Unit #2		
01/18/00	8	4962	5551	278
22772 Atlas Resources, Inc.		Herriott #1		
01/24/00	13	17266	5886	987
22774 Atlas Resources, Inc.		Lehto #2		
01/30/00	13	23133	5855	1020
22786 Atlas Resources, Inc.		Aiken #3		
02/20/00	11	23725	5629	1764
22789 Atlas Resources, Inc.		Byler #76		
02/27/00	11	10223	5865	558
22790 Atlas Resources, Inc.		Gearhart #1		
02/21/00	11	18194	5807	1210
22791 Atlas Resources, Inc.		Byler #80		
03/04/00	8	14402	5899	1355
22811 Atlas Resources, Inc.		Shaffer #7		
12/11/00	3	4464	5508	2402
22816 Atlas Resources, Inc.		Minner #3		
10/18/00	5	4418	5827	773

The Production Data provided in the table below is not intended to imply that the wells to be drilled by the partnership will have the same results, although it is an important indicator in evaluating the economic potential of any well to be drilled by the partnership.

ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D	DATE ON LINE	MOS ON LINE	TOTAL MCF	TOTAL LOGGERS DEPTH	LATEST 30 DAY CLINTON/MEDINA PROD.
22817	Atlas Resources, Inc.	Scott #1		11/09/00	4	11027	5771	3307
22818	Atlas Resources, Inc.	Negrea Unit #1		10/24/00	5	9204	5887	1446
22819	Atlas Resources, Inc.	Aiken #2		10/07/00	6	16571	5595	2982
22824	Atlas Resources, Inc.	Schwartz Unit #3		11/04/00	5	9083	5759	1819
22832	Atlas Resources, Inc.	Mild #2		01/02/01	2	1476	5761	1085
22835	Atlas Resources, Inc.	Leali #8		11/09/00	4	7171	5762	1515
22836	Atlas Resources, Inc.	Tatomirovich #1		01/28/01	1	1919	5877	N/A
22842	Atlas Resources, Inc.	Butchko Unit #1		10/13/00	5	9994	5557	1363
22851	Atlas Resources, Inc.	Revale #1	03/03/01	N/A		N/A	5783	N/A
22868	Atlas Resources, Inc.	Sapala #1	12/14/00	N/A		N/A	5147	N/A
22869	Atlas Resources, Inc.	Jellison #2	N/A	N/A		N/A	N/A	N/A
22882	Atlas Resources, Inc.	Sapala #2	01/03/01	N/A		N/A	5146	N/A
22904	Atlas Resources, Inc.	Nych Unit #2		02/07/01	1	1462	5696	N/A
22919	Atlas Resources, Inc.	Davis #3	05/29/01	N/A		N/A	5715	N/A
22925	Atlas Resources, Inc.	King #6	03/26/01	N/A		N/A	5300	N/A
22929	Atlas Resources, Inc.	McMullen Unit #4	03/20/01	N/A		N/A	5411	N/A
22940	Atlas Resources, Inc.	Cameron #3	06/13/01					

N/A	N/A	5876	N/A	
22942	Atlas Resources, Inc.	Nych #3		05/25/01
N/A	N/A	5716	N/A	
22944	Atlas Resources, Inc.	Sapala Unit #3		06/13/01
N/A	N/A	5137	N/A	
22953	Atlas Resources, Inc.	Byler #81		05/31/01
N/A	N/A	5870	N/A	
22961	Atlas Resources, Inc.	Schuller #1		07/02/01
N/A	N/A	5701	N/A	
22966	Atlas Resources, Inc.	Sapala Unit #4		06/19/01
N/A	N/A	5132	N/A	

UEDC'S

GEOLOGIC EVALUATION

FOR THE

CURRENTLY PROPOSED WELLS

IN

WESTERN PENNSYLVANIA

GEOLOGIC EVALUATION

OF

ATLAS AMERICA PUBLIC #10 LTD PROGRAM

GREATER MERCER COUNTY PROSPECT AREA

PENNSYLVANIA

PROGRAM PROPOSED BY:

ATLAS RESOURCES, INC.

311 ROUSER ROAD

P.O. BOX 611

MOON TOWNSHIP, PA 15108

REPORT SUBMITTED BY:

UEDC

UNITED ENERGY DEVELOPMENT CONSULTANTS, INC.

1715 CRAFTON BLVD.

PITTSBURGH, PA 15205

LOCATION MAP - AREA OF INTEREST

[MAP OF OHIO] **[MAP OF PENNSYLVANIA]**

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INVESTIGATION SUMMARY

OBJECTIVE

The purpose of the following investigation is to evaluate the geologic feasibility and further development of the Greater Mercer County Prospect Area (consisting of Lawrence, Mercer and Crawford Counties in Pennsylvania) as proposed by Atlas Resources, Inc.

AREA OF INVESTIGATION

A portion of this prospect area, herein identified for drilling in Atlas America Public #10 Ltd. Program, contains acreage in the following townships in Mercer, Lawrence and Crawford Counties, Pennsylvania:

Mercer	Lawrence	Crawford

Lackawannock	Shenango	Jefferson	Wilmington	Greenwood
East Lackawannock	Hermitage	Delaware	Washington	
Sandy Creek	Springfield	Findley	Hickory	

Thirty-one (31) drilling prospects will be designated for this program and will be targeted to produce natural gas from Clinton-Medina Group reservoirs, found at an average depth range of approximately 5,100 to 6,300 feet beneath the earth's surface over the prospect area. These will be the only prospects evaluated for the purposes of this report.

METHODOLOGY

The data incorporated into this report was provided by Atlas Resources, Inc. and the in-house archives of UEDC, Inc. Geological mapping and the interpretations by Atlas geologists were also examined. Available "electric" log, completion, and production data on "key" wells within and adjacent to the defined prospect area were utilized to determine productive and depositional trends.

POTENTIAL MARKETS AND PIPELINES

In the area of this drilling program, there are a number of potential purchasers and transporters of natural gas. These include Wheatland Tube Company, Tenneco, National Fuel Supply, National Fuel Distribution and the People's Natural Gas Company.

PROSPECT AREA HISTORY

DRILLING ACTIVITY

The proposed drilling area lies within a region of northwestern Pennsylvania which has been very active for the past decade in terms of exploration for, and exploitation of natural gas reserves. Development within and adjacent to the Mercer Prospect Area has escalated since 1986, with Atlas Resources, Inc. and it's affiliates drilling over eleven hundred (1100) wells during this period. Atlas Resources, Inc. has encountered favorable drilling and production results while solidifying a strong acreage position, and continues to identify and extend productive trends. Drilling is ongoing as of the date of this report with recent wells displaying favorable initial drilling and completion results. Competitive activity has begun both south and east of the prospect area, confirming the Clinton-Medina Group of Lower Silurian age as a viable target for the further development of economic quantities of natural gas.

GEOLOGY

STRATIGRAPHY, LITHOLOGY & DEPOSITION

Regionally, the Clinton-Medina Group was deposited in tide-dominated shoreline, deltaic, and shelf environments and is lithologically comprised of alternating sandstones, siltstones and shales. Productive sandstones are composed of siliceous to dolomitic subarkoses, sublitharenites, and quartz arenites. Reservoir quality sands occur throughout the delta-complex from eastern Ohio through northwestern Pennsylvania and western New York. The Clinton-Medina Group, deposited during the Lower Silurian, overlies the Upper Ordovician age Queenston shale and is capped by the Middle Silurian Reynales Formation. This dolomitic limestone "cap" is known locally to drillers as the "Packer Shell".

Stratigraphically, in descending order, the potentially productive units of the Clinton-Medina Group consist of the: 1) Thorold, 2) Grimsby, 3) Cabot Head, and 4) Whirlpool members. These stratigraphic relationships are illustrated in the following diagram:

STRATIGRAPHIC NAMES-NW PENNSYLVANIA

[CHART]

The WHIRLPOOL is a light gray quartzose sandstone to siltstone ranging in thickness from five (5) to twenty (20) feet. Average porosity values for this sand member range from five (5) to ten (10) percent regionally. Within the area of investigation, porosities in excess of twelve (12) percent occur within localized trends targeted for further development.

The CABOT HEAD is a dark green to black shale, most likely of marine origin. Within the investigated area a CABOT HEAD SANDSTONE has been encountered in numerous wells. This formation has been found to contribute natural gas when reservoir characteristics, including evidence of enhanced permeability, warrant completion. This sand member is considered a secondary target.

The GRIMSBY is the thickest sandstone member of the Clinton-Medina Group. Sand development ranges from ten (10) to forty-five (45) feet within an interval comprised of fine to very

fine, light gray to red sandstones and siltstones broken up by thin dark gray silty shale layers. Average porosity values for the Grimsby are approximately six (6) to (10) percent over the pay interval regionally. Permeability may be enhanced locally by the presence of naturally occurring micro-fractures. Future development focuses on established production trends.

The THOROLD sandstone is the uppermost producing interval of the Clinton-Medina sequence. This interbedded ferric sand, silt and shale interval averages forty (40) to seventy (70) feet, from west to east in the prospect area. Where pay sand development occurs, porosities are in the typical Clinton-Medina group range of six (6) to (10) percent. Permeability may be enhanced locally by the presence of naturally occurring micro-fractures.

RESERVOIR CHARACTERISTICS

Petroleum reservoirs are formed by the presence of an impermeable barrier trapping natural gas of commercial quantities in a more permeable medium. In the Clinton-Medina, this occurs either stratigraphically when a permeable sand containing hydrocarbons encounters an impermeable shale or when a permeable sand changes gradually into a non-permeable sand by a cementation process known as "diagenesis". Thus, this type of trap represents cemented-in hydrocarbon accumulations.

Electric well logs can be used in conjunction with production to interpret reservoir parameters. When sandstones in the Thorold, Grimsby, Cabot Head or Whirlpool develop porosity in excess of 6%, or a bulk density of 2.55 or less, the permeability of the reservoir (which ranges from < 0.l to > 0.2 mD) can become great enough to allow commercial production of natural gas. Small, naturally occurring cracks in the formation, referred to as micro-fractures, can also enhance permeability. A gamma, bulk density, density porosity and neutron log suite showing sand development in the Grimsby, Cabot Head and Whirlpool is illustrated on the following page.

Two other phenomena detected by well logs can occur which are indicators of enhanced permeability. These indicators used to detect productive intervals are:

[CHART]

- Mudcake buildup across the zone of interest - after loading the wellbore with brine fluid and circulating, an interval with enhanced permeability will accept fluid, filtering out the solids and leaving behind a buildup (or mudcake) on the formation wall. This is detectable with a caliper log.

- Invasion profile - during circulation, a brine that has a high conductivity (or low resistivity) that is accepted into the formation (as described above) will change the electrical conductivity of the reservoir rock near and around the wellbore. The resistivity will be low nearest to the wellbore and will increase away from the wellbore. A dual laterolog can be used to detect this profile created by a permeable zone - it records resistivity near the wellbore as well as deeper into the formation. A zone with enhanced permeability will show a separation between the shallow and deep laterologs, while a zone with little or no permeability would cause the two resistivity measurements to read exactly the same. An example follows:

GAMMA RAY LOG **RESISTIVITY LOG**

[CHART]

PRODUCTION CURVE

A model decline curve has been created based on the production histories from approximately 900 wells drilled by Atlas and its programs in the Mercer Fields. This model decline curve is consistent with the average estimated decline curves for over 200 undeveloped well locations in the Mercer Field which were used by Wright & Company, Inc., independent petroleum consultants, in preparing Atlas' year 2000 reserve report. The model decline curve is illustrated in the diagram below:

[GRAPH]

It is important to note that the model decline curve is intended only to present how a well's production may decline from year to year, and does not attempt to predict the average recoverable reserves per well. Also, the model decline curve is a forward-looking statement based on certain assumptions and analyses of historical trends, current conditions and expected future developments. The model decline curve is subject to a number of risks and uncertainties including the risk that the wells are productive but do not produce enough revenue to return the investment made and uncertainties concerning the price of natural gas and oil. Actual results in this drilling program will vary from the model decline curve, although a rapid decline in production within the first several years can be expected.

STATEMENTS

CONCLUSION

UEDC has conducted a geologic feasibility study of the drilling area for ATLAS AMERICA PUBLIC #10 LTD. PROGRAM, which will consist of developmental drilling of the Clinton-Medina Group sands primarily in Mercer, Lawrence and Crawford Counties, Pennsylvania. It is the professional opinion of UEDC that the drilling of wells within this program is supported by sufficient geologic and engineering data.

DISCLAIMER

For the purpose of this evaluation, UEDC did not visit any leaseholds or inspect any of the associated production equipment. Likewise, UEDC has no knowledge as to the validity of title, liabilities, or corporate matters affecting these properties. UEDC does not warrant individual well performance.

NON-INTEREST

We hereby confirm that UEDC is an independent consulting firm and that neither this firm or any of it's employees, contract consultants, or officers has, or is committed to acquire any interest, directly or indirectly, in Atlas Resources, Inc.; nor is this firm, or any employee, contract consultant, or officer thereof, otherwise affiliated with Atlas Resources, Inc. We also confirm that neither the employment of, nor payment of compensation received by UEDC in connection with this report, is on a contingent basis.

Respectfully submitted,

/s/ Robin Anthony

UEDC, Inc.

MAP OF WESTERN PENNSYLVANIA

AND

FAYETTE AND GREENE COUNTIES

[MAP]

LEASE INFORMATION

FOR

FAYETTE AND GREENE COUNTIES

PROSPECT NAME	COUNTY	EFFECTIVE DATE*	EXPIRATION DATE*	LANDOWNER ROYALTY	OVERRIDING ROYALTY INTEREST TO THE MANAGING GENERAL PARTNER	OVERRIDING ROYALTY INTEREST TO 3RD PARTIES
1. Bashour #1	Fayette	1/5/00	1/5/04	12.50%	0%	0%

2.	Bortz #2	Fayette	8/15/00	8/15/02	12.50%	0%	0%
3.	Brant #2	Fayette	6/11/98	6/11/03	12.50%	0%	0%
4.	Bukovitz Tr. 2 #2	Fayette	8/30/99	HBP	12.50%	0%	0%
5.	CFR/USX #5	Fayette	1/4/99	HBP	12.50%	0%	0%
6.	Croftcheck #1	Fayette	12/9/00	12/9/05	12.50%	0%	0%
7.	Darr/USX #2	Fayette	3/15/99	3/15/02	12.50%	0%	0%
8.	Filbert/USX #3	Fayette	3/5/99	HBP	12.50%	0%	0%
9.	Gagglani #1	Fayette	4/16/99	4/16/04	12.50%	0%	0%
10.	Gates/USX #2	Fayette	3/15/99	HBP	12.50%	0%	0%
11.	Genovese #2	Fayette	2/6/01	2/6/04	12.50%	0%	0%
12.	Gilleland #1	Fayette	10/4/00	10/4/05	12.50%	0%	0%
13.	Hall #11	Fayette	7/10/00	7/10/03	12.50%	0%	0%
14.	Hall/Hogsett #8	Fayette	12/10/97	HBP	12.50%	0%	0%
15.	Hall/Hogsett #9	Fayette	12/10/97	HBP	12.50%	0%	0%
16.	Hutcheson #1	Fayette	3/21/01	3/21/06	12.50%	0%	0%
17.	Keslar #6	Fayette	4/9/99	HBP	12.50%	0%	0%
18.	M&Y #1	Fayette	12/23/00	12/23/03	12.50%	0%	0%
19.	Marcinek #1	Fayette	3/5/01	3/5/06	12.50%	0%	0%
20.	McArdle #1	Fayette	11/26/96	11/26/02	12.50%	0%	0%
21.	Newcomer #1	Fayette	3/15/99	3/15/04	12.50%	0%	0%
22.	Plava #1	Fayette	10/14/00	10/14/02	12.50%	0%	0%
23.	Podolinski #1	Fayette	11/20/97	11/20/03	12.50%	0%	0%
24.	Rebidas #1	Fayette	5/29/01	5/29/06	12.50%	0%	0%
25.	Riffle #3	Fayette	4/14/98	HBP	12.50%	0%	0%
26.	Ronco/USX #1	Fayette	3/15/99	3/15/02	12.50%	0%	0%

27. Skovran #10	Fayette	5/17/99	5/17/04	12.50%	0%	0%
28. Skovran #9	Fayette	5/17/99	5/17/04	12.50%	0%	0%
29. Snyder #1	Fayette	2/9/00	2/9/05	12.50%	0%	0%
30. Szuhay #1	Fayette	5/1/01	5/1/02	12.50%	0%	0%
31. Vail #5	Fayette	1/23/01	1/23/03	12.50%	0%	0%
32. Young #1	Fayette	4/29/00	4/29/03	12.50%	0%	0%
33. Biddle #2	Greene	8/31/00	8/31/03	12.50%	0%	0%
34. Harbarger #1	Greene	10/15/98	10/15/01	12.50%	0%	0%
35. Buday #1	Greene	2/5/99	2/4/04	12.50%	0%	0%

PROSPECT NAME	NET REVENUE INTEREST	NET ACRES	ACRES TO BE ASSIGNED TO PARTNERSHIP
1. Bashour #1	87.50%	35.00	20
2. Bortz #2	87.50%	150.00	20
3. Brant #2	87.50%	96.00	20
4. Bukovitz Tr. 2 #2	87.50%	129.24	20
5. CFR/USX #5	87.50%	245.00	20
6. Croftcheck #1	87.50%	95.00	20
7. Darr/USX #2	87.50%	293.81	20
8. Filbert/USX #3	87.50%	247.50	20
9. Gaggiani #1	87.50%	70.91	20
10. Gates/USX #2	87.50%	146.96	20
11. Genovese #2	87.50%	74.51	20
12. Gilleland #1	87.50%	172.00	20
13. Hall #11	87.50%	16.80	16.8
14. Hall/Hogsett #8	87.50%	470.00	20
15. Hall/Hogsett #9	87.50%	470.00	20
16. Hutcheson #1	87.50%	25.00	20
17. Keslar #6	87.50%	223.00	20
18. M&Y #1	87.50%	122.50	20
19. Marcinek #1	87.50%	40.00	20
20. McArdle #1	87.50%	26.81	20
21. Newcomer #1	87.50%	87.00	20
22. Plava #1	87.50%	57.20	20
23. Podolinski #1	87.50%	99.88	20
24. Rebidas #1	87.50%	100.00	20
25. Riffle #3	87.50%	118.81	20

26.	Ronco/USX #1	87.50%	293.81	20
27.	Skovran #10	87.50%	105.00	20
28.	Skovran #9	87.50%	32.23	20
29.	Snyder #1	87.50%	98.72	20
30.	Szuhay #1	87.50%	156.00	20
31.	Vail #5	87.50%	122.52	20
32.	Young #1	87.50%	59.00	20
33.	Biddle #2	87.50%	310.00	20
34.	Harbarger #1	87.50%	102.00	20
35.	Buday #1	87.50%	180.70	20

***HBP - Held by Production**

LOCATION AND PRODUCTION MAP FOR

FAYETTE AND GREENE COUNTIES

[MAP]

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[MAP]

PRODUCTION DATA

FOR

FAYETTE AND GREENE COUNTIES

The Production Data provided in the table below is not intended to imply that the wells to be drilled by the partnership will have the same results, although it is an important indicator in evaluating the economic potential of any well to be drilled by the partnership.

ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D
3	M.E. Davis	Ben Lardin #1	04/08/1956
10	Manufacturers Light & Heat Co	Hogsett #9	10/21/1947
19	Greensboro Gas Co	J.V.Thompson	10/17/1945
29	Carnegie Natural Gas Co	H.C. Frick (Buffington) #2	09/07/1944
34	Greensboro Gas Co	J.V.Thompson #3	02/01/1911
41	Greensboro Gas Co	Hogsett #2	01/01/1922
42	Nollem Oil & Gas Corp.	Lingle (Neff Heirs) #1	05/20/1944
50	Keystone Gas Co	Mercer #1	11/07/1958
51	Greensboro Gas Co	Frasher #1	1918
55	Greensboro Gas Co	Bixler #2	09/27/1941
56	Manufacturers Light & Heat Co	Brown #1	05/21/1945
57	Carnegie Natural Gas Co	H.C.Frick Coke(Ralph)#2	02/05/1945
58	Carnegie Natural Gas Co	H.C.Frick Coke(Ralph)#1	07/22/1944
59	Fayette County Gas Co	Jeffries #1	10/01/1901
62	Manufacturers Light & Heat Co	Puritan Coke Co	08/15/1945
63	Manufacturers Light & Heat Co	Hogsett #6	02/17/1945
66	Manufacturers Light & Heat Co	Hogsett #8	05/26/1947
71	Peoples Natural Gas Co	DiCarlo #1	N/A
78	Orville Eberly	Herrington #1	05/12/1945
84	Greensboro Gas Co	Hogsett #5	08/30/1944
85	Peoples Natural Gas Co	Vail #2	06/20/1946
89	Manufacturers Light & Heat Co	Veltri #1	12/01/1942
118	Peoples Natural Gas Co	Kovach #1	02/07/1943
119	W.Burkland	Natale #1	06/19/1944
121	W. Burkland	J.A. Baer #2	10/11/1937
122	Equitable Gas Co	H.C. Frick (Buffington) #2	02/2/1945
123	Carnegie Natural Gas Co	H.C.Frick Coke(Footedale)#1	10/01/1945
124	Carnegie Natural Gas Co	H.C. Frick Coke (Leckrone)#2	05/3/1944
134	Castle Gas Co	Ed & Claire Donley #1	10/13/1944
135	Castle Gas Co	John Palsi #1	06/15/1915
136	Castle Gas Co	Bryner Lumber Co. #1	02/12/1916
137	Castle Gas Co	Consol. Gas Supply #1	10/05/1915
139	Castle Gas Co	William & Diane Presct #1	10/13/1914
140	Castle Gas Co	Lauretta Duff	1915

ID NUMBER	TOTAL MOS ON LINE	TOTAL MCF	LOGGERS DEPTH	LATEST 30 DAY PROD.*
3	N/A	N/A	3814	N/A
10	N/A	N/A	N/A	N/A
19	N/A	N/A	3044	N/A
29	N/A	101,000/1959	3700	N/A

34	N/A	N/A	2900	N/A
41	N/A	N/A	1968	N/A
42	N/A	N/A	3473	N/A
50	N/A	N/A	2180	N/A
51	N/A	N/A	3191	N/A
55	N/A	N/A	1760	N/A
56	N/A	N/A	2608	N/A
57	N/A	105,000/1963	2595	N/A
58	228	86,428/1963	N/A	N/A
59	N/A	N/A	1408	N/A
62	N/A	N/A	1615	N/A
63	N/A	N/A	2793	N/A
66	N/A	N/A	2475	N/A
71	N/A	N/A	1975	N/A
78	N/A	N/A	3494	N/A
84	N/A	N/A	2128	N/A
85	N/A	171,000/1974	2790	N/A
89	N/A	N/A	1474	N/A
118	N/A	263,000/1992	3162	N/A
119	N/A	267,000/1992	3101	N/A
121	N/A	215,000/1980	3610	N/A
122	N/A	337,000/1995	3041	N/A
123	N/A	192,000/1995	3265	N/A
124	N/A	80,889/1998	1368	N/A
134	N/A	344,000	3845	N/A
135	N/A	147,000	1278	N/A
136	N/A	564,000	2550	N/A
137	N/A	562,000	3017	N/A
139	N/A	N/A	1278	N/A
140	N/A	184,000/1990	1361	N/A

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ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D

141	Castle Gas Co	Brock #2	1916
152	Castle Gas Co	Teggert #2	12/18/1941
156	Castle Gas Co	Harris #2	09/16/1941
158	Castle Gas Co	Julia Kider	06/1/1903
159	Castle Gas Co	Elizabeth Morris	05/14/1947
167	W.Burkland	Salina Rider Heirs #1	05/22/1931
168	Columbia Gas Transmission Corp	Rider #1	07/29/1942
178	Castle Gas Co	Ruby #1	01/24/1943
184	Castle Gas Co	Conrail #2	10/01/1943
190	Columbia Gas Transmission Corp	E.Areford #1	11/18/1897
197	W.Burkland	Horak #1	1946
199	Wahler & Powers	J.R. Gray #27	07/26/1947
202	W.Burkland	J.Desko #2	08/28/1944
206	W. Burkland	G. Morris #1	1939
207	W.Burkland	G. Morris #2	1939
208	W.Burkland	G. Morris #3	1939
210	W.Burkland	D. Sumey #1	04/22/1905
219	W.Burkland	J.R. Gray #2	N/A
224	W.Burkland	Weirton Coal Co #1	07/25/1945
225	W.Burkland	Heller Coal Co #1	09/26/1958
236	W.Burkland	Salina Rider Heirs #1	05/22/1931
242	Fox Brothers	Roy Griffin #1	05/28/1953
243	Fox Brothers	Roy Griffin #2	10/02/1952
248	Peoples Natural Gas Co	Arison #1	01/13/1950
253	Duquesne Natural Gas Co.	Ross #1	04/25/1942
20026	Tri-State Drilling Co.	H. McCracken #2	01/4/1962
20028	Tri-State Drilling Co.	E. Raymond Cooper #1	03/23/1962
20031	Ford & Gaskill	G. Emerson Work #1	08/1/1962
20032	Peoples Natural Gas Co	G. Emerson Work #1	05/1/1963
20034	Peoples Natural Gas Co	G.Emerson Work #1	06/25/1963
20036	James I. Shearer	C. Lerch #1	02/21/1964
20037	W.Burkland	Work #1	01/23/1964
20038	Peoples Natural Gas Co	Work #1	05/13/1964
20039	F.& E. Drilling Co.	J. Ruby #1	04/18/1964
20040	James I. Shearer	A. Ewing #1	08/08/1964

ID NUMBER	TOTAL MOS ON LINE	TOTAL MCF	LOGGERS DEPTH	LATEST 30 DAY PROD.*
141	N/A	314,000/1990	3114	N/A
152	N/A	N/A	2591	N/A
156	N/A	N/A	2556	N/A
158	N/A	N/A	1883	N/A
159	N/A	N/A	2538	N/A
167	N/A	N/A	2382	N/A
168	N/A	477,000/1990	2579	N/A
178	N/A	N/A	3207	N/A

184	N/A	N/A	3026	N/A
190	N/A	N/A	2147	N/A
197	N/A	N/A	2394	N/A
199	N/A	N/A	2452	N/A
202	N/A	N/A	2574	N/A
206	N/A	N/A	N/A	N/A
207	N/A	N/A	N/A	N/A
208	N/A	N/A	N/A	N/A
210	N/A	N/A	N/A	N/A
219	N/A	N/A	N/A	N/A
224	N/A	N/A	1906	N/A
225	N/A	N/A	1892	N/A
236	N/A	N/A	2382	N/A
242	N/A	N/A	3628	N/A
243	N/A	N/A	2188	N/A
248	N/A	N/A	3615	N/A
253	N/A	N/A	2600	N/A
20026	N/A	N/A	1356	N/A
20028	N/A	N/A	1520	N/A
20031	N/A	N/A	1376	N/A
20032	N/A	N/A	1402	N/A
20034	N/A	N/A	1457	N/A
20036	N/A	N/A	3750	N/A
20037	N/A	N/A	1350	N/A
20038	N/A	N/A	4005	N/A
20039	N/A	N/A	1347	N/A
20040	N/A	N/A	3821	N/A

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ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D
20042	F.& E. Drilling Co.	E. Work #2	06/17/1964
20044	Tri-State Drilling Co.	H. McCracken #4	09/05/1954
20046	F.& E. Drilling Co.	Work #3	09/18/1964

20048	N/A	E. Guy Linderman #1	N/A
20054	M.C.Brumage	S.Gorley #1	10/15/1943
20059	M.C.Brumage	DiCarlo #2	12/29/1967
20103	Peoples Natural Gas Co	J.A. Coffman #1	02/12/1947
20108	Orville Eberly	Emma Clifton #1	N/A
20114	Orville Eberly	Sharpnack #1	04/10/1945
20122	R.T. Mosier	R.T. Mosier #1	03/11/1972
20130	Keystone Gas Co	Hecla #2	04/12/1973
20133	R.T. Mosier	Mildred M. Thomas #1	11/24/1973
20138	Peoples Natural Gas Co	Gray #1 (now Keslar)	09/10/1973
20139	George Bortz	Bortz #1	11/21/1945
20158	R.T. Mosier	Robert G. Stewart #1	05/1/1980
20165	J.E. Brumage	C.W. Leighty #1	07/22/1976
20168	R.T. Mosier	R.T. Mosier #2	01/10/1977
20180	Go Enterprises	Reno L. Mosier #1	08/5/1978
20181	W.Burkland	Parshall #1	05/14/1945
20185	W.Burkland	Kalonsky #825-1	11/04/1977
20187	Santa Fe Energy Resources	Rebidas #1	02/14/1978
20188	Adobe Oil & Gas Corp.	L. Warchol #1	02/4/1978
20189	Adobe Oil & Gas Corp.	C.R. Cooper #1	02/9/1978
20191	Santa Fe Energy Resources	McGill #1	02/19/1978
20192	W.Burkland	Sharpnack #1	04/24/1978
20195	Adobe Oil & Gas Corp.	C.R. Cooper #2	05/1/1978
20196	Adobe Oil & Gas Corp.	McCracken #2	05/12/1978
20197	Adobe Oil & Gas Corp.	McCracken #1	05/7/1978
20203	Total Resources	Sloan/Thompson #1	08/31/1978
20210	Adobe Oil & Gas Corp.	Griffin #1	10/30/1978
20221	Peoples Natural Gas Co	Breeding #1	12/13/1978
20255	Peoples Natural Gas Co	Smith Rose #3498	1961
20261	Manufacturers Light & Heat Co	Hogsett #7	08/22/1946
20264	Columbia Gas Transmission Corp	Bryner Lumber Co. #1	10/23/1980
20277	Ashtola Production Co	R.Cerullo #1	07/13/1981

ID NUMBER	TOTAL MOS ON LINE	LATEST 30 TOTAL MCF	LOGGERS DEPTH	DAY PROD.*
20042	N/A	N/A	1350	N/A
20044	N/A	N/A	1351	N/A
20046	N/A	N/A	1487	N/A
20048	N/A	N/A	N/A	N/A
20054	N/A	N/A	2993	N/A
20059	N/A	N/A	3093	N/A
20103	N/A	160,000/1970	2658	N/A
20108	N/A	N/A	N/A	N/A
20114	N/A	N/A	3300	N/A
20122	N/A	N/A	2642	N/A
20130	N/A	N/A	3156	N/A

20133	N/A	N/A	2350	N/A
20138	N/A	N/A	4513	N/A
20139	N/A	N/A	2432	N/A
20158	N/A	N/A	3840	N/A
20165	N/A	N/A	4209	N/A
20168	N/A	N/A	2600	N/A
20180	N/A	N/A	2610	N/A
20181	N/A	139,000/1980	2784	N/A
20185	N/A	N/A	4086	N/A
20187	N/A	N/A	4236	N/A
20188	N/A	N/A	4235	N/A
20189	N/A	N/A	3525	N/A
20191	N/A	N/A	3422	N/A
20192	N/A	N/A	4290	N/A
20195	N/A	N/A	3909	N/A
20196	N/A	N/A	3629	N/A
20197	N/A	N/A	3507	N/A
20203	N/A	N/A	4060	N/A
20210	N/A	N/A	3829	N/A
20221	N/A	N/A	4035	N/A
20255	N/A	N/A	3102	N/A
20261	N/A	N/A	2521	N/A
20264	N/A	N/A	3591	N/A
20277	N/A	N/A	4531	N/A

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ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D
20278	Ashtola Production Co	Honsaker #1	N/A
20287	Ashtola Production Co	McCracken #1	08/26/1981
20290	Orville Eberly	S. Wycinsky #1	02/17/1944
20313	Ashtola Production Co	D'Isodoro #1	12/07/1982
20325	Ashtola Production Co	Best Food Products Inc. #1	11/18/1982
20347	Peoples Natural Gas Co	J. Magerko #1	07/13/1944

20371	W.Burkland	Ludi #2	08/27/1983
20372	W.Burkland	LaCava #1	09/07/1983
20407	Columbia Gas Transmission Corp	Jeffries #1	10/22/1901
20421	W.Burkland	E. Work #1	12/01/1984
20498	James Drilling Corp.	A. Ewing #2	12/15/1988
20555	Castle Gas Co	Bryner Lumber Co. #1	09/28/1991
20723	Kriebel Gas Inc	Kovach #1	03/23/1994
20742	Kriebel Gas Inc	Fairbank Rod & Gun #1	11/05/1996
20767	Equitrans, Inc.	Landsdale America #1	06/18/1995
20771	Equitrans, Inc.	Landsdale America #7	07/13/1995
20890	Atlas	New Salem Vol Fire Co #1	01/17/1997
20892	Atlas	Zalac #1	11/05/1997
20894	Atlas	Zitney #1A	02/04/1997
20919	N/A	USX (Coalbed methane well)	N/A
20951	Atlas	Zalac #3	11/23/1997
20962	Atlas	Lavery #1	01/13/1998
20971	Atlas	Swetz/Densmore #1	01/28/1998
20978	Atlas	Colucci #1	02/7/1998
20979	W.Burkland	Kalonsky #2	N/A
20992	Atlas	Fette/Davis/Sunyak #1	03/30/1998
20995	Atlas	Kutek #1	11/25/1998
21000	Atlas	Edenborn/USX #1	01/13/1999
21001	Atlas	K.Kovach #1	01/2/1999
21004	Atlas	Winter #1	01/29/1999
21010	Atlas	Tippet #1	01/20/1999
21020	Atlas	Ralph/USX #1	11/13/1998
21021	Atlas	Croushore #1	02/10/1998
21029	Atlas	Christopher #1	10/25/1998
21030	Atlas	Pollick #1	11/19/1998

ID NUMBER	TOTAL MOS ON LINE	TOTAL MCF	LOGGERS DEPTH	LATEST 30 DAY PROD.*
20278	N/A	N/A	N/A	N/A
20287	N/A	N/A	4167	N/A
20290	N/A	N/A	3250	N/A
20313	N/A	N/A	3863	N/A
20325	N/A	N/A	3681	N/A
20347	N/A	149,000/1977	3709	N/A
20371	N/A	N/A	5789	N/A
20372	N/A	N/A	5665	N/A
20407	N/A	N/A	1847	N/A
20421	N/A	N/A	N/A	N/A
20498	N/A	N/A	2518	N/A
20555	N/A	N/A	4252	N/A
20723	N/A	N/A	4450	N/A
20742	N/A	N/A	3895	N/A

20767	N/A	N/A	5529	N/A
20771	N/A	N/A	4296	N/A
20890	35	42,724	3980	447
20892	26	24,534	4229	368
20894	34	13,116	4077	155
20919	N/A	N/A	N/A	N/A
20951	26	16,438	4448	341
20962	31	25,729	4476	410
20971	30	4,370	6010	79
20978	31	40,336	4066	560
20979	N/A	N/A	N/A	N/A
20992	30	48,584	6015	644
20995	23	15,246	3560	312
21000	11	12,555	3071	450
21001	19	41,578	3951	1142
21004	21	2,201	4110	87
21010	22	56,956	3805	1306
21020	25	10,138	3957	216
21021	21	29,688	4019	869
21029	22	4,848	4228	98
21030	24	13,068	3540	280

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ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D
21040	Atlas	Howe #1	02/08/1999
21061	Atlas	Jarina Unit #1	02/25/1999
21068	Atlas	Skovran #1	02/15/1999
21073	W. Burkland	Miles #1	N/A
21074	Atlas	E. Riffle #1	03/02/1999
21075	Atlas	Cerullo #1	03/07/1999
21076	Atlas	East Huntingdon Corp #1	36246
21077	W.Burkland	D'Amico #1	N/A
21079	Atlas	Craig #1	03/26/1999

21083	Atlas	K.Kovach #3	04/21/1999
21084	Atlas	Leichliter #3	04/08/1999
21085	Atlas	Filbert/USX #1	03/19/1999
21104	Atlas	Check #1	01/21/2000
21105	Atlas	K.Kovach #2A	02/3/2000
21109	Atlas	Pollick #2	02/11/2000
21110	Atlas	Lee/Fette-Gipson #1	02/02/2000
21111	Atlas	Skovran #3	12/18/1999
21112	Atlas	Skovran #4	01/07/2000
21118	Atlas	Grant #1	01/14/2000
21122	Atlas	Bukovitz Tr. 3#1	01/28/2000
21123	W.Burkland	W.S. Burkland #1	N/A
21127	Atlas	Fette/Davis/Sunyak #2	01/27/2000
21128	Atlas	Bukovitz Tr-2 #1	02/18/2000
21130	Atlas	Koenig #1	02/28/2000
21131	Atlas	Winter #2	02/25/2000
21135	Atlas	Skovran #2	03/2/2000
21138	Atlas	Keslar #1	03/8/2000
21140	Atlas	Skovran #5	03/13/2000
21143	Atlas	Craig #2	03/19/2000
21147	Atlas	Krepps #1	04/01/2000
21161	Atlas	Hall/Hogsett #1	09/29/2000
21165	Atlas	Hoehn #1	09/25/2000
21166	Atlas	Hall/Hogsett #7	09/14/2000
21168	Atlas	Keslar #3	08/18/2000
21171	Atlas	Bukovitz Tr. 3 #2	09/09/2000

TOTAL ID NUMBER	LATEST 30 MOS ON LINE	TOTAL MCF	LOGGERS DEPTH	DAY PROD.*
21040	22	42,242	3643	988
21061	21	2,482	3650	75
21068	11	44,119	4098	4882
21073	N/A	N/A	N/A	N/A
21074	20	11,502	4060	273
21075	20	2,817	3815	76
21076	10	3,864	3866	243
21077	N/A	N/A	2500	N/A
21079	20	11,663	4015	321
21083	21	32,559	3979	725
21084	18	11,425	3839	439
21085	20	23,047	3927	603
21104	10	36,975	3888	4045
21105	3	9,387	4068	3648
21109	12	10,612	3788	368
21110	13	14,137	3933	789
21111	13	187,586	4168	6245

21112	3	2,025	4187	635
21118	3	35,438	3870	13990
21122	10	21,609	3658	2120
21123	N/A	N/A	N/A	N/A
21127	2.5	2,349	3980	1014
21128	12	8,235	3753	394
21130	3	2,510	2070	128
21131	10	8,646	4082	954
21135	2.75	294	4062	102
21138	13	103,633	4085	4800
21140	2.75	1,950	4067	778
21143	P/A	N/A	4090	N/A
21147	12	9,954	4210	355
21161	2.5	4,602	3970	1558
21165	6	17,539	3875	1468
21166	7	6,281	4059	573
21168	8	107,232	3959	6670
21171	N/A	N/A	3580	N/A

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ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D
21172	Atlas	Grant Unit #3	08/26/2000
21173	Atlas	Grant Unit #4	09/01/2000
21174	Atlas	Grant #5	02/08/2001
21175	Atlas	Grant #2	08/04/2000
21176	Atlas	Filbert Supply #2	12/09/2000
21177	Atlas	Keslar #2	08/11/2000
21192	Atlas	Horvat #1	10/10/2000
21194	Atlas	Check Unit #1	02/02/2001
21197	Atlas	Riffle Unit #2	10/04/2000
21198	Atlas	East Huntingdon Corp #2	10/18/2000
21206	Atlas	Stoken #2	11/05/2000
21207	Atlas	Hall #4	11/11/2000

21209	Atlas	CFR/USX #2	11/16/2000
21220	Atlas	Stoken #1	01/26/2001
21221	Atlas	LaCava #1	02/27/2001
21222	Atlas	CFR/USX #1	11/21/2000
21224	Atlas	Crable #1	03/26/2001
21198	Atlas	Edenborn/USX #2	02/09/2000
21226	Atlas	Antram #3	12/02/2000
21227	Atlas	Brown Unit #1	12/29/2000
21232	Atlas	Fairbank Rod & Gun #2	01/11/2001
21237	Atlas	Fairbank Rod & Gun #1	01/19/2001
21238	Atlas	Soberdash #1	02/22/2001
21239	Atlas	Keslar #4	03/19/2001
21241	Atlas	Croushore #2	02/20/2001
21247	Atlas	DiCarlo #2	03/05/2001
21248	Atlas	Bukovitz Tr. 1 #1	03/02/2001
21249	Atlas	Bukovitz Tr. 4 #1	03/14/2001
21250	Atlas	CFR/USX #3	03/12/2001
21252	Atlas	Skovran #6	03/19/2001
21255	Atlas	Faverio #1	07/02/2001
21261	Atlas	Stiner Unit #1	04/01/2001
21263	Atlas	Frankhouser #1	03/26/2001
21265	Atlas	Girolami #1	05/30/2001
21286	Atlas	Vail #2	05/22/2001

TOTAL ID NUMBER	LATEST 30 MOS ON LINE	TOTAL MCF	LOGGERS DEPTH	DAY PROD.*
21172	7	40,116	4085	2864
21173	7	1,753	4595	89
21174	7	927	4180	927
21175	8	39,800	4023	2115
21176	4	67,052	3933	14799
21177	8	37,321	3974	4349
21192	plugged	N/A	3868	N/A
21194	1.5	2,867	3676	2427
21197	6	24,433	3933	2709
21198	6	6,980	3909	781
21206	4 days	17	4028	17
21207	5	8,404	4032	1324
21209	4	10,465	3814	1798
21220	1 day	20	4059	20
21221	N/A	N/A	3914	N/A
21222	4	13,289	3823	2014
21224	N/A	N/A	3995	N/A
21198	2.75	290	3849	135
21226	4	4,600	4121	731
21227	N/A	N/A	3720	N/A

21232	N/A	N/A	3973	N/A
21237	N/A	N/A	4055	N/A
21238	N/A	N/A	3514	N/A
21239	7 days	4,469	4032	4469
21241	N/A	N/A	3942	N/A
21247	5 days	5,491	3890	5491
21248	N/A	N/A	3907	N/A
21249	N/A	N/A	3522	N/A
21250	7 days	713	3825	713
21252	N/A	N/A	4066	N/A
21255	N/A	N/A	4113	N/A
21261	N/A	N/A	4035	N/A
21263	N/A	N/A	4516	N/A
21265	N/A	N/A	4110	N/A
21286	N/A	N/A	3670	N/A

The Production Data provided in the table below is not intended to imply that the wells to be drilled by the partnership will have the same results, although it is an important indicator in evaluating the economic potential of any well to be drilled by the partnership.

ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D
21287	Atlas	Hall/Hogsett #5	06/13/2001
21292	Atlas	Skovran #8	07/7/2001
29063	Atlas	Wycinsky #1	01/21/1998
90011	Greensboro Gas Co	S.Gorley #2	06/21/1944
90012	Manufacturers Light & Heat Co	Hartley #1	12/31/1946
90020	Duquesne Natural Gas Co.	J. Race #1	08/14/1942
90024	Duquesne Natural Gas Co.	Honsaker #2	12/12/1942
90042	Carnegie Natural Gas Co	H.C. Frick Coke Co. #1	02/22/1944
90059	Greensboro Gas Co	Hogsett #4	10/23/1923
90064	Greensboro Gas Co	Jacobs #2	11/15/1912
90066	Greensboro Gas Co	Hogsett #1	01/01/1911
90067	Greensboro Gas Co	Hogsett #3	06/19/1923
90068	Greensboro Gas Co	Christopher #1	01/15/1915
90069	Greensboro Gas Co	Christopher #2	02/13/1917
90073	Greensboro Gas Co	E. Franks #1	09/21/1917

90076	Greensboro Gas Co	Jacobs #3	10/01/1913
90078	Greensboro Gas Co	Jacobs #2	08/03/1916
90081	Greensboro Gas Co	Krepps #2	10/21/1910
90091	Greensboro Gas Co	S. Rose #1	1915
90100	Greensboro Gas Co	Adam M. Jacobs #4	05/23/1917
90101	Greensboro Gas Co	Christopher #3	02/03/1923
90102	Greensboro Gas Co	T.M. Hartley #627	07/27/1924
90103	Greensboro Gas Co	J.B. Riffle #1	01/18/1924
90106	Greensboro Gas Co	A.M.R. Jacobs #3	01/19/1917
90107	Greensboro Gas Co	E.Christopher #1	01/01/1916
90108	Greensboro Gas Co	Brown #1	N/A
90155	Greensboro Gas Co	Frazier #2	1923
90162	Greensboro Gas Co	R. Fleming #1	1918
90163	Greensboro Gas Co	J.S. Rittenhouse #1	1916
90164	Greensboro Gas Co	J. Murphy #2	1918
90165	Greensboro Gas Co	J.Murphy #1	1917
90169	Greensboro Gas Co	J.R. Colley	1918
90172	Greensboro Gas Co	J.H. Rittenhouse	1920
90178	Greensboro Gas Co	Eliza Lyon	1916
90179	Greensboro Gas Co	E.C. Smith	1915

ID NUMBER	TOTAL MOS ON LINE	TOTAL MCF	LOGGERS DEPTH	LATEST 30 DAY PROD.*
21287	N/A	N/A	3916	N/A
21292	N/A	N/A	2152	N/A
29063	29	14,743	4270	267
90011	N/A	N/A	2989	N/A
90012	N/A	N/A	3237	N/A
90020	N/A	N/A	3419	N/A
90024	N/A	N/A	3539	N/A
90042	N/A	N/A	1335	N/A
90059	N/A	N/A	3045	N/A
90064	N/A	N/A	2910	N/A
90066	N/A	N/A	3117	N/A
90067	N/A	N/A	3196	N/A
90068	N/A	N/A	3100	N/A
90069	N/A	N/A	3065	N/A
90073	N/A	N/A	2957	N/A
90076	N/A	N/A	2304	N/A
90078	N/A	N/A	1766	N/A
90081	N/A	N/A	3106	N/A
90091	N/A	N/A	4470	N/A
90100	N/A	N/A	2751	N/A
90101	N/A	N/A	3206	N/A
90102	N/A	N/A	3210	N/A
90103	N/A	N/A	3035	N/A

90106	N/A	N/A	1540	N/A
90107	N/A	N/A	2864	N/A
90108	N/A	N/A	3273	N/A
90155	N/A	N/A	3940	N/A
90162	N/A	N/A	4054	N/A
90163	N/A	N/A	3788	N/A
90164	N/A	N/A	3314	N/A
90165	N/A	N/A	3295	N/A
90169	N/A	N/A	4319	N/A
90172	N/A	N/A	3900	N/A
90178	N/A	N/A	3809	N/A
90179	N/A	N/A	1396	N/A

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ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D
90180	Greensboro Gas Co	E.H. Dean	1916
90181	Greensboro Gas Co	John Croftcheck	1915
90182	Greensboro Gas Co	John Croftcheck	1915
90185	Greensboro Gas Co	O.L. Byers	N/A
F13934	Mid-Atlantic	Haggerty #1	N/A
F22290	N/A	Riffle #1	N/A
F22816	N/A	Hazen #1	N/A
FGN14	N/A	H.C. Frick #1	before 1935
FL38	N/A	Jacobs	N/A
FL49	N/A	N/A	N/A
L2373	Manufacturers Light & Heat Co	H.G. Moore(Skovran) #1	06/18/1919
P1245	Greensboro Gas Co	Barber	08/12/1911
P1247	Greensboro Gas Co	Lightey #1	12/08/1913
P1258	Greensboro Gas Co	J.N. Craft #1	08/11/1914
P16493	Greensboro Gas Co	A. Jacobs #3	09/24/1922
P17459	Greensboro Gas Co	J.E. Craft #1	09/17/1909
P20629	R.Mosier	R. Mosier #1	N/A
P21257	C.D. White & Co.	V. Pollack #1	04/07/1939

P21286	Waller & Powers	G. Reynolds #1	04/03/1939
P22152	George Reynolds	G. Reynolds #2	04/19/1940
P22271	Jack Cornell	Kosky #1	10/05/1940
P22359	Fayette County Gas Co	Puritan Coke Co #2	N/A
P22772	Waller & Powers	G. Reynolds #3	06/29/1940
P23858	N/A	McWilliams #1	before 1935
P23859	N/A	J. Hoover #1	before 1935
P23860	N/A	H.C. Frick	before 1935
P23861	N/A	J. Parreco #1	before 1935
P23862	N/A	T. Hoover	before 1935
P23863	N/A	Unknown	before 1935
P24142	Greensboro Gas Co	Brock #3	1916
P24149	Bortz et al	Jefferies #1	N/A
P24150	Bachman & Rudert	Vail #1	05/11/1929
P24155	Fayette County Gas Co	J. Hoover #1	N/A
P24173	M.C.Brumage	Hartley #1	N/A
P24174	M.C.Brumage	Cameron #1	N/A

ID NUMBER	TOTAL MOS ON LINE	TOTAL MCF	LOGGERS DEPTH	LATEST 30 DAY PROD.*
90180	N/A	N/A	3780	N/A
90181	N/A	N/A	4193	N/A
90182	N/A	N/A	2603	N/A
90185	N/A	N/A	3794	N/A
F13934	N/A	N/A	1314	N/A
F22290	N/A	N/A	N/A	N/A
F22816	N/A	N/A	3768	N/A
FGN14	N/A	N/A	est 1700	N/A
FL38	N/A	N/A	N/A	N/A
FL49	N/A	N/A	N/A	N/A
L2373	N/A	N/A	2005	N/A
P1245	N/A	N/A	3042	N/A
P1247	N/A	N/A	3121	N/A
P1258	N/A	N/A	3117	N/A
P16493	N/A	N/A	1684	N/A
P17459	N/A	N/A	3263	N/A
P20629	N/A	N/A	N/A	N/A
P21257	N/A	N/A	2530	N/A
P21286	N/A	N/A	3345	N/A
P22152	N/A	N/A	1370	N/A
P22271	N/A	N/A	2560	N/A
P22359	N/A	N/A	N/A	N/A
P22772	N/A	N/A	2443	N/A
P23858	N/A	N/A	est 2120	N/A
P23859	N/A	N/A	est 2300	N/A
P23860	N/A	N/A	est 2300	N/A

P23861	N/A	N/A	est 2350	N/A
P23862	N/A	N/A	est 2300	N/A
P23863	N/A	N/A	est 2150	N/A
P24142	N/A	N/A	3722	N/A
P24149	N/A	N/A	2652	N/A
P24150	N/A	N/A	2740	N/A
P24155	N/A	N/A	N/A	N/A
P24173	N/A	N/A	N/A	N/A
P24174	N/A	N/A	N/A	N/A

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ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D
P24175	N/A	L.W. Hartley	about 1896
P24176	Forest Oil Co	W. Larden	about 1900
P24178	N/A	N/A	N/A
P24184	N/A	Hess	N/A
P24185	N/A	Hoover	N/A
P24186	N/A	Hoover	N/A
P24464	M.C.Brumage	Hartley #1	N/A
P24827	N/A	Cook #1	N/A
P24828	Brumage	LaCava #1	09/25/1942
P26092	H.K.Porter	Hartley #1	01/06/1944
P26094	H.K.Porter	Thompson-Connellsville #1	12/17/1943
P26290	Orville Eberly	M. Ellinger #1	02/02/1944
P26456	H.K.Porter	Hartley #1	04/12/1944
P26595	H.K.Porter	Hartley #2	11/03/1944
P26638	Carnegie Natural Gas Co	H.C. Frick Coke & Coal	08/02/1944
P26665	Nollem Oil & Gas Corp.	B.F. Johnson #1	09/22/1944
P26874	J.D. Boyle	Hoover #1	01/09/1945
P27648	R.Murray et al	Hibbs #1	05/19/1946
P27764	Petroleum Drilling Co	Baird #1	10/11/1946
P27813	R.Murray et al	Hibbs Heirs #2	09/04/1946
P28315	N/A	Haggerty #1	N/A

PNG3326	Peoples Natural Gas Co	J.A. Baer #1	02/26/1942
PNG3359	Peoples Natural Gas Co	D.H. Sangston #1	10/26/1942
PNG3381	Peoples Natural Gas Co	T. Seese #1	01/26/1943
PNG3382	Peoples Natural Gas Co	T. Seese #2	02/02/1943
PNG3394	Peoples Natural Gas Co	Parshall #1	05/05/1943
PNG3406	Peoples Natural Gas Co	W.I. Moore #3406	06/08/1943
PNG3426	Peoples Natural Gas Co	Randolph #1	01/19/1944
PNG3473	Peoples Natural Gas Co	Byers #1	01/01/1944
PNG3490	Peoples Natural Gas Co	Stoken #1	01/01/1944
PNG3491	Peoples Natural Gas Co	Kovach #1	04/23/1945
PNG3603	Peoples Natural Gas Co	Republic Colleries #1	07/27/1945
PNG3619	Peoples Natural Gas Co	Girolami #1	09/25/1945
PNG3637	Peoples Natural Gas Co	W. Mapstone #1	02/04/1946
PNG3664	Peoples Natural Gas Co	McCann #1	10/28/1946

TOTAL ID NUMBER	LATEST 30 MOS ON LINE	TOTAL MCF	LOGGERS DEPTH	DAY PROD.*
P24175	N/A	N/A	2907	N/A
P24176	N/A	N/A	N/A	N/A
P24178	N/A	N/A	N/A	N/A
P24184	N/A	N/A	N/A	N/A
P24185	N/A	N/A	N/A	N/A
P24186	N/A	N/A	N/A	N/A
P24464	N/A	N/A	N/A	N/A
P24827	N/A	N/A	N/A	N/A
P24828	N/A	N/A	1900	N/A
P26092	N/A	N/A	N/A	N/A
P26094	N/A	N/A	2930	N/A
P26290	N/A	N/A	3520	N/A
P26456	N/A	N/A	2055	N/A
P26595	N/A	N/A	2684	N/A
P26638	N/A	N/A	3294	N/A
P26665	N/A	N/A	3598	N/A
P26874	N/A	N/A	1525	N/A
P27648	N/A	N/A	1913	N/A
P27764	N/A	N/A	3195	N/A
P27813	N/A	N/A	3087	N/A
P28315	N/A	N/A	1341	N/A
PNG3326	N/A	N/A	3520	N/A
PNG3359	N/A	53,000/1952	3814	N/A
PNG3381	N/A	N/A	3506	N/A
PNG3382	N/A	N/A	2752	N/A
PNG3394	N/A	N/A	3551	N/A
PNG3406	N/A	N/A	3566	N/A
PNG3426	N/A	N/A	3869	N/A
PNG3473	N/A	N/A	N/A	N/A

PNG3490	N/A	N/A	N/A	N/A
PNG3491	N/A	N/A	3750	N/A
PNG3603	N/A	N/A	2989	N/A
PNG3619	N/A	N/A	3258	N/A
PNG3637	N/A	N/A	4085	N/A
PNG3664	N/A	N/A	N/A	N/A

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ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D
PNG3671	Peoples Natural Gas Co	Podolinski #1	09/27/1946
PNG3672	Peoples Natural Gas Co	H.Hogsett #3	12/10/1946
PNG3705	Peoples Natural Gas Co	Jefferies #1	07/21/1947
PNG3718	Peoples Natural Gas Co	A. Vasko #1	11/04/1947
PNG3724	Peoples Natural Gas Co	H.Hogsett #4	08/14/1947
PNG3774	Peoples Natural Gas Co	Springer #1	04/20/1948
PNG3924	Peoples Natural Gas Co	C. Yuras #2	08/8/1950
GRE-00513	Greensboro Gas Co	N.M. Biddle #4	09/24/1941
GRE-00514	Manufacturers Light & Heat Co	Patterson #2	10/16/1947
GRE-00522	Greensboro Gas Co	Goodwin #1	12/22/1923
GRE-00535	Greensboro Gas Co	Patterson #1	10/17/1944
GRE-00537	Greensboro Gas Co	Patterson #1	8680
GRE-00565	Manufacturers Light & Heat Co	Armstrong #1	N/A
GRE-00924	Dunn-Marr Oil & Gas Co	Patterson #1-3882	10/04/1945
GRE-01204	Equitrans, Inc.	Hathaway #3577	06/03/1941
GRE-01399	Castle Gas Co	Patterson #2	02/15/1943
GRE-01660	Greenridge Oil Co.	TV Mt. Joy #1-973	11/27/1945
GRE-01661	Greenridge Oil Co.	Patterson #3902	1946
GRE-01662	Greenridge Oil Co.	Waters #748	04/8/1905
GRE1397	Castle Gas Co	J. Kerr #1	10/22/1918
GRE21132	Equitable Gas Co	Gideon #1	10/28/1925
GRE21229	Equitable Gas Co	Crago #1	12/23/1931
GRE21359	Castle Gas Co	Goodwin #1	06/07/1977
GRE-21726	Kepco, Inc.	Hart #1	10/11/1982

GRE21814	Derby Oil & Gas Co	Hathaway #H-1	01/03/1983
GRE-21837	Kepco, Inc.	Hart #2	05/16/1983
GRE-21838	Kepco, Inc.	Hart #4	05/31/1983
GRE-21840	Kepco, Inc.	Hart #1	04/26/1983
GRE-21843	Kepco, Inc.	Hart #3	06/6/1983
GRE22490	R. Burkland	Luzerne #4	03/26/1993
GRE90020	Duquesne Natural Gas Co.	J. Race #1	08/14/1942
GRE-90021	Equitable Gas Co	O. Hartley #1	09/10/1943
GRE-90022	Equitable Gas Co	Hathaway #1	07/21/1941
GRE-90075	Equitable Gas Co	Kerr #2929	08/24/1926
GRE-90076	Equitable Gas Co	Hathaway #438	03/26/1926

ID NUMBER	TOTAL MOS ON LINE	LATEST 30 TOTAL MCF	LOGGERS DEPTH	DAY PROD.*
PNG3671	N/A	N/A	N/A	N/A
PNG3672	N/A	N/A	3212	N/A
PNG3705	N/A	N/A	2831	N/A
PNG3718	N/A	N/A	3297	N/A
PNG3724	N/A	N/A	3327	N/A
PNG3774	N/A	N/A	N/A	N/A
PNG3924	N/A	N/A	3501	N/A
GRE-00513	N/A	N/A	3145	N/A
GRE-00514	N/A	N/A	2835	N/A
GRE-00522	N/A	N/A	3065	N/A
GRE-00535	N/A	N/A	3076	N/A
GRE-00537	N/A	N/A	1825	N/A
GRE-00565	N/A	N/A	2550	N/A
GRE-00924	N/A	N/A	3067	N/A
GRE-01204	N/A	468,000/1978	1985	N/A
GRE-01399	N/A	190,000/1990	2989	N/A
GRE-01660	N/A	N/A	2363	N/A
GRE-01661	N/A	N/A	3055	N/A
GRE-01662	N/A	N/A	3112	N/A
GRE1397	N/A	337,000/1990	2400	N/A
GRE21132	N/A	N/A	1858	N/A
GRE21229	N/A	N/A	2976	N/A
GRE21359	N/A	504,000/1990	2995	N/A
GRE-21726	N/A	N/A	5945	N/A
GRE21814	N/A	N/A	6100	N/A
GRE-21837	N/A	N/A	5628	N/A
GRE-21838	N/A	N/A	5650	N/A
GRE-21840	N/A	N/A	5650	N/A
GRE-21843	N/A	N/A	4550	N/A
GRE22490	N/A	N/A	2439	N/A
GRE90020	N/A	N/A	3419	N/A
GRE-90021	N/A	N/A	3550	N/A

GRE-90022	N/A	N/A	3067	N/A
GRE-90075	N/A	N/A	3053	N/A
GRE-90076	N/A	N/A	3136	N/A

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ID NUMBER	OPERATOR	WELL NAME	DATE COMPLT'D
GRE-90077	Carnegie Natural Gas Co	Illig #1	02/08/1922
GRE-CAR975	Carnegie Natural Gas Co	TV Mt. Joy #2	06/04/1946
GRE-E1201	Manufacturers Light & Heat Co	Oscar Hartley	N/A
GRE-E9227	Fred Lough	Oscar Hartley	N/A
GRE-EQM337	Philadelphia #M337	M. Fox	08/07/1917
GRE-G347	Greensboro Gas Co	Fuller #2	01/14/1916
GRE-G354	Greensboro Gas Co	Fuller #3	05/13/1916
GRE-G417	Greensboro Gas Co	Kerr #6	05/10/1918
GRE-G526	Greensboro Gas Co	Fuller	01/28/1921

ID NUMBER	TOTAL MOS ON LINE	TOTAL MCF	LOGGERS DEPTH	LATEST 30 DAY PROD.*
GRE-90077	N/A	N/A	2710	N/A
GRE-CAR975	N/A	N/A	3100	N/A
GRE-E1201	N/A	N/A	3125	N/A
GRE-E9227	N/A	N/A	3064	N/A

GRE-EQM337	N/A	N/A	2925	N/A
GRE-G347	N/A	N/A	2895	N/A
GRE-G354	N/A	N/A	2873	N/A
GRE-G417	N/A	N/A	3065	N/A
GRE-G526	N/A	N/A	2398	N/A

Cumulative Production Information Through April 2001

MANAGING GENERAL PARTNER'S

GEOLOGIC EVALUATION

FOR THE

CURRENTLY PROPOSED WELLS

IN

FAYETTE AND GREENE COUNTIES, PENNSYLVANIA

OBJECTIVE

The purpose of the following investigation is to evaluate the geologic feasibility and further development of the Fayette Prospect Area as proposed by Atlas Resources, Inc.

AREA OF INVESTIGATION

A portion of this prospect area contains acreage in German, Luzerne, Redstone, Menallen, Jefferson and Franklin Townships in Fayette County and Cumberland and Monongahela Townships in Greene County. These counties are located in western Pennsylvania. Thirty-five (35) drilling prospects have currently been designated for this program in the prospect area, which will be targeted to produce natural gas from Mississippian and Upper Devonian reservoirs, found at depths from 1900 feet to 4500 feet beneath the earth's surface.

METHODOLOGY

The data incorporated into this report were provided by Atlas Resources, Inc. Geological mapping and the interpretations by Atlas geologists were also examined. Available "electric" log, completion and production data on "key" wells within and adjacent to the defined prospect area were utilized to determine productive and depositional trends.

FAYETTE PROSPECT AREA

DRILLING ACTIVITY

The proposed drilling area lies within a region of southwestern Pennsylvania, which has been active for the past four years in terms of exploration for, and exploitation of natural gas reserves. Development within and adjacent to the Fayette Prospect Area has continued steadily since 1996. Over one hundred (100) wells have been drilled in the area during this period.

Atlas Resources, Inc. has encountered favorable drilling and production results while solidifying a strong acreage position of over 18,000 acres, as

Atlas Resources, Inc. continues to identify and extend productive trends. Drilling is ongoing as of the date of this report with recent wells displaying favorable initial drilling and completion results.

The area of proposed drilling is situated in portions of Fayette and Greene Counties that have had established production from shallower, historic pay zones. Atlas Resources, Inc. will target deeper pay zones when locating a drill site within the "old shallow field area". Otherwise, Atlas Resources, Inc. will maintain a minimum of 1000 feet from any existing producing well in the area.

GEOLOGY

STRATIGRAPHY, LITHOLOGY & DEPOSITION

The Mississippian reservoirs currently producing in the Fayette Prospect Area are the Burgoon Sandstone (lower Big Injun) and the 2nd Gas Sand. The Burgoon Sandstone is part of the massive Big Injun fluvial-deltaic sand system, which extends from eastern Kentucky through West Virginia into southwestern Pennsylvania. This reservoir is an historic prolific producing zone in this region, with some wells still producing long beyond fifty years. There is not much history of production from the 2nd Gas Sand in this area.

The Upper Devonian reservoirs consist of three groups of sands, Upper Venango, Lower Venango and Bradford. Each of these "Groups" has multiple reservoirs making up their total rock section. The Upper Venango Group consists of the Gantz Sand and the Fiftyfoot Sand. The Lower Venango Group consists of the Fifth Sand and the Bayard Sand. Depositional environments of these Upper and lower Venango Group sands are of near shore to offshore marine settings related to the last major advance of the Catskill Delta. The Bradford Group consists of the Lower Warren Sand, Upper Speechley Sand, Lower Speechley Sand, Upper Balltown Sand and the First Bradford Sand. Depositional environments of these sands are offshore marine, pro-delta and basin floor settings related to the intermediate advance of the Catskill Delta.

Stratigraphically, in descending order, the potentially productive units of the Mississippian and Upper Devonian Groups are: 1) Burgoon, 2)2nd Gas Sand, 3)Gantz, 4)Fiftyfoot, 5)Fifth, 6)Bayard, 7)L.Warren, 8)U.Speechley,

9)L.Speechley, 10)U.Balltown and 11)First Bradford Sand. These stratigraphic relationships are illustrated in the following diagram.

STRATIGRAPHIC NAMES-FAYETTE COUNTY AREA

[DIAGRAM]

The BURGOON SANDSTONE is a fine to medium grained, medium to massively bedded, light-gray sandstone ranging in thickness from 200-250 feet. Average porosity values for this sand range from 6% to 12% regionally. It is not uncommon to encounter porosities as high as 20% and attendant large natural open flows from this sand. Tracking these high flow trends is targeted for further development. Also, this zone does produce water in certain locales within the Fayette Prospect Area. This reservoir is considered a secondary target in the high flow trend areas.

The 2ND GAS SAND of this region has limited areal extent and therefore is not discussed in the literature regarding lithology, thickness etc. It can be inferred from underlying and overlying sands that it is probably a fine to very fine grained, light gray sand. Subsurface mapping indicates that the sand can achieve a thickness of twenty (20) feet. Average porosity values for this sand range from 10% to 13% when this zone is present in the area. Peak porosities of 17% have been encountered within the prospect area. This reservoir is considered to be a secondary target when encountered.

The GANTZ SAND is a white to light-gray, medium to coarse grained sandstone ranging in thickness from a few feet to over thirty (30) feet. Average porosity values for this sand range from 5% to 10% regionally. Within the area of investigation, porosities in excess of 13% occur within localized trends characterized by large natural open flows. These trends are targeted for future development. This reservoir is considered a primary target in the high flow trend areas.

The FIFTYFOOT SAND is a white to light gray, thinly bedded, fine grained sandstone ranging in thickness from ten (10) to thirty (30) feet. Average porosity values for this sand range from 5% to 8% regionally. Within the prospect area, porosities in excess of 12% occur within localized trends targeted for future development. This sand reservoir is considered a secondary target.

The FIFTH SAND is a white to light gray, very fine to fine grained sandstone ranging in thickness from a few feet to twenty (20) feet. Within the main Fifth fairway, porosity values average from 9% to 15%. This sand is considered a primary target and will be exploited in future development.

The BAYARD SAND in the prospect area ranges in thickness from a few feet to more than sixty (60) feet. Average porosity values range from 5% to 12% for this fine to coarse grained sandstone. Discreet reservoirs within the sand have been identified and mapped. Gas shows in the member sandstones delineate trends within the prospect area and will be targeted for future development. This sand is considered a primary target.

The LOWER WARREN SAND is a primary target in the prospect area. Average thickness for this sand ranges from zero (0) feet to over forty (40) feet. Porosities average between 8% and 12% in the area. Gas shows are commonly found in this sand, which is probably a fine-grained, well-sorted sand. This reservoir is targeted for future development.

The UPPER SPEECHLEY SAND is considered a secondary target with average thickness ranging from two (2) feet to ten (10) feet over much of the prospect area. Gas shows from this sand are common throughout the area and the zone is combined with other zones when treated.

The LOWER SPEECHLEY SAND is a primary target in the area with reservoir thickness ranging from zero (0) to over forty (40) feet. Average porosity values range from 5% to 12% where the sand is present. Significant natural and after treatment flows from this sand have been encountered. This sand is being targeted throughout the prospect area.

The UPPER BALLTOWN SAND is currently being produced in a few wells in the prospect area. The zone is a siltstone with fracture-enhanced porosity, based on log interpretation, and has associated gas shows. This sand is considered a secondary target and is usually combined with other zones when treated.

The FIRST BRADFORD SAND, like the Balltown above, is currently being produced in a few wells in the prospect area. This silty-sand does have porosity up to 10% in the area and is considered to be a secondary target when encountered.

RESERVOIR CHARACTERISTICS

Petroleum reservoirs are formed by the presence of an impermeable barrier trapping natural gas of commercial quantities in a more permeable medium. In the Mississippian and Upper Devonian reservoirs, this occurs either stratigraphically when a permeable sand containing hydrocarbons encounters impermeable shale or when permeable sand changes gradually into non-permeable sand by a cementation process known as "diagenesis". Thus, this type of trap represents cemented-in hydrocarbon accumulations.

Electric well logs can be used in conjunction with production to interpret reservoir parameters. When sandstones in the Mississippian and Upper Devonian reservoirs develop porosity in excess of 8%, or a bulk density of 2.50 or less, the permeability of the reservoir can become great enough to allow commercial production of natural gas. Small, naturally occurring cracks in the formation, referred to as micro-fractures, can also enhance permeability. A gamma, bulk density, neutron, induction and temperature log suite showing sand development in both the Mississippian and Upper Devonian reservoirs is illustrated below.

[ILLUSTRATION]

The temperature log shown in the illustration identifies where gas is entering the wellbore. Evidence of a temperature "kick" or cooling is also an indication of enhanced permeability and the willingness of the reservoir to produce gas.

PRODUCTION EXPECTATIONS

The prospect area produces from a number of reservoirs of different age and type. Each well has a unique combination of these reservoirs yielding different production declines. While we anticipate production from each reservoir to be comparable to like reservoirs historically produced throughout the Appalachian Basin, a model decline curve for this prospect area is not included due to the multiple sets of commingled reservoirs exclusively found in this area. We expect producing life of the proposed wells to

range from twenty to forty years, which is similar to Atlas' existing wells in the area. This average projected producing life is taken directly from the 2000 audited report from Wright & Company, Inc.

POTENTIAL MARKETS AND PIPELINES

In the area of the drilling program, the partnership will be transporting all the gas through Texas Eastern Transmission Co., via Atlas Pipeline Partners gathering system, and marketing all the gas through Northeast Ohio Gas Marketing Co.

MAP OF

SOUTHERN OHIO

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[MAP]

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LEASE INFORMATION

FOR

SOUTHERN OHIO

PROSPECT NAME	COUNTY	EFFECTIVE DATE*	EXPIRATION DATE*	LANDOWNER ROYALTY	OVERRIDING ROYALTY INTEREST TO THE MANAGING GENERAL PARTNER	OVERRIDING ROYALTY INTEREST TO 3RD PARTIES
1. Mattmark #16	Noble	01/24/2001	01/24/2006	15.00%	0%	0%
2. Mattmark #10	Noble	01/24/2001	01/24/2006	15.00%	0%	0%
3. Mattmark #21	Noble	01/24/2001	01/24/2006	15.00%	0%	0%
4. Mattmark #24	Noble	05/01/2001	05/01/2006	15.00%	0%	0%
5. Mattmark #25	Noble	05/01/2001	05/01/2006	15.00%	0%	0%
6. Mattmark #26	Noble	05/01/2001	05/01/2006	15.00%	0%	0%
7. Mattmark #27	Noble	05/01/2001	05/01/2006	15.00%	0%	0%
8. Mattmark #28	Noble	05/01/2001	05/01/2006	15.00%	0%	0%
9. Mattmark #29	Noble	05/01/2001	05/01/2006	15.00%	0%	0%
10. Lamp #1	Noble	05/09/2001	05/01/2006	12.50%	0%	0%
11. Lamp #2	Noble	05/09/2001	05/01/2006	12.50%	0%	0%
12. Lamp #3	Noble	05/09/2001	05/01/2006	12.50%	0%	0%
13. Williams #1	Noble	06/01/2001	06/01/2006	12.50%	0%	0%
14. Heddleson #1	Noble	04/12/2001				

04/12/2004 12.50% 0% 0%
15. Gill #2 Muskingum 06/23/1980
HBP 17.50% 0% 0%

PROSPECT NAME	NET REVENUE INTEREST	NET ACRES	ACRES TO BE ASSIGNED TO PARTNERSHIP
1. Mattmark #16	85.00%	7,416	40
2. Mattmark #10	85.00%	7,416	40
3. Mattmark #21	85.00%	7,416	40
4. Mattmark #24	85.00%	7,416	40
5. Mattmark #25	85.00%	7,416	40
6. Mattmark #26	85.00%	7,416	40
7. Mattmark #27	85.00%	7,416	40
8. Mattmark #28	85.00%	7,416	40
9. Mattmark #29	85.00%	7,416	40
10. Lamp #1	87.50%	140	40
11. Lamp #2	87.50%	140	40
12. Lamp #3	87.50%	140	40
13. Williams #1	87.50%	49.5	40
14. Heddleson #1	87.50%	326	40
15. Gill #2	82.50%	156	40

***HBP - Held by Production**

LOCATION AND PRODUCTION MAP

FOR

SOUTHERN OHIO

[MAP]

[MAP]

PRODUCTION DATA

FOR

SOUTHERN OHIO

The Production Data provided in the Table below is not intended to imply that the wells to be drilled by the partnership will have the same results, although it is an important indicator in evaluating the economic potential of any well to be drilled by the partnership.

ID NUMBER	OPERATOR	WELL NAME	DATE COMPLETED	PRODUCTION PERIOD
2715	Rocanville Corp.	Jones #1	1/82	1984 - 1996
2913	Triad	Noon #3	3/83	1984 - 1998

2914	Triad	Noon #4	10/82	1985 - 1988
2946	Halwell Company	Orange Coal Co. #8	2/83	1985 - 1999
2959	Artex	Crock #4	12/82	1985 - 2000
3155	NGO Development	Dexter Realty Corp. #3	8/84	1985 - 1999
3156	NGO Development	State of Ohio #4	8/84	1985 - 1999
3158	NGO Development	State of Ohio #10	7/84	1985 - 1999
3229	NGO Development	Buffalo Valley Ranch #7	9/84	1985 - 1999
3526	Buckeye Oil Prod. Co.	Arnold #1	1/86	1986 - 2000
3936	Atlas America	Atlas / Mattmark #2	Not Drilled	Not Drilled
3939	Atlas America	Atlas / Mattmark #6	2/01	NA
3949	Atlas America	Atlas / Mattmark #11	2/01	NA
3953	Triad	Farnese #1	4/01	Not in line
3961	Atlas America	Atlas / Mattmark #17	Not Drilled	Not Drilled
3966	Atlas America	Atlas / Mattmark #20	Not Drilled	Not Drilled
3972	Atlas America	Spence #1	Not Drilled	Not Drilled
3976	Atlas America	Heddleson #2	Not Drilled	Not Drilled
3977	Atlas America	Heddelson #3	Not Drilled	Not Drilled
3979	Atlas America	Eichorn #2	Not Drilled	Not Drilled
4091	Cavendish	OP #31-MD	1/78	1984 - 1992
6476	Atlas America	OP #14-A	5/83	1984 - 2000
6804	Cavendish	OP #36-A	11/89	1984 - 1990
7032	Atlas America	Gill #1	4/84	1984 - 2000

TOTAL LATEST

ID NUMBER	TOTAL MCF GAS EQUIV.	LOGGERS DEPTH	30 DAY PRODUCTION *
2715	8236	NA	NA

2913	6079	6500	NA
2914	2252	6582	NA
2946	9962	6550	NA
2959	27052	6312	NA
3155	41024	6498	NA
3156	40,702	6549	NA
3158	52343	6391	NA
3229	17902	6221	NA
3526	21087	6370	NA
3936	Not Drilled	Not Drilled	Not Drilled
3939	NA	6689	1650
3949	NA	6490	1740
3953	Not in line	6494	Not in line
3961	Not Drilled	Not Drilled	Not Drilled
3966	Not Drilled	Not Drilled	Not Drilled
3972	Not Drilled	Not Drilled	Not Drilled
3976	Not Drilled	Not Drilled	Not Drilled
3977	Not Drilled	Not Drilled	Not Drilled
3979	Not Drilled	Not Drilled	Not Drilled
4091	36875	5076	NA
6476	332161	5070	295
6804	15021	5070	NA
7032	309806	5056	200

Cumulative Production Information Through June 2001

MANAGING GENERAL PARTNER

GEOLOGIC EVALUATION

FOR THE

SOUTHERN OHIO AREA

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PROSPECT SUMMARY

OBJECTIVE

The purpose of this report is to summarize the geologic feasibility and further development of the Southeastern Ohio prospect area (consisting of parts of

Guernsey, Muskingum, Noble and Washington Counties, Ohio) as proposed by Atlas Resources, Inc.

AREA OF INVESTIGATION

Fifteen (15) drilling prospects have currently been designated for Atlas America Public #10 LTD. Program, may contain acreage in the following townships:

Muskingum Co.	Noble Co.	Washington Co.
Meigs Twp.	Brookfield Twp.	Aurelius Twp.
Rich Hill Twp.	Enoch Twp.	
Jefferson Twp.		

Fifteen (15) drilling prospects have currently been designated for the program in the prospect area which will be targeted to produce natural gas and oil from the "Clinton" and "Medina" Sandstone reservoirs, found at depths ranging form 4900 feet to 6500 feet beneath the earth's surface.

DRILLING ACTIVITY

The proposed drilling area lies within a region of southeastern Ohio that has experienced several episodes of drilling. Although shallow drilling has been going on since the early 1900's, substantial drilling for the "Clinton" and "Medina" Sandstones began in the 1970's and has continued through the present. Development of the area was slowed by the presence of strip mining operations restricting potential drilling sites. Much of the active mining has ceased in the last 7 years and drilling is slowly on the increase.

In late 2000, Atlas America, Inc. (through its parent company, Resource America, Inc.) acquired a large block of acreage previously operated by Kingston Oil Co. and leased from Ohio Power Co. The majority of the acreage was strip mined to provide coal to O. P. C.'s power plants and has been reclaimed and opened for drilling. Many of the proposed sites are expected by Atlas to be located on this lease and other strip-mined leases.

GEOLOGY

Regionally, the "Clinton"/ "Medina" Sandstones were deposited in tide-dominated shoreline, deltaic and shelf environments and are lithologically comprised of alternating sandstones, siltstones and shales. Productive sandstones are composed of siliceous to dolomitic sub arkoses, litharenites and quartz arenites. Reservoir quality sands occur throughout the delta-complex from eastern Ohio through Pennsylvania and western New York. In Ohio, the "Clinton" and "Medina" Sandstones overlie the Ordovician Queenston Shale and are capped by the Middle Silurian "Packer Shell" (Dayton Formation) Dolomite.

The "Clinton" and "Medina" Sandstone package consists of five producing units. In descending order they are:

Stray Clinton: The Stray Sand is the first productive unit below the Packer Shell. It is a red, very fine-grained sandstone usually 0 to 10 feet thick. Porosities generally range from 5% to 12% over the pay interval. The Stray Sand is laterally discontinuous however, when found, it can add significant reserves to the well.

Red Clinton: Beneath the Stray Sand is the Red Clinton Sand. This has historically been the main productive zone in the area. It is a red, fine-grained sandstone, usually 10 to 40 feet thick. Porosities range from 5% to 14% over the pay interval. Certain channel deposits are laterally continuous and are traceable across the acreage. High porosity trends are associated with these deposits.

Upper White Clinton Sand: Beneath the Red Sand is the Upper White Sand. This has historically been the secondary target in the area. It is a white to light gray, fine grained sandstone, usually 10 to 30 feet thick. Porosities range from 5% to 12% over the pay interval. Like the Red Sand, traceable channel trends cross the acreage. High porosity trends are associated with these deposits.

Lower White Clinton Sand: Beneath the Upper White Sand is the Lower White Clinton Sand. It is a white to light gray, very fine grained sandstone usually 0 to 20 feet thick. Porosities range from 5% to 10% over the pay interval. The sand is very discontinuous over the acreage and is completed only when it is thick and/or porous.

Medina Sand: At the base of the producing "Clinton" sands lies the Medina Sand. It is a white to light gray, fine-grained sandstone usually 0 to 18 feet thick. Porosities commonly range from 5% to 12%. The sand thickens to the southeast and is found in traceable trends across the acreage. Within these trends, where the sand was reworked and winnowed by tidal action, porosity values can range from 12% to 20%. In these areas, electric logs commonly show very low resistivity. In the past, many southern Ohio operators did not complete the Medina when they found these high porosity / low resistivity zones because they interpreted the low resistivity as an indication that salt water was present. Through its extensive exploration of the Medina (Whirlpool) in Mercer Co., Atlas has studied this phenomenon and determined that the low resistivity is

caused by the presence of conductive minerals in the formation and not the presence of salt water. The Medina is an important target and can add significant reserves to the well.

RESERVOIR CHARACTERISTICS

Petroleum reservoirs are formed by the presence of an impermeable barrier trapping natural gas of commercial quantities in a more permeable medium. In the Clinton-Medina Sandstones, this occurs either stratigraphically when a permeable sand containing hydrocarbons encounters an impermeable shale or when a permeable sand changes gradually into a non-permeable sand by a cementation process known as "diagenesis". Thus, this type of trap represents cemented-in hydrocarbon accumulations.

Geophysical well logs can be used in conjunction with production trends to interpret favorable reservoir parameters and locate places to drill. When the Clinton-Medina sands develop porosity in excess of 6% (or a bulk density of 2.58 grams/cc or less), the permeability of the reservoir (which ranges from < 0.1 to > 0.2 mD) can become great enough to allow commercial production of natural gas. Small, naturally occurring cracks in the formation, referred as micro-fractures, can also enhance permeability. A type log showing an example of the sand development in the Clinton-Medina Sands is illustrated on the following pages. Using well log data and production data, maps are made to track sand thickness and porosity thickness across the acreage. Locations are picked that maximize the potential for multiple producing sands with the highest possible porosity in favorable producing trends.

CORRELATION CHART OF FORMATION NAMES

[CHART]

[CHART]

COMPETITION, MARKETS AND REGULATION

NATURAL GAS REGULATION

Governmental agencies regulate the production and transportation of natural gas. Generally, the regulatory agency in the state where a producing natural gas well is located supervises production activities and the transportation of natural gas sold into intrastate markets and the Federal Energy Regulatory Commission

("FERC") regulates the interstate transportation of natural gas.

Natural gas prices are not regulated and the price of natural gas is subject to the supply and demand for the natural gas along with factors such as the natural gas' BTU content and where the wells are located. See "- Competition and Markets" below for certain measures which FERC has taken to increase the competitiveness in natural gas markets.

CRUDE OIL REGULATION

Oil prices are not regulated and the price is subject to the supply and demand for oil, along with qualitative factors such as the gravity of the crude oil and sulfur content differentials.

COMPETITION AND MARKETS

There are many companies engaged in natural gas and oil drilling operations in the areas where the partnership is expected to conduct its activities. The industry is highly competitive in all phases, including acquiring suitable properties for drilling and marketing natural gas and oil. Product availability and price are the principal means of competing in selling natural gas and oil. Many of the partnership's competitors will have financial resources and staffs larger than those available to the partnership. While it is impossible to accurately determine the partnership's industry position, the managing general partner does not consider the partnership's operations to be a significant factor in the industry.

Current economic conditions indicate that the costs of exploration and development are increasing gradually. However, the natural gas and oil industry historically has experienced periods of rapid cost increases from time to time. There is a risk that over the term of the partnership there will be fluctuating or increasing costs in doing business, which would directly affect the managing general partner's ability to operate the partnership's wells at acceptable price levels. Also, the natural gas price increases which occurred at the end of 2000 and the first quarter of 2001 may increase the demand for drilling rigs and other related equipment. This may increase the cost to drill the wells or reduce the availability of drilling rigs and related equipment, both of which could adversely affect the partnership.

In order for you to realize revenues the natural gas and oil produced by the partnership's wells must be marketed. As set forth above, natural gas and oil prices are not regulated and instead are subject to supply and demand factors as well as other factors largely beyond the control of the partnership. For example, reduced natural gas demand and/or excess natural gas supplies will result in lower prices. In recent years natural gas and oil prices have been volatile.

The marketing of natural gas and oil production will be affected by numerous factors beyond the control of the partnership and which cannot be accurately predicted. These factors include, but are not limited to, the following:

- the proximity, availability and capacity of pipeline and other transportation facilities;

- competition from other energy sources such as coal and nuclear energy;

- local, state and federal regulations regarding production and transportation;

- fluctuating seasonal supply and demand because of various factors such as home heating requirements in the winter months;

- the amount of domestic production and foreign imports of natural gas and oil; and

- political instability in oil producing countries.

For example, increased imports of Canadian natural gas have occurred and are expected to continue which will increase the supply of natural gas in the U.S. Without a corresponding increase in demand, the imported natural gas would have an adverse effect on both the price and volume of natural gas sales from the partnership's wells. This increase in natural gas imports was the result of the North American Free Trade Agreement ("NAFTA"), which eliminated trade and investment barriers in the United States, Canada and Mexico and new pipeline projects which have been constructed and/or proposed to the FERC. Also, members of the Organization of Petroleum Exporting Countries ("OPEC") establish production quotas for petroleum products from time to time with the intent of increasing, maintaining, or decreasing price levels. The managing general partner, however, is unable to predict what effect these actions will have on the price of the natural gas and oil sold from the partnership's wells.

FERC has sought to promote greater competition in natural gas markets in the U.S. Traditionally, natural gas was sold by producers to interstate pipeline companies, which then resold the natural gas to local distribution companies for resale to end-users. FERC changed this market structure by requiring interstate pipeline companies to transport natural gas for others. Thereafter, FERC Order 636 was issued which requires pipeline companies to, among other things, separate their sales services from their transportation services and provide an open access transportation service that is comparable in quality for all natural gas producers or suppliers. The premise behind FERC Order 636 was that the interstate pipeline companies had an unfair advantage over other natural gas producers or suppliers because they could bundle their sales and transportation services together. FERC Order 636 is designed to ensure that no natural gas seller has a competitive advantage over another natural gas seller because it also provides transportation services.

In February, 2000, FERC Order 637 was issued to provide further competitive initiatives by removing price ceilings on short-term capacity release transactions. It also enacted other regulatory policies that are intended to increase the flexibility of interstate natural gas transportation. Further, FERC has required pipeline companies to develop electronic bulletin boards to provide standardized access to information concerning capacity and prices.

There have been several developments which the managing general partner believes have the effect of increasing the demand for natural gas. For example, the Clean

Air Act Amendments of 1990 contain incentives for the future development of "clean alternative fuel," which includes natural gas and liquefied petroleum gas for "clean-fuel vehicles." Also, the accelerating deregulation of electricity transmission has caused a convergence between the natural gas and electricity industries. The electricity industry has increased its reliance on natural gas because of increased competition in the electricity industry and the enforcement of stringent environmental regulations. For example, to reduce urban smog the Environmental Protection Agency has sought to enforce environmental regulations which increase the cost of operating coal-fired power plants, which in December 2000 produced more than half of the U.S.'s electricity. The Department of Energy has also denied financial incentives to utilities to build more nuclear power plants and large scale hydroelectric projects. Together, these policies tend to make natural gas the fuel of choice for electricity producers which have started moving away from dirtier-burning fuels, such as coal and oil. The electricity industry has started plans to bring new natural gas-fired power plants into service, some of which are not designed to allow for switching to other fuels. Natural gas was used to generate approximately 16% of the U.S.'s electricity in December 2000, and this demand is expected to increase through the decade.

STATE REGULATIONS

Oil and gas operations are regulated in Pennsylvania by the Department of Environmental Resources. Pennsylvania and the other states where the partnership's wells may be situated impose a comprehensive statutory and regulatory scheme for natural gas and oil operations, which creates additional financial and operational burdens. Among other things, these regulations involve:

- new well permit and well registration requirements, procedures and fees;

- minimum well spacing requirements;

- restrictions on well locations and underground gas storage;

- certain well site restoration, groundwater protection and safety measures;

- landowner notification requirements;

- certain bonding or other security measures;

- various reporting requirements; and

- well plugging standards and procedures.

These state regulatory agencies also have broad regulatory and enforcement powers including those associated with pollution and environmental control laws which are discussed below.

ENVIRONMENTAL REGULATION

The partnership's drilling and producing operations are subject to various federal, state, and local laws covering the discharge of materials into the environment, or otherwise relating to the protection of the environment. The Environmental Protection Agency and state and local agencies will require the partnership to obtain permits and take other measures with respect to the discharge of pollutants into navigable waters, disposal of wastewater and air pollutant emissions. If these requirements or permits are violated there can be substantial civil and criminal penalties which will increase if there was willful negligence or misconduct. Also, the partnership has unlimited liability for cleanup costs under various federal laws such as the Federal Clean Water Act for oil or hazardous substance pollution and the Resource Conservation and Recovery Act and the Comprehensive Environmental Response, Compensation and Liability Act of 1980 for hazardous substance contamination.

The partnership's liability can also extend to pollution costs that occurred on the leases before they were acquired by the partnership. Although the managing general partner will not transfer any lease to the partnership if it has actual knowledge that there is an existing potential environmental liability on the lease, there will not be an independent environmental audit of the leases before they are transferred to the partnership. Thus, there is a risk that the leases will have potential environmental liability even before drilling begins.

The partnership's required compliance with these environmental laws and regulations may cause delays or increase the cost of the partnership's drilling and producing activities. Because these laws and regulations are constantly being revised and changed, the managing general partner is unable to predict the ultimate costs of complying with present and future environmental laws and regulations. Also, the managing general partner is unable to obtain insurance to protect against most environmental claims.

PROPOSED REGULATION

From time to time there are a number of proposals considered in Congress and in the legislatures and agencies of various states that if enacted would significantly and adversely affect the natural gas and oil industry and the partnership. The proposals involve, among other things:

- limiting the disposal of waste water from wells which could substantially increase the partnership's operating costs and make the partnership's wells uneconomical to produce; and

- changes in the tax laws as discussed in "Tax Aspects-Changes in the Law."

However, it is impossible to accurately predict what proposals, if any, will be enacted and their subsequent effect on the partnership's activities.

PARTICIPATION IN COSTS AND REVENUES

IN GENERAL

The partnership agreement provides for the sharing of costs and revenues among the managing general partner and you and the other investors. A tabular summary of the following discussion appears below.

COSTS

1. ORGANIZATION AND OFFERING COSTS. Organization and offering costs will be charged 100% to the managing general partner. However, the managing general partner will not receive any credit towards its required capital contribution or its revenue share for any organization and offering costs that it pays in excess of 15% of the investors' subscription proceeds.

- Organization and offering costs generally means all costs of organizing and selling the offering and includes the dealer-manager fee, sales commissions, the .5% reimbursement for bona fide accounTable due diligence expenses and the .5% reimbursement of marketing expenses.

2. LEASE COSTS. The leases will be contributed to the partnership by the managing general partner. The managing general partner will be credited with a capital contribution for each lease valued at:

- its cost; or

- fair market value if the managing general partner has reason to believe that cost is materially more than fair market value.

3. INTANGIBLE DRILLING COSTS. Intangible drilling costs will be charged 100% to you and the other investors.

- Intangible drilling costs generally means those costs of drilling and completing a well that are currently deductible, as compared with lease costs which must be recovered through the depletion allowance and equipment costs which must be recovered through depreciation deductions.

Although subscription proceeds may be used to pay the costs of drilling different wells depending on when the subscriptions are received, not less than 90% of the subscription proceeds of you and the other investors will be used to pay intangible drilling costs regardless of when you subscribe. Also, the IRS could challenge the managing general partner's characterization of a portion of these costs as deductible intangible drilling costs and instead recharacterize the costs as some other item which may be non-deductible such as equipment costs and/or lease costs. However, this recharacterization by the IRS would have no effect on the allocation and payment of the costs under the partnership agreement.

4. EQUIPMENT COSTS. Equipment costs will be charged 66% to the managing general partner and 34% to you and the other investors. However, if the total equipment costs for all the partnership's wells that would be charged to you and the other investors exceeds an amount equal to 10% of the subscription proceeds of you and the other investors in the partnership, then the excess will be charged to the managing general partner.

- Equipment costs generally means the costs of drilling and completing a well that are not currently deductible and are not lease costs.

5. OPERATING COSTS, DIRECT COSTS, ADMINISTRATIVE COSTS AND ALL OTHER COSTS. Operating costs, direct costs, administrative costs, and all other partnership costs not specifically charged will be charged to the parties in the same ratio as the related production revenues are being credited.

- These costs generally include all costs of partnership administration and producing and maintaining the partnership's wells.

6. THE MANAGING GENERAL PARTNER'S REQUIRED CAPITAL CONTRIBUTION. The managing general partner's aggregate capital contributions to the partnership, including its credit for the cost of the leases contributed, must not be less than 25% of all capital contributions to the partnership and will not exceed 28% of all capital contributions to the partnership. The managing general partner's capital contributions must be paid at the time the costs are required to be paid by the partnership, but not later than December 31, 2002.

REVENUES

The production revenues from all partnership wells will be commingled. Thus, regardless of when you subscribe you will share in the production revenues from all wells on the same basis as the other investors in the partnership in proportion to your number of units.

1. PROCEEDS FROM THE SALE OF LEASES. If a partnership well is sold, a portion of the sales proceeds will be allocated to the partners in the same proportion as their share of the adjusted tax basis of the property. In addition, proceeds will be allocated to the managing general partner to the extent of the pre-contribution appreciation in value of the property, if any. Any excess will be credited as provided in 4, below.

2. INTEREST PROCEEDS. Interest earned on your subscription proceeds before the offering closes will be credited to your account and paid approximately eight weeks after the offering closes. If your subscription is refunded, then any interest allocated to your subscription proceeds will also be refunded.

After the offering closes and until the subscription proceeds are invested in the partnership's operations any interest income from temporary investments will be allocated pro rata to the investors providing the subscription proceeds. All other interest income, including interest earned on the deposit of production revenues, will be credited as provided in 4, below.

3. EQUIPMENT PROCEEDS. Proceeds from the sale or other disposition of equipment will be credited to the parties charged with the costs of the equipment in the ratio in which the costs were charged.

4. PRODUCTION REVENUES. Subject to the managing general partner's subordination obligation as described below, the managing general partner and you and the other investors will share in all of the partnership's other revenues, including production revenues, in the same percentage as your respective capital contribution bears to the total partnership capital contributions, except that the managing general partner will receive an additional 7% of partnership revenues. For example, if the managing general partner contributes 25% of the total partnership capital contributions and you and the other investors contribute 75% of the total partnership capital contributions, then the managing general partner will receive 32% of the partnership revenues and you and the other investors will receive 68% of the partnership revenues.

SUBORDINATION OF PORTION OF MANAGING GENERAL PARTNER'S NET REVENUE SHARE The partnership is structured to provide you and the other investors with preferred cash distributions equal to a minimum of 10% per unit, based on $10,000 per unit regardless of the actual subscription price for your units, in each of the first five 12-month periods beginning with the partnership's first cash distributions from operations. To help achieve this investment feature, the managing general partner will subordinate up to 50% of its share of partnership net production revenues during this subordination period.

- Partnership net production revenues means gross revenues after deduction of the related operating costs, direct costs, administrative costs and all other costs not specifically allocated.

The partnership's 60-month subordination period will begin with the first partnership cash distribution from operations to you and the other investors. However, no subordination distributions to you and the other investors will be required until the partnership's first cash distribution after substantially all of the partnership wells are drilled, completed and begin producing into a sales line. Subordination distributions will be determined by debiting or crediting current period partnership revenues to the managing general partner as may be necessary to provide the distributions to you and the other investors. At any time during the subordination period the managing general partner is entitled to an additional share of partnership revenues to recoup previous

subordination distributions to the extent your cash distributions from the partnership exceed the 10% return described above. The specific formula is set forth in Section 5.01(b)(4)(a) of the partnership agreement.

The managing general partner anticipates you will benefit from the subordination if the price of natural gas and oil received by the partnership and/or the results of the partnership's drilling activities are unable to provide the required return. However, if the wells produce small natural gas and oil volumes or natural gas and oil prices decrease, then even with subordination your cash flow may be very small and you may not receive the 10% return for each of the first five years beginning with the partnership's first cash distribution from operations. As of December 31, 2000, the managing general partner was subordinating a portion or all of its net revenues in seven of its previous 14 limited partnerships which have the subordination feature in effect, and from time to time it has subordinated its partnership revenues in all 14 of these partnerships. The managing general partner is entitled to recoup these subordination distributions during the subordination period to the extent cash distributions to the investors in these previous partnerships would exceed the specified return to the investors.

TABLE OF PARTICIPATION IN COSTS AND REVENUES

The following Table sets forth the participation in partnership costs and revenues between the managing general partner and you and the other investors after deducting from the partnership's gross revenues:

- the landowner royalties; and

- any other lease burdens.

	MANAGING GENERAL PARTNER	INVESTORS
PARTNERSHIP COSTS		
Organization and offering costs	100%	0%
Lease costs	100%	0%
Intangible drilling costs	0%	100%
Equipment costs (1)	66%	34%
Operating costs, administrative costs, direct costs and all other costs	(2)	(2)
PARTNERSHIP REVENUES		
Interest income	(3)	(3)
Equipment proceeds (1)	66%	34%

All other revenues including production revenues.................................	(4)(5)	(4)(5)
PARTICIPATION IN DEDUCTIONS		
Intangible drilling costs..	0%	100%
Depreciation (1)...	66%	34%
Percentage depletion allowance (5)...	(6)	(6)

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(1) These percentages may vary. If the total equipment costs for all of the partnership's wells that would be charged to you and the other investors exceeds an amount equal to 10% of the subscription proceeds of you and the other investors in the partnership, then the excess will be charged to the managing general partner.

(2) These costs will be charged to the parties in the same ratio as the related production revenues are being credited.

(3) Interest earned on your subscription proceeds before the offering closes will be credited to your account and paid approximately eight weeks after the offering closes. After the offering closes and until proceeds from the offering are invested in the partnership's operations any interest income from temporary investments will be allocated pro rata to the

investors providing the subscription proceeds. All other interest income, including interest earned on the deposit of operating revenues, will be credited as production revenues are credited.

(4) Subject to the managing general partner's subordination obligation, the managing general partner and you and the other investors will share in all

of the partnership's other revenues in the same percentage as your respective capital contributions bears to the total partnership capital contributions except that the managing general partner will receive an additional 7% of the partnership revenues.

(5) These percentages may vary if a portion of the managing general partner's partnership net production revenues is subordinated.

(6) The percentage depletion allowances will be in the same percentages as the production revenues.

ALLOCATION AND ADJUSTMENT AMONG INVESTORS

The investors' share of the partnership's revenues, gains, income, costs, expenses, losses and other charges and liabilities generally will be charged and credited among you and the other investors in accordance with your respective number of units, and will take into account any investor general partner's status as a defaulting investor general partner. Certain investors, however, will pay a reduced amount for their units as described in "Plan of Distribution." Therefore, intangible drilling costs and the investors' share of the equipment costs of drilling and completing the partnership's wells will be charged among you and the other investors in the partnership in accordance with your respective subscription price for your units rather than the number of your units.

DISTRIBUTIONS

The managing general partner will review your account at least quarterly to determine whether cash distributions are appropriate and the amount to be distributed, if any. The partnership will distribute funds to you and the other investors which the managing general partner does not believe are necessary for the partnership to retain. Also, funds will not be advanced or borrowed for distributions if the distribution amount would exceed the partnership's accrued and received revenues for the previous four quarters, less paid and accrued operating costs with respect to the revenues. Any cash distributions from the partnership to the managing general partner will only be made in conjunction with distributions to you and the other investors and only out of funds properly allocated to the managing general partner's account.

LIQUIDATION

The partnership will continue for 50 years unless it is terminated earlier by a final terminating event as described below, or an event which causes the dissolution of a limited partnership under state law. However, if the partnership terminates on an event which causes a dissolution under state law and it is not a final terminating event, then a successor limited partnership will automatically be formed. Thus, only on a final terminating event will the partnership be liquidated. A final terminating event is any of the following:

- the election to terminate the partnership by the managing general partner or the affirmative vote of investors whose units equal a majority of the total units;

- the termination of the partnership under Section 708(b)(1)(A) of the Internal Revenue Code; or

- the partnership ceases to be going concern.

On liquidation of the partnership you will receive your interest in the partnership. Generally, your interest in the partnership means an undivided interest in the partnership assets, after payments to the partnership's creditors, in the ratio your capital account bears to all the capital accounts until they have been reduced to zero. Thereafter, your interest in the remaining partnership assets will equal your interest in the related partnership revenues.

Any in-kind property distributions to you must be made to a liquidating trust or similar entity, unless you affirmatively consent to receive an in-kind property distribution after being told of the risks associated with the direct ownership or there are alternative arrangements in place which assure that you will not be responsible for the operation or disposition of the partnership properties. If the managing general partner has not received your written consent to the in-kind distribution within 30 days after it is mailed, then it will be presumed that you have not consented. The managing general partner may then sell the asset at the best price reasonably obtainable from an independent third-party or to itself or its affiliates, at fair market value as determined by an independent expert selected by the managing general partner. Also, if the partnership is liquidated, the managing general partner will be repaid for any debts owed it by the partnership before there are any payments to you and the other investors.

CONFLICTS OF INTEREST

IN GENERAL

Conflicts of interest are inherent in natural gas and oil partnerships involving non-industry investors because the transactions are entered into without arms' length negotiation. Your interests and those of the managing general partner and its affiliates may be inconsistent in some respects or in certain instances, and the managing general partner's actions may not be the most advantageous to you.

The following discussion describes certain possible conflicts of interest that may arise for the managing general partner and its affiliates in the course of the partnership, and with respect to some of the conflicts of interest, but not all, certain limitations which are designed to reduce, but which will not eliminate, the conflicts. Other than these limitations the managing general partner has no procedures to resolve a conflict of interest and under the terms of the partnership agreement the managing general partner may resolve the conflict of interest in its sole discretion and best interest.

The following discussion is not intended to be inclusive and other transactions or dealings may arise in the future that could result in conflicts of interest for the managing general partner and its affiliates.

CONFLICTS REGARDING TRANSACTIONS WITH THE MANAGING GENERAL PARTNER AND ITS

AFFILIATES

Although the managing general partner believes that the compensation and reimbursement that it and its affiliates will receive in connection with the partnership are reasonable, the compensation has been determined solely by the managing general partner and did not result from negotiations with any unaffiliated third-party dealing at arms' length. The managing general partner and its affiliates will receive compensation and reimbursement from the partnership for their services in drilling, completing and operating the partnership's wells under the drilling and operating agreement and will receive the other fees described in "Compensation" regardless of the success of the partnership's wells. The managing general partner and its affiliates providing the services or equipment can be expected to profit from the transactions, and it is usually in the managing general partner's best interest to enter into contracts with itself and its affiliates rather than unaffiliated parties even if the contract terms, or skill and experience, offered by the unaffiliated third-parties is comparable.

The partnership agreement provides that when the managing general partner and any affiliate provide services or equipment to the partnership their fees must be competitive with the fees charged by unaffiliated persons in the same geographic area engaged in similar businesses. Also, before the managing general partner and any affiliate may provide services or equipment to the partnership they must be engaged, independently of the partnership and as an ordinary and ongoing business, in rendering the services or selling or leasing the equipment and supplies to a substantial extent to other persons in the natural gas and oil industry. If the managing general partner and any affiliate is not engaged in such a business, then the compensation must be the lesser of its cost or the competitive rate which could be obtained in the area.

Any services not otherwise described in this prospectus for which the managing general partner or an affiliate is to be compensated must be:

- set forth in a written contract which describes the services to be rendered and the compensation to be paid; and

- cancelable without penalty on 60 days written notice by investors whose units equal a majority of the total units.

The compensation, if any, will be reported to you in the partnership's annual and semiannual reports and a copy of the contract will be provided to you on request.

There is also a conflict of interest concerning the purchase price if the managing general partner or an affiliate purchases a producing property from the partnership, which they may do in certain limited circumstances as described in "Conflicts Involving the Acquisition of Leases - (6) No Sale of Undeveloped Leases to the Managing General Partner and Limitations on Sales of Developed Leases to the Managing General Partner," below.

CONFLICT REGARDING THE DRILLING AND OPERATING AGREEMENT

The managing general partner anticipates that all of the wells drilled by the partnership will be drilled and operated under the drilling and operating agreement. This creates a continuing conflict of interest because the managing general partner must monitor and enforce, on behalf of the partnership, its own compliance with the drilling and operating agreement.

CONFLICTS REGARDING SHARING OF COSTS AND REVENUES

The managing general partner will receive a percentage of revenues greater than the percentage of costs that it pays. This sharing arrangement may create a conflict of interest between the managing general partner and you and the other investors concerning the determination of which wells will be drilled by the partnership based on the risk and profit potential associated with the wells.

In addition, the allocation of all the intangible drilling costs to you and the other investors and the majority of the equipment costs to the managing general partner creates a conflict of interest between the managing general partner and you and the other investors concerning whether to complete a well. For example, the completion of a marginally productive well might prove beneficial to you and the other investors but not to the managing general partner. When a completion decision is made you and the other investors will have already paid the majority of your costs so you will want to complete the well if there is any opportunity to recoup any of the costs. On the other hand, the managing general partner will have paid only a portion of its costs before this time and it will want to pay its additional equipment costs to complete the well only if it is reasonably certain of recouping its money and making a profit. Based on its past experience, however, the managing general partner anticipates that the partnership wells in the three primary areas will have to be completed before it can determine the well's productivity. In any event, the managing general partner will not cause any partnership well to be plugged and abandoned without a completion attempt unless it makes the decision in accordance with generally accepted oil and gas field practices in the geographic area of the well location.

CONFLICTS REGARDING TAX MATTERS PARTNER

The managing general partner will serve as the partnership's tax matters partner and represent the partnership before the IRS. The managing general partner will have broad authority to act on behalf of you and the other investors in any administrative or judicial proceeding involving the IRS, and this authority may involve conflicts of interest. For example, potential conflicts include:

- whether or not to expend partnership funds to contest a proposed adjustment by the IRS, if any, to:

- the amount of the partnership's deduction for intangible drilling costs, which is allocated 100% to you and the other investors; or

- the amount of the managing general partner's depreciation deductions, or the credit to its capital account for contributing the leases to the partnership which would decrease the managing general partner's liquidation interest in the partnership; or

- the amount of the managing general partner's reimbursement from the partnership for expenses incurred by it in its role as the tax matters partner.

CONFLICTS REGARDING OTHER ACTIVITIES OF THE MANAGING GENERAL PARTNER, THE

OPERATOR AND THEIR AFFILIATES

The managing general partner will be required to devote to the partnership the time and attention which it considers necessary for the proper management of the partnership's activities. However, the managing general partner has sponsored and continues to manage other natural gas and oil drilling partnerships, which may be concurrent, and will engage in unrelated business activities,

either for its own account or on behalf of other partnerships, joint ventures, corporations or other entities in which it has an interest. This creates a continuing conflict of interest in allocating management time, services and other activities between the partnership and its other activities. The managing general partner will determine the allocation of its management time, services and other functions on an as-needed basis consistent with its fiduciary duties among the partnerships and its other activities.

Subject to its fiduciary duties, the managing general partner will not be restricted from participating in other businesses or activities, even if these other businesses or activities compete with the partnership's activities and operate in the same areas as the partnership. However, the managing general partner and its affiliates may pursue business opportunities that are consistent with the partnership's investment objectives for their own account only after they have determined that the opportunity either:

- cannot be pursued by the partnership because of insufficient funds; or

- it is not appropriate for the partnership under the existing circumstances.

CONFLICTS INVOLVING THE ACQUISITION OF LEASES

The managing general partner will select, in its sole discretion, the wells to be drilled by the partnership. Conflicts of interest may arise concerning which wells will be drilled by the partnership and which wells will be drilled by the managing general partner and its affiliates, their other affiliated partnerships or third-party programs in which they serve as driller/operator. It may be in the managing general partner's or its affiliates' advantage to have the partnership bear the costs and risks of drilling a particular well rather than another affiliate. These potential conflicts of interest will be increased if the managing general partner organizes and allocates wells to more than one partnership at a time. To lessen this conflict of interest the managing general partner generally takes a similar interest in other partnerships when it serves as managing general partner and/or driller/operator.

No procedures, other than the guidelines set forth below and in " - Procedures to Reduce Conflicts of Interest," have been established by the managing general partner to resolve any conflicts which may arise. The partnership agreement provides that the managing general partner and its affiliates will abide by the guidelines set forth below. However, with respect to (2), (3), (4), (5) and (7) there is an exception in the partnership agreement for another program in which the interest of the managing general partner is substantially similar to or less than its interest in the partnership.

(1) TRANSFERS AT COST. All leases will be acquired from the managing general partner and credited towards its required capital contribution at the cost of the lease, unless the managing general partner has a reason to believe

that cost is materially more than the fair market value of the property. If the managing general partner believes cost is materially more than fair market value, then the managing general partner's credit for the contribution must be at a price not in excess of the fair market value.

- A determination of fair market value must be supported by an appraisal from an independent expert and be maintained in the partnership's records for at least six years.

(2) EQUAL PROPORTIONATE INTEREST. When the managing general partner sells or transfers an oil and gas interest to the partnership, it must, at the same time, sell or transfer to the partnership an equal proportionate interest in all its other property in the same prospect.

- The term "prospect" generally means an area which is believed to contain commercially productive quantities of natural gas or oil.

However, a prospect will be limited to the drilling or spacing unit on which one well will be drilled if the following two conditions are met:

- the well is being drilled to a geological feature which contains proved reserves; and

- the drilling or spacing unit protects against drainage.

The managing general partner believes that for a prospect located in Ohio, Pennsylvania and New York on which a well will be drilled to test the Clinton/Medina geologic formation or the Mississippian/Upper Devonian

Sandstone reservoirs, a prospect will consist of the drilling and spacing unit because it will meet the test in the preceding sentence.

- Proved reserves, generally, are the estimated quantities of natural gas and oil which have been demonstrated to be recoverable in future years with reasonable certainty under existing economic and operating conditions. Proved reserves include proved undeveloped reserves which generally are reserves expected to be recovered from existing wells where a relatively major expenditure is required for recompletion or from new wells on undrilled acreage. Reserves on undrilled acreage will be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved Reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

The managing general partner anticipates that the majority of the wells drilled by the partnership will develop either the Clinton/Medina geologic formation or the Mississippian/Upper Devonian Sandstone reservoirs. The drilling of these wells may provide the managing general partner with offset sites by allowing it to determine at the partnership's expense the value of adjacent acreage in which the partnership would not have any interest. The managing general partner owns acreage in the area surrounding the currently proposed wells. To lessen this conflict of interest, for five years the managing general partner may not drill any well:

- in the Clinton/Medina geologic formation within 1,650 feet of an existing partnership well in Pennsylvania or within 1,000 feet of an existing partnership well in Ohio; or

- in the Mississippian/Upper Devonian Sandstone reservoirs within 1,000 feet of an existing partnership well.

If the partnership abandons its interest in a well, then this restriction will continue for one year following the abandonment.

(3) SUBSEQUENTLY ENLARGING PROSPECT. In areas where the prospect is not limited to the drilling or spacing unit and the area constituting the partnership's

prospect is subsequently enlarged based on geological information which is later acquired then there is the following special provision:

- if the prospect is enlarged to cover any area where the managing general partner owns a separate property interest and the partnership activities were material in establishing the existence of proved undeveloped reserves which are attribuTable to the separate property interest, then the separate property interest or a portion thereof must be sold to the partnership in accordance with

(1), (2) and (4).

(4) TRANSFER OF LESS THAN THE MANAGING GENERAL PARTNER'S AND ITS AFFILIATES' ENTIRE INTEREST. If the managing general partner sells or transfers to the partnership less than all of its ownership in any prospect, then it must comply with the following conditions:

- the retained interest must be a proportionate interest;

- the managing general partner's obligations and the partnership's obligations must be substantially the same after the sale of the interest by the managing general partner or its affiliates; and

- the managing general partner's revenue interest must not exceed the amount proportionate to its retained interest.

For example, if the managing general partner transfers 50% of its interest in a prospect to the partnership and retains a 50% interest, then the partnership will not pay any of the costs associated with the managing general partner's retained interest as a part of the transfer. This limitation does not prevent the managing general partner and its affiliates from subsequently dealing with their retained interest as they may choose with unaffiliated parties or affiliated partnerships. For example, the managing general partner may sell its retained interest to a third party for a profit.

(5) LIMITATIONS ON ACTIVITIES OF THE MANAGING GENERAL PARTNER AND ITS AFFILIATES ON LEASES ACQUIRED BY THE PARTNERSHIP.
For a five year period after the closing, if the managing general partner proposes to acquire an interest from an unaffiliated person in a prospect in which the partnership owns an interest or in a prospect in which the partnership's interest has been terminated without compensation within one year before the proposed acquisition, then the following conditions apply:

- if the managing general partner does not currently own property in the prospect separately from the partnership, then the managing general partner may not buy an interest in the prospect; and

- if the managing general partner currently owns a proportionate interest in the prospect separately from the partnership, then the interest to be acquired must be divided in the same proportion between the managing general partner and the partnership as the other property in the prospect. However, if the partnership does not have the cash or financing to buy the additional interest, then the managing general partner is also prohibited from buying the additional interest.

(6) NO SALE OF UNDEVELOPED LEASES TO THE MANAGING GENERAL PARTNER AND LIMITATIONS ON SALE OF DEVELOPED LEASES TO THE MANAGING GENERAL PARTNER.
The managing general partner and its affiliates may not purchase non-producing natural gas and oil properties from the partnership.

The managing general partner and its affiliates, other than an affiliated income program, may not purchase any producing natural gas or oil property from the partnership unless:

- the sale is in connection with the liquidation of the partnership; or

- the managing general partner's well supervision fees under the Drilling and Operating Agreement for the well have exceeded the net revenues of the well, determined without regard to the managing general partner's well supervision fees for the well, for a period of at least three consecutive months.

In both cases, the sale must be at fair market value supported by an appraisal of an independent expert selected by the managing general partner.

An affiliated income program may purchase a producing natural gas and oil property from the partnership at any time at fair market value as supported by an appraisal from an independent expert if the property has been held by the partnership for more than six months or there have been significant expenditures made in connection with the property or at cost as adjusted for intervening operations if the managing general partner deems it to be in the best interest of the partnership.

The appraisal of the property must be maintained in the partnership's records for at least six years.

(7) NO TRANSFER OF LEASES BETWEEN AFFILIATED LIMITED PARTNERSHIPS. Subject to

(6), the partnership may not purchase properties from or sell properties to any other affiliated partnership. Also, this prohibition does not apply to joint ventures among affiliated partnerships, provided that:

- the respective obligations and revenue sharing of all parties to the transaction are substantially the same; and

- the compensation arrangement or any other interest or right of either the managing general partner or its affiliates is the same in each affiliated partnership or if different, the aggregate compensation of the managing general partner or the affiliate is reduced to reflect the lower compensation arrangement.

(8) LEASES WILL BE ACQUIRED ONLY FOR STATED PURPOSE OF THE PARTNERSHIP. The partnership must acquire only leases that are reasonably expected to meet the stated purposes of the partnership. Also, no leases may be acquired for the purpose of a

subsequent sale unless the acquisition is made after a well has been drilled to a depth sufficient to indicate that the acquisition would be in the partnership's best interest.

CONFLICTS BETWEEN INVESTORS AND THE MANAGING GENERAL PARTNER AS AN INVESTOR
The managing general partner, its officers, directors and affiliates may subscribe for units and the price of their units will be reduced by 10.5%, which is equal to the dealer-manager fee and the sales commission and the reimbursements to the dealer-manger for marketing expenses and the selling agents' bona fide accounTable due diligence expenses. These investors generally will share in the partnership's costs, revenues and distributions on the same basis as the other investors as described in "Participation in Costs and Revenues," and will have the same voting rights, except as discussed below, even though they pay a reduced price for their units.

Any subscription by the managing general partner, its officers, directors, or affiliates will dilute the voting rights of you and the other investors and there may be a conflict with respect to certain matters. The managing general partner and its officers, directors and affiliates, however, are prohibited from voting with respect to certain matters.

LACK OF INDEPENDENT UNDERWRITER AND DUE DILIGENCE INVESTIGATION
The terms of this offering, the partnership agreement and the drilling and

operating agreement were determined by the managing general partner without arms' length negotiations. You and the other investors have not been separately represented by legal counsel, who might have negotiated more favorable terms for you and the other investors in the offering and the agreements.

Also, there was not an extensive in-depth "due diligence" investigation of the existing and proposed business activities of the partnership and the managing general partner which would be provided by independent underwriters. Although Anthem Securities, which is affiliated with the managing general partner, serves as dealer-manager and will receive reimbursement of accounTable due diligence expenses for certain due diligence investigations conducted by the selling agents which will be reallowed to the selling agents, its due diligence examination concerning this offering cannot be considered to be independent.

CONFLICTS CONCERNING LEGAL COUNSEL

The managing general partner anticipates that its legal counsel will also serve as legal counsel to the partnership and that this dual representation will continue in the future. If a future dispute arises between the managing general partner and you and the other investors, then the managing general partner will cause you and the other investors to retain separate counsel. Also, if counsel advises the managing general partner that counsel reasonably believes its representation of the partnership will be adversely affected by its responsibilities to the managing general partner, then the managing general partner will cause you and the other investors to retain separate counsel.

CONFLICTS REGARDING PREPARATION OF GEOLOGICAL REPORTS

The geological report for Fayette County, Pennsylvania and the geological report for the Clinton/Medina geological formation in southern Ohio which cover a portion of the currently proposed wells were prepared by the managing general partner which is not independent. This lack of independence in the preparation of the reports may affect their reliability since the managing general partner has an incentive to prepare more positive reports than an independent geologist.

CONFLICTS REGARDING PRESENTMENT FEATURE

You and the other investors have the right to present your units to the managing general partner for repurchase beginning in 2006. This creates the following conflicts of interest between you and the managing general partner.

- The managing general partner may suspend the presentment feature if it does not have the necessary cash flow or it cannot arrange borrowings for this purpose on terms which it deems reasonable. Both of these determinations are subjective and will be made in the managing general partner's sole discretion.

- The managing general partner will also determine the repurchase price based on a reserve report that it prepares and is reviewed by an independent expert which it chooses. The formula for arriving at the repurchase price has many subjective determinations that are within the discretion of the managing general partner.

CONFLICTS REGARDING MANAGING GENERAL PARTNER WITHDRAWING AN INTEREST
A conflict of interest is created with you and the other investors by the managing general partner's right to mortgage its interest or withdraw an interest in the partnership's wells to be used as collateral for a loan to the managing general partner. If there was

a default under the loan, this could reduce the amount of the managing general partner's partnership net production revenues available for its subordination obligation to you and the other investors.

CONFLICTS REGARDING ORDER OF PIPELINE CONSTRUCTION AND GATHERING FEES
A conflict of interest is created by the right of the managing general partner's parent company, Atlas America, and its affiliate, Atlas Pipeline Partners, L.P., to determine the order of priority for constructing gathering lines because this could delay connecting some of the partnership's wells into the gathering system of Atlas Pipeline Partners, L.P. Also, the managing general partner may choose

well locations along the gathering system which would benefit its parent company by providing more gathering fees to Atlas Pipeline Partners L.P., even if there are other well locations available in the area or other areas which offer the partnership a greater potential return.

The managing general partner and its affiliates will pay the difference between the gathering fees to be paid by the partnership to Atlas Pipeline Partners, which are set forth in "Compensation - Gathering Fees," and the greater of $.35 per mcf or 16% of the gross sales price for the gas. This provides an incentive to the managing general partner to increase the amount of the gathering fees paid by the partnership in the future which are not locked-in as described in "Compensation-Gathering Fees."

PROCEDURES TO REDUCE CONFLICTS OF INTEREST

In addition to the procedures set forth in " - Conflicts Involving the Acquisition of Leases," the managing general partner and its affiliates will comply with the following procedures in the partnership agreement to reduce some of the conflicts of interest with you and the other investors. The managing general partner does not have any other conflict of interest resolution procedures. Thus, conflicts of interest between the managing general partner and you and the other investors may not necessarily be resolved in your best interests. However, the managing general partner believes that its significant capital contribution to the partnership will reduce the conflicts of interest.

(1) FAIR AND REASONABLE. The managing general partner may not sell, transfer, or convey any property to, or purchase any property from, the partnership except pursuant to transactions that are fair and reasonable, nor take any action with respect to the assets or property of the partnership which does not primarily benefit the partnership.

(2) NO COMPENSATING BALANCES. The managing general partner may not use the partnership's funds as a compensating balance for its own benefit.

(3) FUTURE PRODUCTION. The managing general partner may not commit the future production of a partnership well exclusively for its own benefit.

(4) DISCLOSURE. Any agreement or arrangement that binds the partnership, must be fully disclosed in this prospectus.

(5) NO LOANS FROM THE PARTNERSHIP. The partnership may not loan money to the managing general partner.

(6) NO REBATES. The managing general partner may not participate in any business arrangements which would circumvent these guidelines including receiving rebates or give-ups.

(7) SALE OF ASSETS. The sale of all or substantially all of the assets of the partnership may only be made with the consent of investors whose units equal a majority of the total units.

(8) PARTICIPATION IN OTHER PARTNERSHIPS. If the partnership participates in other partnerships or joint ventures then the terms of the arrangements must not circumvent any of the requirements contained in the partnership agreement, including the following:

- there may be no duplication or increase in organization and offering expenses, the managing general partner's compensation, partnership expenses or other fees and costs;

- there may be no substantive change in the fiduciary and contractual relationship between the managing general partner and you and the other investors; and

- there may be no diminishment in your voting rights.

(9) INVESTMENTS. Partnership funds may not be invested in the securities of another person except in the following instances:

- investments in interests made in the ordinary course of the partnership's business;

- temporary investments in income producing short-term highly liquid investments, in which there is appropriate safety of principal, such as U.S. Treasury Bills;

- multi-tier arrangements meeting the requirements of (8) above;

- investments involving less than 5% of the total subscriptions which are a necessary and incidental part of a property acquisition transaction; and

- investments in entities established solely to limit the partnership's liabilities associated with the ownership or operation of property or equipment, provided, that duplicative fees and expenses are prohibited.

(10) SAFEKEEPING OF FUNDS. The managing general partner may not employ, or permit another to employ, the funds or assets of the partnership in any manner except for the exclusive benefit of the partnership. The managing general partner has a fiduciary responsibility for the safekeeping and use of all funds and assets of the partnership whether or not in its possession or control.

(11) ADVANCE PAYMENTS. Advance payments by the partnership to the managing general partner and its affiliates are prohibited except when advance payments are required to secure the tax benefits of prepaid intangible

drilling costs and for a business purpose.

POLICY REGARDING ROLL-UPS

It is possible at some indeterminate time in the future that the partnership may become involved in a roll-up. In general, a roll-up means a transaction involving the acquisition, merger, conversion, or consolidation of the partnership with or into another partnership, corporation or other entity, and the issuance of securities by the roll-up entity to you and the other investors. A roll-up will also include any change in the rights, preferences, and privileges of you and the other investors in the partnership. These changes could include the following:

- increasing the compensation of the managing general partner;
- amending your voting rights;
- listing the units on a national securities exchange or on NASDAQ;
- changing the fundamental investment objectives of the partnership; or
- materially altering the duration of the partnership.

If a roll-up should occur in the future the partnership agreement provides various policies which include the following:

- an independent expert must appraise all partnership assets and you must receive a summary of the appraisal in connection with a proposed roll-up;

- if you vote "no" on the roll-up proposal, then you will be offered a choice of:

- accepting the securities of the roll-up entity;

- remaining a partner in the partnership and preserving your units in the partnership on the same terms and conditions as existed previously; or

- receiving cash in an amount equal to your pro-rata share of the appraised value of the partnership's net assets; and

- the partnership will not participate in a proposed roll-up:

- unless approved by investors whose units equal 75% of the total units;

- which would result in the diminishment of your voting rights under the roll-up entity's chartering agreement;

- in which your right of access to the records of the roll-up entity would be less than those provided by the partnership agreement; or

- in which any of the transaction costs would be borne by the partnership if the proposed roll-up is not approved by investors whose units equal 75% of the total units.

FIDUCIARY RESPONSIBILITY OF THE MANAGING GENERAL PARTNER

IN GENERAL

The managing general partner will manage the partnership and its assets. In conducting the partnership's affairs it is accountable to you as a fiduciary and it must exercise good faith and deal fairly with you and the other investors. If the managing general partner breaches its fiduciary responsibilities, then you are entitled to an accounting and the recovery of any economic loss caused by the breach. Neither the partnership agreement nor any other agreement between the managing general partner and the partnership may contractually limit any fiduciary duty owed to you and the other investors by the managing general partner under applicable law except as set forth in Sections 4.01, 4.02, 4.04, 4.05 and 4.06 of the partnership agreement. This is a rapidly expanding and changing area of the law and if you have questions concerning the managing general partner's duties you should consult your own counsel.

LIMITATIONS ON MANAGING GENERAL PARTNER LIABILITY AS FIDUCIARY

Under the terms of the partnership agreement, the managing general partner, the operator, and their affiliates have limited their liability to the partnership and to you and the other investors for any loss suffered by the partnership or you and the other investors which arises out of any action or inaction on their part if:

- they determined in good faith that the course of conduct was in the best interest of the partnership;

- they were acting on behalf of, or performing services for, the partnership; and

- their course of conduct did not constitute negligence or misconduct.

Thus, you and the other investors may have a more limited right of action than you would have had without these limitations in the partnership agreement.

In addition, the partnership agreement provides for indemnification of the managing general partner, the operator, and their affiliates by the partnership against any losses, judgments, liabilities, expenses and amounts paid in settlement of any claims sustained by them in connection with the partnership provided that they meet the standards set forth above. However, there is a more restrictive standard for indemnification for losses arising from or out of an alleged violation of federal or state securities laws. Also, to the extent that any indemnification provision in the partnership agreement purports to include indemnification for liabilities arising under the Securities Act of 1933, as amended, you should be aware that, in the SEC's opinion, this indemnification is contrary to public policy and therefore unenforceable.

Payments arising from the indemnification or agreement to hold harmless are recoverable only out of the following:

- tangible net assets;

- revenues; and

- insurance proceeds.

Still, use of partnership funds or assets for indemnification would reduce amounts available for partnership operations or for distribution to you and the other investors.

The partnership will not pay the cost of the portion of any insurance which insures the managing general partner, the operator, or an affiliate against any liability for which they cannot be indemnified. In addition, partnership funds can be advanced to them for legal expenses and other costs incurred in any legal action for which indemnification is being sought only if the partnership has adequate funds available and certain conditions in the partnership agreement are met.

TAX ASPECTS

SUMMARY OF TAX OPINION

The managing general partner has received the tax opinion of special counsel, Kunzman & Bollinger, Inc., Oklahoma City, Oklahoma, which is included as Exhibit

(8) to the registration statement. This section of the prospectus is a summary of the tax opinion and all the material federal income tax consequences of the purchase, ownership and disposition of the general and limited partner interests. You are strongly urged to read the entire tax opinion.

The tax opinion represents only special counsel's best legal judgment, and has no binding effect or official status. It is only special counsel's prediction as to the outcome of the issues addressed and the results are not certain. As required by IRS regulations, special counsel's opinions state whether it is "more likely than not" that the predicted outcome will occur. There is no assurance that the present laws or regulations will not be changed and adversely affect you. Also, the IRS may challenge the deductions claimed by the partnership or you, or the taxable year in which the deductions are claimed, and no guaranty can be given that the challenge would not be upheld if litigated. No advance ruling on any tax consequence of an investment in the partnership will be requested from the IRS.

Different tax considerations than these addressed in this discussion may apply to foreign persons, corporations, partnerships, trusts and other prospective investors which are not treated as individuals for federal income tax purposes. Also, the treatment of the tax attributes of the partnership may vary among investors. Accordingly, you are urged to seek qualified, professional assistance in the preparation of your federal, state and local tax returns with specific reference to your own tax situation.

In special counsel's opinion it is more likely than not that the following tax treatment will be upheld if challenged by the IRS and litigated.

- PARTNERSHIP CLASSIFICATION. The partnership will be classified as a partnership for federal income tax purposes, and not as a corporation. The partnership, as such, will not pay any federal income taxes, and all items of income, gain, loss, and deduction of the partnership will be reporTable by the partners in the partnership.

- PASSIVE ACTIVITY CLASSIFICATION.

- Generally, the passive activity limitations on losses under Section469 of the Internal Revenue Code will apply to limited partners, but will not apply to investor general partners before the conversion of investor general partner units to limited partner units.

- The partnership's income and gain from its natural gas and oil properties which are allocated to limited partners, other than converted investor general partners, generally will be characterized as passive activity income which may be offset by passive activity losses.

- Income or gain attribuTable to investments of working capital of the partnership will be characterized as portfolio income, which cannot be offset by passive activity losses.

- NOT A PUBLICLY TRADED PARTNERSHIP. Assuming that no more than 10% of the units are transferred in any taxable year of the partnership, other than in private transfers described in Treas. Reg. Section1.7704-1(e), the partnership will not be treated as a "publicly traded partnership" under the Internal Revenue Code.

- AVAILABILITY OF CERTAIN DEDUCTIONS. Business expenses, including payments for personal services actually rendered in the taxable year in which accrued, which are reasonable, ordinary and necessary and do not include

amounts for items such as lease acquisition costs, organization and syndication fees and other items which are required to be capitalized, are currently deductible.

- INTANGIBLE DRILLING COSTS. The partnership will elect to deduct currently all intangible drilling costs. However, each investor may elect instead to capitalize and deduct all or part of his share of the intangible drilling costs ratably over a 60 month period as discussed in "Minimum Tax - Tax Preferences", below. Subject to the foregoing, intangible drilling costs paid by the partnership under the terms of bona fide drilling contracts for the partnership's wells will be deductible in the taxable year in which the payments are made and the drilling services are rendered, assuming the amounts are fair and reasonable consideration and subject to certain restrictions summarized below, including basis and "at risk" limitations and the passive activity loss limitation with respect to the limited partners.

- PREPAYMENTS OF INTANGIBLE DRILLING COSTS. Depending primarily on when the partnership subscriptions are received, the managing general partner anticipates that the partnership will prepay in 2001 most, if not all, of the intangible drilling costs related to partnership wells the drilling of which will begin in 2002. Assuming that the amounts are fair and reasonable, and based in part on the factual assumptions set forth below, in special counsel's opinion the prepayments of intangible drilling costs will be deductible for the 2001 taxable year even though all owners in the well may not be required to prepay intangible drilling costs, subject to certain restrictions summarized below, including basis and "at risk" limitations, and the passive activity loss limitation with respect to the limited partners.

The foregoing opinion is based in part on the assumptions that:

- the intangible drilling costs will be required to be prepaid in 2001 for specified wells under the drilling and operating agreement;

- under the drilling and operating agreement the drilling of the wells is required to be, and actually is, begun on or before March 31, 2002, and the wells are continuously drilled thereafter until completed, if warranted, or abandoned; and

- the required prepayments are not refundable to the partnership and any excess prepayments are applied to intangible drilling costs of substitute wells.

- DEPLETION ALLOWANCE. The greater of cost depletion or percentage depletion will be available to qualified investors as a current deduction against the partnership's natural gas and oil production income, subject to certain restrictions summarized below.

- MACRS. The partnership's reasonable costs for equipment placed in the wells which cannot be deducted immediately will be eligible for cost recovery deductions under the Modified Accelerated Cost Recovery System ("MACRS"), generally over a seven year "cost recovery period," subject to certain restrictions summarized below, including basis and "at risk" limitations, and the passive activity loss limitation in the case of limited partners.

- TAX BASIS OF UNITS. Each investor's adjusted tax basis in his units will be increased by his total subscription proceeds.

- AT RISK LIMITATION ON LOSSES. Each investor initially will be "at risk" to the full extent of his subscription proceeds.

- ALLOCATIONS. Assuming the effect of the allocations of income, gain, loss and deduction, or items thereof, set forth in the partnership agreement, including the allocations of basis and amount realized with respect to natural gas and oil properties, is substantial in light of an investor's tax attributes that are unrelated to the partnership, the allocations will have "substantial economic effect" and will govern each investor's distributive share of those items to the extent the allocations do not cause or increase deficit balances in the investors' capital accounts.

- SUBSCRIPTION. No gain or loss will be recognized by the investors on payment of their subscriptions.

- PROFIT MOTIVE AND NO TAX SHELTER REGISTRATION. Based on the managing general partner's representation that the partnership will be conducted as described in the prospectus, the partnership will possess the requisite profit motive under Section 183 of the Internal Revenue Code and is not required to register with the IRS as a tax shelter.

- IRS ANTI-ABUSE RULE. Based on the managing general partner's representation that the partnership will be conducted as described in the prospectus, the partnership will not be subject to the anti-abuse rule set forth in Treas. Reg. Section 1.701-2.

- OVERALL EVALUATION OF TAX BENEFITS. Based on special counsel's conclusion that substantially more than half of the material tax benefits of the partnership, in terms of their financial impact on a typical investor, more likely than not will be realized if challenged by the IRS, the tax benefits of the partnership, in the aggregate, which are a significant feature of an investment in the partnership by a typical original investor more likely than not will be realized as contemplated by the prospectus.

PARTNERSHIP CLASSIFICATION

For federal income tax purposes, a partnership is not a taxable entity. The partners, rather than the partnership, receive any deductions, as well as the income, from the operations engaged in by the partnership. A business entity with two or more members is classified for federal tax purposes as either a corporation or a partnership. Because the partnership was formed under the Pennsylvania Revised Uniform Limited Partnership Act which describes the partnership as a "partnership," it will automatically be classified as a partnership unless it elects to be classified as a corporation. In this regard, the managing general partner has represented that the partnership will not elect to be classified as a corporation.

LIMITATIONS ON PASSIVE ACTIVITIES

Under the passive activity rules, all income of a taxpayer who is subject to the rules is categorized as:

- income from passive activities such as limited partners' interests in a business;

- active income such as salary, bonuses, etc.; or

- portfolio income such as gain, interest, dividends and royalties unless earned in the ordinary course of a trade or business.

Losses generated by "passive activities" can offset only passive income and cannot be applied against active income or portfolio income. Suspended losses may be carried forward, but not back, and used to offset future years' passive activity income.

Passive activities include any trade or business in which the taxpayer does not materially participate on a regular, continuous, and substantial basis. Under the partnership agreement, limited partners will not have material participation in the partnership and generally will be subject to the passive activity limitations.

Investor general partners also do not materially participate in the partnership. However, because the partnership will own only "working interests," as defined in the Internal Revenue Code, in its wells and investor general partners will not have limited liability under Pennsylvania law until they are converted to limited partners, their deductions generally will not be treated as passive deductions before the conversion. However, if an investor general partner invests in the partnership through an entity which limits his liability, for example, a limited partnership, limited liability company, or S corporation, he will be treated the same as a limited partner and generally will be subject to the passive activity limitations. Contractual limitations on the liability of investor general partners under the partnership agreement such as insurance, limited indemnification, etc. will not cause investor general partners to be subject to the passive activity limitations.

PUBLICLY TRADED PARTNERSHIP RULES. Net losses of a partner from each publicly traded partnership are suspended and carried forward to be netted against income from that publicly traded partnership only. In addition, net losses from other passive activities may not be used to offset net passive income from a publicly traded partnership. However, in the opinion of special counsel it is more likely than not that the partnership will not be characterized as a publicly traded partnership under the Internal Revenue Code so long as no more than 10% of the Units are transferred in any taxable year of the partnership other than in private transfers described in Treas. Reg. Section 1.7704-1(e).

CONVERSION FROM INVESTOR GENERAL PARTNER TO LIMITED PARTNER. Investor general partner units will be converted by the managing general partner to limited partner units after substantially all of the partnership wells have been drilled and completed, which the managing general partner anticipates will be in the late summer of 2002. Thereafter, each investor general partner will have limited liability as a limited partner under the Pennsylvania Revised Uniform Limited Partnership Act with respect to his interest in the partnership.

Concurrently, the investor general partner will become subject to the passive activity limitations. However, because he previously will have received a non-passive deduction for intangible drilling costs, the Internal Revenue Code requires that his net income from the partnership's wells following the conversion must continue to be characterized as non-passive income which cannot be offset with passive losses. An investor general partner's conversion of his partnership interest into a limited partner interest should not have any other adverse tax consequences unless the investor general partner's share of any partnership liabilities is reduced as a result of the conversion. A reduction in a partner's share of liabilities is treated as a constructive distribution of cash to the partner, which reduces the basis of the partner's interest in the partnership and is taxable to the extent it exceeds his basis.

TAXABLE YEAR

The partnership intends to adopt a calendar year taxable year.

2001 EXPENDITURES

The managing general partner anticipates that all of the partnership's subscription proceeds will be expended in 2001 and that your share of the partnership's income and deductions will be reflected on your federal income tax return for that period. Depending primarily on when the partnership subscriptions are received, the managing general partner anticipates that the partnership will prepay in 2001 most, if not all, of its intangible drilling costs for wells the drilling of which will begin in 2002. The deductibility in 2001 of these advance payments cannot be guaranteed.

AVAILABILITY OF CERTAIN DEDUCTIONS

Ordinary and necessary business expenses, including reasonable compensation for personal services actually rendered, are deductible in the year incurred. The managing general partner has represented to special counsel that the amounts payable to the managing general partner and its affiliates, including the amounts paid to the managing general partner or its affiliates as general drilling contractor, are the amounts which would ordinarily be paid for similar services in similar transactions. The fees paid to the managing general partner and its affiliates will not be currently deductible if they are:

- in excess of reasonable compensation;

- properly characterized as organization or syndication fees, other capital costs such as the acquisition cost of the leases; or

- not "ordinary and necessary" business expenses.

In the event of an audit, payments to the managing general partner and its affiliates by the partnership will be scrutinized by the IRS to a greater extent than payments to an unrelated party.

INTANGIBLE DRILLING COSTS

Subject to the passive activity loss rules in the case of limited partners, you will be entitled to deduct your share of intangible drilling costs which include items which do not have salvage value, such as labor, fuel, repairs, supplies and hauling necessary to the drilling of a well. Intangible drilling costs generally will be treated as ordinary income if a property is sold at a gain. Also, productive-well intangible drilling costs may subject you to an alternative minimum tax in excess of regular tax unless you elect to deduct all or part of these costs ratably over a 60-month period as discussed in "Minimum Tax - Tax Preferences", below.

The managing general partner estimates that on average approximately 75.6% of the total price to be paid by the partnership for all of its completed wells will be intangible drilling costs which are charged 100% to you and the other investors under the partnership agreement. Under the partnership agreement not less than 90% of the subscription proceeds received by the partnership from you and the other investors will be used to pay intangible drilling costs. The IRS could challenge the characterization of a portion of these costs as deductible intangible drilling costs and recharacterize the costs as some other item which may be non-deductible; however, this would have no effect on the allocation and payment of the costs under the partnership agreement.

YOU SHOULD CONSULT WITH YOUR PERSONAL TAX ADVISOR CONCERNING THE TAX BENEFITS TO YOU OF THE PARTNERSHIP'S DEDUCTION FOR INTANGIBLE DRILLING COSTS IN LIGHT OF YOUR OWN TAX SITUATION.

DRILLING CONTRACTS

The partnership will enter into the drilling and operating agreement with the managing general partner or its affiliates, as a third-party general drilling contractor, to drill and complete the partnership's development wells on a cost plus 15% basis. For its

services as general drilling contractor, the managing general partner anticipates that on average over all of the wells drilled and completed by the partnership it will have reimbursement of general and administrative overhead of approximately $14,975 per well and a profit of 15% (approximately $29,120) per well with respect to the intangible drilling costs and the portion of equipment costs paid by you and the other investors as described in "Compensation - Drilling Contracts". However, the actual cost of drilling and completing the wells may be more or less than the estimated amount, due primarily to the uncertain nature of drilling operations, and the managing general partner's reimbursement of overhead and profit also could be more or less than the amount estimated by the managing general partner.

The managing general partner believes the prices under the drilling and operating agreement are competitive in the proposed areas of operation. Nevertheless, the amount of the profit realized by the managing general partner under the drilling and operating agreement could be challenged by the IRS as unreasonable and disallowed as a deductible intangible drilling cost.

Depending primarily on when the partnership subscriptions are received, the managing general partner anticipates that the partnership will prepay in 2001 most, if not all, of the intangible drilling costs for drilling activities that will begin in 2002. In KELLER V. COMMISSIONER, 79 T.C. 7 (1982), aff'd 725 F.2d 1173 (8th Cir. 1984), the Tax Court applied a two-part test for the current deductibility of prepaid intangible drilling costs. First, the expenditure must be a payment rather than a refundable deposit. Second, the deduction must not result in a material distortion of income taking into substantial consideration the business purpose aspects of the transaction.

The partnership will attempt to comply with the guidelines set forth in KELLER with respect to prepaid intangible drilling costs. The drilling and operating agreement will require the partnership to prepay in 2001 intangible drilling costs for specified wells the drilling of which will begin in 2002. Prepayments should not result in a loss of current deductibility where there is a legitimate business purpose for the required prepayment, the contract is not merely a sham to control the timing of the deduction and there is an enforceable contract of economic substance. The drilling and operating agreement will require the partnership to prepay the intangible drilling costs of drilling and completing the wells in order to enable the operator to commence site preparation for the wells, obtain suiTable subcontractors at the then current prices and insure the availability of equipment and materials. Under the drilling and operating agreement excess prepaid amounts, if any, will not be refundable to the partnership but will be applied to intangible drilling costs to be incurred in drilling and completing substitute wells. Under KELLER, a provision for substitute wells should not result in the prepayments being characterized as refundable deposits.

The likelihood that prepayments will be challenged by the IRS on the grounds that there is no business purpose for the prepayment is increased if prepayments are not required with respect to the entire well. It is possible that less than 100% of the interest will be acquired by the partnership in one or more wells and prepayments may not be required of all owners of interests in the wells. However, in the view of special counsel, a legitimate business purpose for the required prepayments may exist under the guidelines set forth in KELLER, even though prepayment is not required, or actually received, by the drilling contractor with respect to a portion of the interest in the wells.

In addition, a current deduction for prepaid intangible drilling costs is available only if the drilling of the wells begins before the close of the 90th day after the close of the taxable year. The managing general partner will attempt to cause the drilling of all prepaid partnership wells to begin on or before March 31, 2002. However, the drilling of any partnership well may be delayed due to circumstances beyond the control of the partnership or the drilling contractor. Such circumstances include, for example, the unavailability of drilling rigs, decisions of third-party operators to delay drilling the wells, weather conditions, inability to obtain drilling permits or access right to the drilling site, or title problems. Due to the foregoing factors no guaranty can be given that the drilling of all prepaid partnership wells required by the drilling and operating agreement to begin on or before March 31, 2002, will actually begin by that date. In that event, deductions claimed in 2001 for prepaid intangible drilling costs would be disallowed and deferred to the 2002 taxable year.

No assurance can be given that on audit the IRS would not disallow the current deductibility of a portion or all of any prepayments of intangible drilling costs under the partnership's drilling contracts, thereby decreasing the amount of deductions allocable to the investors for the current taxable year, or that the challenge would not ultimately be sustained. In the event of disallowance, the deduction would be available in the year the work is actually performed.

DEPLETION ALLOWANCE

Proceeds from the sale of the partnership's natural gas and oil production will constitute ordinary income. A certain portion of the income will not be taxable under the depletion allowance which permits the deduction from gross income for federal income tax purposes of either the percentage depletion allowance or the cost depletion allowance, whichever is greater. Depletion deductions generally will be treated as ordinary income if a property is sold at a gain.

Cost depletion for any year is determined by dividing the adjusted tax basis for the property by the total units of natural gas or oil expected to be recoverable from the property and then multiplying the resultant quotient by the number of units actually sold during the year. Cost depletion cannot exceed the adjusted tax basis of the property to which it relates.

Percentage depletion generally is available to taxpayers other than integrated oil companies. Percentage depletion is based on your share of the partnership's gross production income from its natural gas and oil properties. The rate of percentage depletion is 15%. However, percentage depletion for marginal production increases 1%, up to a maximum increase of 10%, for each whole dollar that the domestic wellhead price of crude oil for the immediately preceding year is less than $20 per barrel without adjustment for inflation. The term "marginal production" includes natural gas and oil produced from a domestic stripper well property, which is defined as any property which produces a daily average of 15 or less equivalent barrels of oil, which is 90 MCF of natural gas, per producing well on the property in the calendar year. The rate of percentage depletion for marginal production in 2001 is 15%. This rate fluctuates from year to year depending on the price of oil, but will not be less than the statutory rate of 15% nor more than 25%.

Also, percentage depletion:

- may not exceed 100% of the net income from each natural gas and oil property before the deduction for depletion; and

- is limited to 65% of the taxpayer's taxable income for a year computed without regard to deductions for percentage depletion, net operating loss carry-backs and capital loss carry-backs.

However, with respect to marginal properties, which will include most, if not all, of the partnership's wells, the 100% of net income property limitation is suspended for 2001.

AVAILABILITY OF PERCENTAGE DEPLETION MUST BE COMPUTED SEPARATELY BY YOU, AND NOT BY THE PARTNERSHIP OR FOR INVESTORS AS A WHOLE. YOU ARE URGED TO CONSULT YOUR OWN TAX ADVISORS WITH RESPECT TO THE AVAILABILITY OF PERCENTAGE DEPLETION TO YOU.

DEPRECIATION - MODIFIED ACCELERATED COST RECOVERY SYSTEM ("MACRS")
Equipment costs and the related depreciation deductions of the partnership generally are charged and allocated under the partnership agreement 66% to the managing general partner and 34% to you and the other investors in the partnership. However, if the total equipment costs for all of the partnership's wells that would be charged to you and the other investors exceeds an amount equal to 10% of the subscription proceeds of you and the other investors, then the excess, together with the related depreciation deductions, will be charged and allocated to the managing general partner. These deductions are subject to recapture as ordinary income rather than capital gain on the disposition of the property or an investor's units. The cost of most equipment placed in service by the partnership will be recovered through depreciation deductions over a seven year cost recovery period, using the 200% declining balance method, with a switch to straight-line to maximize the deduction. Smaller depreciation deductions are used for purposes of the alternative minimum tax. Only a half-year of depreciation is allowed for the year recovery property is placed in service or disposed of, and in the case of a short tax year the MACRS deduction is prorated on a 12-month basis. No distinction is made between new and used property and salvage value is disregarded.

LEASEHOLD COSTS AND ABANDONMENT

Lease costs, together with the related cost depletion deduction and any abandonment loss, are allocated under the partnership agreement 100% to the managing general partner, which will contribute the leases to the partnership as a part of its capital contribution.

TAX BASIS OF UNITS

Your distributive share of partnership loss is allowable only to the extent of the adjusted basis of your units at the end of the partnership's taxable year. The adjusted basis of your units will be adjusted, but not below zero, for any gain or loss to you from a disposition by the partnership of a natural gas or oil property, and will be increased by your:

- cash subscription payment;

- share of partnership income; and

- share, if any, of partnership debt.

The adjusted basis of your units will be reduced by your:

- share of partnership losses;

- depletion deduction, but not below zero; and

- cash distributions from the partnership.

The reduction in your share of partnership liabilities, if any, is considered a cash distribution. Should cash distributions exceed the tax basis of your units taxable gain would result to the extent of the excess.

"AT RISK" LIMITATION FOR LOSSES

Subject to the limitations on "passive losses" generated by the partnership in the case of limited partners and your basis in your units, you may use your share of the partnership's losses to offset income from other sources. However, you may deduct the loss only to the extent of the amount you have "at risk" in the partnership at the end of a taxable year. Your initial amount "at risk" is the amount you paid for your units in the partnership. However, the amount you have "at risk" may not include the amount of any loss that you are protected against through:

- nonrecourse loans;
- guarantees;
- stop loss agreements; or
- other similar arrangements.

DISTRIBUTIONS FROM THE PARTNERSHIP

Generally, a cash distribution from the partnership to you in excess of the adjusted basis of your units immediately before the distribution is treated as gain from the sale or exchange of your units to the extent of the excess. No loss can be recognized by you on these distributions. Other distributions of property and liquidating distributions may result in taxable gain or loss.

SALE OF THE PROPERTIES

Generally, net long-term capital gains of a noncorporate taxpayer on the sale of assets held more than a year are taxed at a maximum rate of 20%, or 10% if they would be subject to tax at a rate of 15% if they were not eligible for long-term capital gains treatment. These rates are 18% and 8%, respectively, for gain on qualifying assets held for more than five years. The capital gain rates also apply for purposes of the alternative minimum tax. The annual capital loss limitation for noncorporate taxpayers is the amount of capital gains plus the lesser of $3,000, which is reduced to $1,500 for married persons filing separate returns, or the excess of capital losses over capital gains.

Gains or losses from sales of natural gas and oil properties held for more than 12 months generally will be treated as a long-term capital gain, while a net loss will be an ordinary deduction. However, on disposition of a natural gas or oil property gain is treated as ordinary income to the extent of the lesser of:

- the amounts that were deducted as intangible drilling costs rather than added to basis, plus depletion deductions that reduced the basis of the property and certain losses, if any, on previous sales of partnership assets; or

- the amount realized in the case of a sale, exchange or involuntary conversion or fair market value in all other cases, minus the property's adjusted basis.

Other gains and losses on sales of natural gas and oil properties will generally result in ordinary gains or losses.

DISPOSITION OF UNITS

The sale or exchange, including a repurchase by the managing general partner, of all or part of your units held by you for more than 12 months will generally result in a recognition of long-term capital gain or loss. However, the recapturable portions of depletion and intangible drilling costs will constitute ordinary income. If the units are held for 12 months or less, the gain or loss will generally be short-term gain or loss. Also, your pro rata share of the partnership's liabilities, if any, as of the date of the sale or exchange must be included in the amount realized. Therefore, the gain recognized may result in a tax liability greater than the cash proceeds, if any, from the disposition. In addition to gain from a passive activity, a portion of any gain recognized by a limited partner on the sale or other disposition of his units may be characterized as portfolio income.

A gift of your units may result in federal and/or state income tax and gift tax liability to you, and interests in different partnerships do not qualify for tax-free like-kind exchanges. Other dispositions of your units, may or may not result in recognition of taxable gain. However, no gain should be recognized by an investor general partner whose units are converted to limited partner units so long as there is no change in his share of the partnership's liabilities or certain partnership assets as a result of the conversion. In addition, if you sell or exchange all or part of your units you are required by the Internal Revenue Code to notify the partnership within 30 days or by January 15 of the following year, if earlier.

NO DISPOSITION OF YOUR UNITS, INCLUDING REPURCHASE OF THE UNITS BY THE MANAGING GENERAL PARTNER, SHOULD BE MADE BY YOU BEFORE CONSULTATION WITH YOUR TAX ADVISOR.

MINIMUM TAX - TAX PREFERENCES

With limited exceptions, all taxpayers are subject to the alternative minimum tax. If your alternative minimum tax exceeds the regular tax, then the excess is payable in addition to the regular tax. The alternative minimum tax is intended to insure that no one with substantial income can avoid tax liability by using deductions and credits. The alternative minimum tax accomplishes this objective by not treating favorably certain items that are treated favorably for purposes of the regular tax, including the deduction for intangible drilling costs and accelerated depreciation. Generally, the alternative minimum tax rate for individuals is 26% on alternative minimum taxable income up to $175,000, $87,500 for married individuals filing separate returns, and 28% thereafter. Under recent changes to the tax laws, for tax years beginning in 2001 through 2004, the exemption is $49,000 for married couples filing jointly and surviving spouses; $35,750 for single filers, and $24,500 for married persons filing separately. Also, for these tax years only, married persons filing separately must increase their alternative minimum taxable income by the lesser of 25% of alternative minimum taxable income over $173,000; or $24,500. The regular tax rates on capital gains also apply for purposes of the alternative minimum tax. Regular tax personal exemptions are not available for purposes of the alternative minimum tax, however, alternative minimum taxable income may be reduced by certain itemized deductions, exemption amounts and net operating losses.

Alternative minimum taxable income generally is taxable income, plus or minus adjustments, plus preferences. For taxpayers other than integrated oil companies, the 1992 National Energy Bill repealed the preference for:

- excess intangible drilling costs; and

- the excess percentage depletion preference for natural gas and oil.

The repeal of the excess intangible drilling costs preference, however, may not result in more than a 40% reduction in the amount of the taxpayer's alternative minimum taxable income computed as if the excess intangible drilling costs preference had not been repealed. Under the prior rules, the amount of intangible drilling costs which is not deductible for alternative minimum tax purposes is the excess of the "excess intangible drilling costs" over 65% of net income from natural gas and oil properties. Excess intangible drilling costs is the regular intangible drilling costs deduction minus the amount that would have been deducted under 120-month straight-line amortization, or, at the taxpayer's election, under the cost depletion method. There is no preference item for costs of nonproductive wells.

Also, you may elect to capitalize all or part of your share of the partnership's intangible drilling costs and deduct the costs ratably over a 60-month period beginning with the month in which the costs were paid or incurred. This election also applies for regular tax purposes and can be revoked only with the IRS' consent. Making this election, therefore, generally will result in the following consequences to you:

- your regular tax deduction in 2001 for intangible drilling costs will be reduced because you must spread the deduction for the amount of intangible drilling costs which you elect to capitalize over the 60-month amortization period; and

- the capitalized intangible drilling costs will not be treated as a preference that is included in your alternative minimum taxable income.

THE LIKELIHOOD OF YOU INCURRING, OR INCREASING, ANY MINIMUM TAX LIABILITY BECAUSE OF AN INVESTMENT IN THE PARTNERSHIP MUST BE DETERMINED ON AN INDIVIDUAL BASIS, AND REQUIRES YOU TO CONSULT WITH YOUR PERSONAL TAX ADVISOR.

LIMITATIONS ON DEDUCTION OF INVESTMENT INTEREST

Investment interest is deductible by a noncorporate taxpayer only to the extent of net investment income each year, with an indefinite carryforward of disallowed investment interest. An investor general partner's share of any interest expense incurred by the partnership before the investor general partner units are converted to limited partner units will be subject to the investment interest limitation. In addition, an investor general partner's income and losses, including intangible drilling costs, from the partnership will be considered investment income and losses. Losses allocable to an investor general partner will reduce his net investment income and may affect the deductibility of his investment interest expense, if any. These rules do not apply to partnership income or expense subject to the passive activity loss limitations for limited partners.

ALLOCATIONS

The partnership agreement allocates to you your share of the partnership's income, gains, losses and deductions, including the deductions for intangible drilling costs and depreciation. Your capital account will be adjusted to reflect these allocations and your capital account, as adjusted, will be given effect in distributions made to you on liquidation of the partnership or your interest in the partnership. Generally, your capital account will be:

- increased by the amount of money you contribute to the partnership and allocations to you of income and gain; and

- decreased by the value of property or cash distributed to you and allocations to you of loss and deductions.

It should be noted that your share of partnership items of income, gain, loss, and deduction must be taken into account whether or not there is any distribuTable cash. Your share of partnership revenues applied to the repayment of loans or the reserve for plugging wells, for example, will be included in your gross income in a manner analogous to an actual distribution of the income to you. Thus, you may have tax liability from the partnership for a particular year in excess of any cash distributions from the partnership to you with respect to that year. To the extent the partnership has cash available for distribution, however, it is the managing general partner's policy that partnership distributions will not be less than the managing general partner's estimate of the investors' income tax liability with respect to partnership income.

If any allocation under the partnership agreement is not recognized for federal income tax purposes, your distributive share of the items subject to that allocation generally will be determined in accordance with your interest in the partnership, determined by considering relevant facts and circumstances. To the extent the deductions allocated by the partnership agreement exceed deductions which would be allowed pursuant to a reallocation by the IRS, you may incur a greater tax burden.

PARTNERSHIP BORROWINGS

Under the partnership agreement, the managing general partner and its affiliates may make loans to the partnership. The use of partnership revenues taxable to you to repay partnership borrowings could create income tax liability for you in excess of your cash distributions from the partnership, since repayments of principal are not deductible for federal income tax purposes. In addition, interest on the loans will not be deductible unless the loans are bona fide loans that will not be treated as capital contributions in light of all the surrounding facts and circumstances.

PARTNERSHIP ORGANIZATION AND SYNDICATION FEES

Expenses connected with the sale of units in the partnership, including the dealer-manager fee, sales commissions, and reimbursements to the dealer-manager which are charged 100% to the managing general partner under the partnership agreement, are not deductible. Although certain organization expenses of the partnership may be amortized over a period of not less than 60 months, these expenses are also paid by the managing general partner as part of the partnership's organization and offering costs and any related deductions, which the managing general partner does not expect will be material in amount, will be allocated to the managing general partner.

TAX ELECTIONS

The partnership may elect to adjust the basis of partnership property on the transfer of a unit in the partnership by sale or exchange or on the death of an investor, and on the distribution of property by the partnership to a partner. The general effect of this election is that transferees of the units are treated, for purposes of depreciation and gain, as though they had acquired a direct interest in the partnership assets and the partnership is treated for these purposes, on certain distributions to partners, as though it had newly acquired an interest in the partnership assets and therefore acquired a new cost basis for the assets. Also, certain "start-up expenditures" must be capitalized and can only be amortized over a 60-month period. If it is ultimately determined that any of the partnership's expenses constituted start-up expenditures and not deductible business expenses, the partnership's deductions for those expenses would be deferred.

DISALLOWANCE OF DEDUCTIONS UNDER SECTION 183 OF THE INTERNAL REVENUE CODE
Your ability to deduct your share of the partnership's losses could be lost if the partnership lacks the appropriate profit motive. There is a presumption that an activity is engaged in for profit, if, in any three of five consecutive taxable years, the gross income derived from the activity exceeds the deductions attribuTable to the activity. Thus, if the partnership fails to show a profit in at least three of five consecutive years, this presumption will not be available and the possibility that the IRS could successfully challenge the partnership deductions claimed by you would be substantially increased.

The fact that the possibility of ultimately obtaining profits is uncertain, standing alone, does not appear to be sufficient grounds for the denial of losses. Based on the managing general partner's representation that the partnership will be conducted as described in this prospectus, in the opinion of special counsel it is more likely than not that the partnership will possess the requisite profit motive.

TERMINATION OF THE PARTNERSHIP

The partnership will be considered as terminated for federal income tax purposes if within a twelve month period there is a sale or exchange of 50% or more of the total interest in partnership capital and profits. In that event, you would realize taxable gain on a termination of the partnership to the extent that money regarded as distributed to you exceeds the adjusted basis of your units. The conversion of investor general partner units to limited partner units, however, will not terminate the partnership.

LACK OF REGISTRATION AS A TAX SHELTER

An organizer of a "tax shelter" must obtain an identification number which must be included on the tax returns of investors in the tax shelter. For this purpose, a "tax shelter" includes investments with respect to which any person could reasonably infer that the ratio that the aggregate amount of the potentially allowable deductions and 350% of the potentially allowable credits with respect to the investment during the first five years of the investment bears to the amount of money and the adjusted basis of property contributed to the investment exceeds 2 to 1.

The managing general partner does not believe that the partnership will have a tax shelter ratio greater than 2 to 1. Also, because the purpose of the partnership is to locate, produce and market natural gas and oil on an economic basis, the managing general partner does not believe that the partnership will be a "potentially abusive tax shelter." Accordingly, the managing general partner does not intend to register the partnership with the IRS as a tax shelter.

If it is subsequently determined by the IRS or the courts that the partnership was required to be registered with the IRS as a tax shelter, the managing general partner would be subject to certain penalties and you would be liable for a $250 penalty for failure to include the tax shelter registration number on your tax return, unless the failure was due to reasonable cause. You also would be liable for a penalty of $100 for failing to furnish the tax shelter registration number to any transferee of your units. However, based on the representations of the managing general partner, special counsel has expressed the opinion that the partnership, more likely than not, is not required to register with the IRS as a tax shelter.

Issuance of a registration number does not indicate that an investment or the claimed tax benefits have been reviewed, examined, or approved by the IRS.

INVESTOR LISTS. Any person who organizes a tax shelter required to be registered with the IRS must maintain a list of each investor in the tax shelter. For the reasons described above, the managing general partner does not believe the partnership is a tax shelter for this purpose. If this determination is wrong there is a penalty of $50 for each person, unless the failure is due to reasonable cause.

TAX RETURNS AND AUDITS

IN GENERAL. The tax treatment of all partnership items is generally determined at the partnership, rather than the partner, level; and the partners are generally required to treat partnership items on their individual returns in a manner which is consistent with the treatment of the partnership items on the partnership return. Generally, the IRS must conduct an administrative determination as to partnership items at the partnership level before conducting deficiency proceedings against a partner, and the partners must file a request for an administrative determination before filing suit for any credit or refund. The period for assessing tax against you and the other investors attribuTable to a partnership item may be extended by agreement between the IRS and the managing general partner, which will serve as the partnership's representative in all administrative and judicial proceedings conducted at the partnership level. The managing general partner generally may enter into a settlement on behalf of, and binding on, any investor owning less than a 1% profits interest if the partnership has more than 100 partners. In addition, a partnership with at least 100 partners may elect to be governed under simplified tax reporting and audit rules as an "electing large partnership." These rules also facilitate the matching of partnership items with individual partner tax returns by the IRS. The managing general partner does not anticipate that the partnership will make this election. By executing the partnership agreement, you agree that you will not form or exercise any right as a member of a notice group and will not file a statement notifying the IRS that the managing general partner does not have binding settlement authority.

TAX RETURNS. Your income tax returns are your responsibility. The partnership will provide you with the tax information applicable to your investment in the partnership necessary to prepare your returns.

PENALTIES AND INTEREST

IN GENERAL. Interest is charged on underpayments of tax and various civil and criminal penalties are included in the Internal Revenue Code.

PENALTY FOR NEGLIGENCE OR DISREGARD OF RULES OR REGULATIONS. If any portion of an underpayment of tax is attribuTable to negligence or disregard of rules or regulations, 20% of that portion is added to the tax. Negligence is strongly indicated if you fail to treat partnership items on your tax return in a manner that is consistent with the treatment of those items on the partnership's return or to notify the IRS of the inconsistency.

VALUATION MISSTATEMENT PENALTY. There is an addition to tax of 20% of the amount of any underpayment of tax of $5,000 or more which is attribuTable to a substantial valuation misstatement. There is a substantial valuation misstatement if:

- the value or adjusted basis of any property claimed on a return is 200% or more of the correct amount; or

- the price for any property or services, or for the use of property, claimed on a return is 200% or more, or 50% or less, of the correct price.

If there is a gross valuation misstatement, which is 400% or more of the correct value or adjusted basis or the undervaluation is 25% or less of the correct amount, then the penalty is 40%.

SUBSTANTIAL UNDERSTATEMENT PENALTY. There is also an addition to tax of 20% of any underpayment if the difference between the tax required to be shown on the return over the tax actually shown on the return, exceeds the greater of:

- 10% of the tax required to be shown on the return; or

- $5,000.

The amount of any understatement generally will be reduced to the extent it is attribuTable to the tax treatment of an item:

- supported by substantial authority; or

- adequately disclosed on the taxpayer's return.

However, in the case of "tax shelters," the understatement may be reduced only if the tax treatment of an item attribuTable to a tax shelter was supported by substantial authority and the taxpayer established that he reasonably believed that the tax treatment claimed was more likely than not the proper treatment.

- A "tax shelter" for this purpose is any entity which has as a significant purpose the avoidance or evasion of federal income tax.

IRS ANTI-ABUSE RULE. If a principal purpose of a partnership is to reduce substantially the partners' federal income tax liability in a manner that is inconsistent with the intent of the partnership rules of the Internal Revenue Code, based on all the facts and circumstances, the IRS is authorized to remedy the abuse. Based on the managing general partner's representation that the partnership will be conducted as described in this prospectus, in the opinion of special counsel it is more likely than not that the partnership will not be subject to this rule.

STATE AND LOCAL TAXES

Under Pennsylvania law, the partnership is required to withhold state income tax at the rate of 2.8% of partnership income allocable to investors who are not residents of Pennsylvania. Also, the partnership will operate in states and localities which impose a tax on its assets or its income, or on you. Deductions which are available to you for federal income tax purposes may not be available for state or local income tax purposes.

YOU SHOULD CONSULT WITH YOUR OWN TAX ADVISORS CONCERNING THE POSSIBLE EFFECT OF

VARIOUS STATE AND LOCAL TAXES ON YOUR PERSONAL TAX SITUATION.

SEVERANCE AND AD VALOREM (REAL ESTATE) TAXES

The partnership may incur various ad valorem or severance taxes imposed by state or local taxing authorities. Currently, there is no such tax liability in Mercer County, Pennsylvania.

SOCIAL SECURITY BENEFITS AND SELF-EMPLOYMENT TAX

A limited partner's share of income or loss from the partnership is excluded from the definition of "net earnings from self-employment." No increased benefits under the Social Security Act will be earned by limited partners, and if any limited partners are currently receiving Social Security benefits their shares of partnership taxable income will not be taken into account in determining any reduction in benefits because of "excess earnings."

An investor general partner's share of income or loss from the partnership will constitute "net earnings from self-employment" for these purposes. For 2001 the ceiling for social security tax of 12.4% is $80,400 and there is no ceiling for medicare tax of 2.9%. Self-employed individuals can deduct one-half of their self-employment tax.

FOREIGN PARTNERS

The partnership will be required to withhold and pay to the IRS tax at the highest rate under the Internal Revenue Code applicable to partnership income allocable to foreign partners, even if no cash distributions are made to them. In the event of overwithholding, a foreign partner must file a United States tax return to obtain a refund.

ESTATE AND GIFT TAXATION

There is no federal tax on lifetime or testamentary transfers of property between spouses. The gift tax annual exclusion is $10,000 per donee, which will be adjusted for inflation. Under the Economic Growth and Tax Relief Reconciliation Act of 2001 ("the 2001 Act") estates of $675,000 in 2001, which increases in stages to $3.5 million by 2009, or less generally are not subject to federal estate tax. The federal estate tax is scheduled to be repealed in 2010, and then reinstated in 2011 under the rules in effect before the 2001 Act.

CHANGES IN THE LAW. Your investment in the partnership will be adversely affected by changes in the tax laws. For example, under the Economic Growth and Tax Relief Reconciliation Act of 2001 the federal income tax rates are being reduced in stages between 2001 and 2006, including reducing the top rate from 39.6% to 39.1% in 2001, and ultimately to 35% by 2006. This will reduce to some degree the amount of taxes you save by virtue of your share of the partnership's deductions for intangible drilling costs, depletion and depreciation.

SUMMARY OF PARTNERSHIP AGREEMENT

NOTE: THE RIGHTS AND OBLIGATIONS OF THE MANAGING GENERAL PARTNER AND YOU AND THE OTHER INVESTORS ARE GOVERNED BY THE PARTNERSHIP AGREEMENT, A COPY OF WHICH IS ATTACHED AS EXHIBIT (A) TO THIS PROSPECTUS. YOU SHOULD NOT INVEST IN THE PARTNERSHIP WITHOUT FIRST THOROUGHLY REVIEWING THE PARTNERSHIP AGREEMENT. THE FOLLOWING IS A SUMMARY OF THE MATERIAL PROVISIONS IN THE PARTNERSHIP AGREEMENT WHICH ARE NOT COVERED ELSEWHERE IN THIS PROSPECTUS.

LIABILITY OF LIMITED PARTNERS

The partnership will be governed by the Pennsylvania Revised Uniform Limited Partnership Act. If you invest as a limited partner, then generally you will not be liable to third-parties for the obligations of the partnership unless you:

- also invest as an investor general partner;

- take part in the control of the partnership's business in addition to the exercise of your rights and powers as a limited partner;

- fail to make a required capital contribution to the extent of the required capital contribution; or

- receive a return of your capital contribution in violation of the partnership agreement or Pennsylvania law to the extent of the capital contribution wrongfully returned to you, with interest for two years after its return. This includes, but is not limited to, any distribution to you and the other limited partners to the extent that, after giving effect to the distribution, all partnership liabilities exceed partnership assets.

AMENDMENTS

Amendments to the partnership agreement may be proposed in writing by:

- the managing general partner and adopted with the consent of investors whose units equal a majority of the total units; or

- investors whose units equal 10% or more of the total units and adopted by an affirmative vote of investors whose units equal a majority of the total units.

The partnership agreement may also be amended by the managing general partner without the consent of the investors for certain limited purposes. However, an amendment that materially and adversely affects the investors can only be made with the consent of the affected investors.

NOTICE

The following provisions apply regarding notices:

- when the managing general partner gives you and other investors notice it begins to run from the date of mailing the notice and is binding even if it is not received;

- the notice periods are frequently quite short, a minimum of 22 calendar days, and apply to matters which may seriously affect your rights; and

- if you fail to respond in the specified time to the managing general partner's second request for approval of or concurrence in a proposed action, then you will conclusively be deemed to have approved the action unless the partnership agreement expressly requires your affirmative approval.

VOTING RIGHTS

Other than as set forth below, you generally will not be entitled to vote on any partnership matters at any partnership meeting. However, at any time investors whose units equal 10% or more of the total units, may call a meeting to vote, or vote without a meeting, on the matters set forth below, without the concurrence of the managing general partner. On the matters being voted on you are entitled to one vote per unit or if you own a fractional unit that fraction of one vote equal to the fractional interest in the unit. Investors whose units equal a majority of the total units may vote to:

- dissolve the partnership;

- remove the managing general partner and elect a new managing general partner;

- elect a new managing general partner if the managing general partner elects to withdraw from the partnership;

- remove the operator and elect a new operator;

- approve or disapprove the sale of all or substantially all of the partnership assets;

- cancel any contract for services with the managing general partner, the operator or their affiliates without penalty on 60 days notice; and

- amend the partnership agreement; provided however, any amendment may not:

- without the approval of you or the managing general partner increase the duties or liabilities of you or the managing general partner or increase or decrease the profits or losses or required capital contribution of you or the managing general partner; or

- without the unanimous approval of all investors affect the classification of partnership income and loss for federal income tax purposes.

The managing general partner, its officers, directors, and affiliates may also subscribe for units in the partnership and they may vote on all matters other than:

- the issues set forth above concerning removing the managing general partner and operator; and

- any transaction between the managing general partner or its affiliates and the partnership.

Any units owned by the managing general partner and its affiliates will not be included in determining the requisite number of units necessary to approve any partnership matter on which the managing general partner and its affiliates may not vote or consent.

ACCESS TO RECORDS

Generally, as a participant you will have access to all partnership records at any reasonable time on adequate notice. However, logs, well reports and other drilling and operating data may be kept confidential for reasonable periods of time. Your ability to obtain the list of investors is subject to additional requirements set forth in the partnership agreement.

WITHDRAWAL OF MANAGING GENERAL PARTNER

After 10 years, the managing general partner may voluntarily withdraw as managing general partner for whatever reason by giving 120 days' written notice to you and the other investors. Although the withdrawing managing general partner is not required to provide a substitute managing general partner, a new managing general partner may be substituted by the affirmative vote of investors whose units equal a majority of the total units. If the investors, however, choose not to continue the partnership and select a substitute managing general partner, then the partnership would terminate and dissolve, which could result in adverse tax and other consequences to you.

Also, subject to a required participation of not less than 1% of the partnership revenues, the managing general partner may partially withdraw a property interest in the partnership's wells equal to or less than its revenue interest if the withdrawal is:

- to satisfy the bona fide request of its creditors; or

- approved by investors whose units equal a majority of the total units.

RETURN OF SUBSCRIPTION PROCEEDS IF FUNDS ARE NOT INVESTED IN TWELVE MONTHS
Although the managing general partner anticipates that the partnership will spend all the subscription proceeds soon after the offering closes, the partnership will have 12 months in which to use or commit funds to drilling activities. If within the 12-month period the partnership has not used or committed for use all the subscription proceeds, then the managing general partner will distribute the remaining subscription proceeds to you and the other investors in the partnership in accordance with your subscription proceeds as a return of capital.

SUMMARY OF DRILLING AND OPERATING AGREEMENT

The managing general partner will serve as the operator under the drilling and operating agreement, Exhibit (II) to the partnership agreement. The operator may be replaced at any time on 60 days' advance written notice by the managing general partner acting on behalf of the partnership on the affirmative vote of investors whose units equal a majority of the total units.

The drilling and operating agreement includes a number of material provisions, including, without limitation, those set forth below.

- The operator's right to resign after five years.

- The operator's right beginning one year after a partnership well begins producing to retain $200 per month to cover future plugging and abandonment costs of the well, although the managing general partner historically has never done this after only one year.

- The grant of a first lien and security interest in the wells and related production to secure payment of amounts due to the operator by the partnership.

- The prescribed insurance coverage to be maintained by the operator.

- Limitations on the operator's authority to incur extraordinary costs with respect to producing wells in excess of $5,000 per well.

- Restrictions on the partnership's ability to transfer its interest in fewer than all wells, unless the transfer is of an equal undivided interest in all wells.

- The limitation of the operator's liability except for:

- violations of law;

- negligence or misconduct by it, its employees, agents or subcontractors; and

- breach of the drilling and operating agreement.

- The excuse for nonperformance by the operator due to force majeure which generally means acts of God, catastrophes and other causes which preclude the operator's performance and are beyond its control.

THE FOREGOING IS A SUMMARY OF THE MATERIAL PROVISIONS OF THE PROPOSED FORM OF DRILLING AND OPERATING AGREEMENT WHICH ARE NOT COVERED ELSEWHERE IN THIS PROSPECTUS. IT IS QUALIFIED IN ITS ENTIRETY BY REFERENCE TO THE FORM ATTACHED TO THE PARTNERSHIP AGREEMENT AS EXHIBIT (II). YOU SHOULD NOT SUBSCRIBE TO THE PARTNERSHIP WITHOUT FIRST THOROUGHLY REVIEWING THE DRILLING AND OPERATING AGREEMENT.

REPORTS TO INVESTORS

Under the partnership agreement you will be provided the reports and information set forth below which the partnership will pay as a direct cost.

- Beginning with the 2001 calendar year, you will be provided an annual report within 120 days after the close of the calendar year, and beginning with the 2002 calendar year, a report within 75 days after the end of the first six months of its calendar year, containing at least the following information.

- Audited financial statements of the partnership prepared in accordance with generally accepted accounting principles. Semiannual reports will not be audited.

- A summary of the total fees and compensation paid by the partnership to the managing general partner, the operator and their affiliates, including the percentage that the annual unaccounTable, fixed payment reimbursements for administrative costs bears to annual partnership revenues.

- A description of each well location owned by the partnership, including the cost, location, number of acres and the interest.

- A list of the wells drilled or abandoned by the partnership, indicating:

- whether each of the wells has or has not been completed; and

- a statement of the cost of each well completed or abandoned.

- A description of all farmins and joint ventures.

- A schedule reflecting:

- the total partnership costs;

- the costs paid by the managing general partner and the costs paid by the investors;

- the total partnership revenues; and

- the revenues received or credited to the managing general partner and the revenues received or credited to you and the other investors.

- By March 15 of each year, you will receive the information which is required for you to file your federal and state income tax returns.

- Beginning January 1, 2003, and every year thereafter, you will receive a computation of the partnership's total natural gas and oil proved reserves and its dollar value. The reserve computations will be based on engineering reports prepared by the managing general partner and reviewed by an independent expert.

PRESENTMENT FEATURE

Beginning in 2006 you and the other investors may present your units to the managing general partner for repurchase. You are not required to present your units to the managing general partner and you may receive a greater return if you retain your units. The managing general partner may immediately suspend its repurchase obligation by notice to you if it determines, in its sole discretion, that it:

- does not have the necessary cash flow; or

- cannot borrow funds for this purpose on terms it deems reasonable.

The managing general partner will not purchase less than one unit unless the fractional unit represents your entire interest, nor more than 5% of the units in any calendar year. If fewer than all units presented at any time are to be purchased, then the units to be purchased will be selected by lot. The managing general partner may not waive the limit on its purchasing more than 5% of the units in any calendar year.

The managing general partner's obligation to purchase the units presented may be discharged for its benefit by a third-party or an affiliate. If you sell your unit it will be transferred to the party who pays for it and you will be required to deliver an executed assignment of your unit along with any other documents that the managing general partner requests. Also, your presentment must be within 120 days of the partnership reserve report discussed below, and in accordance with Treas. Reg. Section1.7704-1(f) the repurchase may not be made by the managing general partner until at least 60 calendar days after you notify the partnership in writing of your intent to present your unit. The repurchase will not be considered effective until the presentment price has been paid to you in cash.

The amount attribuTable to partnership natural gas and oil reserves will be determined based on the last reserve report prepared by the managing general partner and reviewed by an independent expert. Beginning in 2003 the managing general partner will estimate the present worth of future net revenues attribuTable to the partnership's interest in proved reserves. In making this estimate, the managing general partner will use:

- a 10% discount rate;

- a constant oil price; and

- base natural gas prices on the existing natural gas contracts at the time of the presentment.

Your presentment price will be based on your share of the partnership's net assets and liabilities as described below based on the ratio that the number of your units bears to the total number of units. The presentment price will include the sum of the following partnership items:

- an amount based on 70% of the present worth of future net revenues from the proved reserves, determined as described above;

- cash on hand;

- prepaid expenses and accounts receivable, less a reasonable amount for doubtful accounts; and

- the estimated market value of all assets not separately specified above, determined in accordance with standard industry valuation procedures.

There will be deducted from the foregoing sum the following items:

- an amount equal to all debts, obligations and other liabilities, including accrued expenses; and

- any distributions made to you between the date of the request and the actual payment. However, if any cash distributed was derived from the sale, after the presentment request, of oil, natural gas or of a producing property, for purposes of determining the reduction of the presentment price, the distributions will be discounted at the same rate used to take into account the risk factors employed to determine the present worth of the partnership's proved reserves.

The amount may be further adjusted by the managing general partner for estimated changes from the date of the reserve report to the date of payment of the presentment price to you because of the following:

- the production or sales of, or additions to, reserves and lease and well equipment, sale or abandonment of leases, and similar matters occurring before the presentment request; and

- any of the following occurring before payment of the presentment price to you;

- changes in well performance;

- increases or decreases in the market price of oil, natural gas or other minerals,

- revision of regulations relating to the importing of hydrocarbons; and

- changes in income, ad valorem and other tax laws such as material variations in the provisions for depletion and similar matters.

As of March 1, 2001, fewer than 25 units have been presented to the managing general partner for repurchase in its previous 36 limited partnerships.

TRANSFERABILITY OF UNITS

RESTRICTIONS ON TRANSFER IMPOSED BY THE SECURITIES LAWS, TAX LAWS AND THE

PARTNERSHIP AGREEMENT

Your ability to sell or otherwise transfer your units is restricted by the securities laws, the tax laws, and the partnership agreement as described below.

First, under the securities laws you will not be able to sell, assign, pledge, hypothecate or transfer your unit unless there is:

- an effective registration of the unit under the 1933 Act and qualification under applicable state securities law; or

- an opinion of counsel accepTable to the managing general partner that the registration and qualification are not required.

The managing general partner and the partnership are not obligated to, and do not intend to, register the units for resale.

Second, under the tax laws, you will not be able to sell, assign, exchange or transfer your unit if it would, in the opinion of counsel for the partnership, result in the following:

- the termination of the partnership for tax purposes; or

- the partnership being treated as a "publicly-traded" partnership for tax purposes.

Finally, under the partnership agreement you may not transfer your unit unless the managing general partner consents. The partnership will recognize the assignment of one or more whole units unless you own less than a whole unit, in which case your entire fractional interest must be assigned. Any transfer that is consented to by the managing general partner when the assignee of the unit does not become a substituted partner as described below will be effective as of:

- midnight of the last day of the calendar month in which it is made; or

- at the managing general partner's election 7:00 A.M. of the following day.

CONDITIONS TO BECOMING A SUBSTITUTE PARTNER

Under the partnership agreement an assignee of a unit may become a substituted partner only on meeting certain further conditions. A substitute partner is entitled to all of the rights of full ownership of the assigned units including the right to vote. The conditions to become a substitute partner are as follows:

- the assignor gives the assignee the right;

- the managing general partner consents to the substitution;

- the assignee pays all costs and expenses incurred in connection with the substitution; and

- the assignee executes and delivers the instruments to effect the substitution and to confirm his agreement to be bound by all terms and provisions of the partnership agreement.

The partnership will amend its records at least once each calendar quarter to effect the substitution of substituted partners.