UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2004

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE TRANSITION PERIOD FROM _____TO_____

COMMISSION FILE NO.: 0-26823

ALLIANCE RESOURCE PARTNERS, L.P.

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

DELAWARE	**73-1564280**
(STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION)	**(IRS EMPLOYER IDENTIFICATION NO.)**

1717 SOUTH BOULDER AVENUE, SUITE 600, TULSA, OKLAHOMA 74119

(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES AND ZIP CODE)

(918) 295-7600

(REGISTRANT S TELEPHONE NUMBER, INCLUDING AREA CODE)

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

Securities registered pursuant to Section 12(g) of the Act: common units representing limited partner interests

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

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

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

The aggregate value of the common units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $465,898,654 as of June 30, 2004, the last business day of the registrant s most recently completed second fiscal quarter, based on $46.66 per unit, the closing price of the common units as reported on the Nasdaq National Market on such date.

As of March 15, 2005, 18,130,440 common units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: None

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FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K/A contains forward-looking statements. These statements are based on our beliefs as well as assumptions made by, and information currently available to, us. When used in this document, the words anticipate, believe, continue, estimate, expect, forecast , may, project , will, and similar expressions identify forward-looking statements. These statements reflect our current views with respec to future events and are subject to various risks, uncertainties and assumptions. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

- competition in coal markets and our ability to respond to the competition;
- fluctuation in coal prices, which could adversely affect our operating results and cash flows;
- deregulation of the electric utility industry or the effects of any adverse change in the domestic coal industry, electric utility industry, or general economic conditions;
- dependence on significant customer contracts, including renewing customer contracts upon expiration of existing contracts;
- customer bankruptcies and/or cancellations of, or breaches to existing contracts;
- customer delays or defaults in making payments;
- fluctuations in coal demand, prices and availability due to labor and transportation costs and disruptions, equipment availability, governmental regulations and other factors;
- our productivity levels and margins that we earn on our coal sales;
- any unanticipated increases in labor costs, adverse changes in work rules, or unexpected cash payments associated with post-mine reclamation and workers compensation claims;
- any unanticipated increases in transportation costs and risk of transportation delays or interruptions;
- greater than expected environmental regulation, costs and liabilities;
- a variety of operational, geologic, permitting, labor and weather-related factors;
- risk of major mine-related accidents, such as mine fires, or interruptions;

results of litigation;

difficulty maintaining our surety bonds for mine reclamation as well as workers   compensation and black lung benefits; and

difficulty obtaining commercial property insurance, and risks associated with our current 10.0% participation (excluding any applicable deductible) in our commercial insurance property program.

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If one or more of these or other risks or uncertainties materialize, or should underlying assumptions prove incorrect, our actual results may differ materially from those described in any forward-looking statement. When considering forward-looking statements, you should also keep in mind the risk factors described in Risk Factors below. The risk factors could also cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

You should consider the information above when reading any forward-looking statements contained:

- in this Annual Report on Form 10-K/A;
- other reports filed by us with the SEC;
- our press releases; and
- written or oral statements made by us or any of our officers or other authorized persons acting on our behalf.

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Explanatory Note

This Amendment No. 1 on Form 10-K/A is being filed to reflect the restatements of basic and diluted net income per limited partner unit and the pro forma disclosure related to common unit-based compensation for each of the three years in the period ended December 31, 2004 and for the quarterly periods in the years 2004 and 2003 as discussed in Note 21 to the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data. Note 21. Restatements.

We previously computed net income per limited partner unit without applying certain provisions of Emerging Issues Task Force Issue No. 03-6 (EITF 03-6), Participating Securities and the Two-Class Method under FASB Statement No. 128 .

We previously disclosed pro forma information under Statement of Financial Accounting Standards (SFAS) No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*, assuming compensation expense for the non-vested restricted units granted would be different under our accounting method (the intrinsic method of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees) and the provisions of SFAS No. 123, Accounting for Stock-Based Compensation (SFAS 123). Our previous disclosure has been restated since compensation expense for the non-vested restricted units granted is the same under the intrinsic method and the provisions of SFAS 123. For additional information regarding the restatements, refer to Item 8. Financial Statements and Supplementary Data. Notes 2, 11, 19 and 21 .

This Amendment No. 1 on Form 10-K/A amends and restates only Item 6 Selected Financial Data , Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8 Financial Statements and Supplementary Data of the original Form 10-K to reflect the restatement of net income per limited partner unit as discussed in Note 21 to the consolidated financial statements included at Item 8 and Item 9A. The remaining items are not amended hereby. Except for the foregoing amended information, the Form 10-K/A continues to describe conditions as of the date of the original Form 10-K and the Partnership has not updated the disclosure contained herein to reflect events that occurred subsequently. Accordingly, the Form 10-K/A should be read in conjunction with Partnership filings made with the Securities and Exchange Commission subsequent to the filing of the original Form 10-K, including any amendments of those filings.

The restatements have no impact on previously reported income before income taxes, net income, limited partners interest in net income, the consolidated balance sheets, the consolidated statements of cash flows or the consolidated statements of partners capital (deficit) and comprehensive income.

The Partnership is also filing contemporaneously with this Form 10-K/A, its quarterly report on Form 10-Q/A for the quarterly period ended March 31, 2005.

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PART II

ITEM 6. SELECTED FINANCIAL DATA

Our historical financial data below were derived from our audited consolidated financial statements as of and for the years ended December 31, 2004, 2003, 2002, 2001 and 2000. We acquired Warrior from ARH Warrior Holdings, a subsidiary of Alliance Resource Holdings, in February 2003. Because the Warrior acquisition was between entities under common control, it is accounted for at historical cost in a manner similar to that used in a pooling of interests. Accordingly, the financial statements as of December 31, 2002 and 2001, and for each of the two years in the period ended December 31, 2002, have been retroactively adjusted to reflect the combined historical results of operations, financial position, and cash flows of the Partnership and Warrior. ARH Warrior Holdings acquired the assets that comprise Warrior on January 26, 2001.

(in millions, except per unit and per ton data)

	Year Ended December 31,				
	2004	2003	2002	2001	2000
Statements of Income:					
Sales and operating revenues					
Coal sales	$ 599.4	$ 501.6	$ 479.5	$ 453.1	$ 347.2
Transportation revenues	29.8	19.5	19.0	18.2	13.5
Other sales and operating revenues	24.1	21.6	20.4	6.2	2.8
Total revenues	653.3	542.7	518.9	477.5	363.5
Expenses:					
Operating expenses	436.4	368.8	367.5	337.2	257.4
Transportation expenses	29.8	19.5	19.0	18.2	13.5
Outside purchases	9.9	8.5	10.1	28.9	16.9
General and administrative	45.4	28.3	20.3	18.7	15.2
Depreciation, depletion and amortization	53.7	52.5	52.4	50.7	39.1
Interest expense	15.0	16.0	16.4	16.8	16.6
Unusual items (1)					(9.5)
Net gain from insurance settlement (2)	(15.2)				
Total expenses	575.0	493.6	485.7	470.5	349.2
Income from operations	78.3	49.1	33.2	7.0	14.3
Other income	1.0	1.4	0.5	0.8	1.3
Income before income taxes and cumulative effect of accounting change	79.3	50.5	33.7	7.8	15.6
Income tax expense (benefit)	2.7	2.6	(1.1)	(0.8)	
Income before cumulative effect of accounting change	76.6	47.9	34.8	8.6	15.6

Cumulative effect of accounting change (3)				7.9	
Net income	$ 76.6	$ 47.9	$ 34.8	$ 16.5	$ 15.6
General Partners interest in net income	$ 3.3	$ 0.3	$ (0.8)	$ (0.2)	$ 0.3
Limited Partners interest in net income	$ 73.3	$ 47.6	$ 35.6	$ 16.7	$ 15.3
Basic net income per limited partner unit (8)	$ 3.52	$ 2.61	$ 2.29	$ 1.09	$ 0.99
Basic net income per limited partner unit before accounting change (8)	$ 3.52	$ 2.61	$ 2.29	$ 0.58	$ 0.99
Diluted net income per limited partner unit (8)	$ 3.42	$ 2.53	$ 2.22	$ 1.07	$ 0.98
Diluted net income per limited partner unit before accounting change (8)	$ 3.42	$ 2.53	$ 2.22	$ 0.57	$ 0.98
Weighted average number of units outstanding-basic	17,940,948	17,580,734	15,405,311	15,405,311	15,405,311
Weighted average number of units outstanding-diluted	18,437,168	18,162,839	15,842,708	15,684,550	15,551,062
Balance Sheet Data:					
Working capital (deficit)	$ 54.2	$ 16.4	$ (15.8)	$ 0.9	$ 38.6
Total assets	412.8	336.5	316.9	310.3	309.2
Long-term debt	162.0	180.0	195.0	211.3	226.3
Total liabilities	357.6	323.9	355.7	347.8	341.0
Partners capital (deficit)	55.2	12.6	(38.8)	(37.6)	(31.8)
Other Operating Data:					
Tons sold	20.8	19.5	18.4	18.6	15.0
Tons produced	20.4	19.2	18.0	17.4	13.7
Revenues per ton sold (4)	$ 29.98	$ 26.83	$ 27.17	$ 24.69	$ 23.33
Cost per ton sold (5)	$ 23.64	$ 20.80	$ 21.63	$ 20.69	$ 19.30
Other Financial Data:					
Net cash provided by operating activities	$ 145.1	$ 110.3	$ 101.3	$ 70.5	$ 71.4
Net cash used in investing activities	(77.6)	(77.8)	(56.9)	(31.1)	(41.0)
Net cash used in financing activities	(46.4)	(31.3)	(46.4)	(35.2)	(31.4)
EBITDA (6)	148.0	119.0	102.5	83.2	71.3
Maintenance capital expenditures (7)	31.6	30.0	29.0	24.4	21.2

(1) Represents income from the final resolution of an arbitrated dispute with respect to the termination of a long-term contract, net of impairment charges relating to certain transloading facility assets, partially offset by expenses associated with other litigation matters in 2000.

(2) Represents the net gain from the final settlement with the Partnership s insurance underwriters for claims relating to the Dotiki Mine Fire Incident. Please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations; Summary for a description of the accounting treatment of expenses and insurance proceeds associated with the Dotiki Fire Incident.

(3) Represents the cumulative effect of the change in the method of estimating coal workers pneumoconiosis (black lung) benefits liability effective January 1, 2001. Please see Item 7. Management Discussion and Analysis of Financial Condition and Results of Operations. Critical Accounting Policies and Item 8. Financial Statements and Supplementary Data. - Note 4. Accounting Change.

(4) Revenues per ton sold are based on the total of coal sales and other sales and operating revenues divided by tons sold.

(5) Cost per ton sold is based on the total of operating expenses, outside purchases and general and administrative expenses divided by tons sold.

(6) EBITDA is defined as net income before net interest expense, income taxes and depreciation, depletion and amortization. EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on investment as compared to those of other companies in the coal energy sector, without regard to financing or capital structures; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

EBITDA should not be considered as an alternative to net income, income from operations, cash flows from operating activities or any other measure of financial performance presented in accordance with generally accepted accounting principles. EBITDA is not intended to represent cash flow and does not represent the measure of cash available for distribution. Our method of computing EBITDA may not be the same method used to compute similar measures reported by other companies, or EBITDA may be computed differently by us in different contexts (i.e. public reporting versus computation under financing agreements).

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The following table presents a reconciliation of the non-GAAP financial measure of EBITDA to the GAAP financial measure of net income:

	Year Ended December 31,				
	2004	2003	2002	2001	2000
Net Income	$ 76.6	$ 47.9	$ 34.8	$ 16.5	$ 15.6
Add:					
Depreciation, depletion and amortization	53.7	52.5	52.4	50.7	39.1
Interest expense	15.0	16.0	16.4	16.8	16.6
Income tax expense (benefit)	2.7	2.6	(1.1)	(0.8)	
EBITDA	$ 148.0	$ 119.0	$ 102.5	$ 83.2	$ 71.3

(7) Our maintenance capital expenditures, as defined under the terms of our partnership agreement, are those capital expenditures required to maintain, over the long-term, the operating capacity of our capital assets. Maintenance capital expenditures for our predecessor reflect our historical designation of maintenance capital expenditures. Maintenance capital expenditures for the years ended December 31, 2002 and 2001 have not been restated to include Warrior.

(8) Basic and diluted net income per limited partner unit for the years 2004, 2003 and 2002 have been restated to reflect the application of EITF 03-6. The dilutive effect of EITF 03-6 on basic net income per limited partner unit was $0.57, $0.10 and $0.02 for years ended 2004, 2003 and 2002, respectively. The dilutive effect of EITF 03-06 on diluted net income per limited partner unit was $0.56, $0.09 and $0.02 for years ended December 31, 2004, 2003 and 2002, respectively. There was no effect on basic and diluted net income per limited partner unit for the years ended December 31, 2001 and 2000 because the Partnership s aggregate distributions exceeded aggregate earnings for these annual periods. Refer to Item 8. Financial Statements and Supplementary Data. Notes 2, 11, 19 and 21 for further discussion of this matter.

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

The financial statements in this amended Form 10-K/A reflect restatements of basic and diluted net income per limited partner unit for 2004, 2003 and 2002 and the pro forma disclosure related to common unit-based compensation. This Management s Discussion and Analysis of Financial Condition and Results of Operations gives effect to the restatements.

For additional information regarding the restatements, refer to Item 8. Financial Statements and Supplementary Data. Notes 2, 11, 19 and 21.

General

The following discussion of our financial condition and results of operation should be read in conjunction with the historical financial statements and notes thereto included elsewhere in this Annual Report on Form 10-K/A. We acquired Warrior from ARH Warrior Holdings, a subsidiary of Alliance Resource Holdings, in February 2003. Because the Warrior acquisition was between entities under common control, it is accounted for at historical cost in a manner similar to that used in a pooling of interests. Accordingly, the financial statements as of December 31, 2002 and 2001, and for each of the two years in the period ended December 31, 2002, have been restated to reflect the combined historical results of operations, financial position and cash flows of the Partnership and Warrior. ARH Warrior Holdings acquired Warrior on January 26, 2001. For more detailed information regarding the basis of presentation for the following financial information, please see Item 8. Financial Statements and Supplementary Data. - Note 1. Organization and Presentation and Note 2. Summary of Significant Accounting Policies.

Business

We are a diversified producer and marketer of coal to major U.S. utilities and industrial users. In 2004, our total production was 20.4 million tons and our total sales were 20.8 million tons. The coal we produced in 2004 was approximately 32.3% low-sulfur coal, 15.7% medium-sulfur coal and 52.0% high-sulfur coal.

At December 31, 2004, we had approximately 442.4 million tons of proven and probable coal reserves in Illinois, Indiana, Kentucky, Maryland and West Virginia. We believe we control adequate reserves to implement our currently contemplated mining plans. In addition, there are substantial unleased reserves on properties adjacent to some of our Illinois Basin region operations that we currently intend to acquire or lease as our mining operations approach these areas.

In 2004, approximately 79% of our sales tonnage was consumed by electric utilities with the balance consumed by cogeneration plants and industrial users. Our largest customers in 2004 were SSO and VEPCO. In 2004, approximately 92% of our sales tonnage, including approximately 94% of our medium- and high-sulfur coal sales tonnage, was sold under long-term contracts. The balance of our sales was made in the spot market. Our long-term contracts contribute to our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2004, approximately 88% of our medium- and high-sulfur coal was sold to utility plants with installed pollution control devices, also known as scrubbers, to remove sulfur dioxide.

We have entered into long-term agreements with SSO to host and operate its coal synfuel production facility currently located at Warrior, supply the facility with coal feedstock, assist SSO with the marketing of coal synfuel and provide it with other services. These agreements expire on December 31, 2007 and provide us with coal sales and rental and service fees from SSO based on the synfuel facility throughput tonnages. These amounts are dependent on the ability of SSO s members to use certain qualifying tax credits applicable to the facility. The term of each of these agreements is subject to early cancellation provisions customary for transactions of these types, including the unavailability of coal synfuel tax credits, the termination of associated coal synfuel sales contracts, and the occurrence of certain force majeure events. We have maintained back up coal supply agreements with each coal synfuel customer that automatically provide for sale of our coal to these customers in the event they do not purchase coal synfuel from SSO. In conjunction with a decision to relocate the coal synfuel production facility from Hopkins to Warrior, agreements for providing certain of these services were assigned to Alliance Service, a wholly-owned subsidiary of Alliance Coal, in December 2002. Alliance Service is subject to federal and state income taxes.

For 2004, the incremental annual net income benefit from the combination of the various coal synfuel-related agreements was approximately $16.9 million, assuming that coal pricing would not have increased without the availability of synfuel. The continuation of the incremental net income benefit associated with SSO s coal synfuel facility cannot be assured. We earn income by supplying SSO s synfuel facility with coal feedstock, assisting SSO with the marketing of coal synfuel, and providing rental and other services. Pursuant to our agreement with SSO, we are not obligated to make retroactive adjustments or reimbursements if SSO s tax credits are disallowed.

In June 2003, the IRS suspended the issuance of private letter rulings on the significant chemical change requirement to qualify for synfuel tax credits and announced that it was reviewing the test procedures and results used by taxpayers to establish that a significant chemical change had occurred. In October 2003, the IRS completed its review and concluded that the test procedures and results were scientifically valid if applied in a consistent and unbiased manner. The IRS has resumed issuing private letter rulings under its existing guidelines. SSO has advised us that its private letter ruling could be reviewed by the IRS as part of a tax audit, similar to the IRS reviews of other synfuel procedures. SSO has also advised us that the Permanent Subcommittee on Investigations of the Senate Committee on Governmental Affairs (Subcommittee) is reviewing the synfuel industry, that the Subcommittee has indicated that they hope to interview almost all taxpayers that are involved in the synfuel business, and that SSO has been requested to meet informally with the Subcommittee to help enhance the Subcommittee s knowledge of the synfuel industry.

One of our business strategies is to continue to make productivity improvements to remain a low-cost producer in each region in which we operate. Our principal expenses related to the production of coal are labor and benefits, equipment, materials and supplies, maintenance, royalties and excise taxes. Unlike most of our competitors in the eastern U.S., we employ a totally union-free workforce. Many of the benefits of the union-free workforce are not necessarily reflected in direct costs, but we believe are related to higher productivity. In addition, while we do not pay our customers transportation costs, they may be substantial and often the determining factor in a coal consumer s contracting decision. Our mining operations are located near many of the major eastern utility generating plants and on major coal hauling railroads in the eastern U.S.

Summary

In 2004, we reported record net income of $76.6 million, an increase of 60% over 2003 net income of $47.9 million. We grew through expansion of production capacity at Gibson, Dotiki and Pattiki, resumption of operations at the surface mine at Hopkins County Coal, and the addition of two third-party mining operations at our Mettiki operation. Tons produced increased 5.9% to 20.4 million tons. Tons sold increased 7.0% to 20.8 million tons.

During 2004, we benefited from strong coal markets as revenues rose to record levels and average coal sales prices in 2004 increased 11.7% compared to 2003.

We have commitments for substantially all of our 2005 production. For our estimated 2006 production, approximately 84% is committed under existing coal sales agreements and approximately 36% of the committed tonnage is subject to market price negotiations.

On December 26, 2004 the MC Mining Excel No. 3 mine was temporarily idled following the occurrence of a mine fire. The fire was discovered by mine personnel near the bottom of the Excel No. 3 mine slope late the evening of December 25, 2004. Under a firefighting plan developed by MC Mining, in cooperation with mine emergency response teams from the Mine Safety and Health Administration and Kentucky Office of Mine Safety and Licensing, the four portals at the Excel No. 3 mine were capped to deprive the fire of oxygen. A series of boreholes were then drilled into the fire area to further suppress the fire. As a result of these efforts, the mine atmosphere was rendered substantially inert, or without oxygen, and the Excel No. 3 mine fire was effectively suppressed. MC Mining then began construction of temporary and permanent barriers designed to completely isolate the mine fire area. When construction of the permanent barriers was completed, MC Mining began efforts to repair and rehabilitate the Excel No. 3 mine infrastructure. On February 21, 2005, the repair and rehabilitation efforts had progressed sufficiently to allow initial resumption of production. We anticipate that MC Mining may return to full production by the end of the first quarter of 2005, but we cannot assure that our ability to produce will not continue to be adversely impacted by the MC Mining Fire Incident for a period of time. The boreholes continue to be used to monitor the mine atmosphere and to inject nitrogen into the area of the fire now isolated behind the permanent barriers.

We maintain commercial property (including business interruption) insurance policies, which are renewed annually in September and provide for self-retention and various applicable deductibles, including certain monetary and/or time element forms of deductibles, (collectively the 2005 Deductibles) and 10% co-insurance (2005 Co-Insurance), but we cannot give any assurances as to the eventual timing or amount of any recovery of proceeds under these policies. We have made initial estimates of certain costs primarily associated with activities relating to the suppression of the fire and the resumption of operations. Operating expenses for the 2004 fourth quarter increased by $4.1 million reflecting an initial estimate of certain minimum costs attributable to the MC Mining Fire Incident that are not reimbursable under our insurance policies due to the application of the 2005 Deductibles and 2005 Co-Insurance. An increase in the amount of such costs is possible, but is not currently subject to a reasonable estimate at this time. In addition to these initial cost estimates, we expect to incur additional out-of-pocket costs that will generally fall into the categories of extra expenses, expediting expenses and other areas of coverage under the commercial insurance policies. These future out-of-pocket costs, which are not currently subject to reasonable estimation, will be expensed as incurred. The related estimated insurance recovery of these costs will be recorded, net of 2005 Deductibles and 2005 Co-Insurance, as we determine that such recoveries are probable. Any recovery under the insurance policies of business interruption proceeds attributable to amounts in excess of actual costs incurred will be recorded as gains when the claims are settled with the insurance underwriters.

On February 11, 2004, Webster County Coal s Dotiki mine was temporarily idled for a period of twenty-seven calendar days following the occurrence of a mine fire that originated with a diesel supply tractor. As a

result of the firefighting efforts of the Mine Safety and Health Administration, Kentucky Department of Mines and Minerals, and Webster County Coal personnel, Dotiki successfully extinguished the fire and totally isolated the affected area of the mine behind permanent barriers. Initial production resumed on March 8, 2004. For the Dotiki Fire Incident, we had commercial property insurance that provided coverage for damage to property destroyed, interruption of business operations, including profit recovery, and expenditures incurred to minimize the period and total cost of disruption to operations.

On September 10, 2004, we filed a third and final proof of loss with the applicable insurance underwriters reflecting a settlement (the Dotiki Settlement) of all expenses, losses and claims incurred by Webster County Coal and other affiliates arising from or in connection with the Dotiki Fire Incident (the Dotiki Insurance Claim) in the aggregate amount of $27.0 million, inclusive of a $1.0 million self-retention, a $2.5 million deductible (collectively, the 2004 Insurance Deductibles) and 10% Co-Insurance (the 2004 Co-Insurance). The 2004 Insurance Deductibles and 2004 Co-Insurance were allocated on a pro-rata basis to each of the three areas of insurance recoveries discussed below. In addition, the accounting for two net partial advance payments in the aggregate amount of $8.1 million and the final net payment of $13.05 million, exclusive of the 2004 Insurance Deductible and 2004 Co-Insurance, were subject to the accounting methodology described below. Specifically, we evaluated and accounted for the insurance recoveries in the following areas:

1. Expenses incurred as a result of the fire: We incurred extra expenses, expediting expenses, and other costs associated with extinguishing the fire in an aggregate amount of approximately $7.1 million. With application of $5.6 million of the insurance recovery proceeds, we recorded net expenses of approximately $1.5 million.

2. Damage to Dotiki mine property: We incurred damage to Dotiki s mine property (exclusive of any amounts relating to matters discussed in 1. above) of approximately $1.2 million, which property had a net book value of $138,000. Based on discussions with the underwriters culminating in the Dotiki Settlement, we recorded a net gain of approximately $785,000, reflecting the amount that the allocated insurance proceeds exceeded the net book value of the damaged property.

3. Dotiki mine business interruption costs and extra expense: Based on the negotiations with the underwriters leading to the Dotiki Settlement, we recorded a net gain of approximately $14.4 million for the recovery of business interruption costs and extra expenses stemming from the Dotiki Fire Incident. This net gain amount reflects an offset of approximately $200,000 for professional services expenses incurred in resolving the business interruption portion of the Dotiki Settlement.

Pursuant to the accounting methodology described above, in 2004 we recorded (a) an offset to operating expenses of approximately $5.9 million and (b) a combined net gain of approximately $15.2 million for damage to property destroyed, interruption of business operations (including profit recovery), and extra expenses incurred to minimize the period and total cost of disruption to operations associated with the Dotiki Fire Incident.

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Results of Operations

2004 Compared with 2003

	2004	2003	Per Ton Sold 2004	Per Ton Sold 2003
	(in thousands)			
Tons sold	20,823	19,467	N/A	N/A
Tons produced	20,377	19,238	N/A	N/A
Coal Sales	$ 599,399	$ 501,596	$ 28.79	$ 25.77
Operating Expenses and Outside Purchases	$ 446,384	$ 377,343	$ 21.44	$ 19.38

Coal sales. Coal sales increased 19.5% to $599.4 million for 2004 from $501.6 million for 2003. The increase of $97.8 million reflects higher prices on long-term coal sales agreements and the sale of additional production at significantly higher prices on short-term coal sales agreements into the export and Central Appalachia coal markets. Higher prices on long-term contracts reflect a stronger market in the second half of 2003 when contracts were entered into for shipments in 2004. The export market opportunities for the U.S. coal industry were attributable generally to the strong economic expansion in China. The increase in Central Appalachia spot market pricing was attributable primarily to a combination of the diversion of coal production from domestic markets to export markets and a decline in region-wide production. Tons sold increased 7.0% to 20.8 million for 2004 from 19.5 million in 2003, primarily reflecting an increase in tons produced. Tons produced increased 5.9% to 20.4 million for 2004 from 19.2 million in 2003.

Operating expenses. Operating expenses increased 18.3% to $436.5 million in 2004 from $368.8 million in 2003. The increase of $67.7 million was primarily attributable to (a) additional sales of 1.4 million tons, (b) higher maintenance expense and materials and supplies costs (particularly fuel, power and steel), (c) adverse geologic conditions at the Pontiki mine, (d) increased longwall moves associated with shorter longwall panels at the Mettiki mine and (e) additional costs associated with the MC Mining and Dotiki Fire Incidents described above. Operating expenses include an accrual of $4.1 million reflecting our initial estimate of the minimum non-reimbursable costs attributable to the MC Mining Fire Incident. Additionally, 2004 includes a $3.5 million buy-out expense of several coal contracts which will allow us to take advantage of anticipated higher spot coal prices in 2005.

Other sales and operating revenues. Other sales and operating revenues, which are primarily comprised of services to the coal synfuel production facility, increased 11.5% to $24.1 million in 2004 from $21.6 million in 2003. The increase of $2.5 million was primarily attributable to additional rent and service fees associated with increased volumes at a third-party coal synfuel facility at Warrior.

General and administrative. General and administrative expenses for 2004 increased to $45.4 million compared to $28.3 million for 2003. The $17.1 million increase was primarily attributable to higher incentive compensation expense, which increased approximately $16.0 million. The incentive compensation plans include the Long-Term Incentive Plan, a restricted unit plan, and the Supplemental Executive Retirement Plan, a phantom unit plan, both of which are impacted by the increased market value of our common units, which had a closing market price of $74.00 on December 31, 2004 compared to a closing market price of $34.38 on December 31, 2003, and the Short-Term Incentive Plan, which provides our employees an opportunity to receive additional compensation based on our financial performance.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased to $53.7 million in 2004 compared to $52.5 million in 2003. The increase of $1.2 million was primarily the result of

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additional depreciation expense associated with increased capital expenditures and infrastructure investments over the last few years, which have increased our production capacity. The increase was partially offset by a $2.6 million decrease in depreciation attributable to operating Hopkins County Coal six months in 2003 compared to three months in 2004.

Interest expense. Interest expense declined 6.4% to $15.0 million in 2004 from $16.0 million in 2003. The decrease of $1.0 million was attributable to reduced interest expense associated with the revolving credit facility. We had no borrowings under the credit facility during 2004.

Outside purchases. Outside purchases increased 16.5% to $9.9 million in 2004 from $8.5 million in 2003. The increase was primarily attributable to an increase in outside purchases associated with our East Kentucky and Illinois Basin operations partially offset by a decrease in the domestic brokerage market.

Transportation revenues and expenses. Transportation revenues and expenses increased 52.5% to $29.8 million in 2004 from $19.6 million for 2003. The increase of $10.3 million was primarily attributable to increased shipments to customers that reimburse us for transportation costs rather than arranging and paying for transportation directly with transportation providers.

Income before income tax expense (benefit). Income before income tax expense (benefit) increased 57.0% to $79.3 million for 2004 compared to $50.5 million for 2003. The increase was primarily attributable to higher sales prices, reflecting the continued strengthening of domestic and international coal markets, partially offset by higher operating expenses and increased general and administrative expense, primarily attributable to higher incentive compensation expense.

Income tax expense (benefit). Income tax expense was comparable for both 2004 and 2003 at $2.6 million for each year.

2003 Compared with 2002

			Per Ton Sold	
	2003	**2002**	**2003**	**2002**
	(in thousands)			
Tons sold	19,467	18,370	N/A	N/A
Tons produced	19,238	17,970	N/A	N/A
Coal Sales	$ 501,596	$ 479,515	$ 25.77	$ 26.10
Operating Expenses and Outside Purchases	$ 377,343	$ 377,644	$ 19.38	$ 20.56

Coal sales. Coal sales for 2003 increased 4.6% to $501.6 million from $479.5 million for 2002. The increase of $22.1 million was attributable to increased tons sold partially offset by lower sales prices. Sales prices in 2002 benefited from coal sales agreements entered into during the second half of 2001 when sales prices for deliveries in 2002 increased in response to a combination of factors including low coal stockpiles and supply shortages. Tons sold increased 6.0% to 19.5 million for 2003 from 18.4 million in 2002, reflecting an increase in tons produced. Tons produced increased 7.1% to 19.2 million for 2003 from 18.0 million in 2002. Please see Operating Expenses below concerning the increase in tons produced.

Operating expenses. Operating expenses were comparable for 2003 and 2002 at $368.8 million and $367.6 million, respectively. Increased operating expenses associated with higher production and sales levels at our active mines were offset by a decrease associated with the idling of the Hopkins complex on June 2, 2003. Operating expenses declined on a cost-per-ton sold basis as production increased at all of our active operations except Pattiki. Pattiki s production was essentially the same in 2003 and 2002.

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Increased production reflects the absence of the adverse geologic conditions encountered at Mettiki in the third quarter of 2002 and the emerging benefit of several strategic capital investments made during the past two years. We have added continuous miner units at Gibson, Warrior and MC Mining and have made infrastructure investments, such as new mine shafts, at Dotiki, Warrior and MC Mining. Additionally, operating expenses decreased due to the reversal of an expense accrual of $1.2 million established in 1998. The expense accrual was established in conjunction with the idling of Pontiki in 1998 that created an expectation of a probable increase in workers compensation costs associated with the terminated workforce. The anticipated increase in workers compensation claims did not emerge and, with limited exceptions, the statute of limitations expired in December 2003 for the filing or reopening of workers compensation claims associated with the employee terminations.

Other sales and operating revenues. Other sales and operating revenues, which is primarily comprised of services to the coal synfuel production facility, increased 6.0% to $21.6 million from $20.4 million in 2002. However, the $1.2 million increase was primarily attributable to providing additional services for treating, handling and transporting coal unrelated to the coal synfuel services.

General and administrative. General and administrative expenses for 2003 increased 39.0% to $28.3 million compared to $20.3 million for 2002. The $8.0 million increase was primarily attributable to higher expense accruals of $6.9 million associated with incentive compensation programs, and the remaining increase in expense reflects various other increases in administrative compliance costs.

Depreciation, depletion and amortization. Depreciation, depletion and amortization were comparable for 2003 and 2002 at $52.5 million and $52.4 million, respectively. Additional depreciation associated with the capital additions described in Operating Expenses above was offset by lower depreciation of $3.0 million at the idled Hopkins complex. Please see Item 1. Business, Mining Operations, Illinois Basin Operations.

Interest expense. Interest expense for 2003 declined 2.3% to $16.0 million from $16.4 million in 2002 primarily attributable to decreased borrowings under the revolving credit facility.

Outside purchases. Outside purchases for 2003 decreased 15.6% to $8.5 million from $10.1 million in 2002. The decrease was primarily attributable to a decrease in coal purchases from a third-party producer that ceased production in the fourth quarter of 2002.

Transportation revenues and expenses. Transportation revenues and expenses for 2003 increased 3.0% to 19.6 million from $19.0 million for 2002. The increase of $0.6 million was primarily attributable to the increase in tons sold. We reflect reimbursement of the cost of transporting coal to customers through third party carriers as transportation revenues and the corresponding expense as transportation expense in the consolidated statements of income. No margin is realized on transportation revenues.

Income before income tax expense (benefit) and cumulative effect of accounting change. Income before income tax expense (benefit) and cumulative effect of accounting change increased 49.8% to $50.5 million for 2003 compared to $33.7 million for 2002. The increase was primarily attributable to lower cost per-ton-sold operating costs and higher sales volumes, partially offset by lower sales prices and increased general and administrative expenses.

Income tax expense (benefit). Income tax expense for 2003 was $2.6 million compared to an income tax benefit of $1.1 million in 2002. Although we are not a taxable entity for federal or state income tax purposes, our subsidiary, Alliance Service is subject to federal and state income taxes. In conjunction with a decision to

relocate the coal synfuel facility, agreements for a portion of the services provided to the coal synfuel producer were assigned to Alliance Service in December 2002. Approximately $2.1 million of the increase in income tax expense was associated with coal synfuel-related services performed by Alliance Service. The balance of the income tax expense increase was attributable to Warrior, which had a net income tax benefit for the year 2002 of approximately $1.3 million. Since our acquisition of Warrior on February 14, 2003, the financial results of Warrior are no longer subject to federal or state income taxes.

Ongoing Acquisition Activities

Consistent with our business strategy, from time-to-time we engage in discussions with potential sellers regarding possible acquisitions of certain assets and/or companies by us.

Liquidity and Capital Resources

Liquidity

We generally satisfy our working capital requirements and fund our capital expenditures and debt service obligations from cash generated from operations and borrowings under our revolving credit facility. We believe that the cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated capital expenditures (other than major capital improvements or acquisitions), scheduled debt payments and distribution payments. To further develop available financing alternatives, in October 2002, we entered into a master lease agreement. Under the master lease agreement, lease terms and rental payments are negotiated individually when specific pieces of equipment are leased. During 2004 and 2003, we had rental expense of $1.3 million and $1.0 million, respectively, under the master lease agreement. We had no equipment leased under the master equipment lease at December 31, 2002. Our credit facility limits the amount of total operating lease obligations to $15.0 million payable in any period of 12 consecutive months. Our ability to satisfy our obligations and planned expenditures will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry, some of which are beyond our control.

Cash Flows

Cash provided by operating activities was $145.1 million in 2004, compared to $110.3 million in 2003. The increase in cash provided by operating activities was principally attributable to an increase in net income and a greater reduction in total working capital.

Net cash used in investing activities was comparable for 2004 and 2003 at $77.6 million and $77.8 million, respectively.

Net cash used in financing activities was $46.4 million for 2004 compared to $31.3 million for 2003. The increase is primarily attributable to the increased distributions to partners in 2004 compared to 2003.

We have various commitments primarily related to long-term debt, operating lease commitments related to buildings and equipment, obligations for estimated reclamation and mining closing costs, capital project commitments, and pension funding. We expect to fund these commitments with cash generated from operations, proceeds from marketable securities, and borrowings under our revolving credit facility. The following table provides details regarding our contractual cash obligations as of December 31, 2004 (in thousands):

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Contractual Obligations	Total	Less than 1 year	2-3 years	4-5 years	After 5 years
Long-term debt	$ 180,000	$ 18,000	$ 36,000	$ 36,000	$ 90,000
Future interest obligations	76,819	14,413	24,339	18.355	19,712
Operating leases	20,602	4,666	7,659	5,467	2,810
Other long-term obligations (excluding discount effect of $28.8 million for reclamation liability)	62,778	1,180	6,106	822	54,670
Capital projects	8,386	8,386			
	$ 348,585	$ 46,645	$ 74,104	$ 60,644	$ 167,192

We expect to contribute $2.7 million to the defined benefit pension plan (Pension Plan) during 2005. We estimate that our interest and income tax cash requirements will be approximately $14.3 million and $2.7 million, respectively in 2005.

Capital Expenditures

Capital expenditures decreased to $54.7 million in 2004 compared to $55.7 million in 2003, which includes the acquisition of Warrior Coal. Excluding the Warrior acquisition, capital expenditures for 2004 increased $11.7 million compared to capital expenditures for the 2003 period. The increase in capital expenditures is associated with Dotiki expanding its preparation plant and adding two continuous miners, and the addition of one continuous mining unit at Gibson and Pattiki.

In February 2003, we acquired Warrior from an affiliate, ARH Warrior Holdings, pursuant to the terms of a previously existing agreement. Warrior owns an underground mining complex located between and adjacent to our other western Kentucky operations near Madisonville, Kentucky. We paid $12.7 million to ARH Warrior Holdings in accordance with the terms of an Amended and Restated Put and Call Option Agreement. In addition, we repaid Warrior s borrowings of $17.0 million under the revolving credit agreement between our special general partner and Warrior. We funded the Warrior acquisition through a portion of the proceeds received from the issuance of 2,250,000 common units in February 2003.

We currently project that our average annual maintenance capital expenditures will be approximately $50.0 million. We also currently expect to fund our anticipated total capital expenditures for 2005 of $79.9 million, with cash generated from operations and borrowings under our revolving credit facility described below.

Notes Offering and Credit Facility

Alliance Resource Operating Partners, L.P., our intermediate partnership, has $180 million principal amount of 8.31% senior notes due August 20, 2014, payable in ten equal annual installments of $18 million beginning in August 2005 with interest payable semi-annually (Senior Notes). On August 22, 2003, our intermediate partnership completed an $85 million revolving credit facility (Credit Facility), which expires September

30, 2006. The Credit Facility replaced a $100 million credit facility that would have expired August 2004. We paid in full all amounts outstanding under the $100 million original credit facility with borrowings of $20 million under the Credit Facility. The interest rate on the Credit Facility is based on either the (i) London Interbank Offered Rate or (ii) the Base Rate , which is equal to the greater of the JPMorgan Chase Prime Rate or the Federal Funds Rate plus 1/2 of 1%, plus, in either case, an applicable margin. We incurred certain costs aggregating $1.2 million associated with the Credit Facility. These costs have been deferred and are being amortized as a component of interest expense over the term of the Credit Facility. We had no borrowings outstanding under the Credit Facility at December 31, 2004. Letters of credit can be issued under the Credit Facility not to exceed $30 million. Outstanding letters of credit reduce amounts available under the Credit Facility. At December 31, 2004, we had letters of credit of $9.0 million outstanding under the Credit Facility.

The Senior Notes and Credit Facility are guaranteed by all of the subsidiaries of our intermediate partnership. The Senior Notes and Credit Facility contain various restrictive and affirmative covenants, including restrictions on the amount of distributions by our intermediate partnership and the incurrence of other debt. We were in compliance with the covenants of both the Credit Facility and Senior Notes at December 31, 2004.

We have previously entered into and have maintained agreements with two banks to provide additional letters of credit in an aggregate amount of $25.0 million to maintain surety bonds to secure our obligations for reclamation liabilities and workers compensation benefits. At December 31, 2004, we had $22.2 million in letters of credit outstanding under these agreements. Our special general partner guarantees the letters of credit.

Critical Accounting Policies

From our Summary of Significant Accounting Policies, we have identified the following accounting policies that require the exercise of our most difficult, complex and subjective levels of judgment. Our judgments in the following areas are principally based on estimates and assumptions that affect the reported amounts and disclosures in the consolidated financial statements. Please see Item 8. Financial Statements and Supplementary Data. Actual results that are influenced by future events could materially differ from the current estimates.

Long-Lived Assets

We review the carrying value of long-lived assets whenever events or changes in circumstances indicate that the carrying amount may not be recoverable based upon estimated undiscounted future cash flows. The amount of impairment is measured by the difference between the carrying value and the fair value of the asset, which is based on cash flows from that asset, discounted at a rate commensurate with the risk involved. Events or changes in circumstance that could cause us to perform such a review include, but are not limited to, the loss of a major coal supply agreement, a significant decline in demand for our coal and an adverse change in geologic conditions.

Reclamation and Mine Closing Costs

The Federal SMCRA and similar state statutes require that mine property be restored in accordance with specified standards and an approved reclamation plan. We record the liability for the estimated cost of future mine reclamation and closing procedures on a present value basis when incurred, and the associated cost is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to sealing portals at underground mines and to reclaiming the final pit and support acreage at surface mines. Other costs common to both types of mining are related to removing or covering refuse piles and settling ponds, and dismantling preparation plants, other facilities and roadway infrastructure. We had accrued liabilities of $34.0 million and $23.5 million for these costs at December 31, 2004 and 2003, respectively. The liability for mine reclamation and closing procedures is sensitive to changes in cost estimates and estimated mine lives.

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Workers Compensation and Pneumoconiosis (Black Lung) Benefits

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. We provide for these claims through self-insurance programs. The liability for traumatic injury claims is the estimated present value of current workers compensation benefits, based on an annual independent actuarial study. The actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including development patterns, mortality, medical costs and interest rates. We had accrued liabilities of $32.6 million and $28.7 million for these costs at December 31, 2004 and 2003, respectively. A one-percentage-point reduction in the discount rate would have increased the liability at December 31, 2004 approximately $1.8 million, which would have a corresponding increase in operating expenses.

Coal mining companies are subject to the Federal Coal Mine Health and Safety Act of 1969, as amended, and various state statutes for the payment of medical and disability benefits to eligible recipients related to coal worker s pneumoconiosis (black lung). We provide for these claims through self-insurance programs. Our estimated black lung liability is based on an annual actuarial study performed by an independent actuary. The actuarial calculations are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and interest rates. We had accrued liabilities of $20.3 million and $17.6 million for these benefits at December 31, 2004 and 2003, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2004 by approximately $0.9 million. Under the service cost method used to estimate our black lung benefits liability, actuarial gains or losses attributable to changes in actuarial assumptions such as the discount rate are amortized over the remaining service period of active miners.

Universal Shelf

In April 2002, we filed with the Securities and Exchange Commission a universal shelf registration statement allowing us to issue from time-to-time up to an aggregate of $200 million of debt or equity securities. At March 1, 2005, we had approximately $142.9 million available under this registration statement.

Related Party Transactions

Administrative Services

Our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses they incur or payments they make on our behalf including, but not limited to, management s salaries and related benefits (including incentive compensation), and accounting, budget, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers compensation management, legal and information technology services. Our managing general partner may determine in its sole discretion the expenses that are allocable to us. Total costs billed by our managing general partner and its affiliates to us were approximately $28,536,000, $12,471,000, and $6,559,000 for the years ended December 31, 2004, 2003, and 2002, respectively. The increases from 2003 to 2004 and 2002 to 2003 were primarily attributable to higher accruals related to common unit based incentive plans, which were impacted by the increased market value of our common units, and the Short Term Incentive Plan (STIP).

Warrior Acquisition

On February 14, 2003, we acquired Warrior from an affiliate, ARH Warrior Holdings a subsidiary of Alliance Resource Holdings, pursuant to an Amended and Restated Put and Call Option Agreement (Put/Call

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Agreement). Warrior purchased the capital stock of Roberts Bros. Coal Co., Inc., Warrior Coal Mining Company, Warrior Coal Corporation and certain assets of Christian Coal Corp. and Richland Mining Co., Inc. in January 2001. Our managing general partner had previously declined the opportunity to purchase these assets as we had previously committed to major capital expenditures at two existing operations. As a condition to not exercising its right of first refusal, we requested that ARH Warrior Holdings enter into a put and call arrangement for Warrior. We and ARH Warrior Holdings, with the approval of the conflicts committee of our managing general partner, entered into the Put/Call Agreement in January 2001. Concurrently, ARH Warrior Holdings acquired Warrior in January 2001 for $10.0 million.

The Put/Call Agreement preserved the opportunity for us to acquire Warrior during a specified time period. Under the terms of the Put/Call Agreement, ARH Warrior Holdings exercised its put option requiring us to purchase Warrior at a put option price of approximately $12.7 million.

The option provisions of the Put/Call Agreement were subject to certain conditions (unless otherwise waived), including, among others, (a) the non-occurrence of a material adverse change in the business and financial condition of Warrior, (b) the prohibition of any dividends or other distributions to Warrior s shareholders, (c) the maintenance of Warrior s assets in good working condition, (d) the prohibition on the sale of any equity interest in Warrior except for the options contained in the Put/Call Agreement, and (e) the prohibition on the sale or transfer of Warrior s assets except those made in the ordinary course of its business.

The Put/Call Agreement option prices reflected negotiated sale and purchase amounts that both parties determined would allow each party to satisfy acceptable minimum investment returns in the event either the put or call options were exercised. In January 2001 and in December 2002, we developed financial projections for Warrior based on due diligence procedures we customarily perform when considering the acquisition of a coal mine. The assumptions underlying the financial projections made by us for Warrior included, among others, (a) annual production levels ranging from 1.5 million to 1.8 million tons, (b) coal prices at or below the then current coal prices and (c) a discount rate of 12 percent. Based on these financial projections, as of the date of the acquisition and at December 31, 2002 and 2001, we believe that the fair value of Warrior was equal to or greater than the put option exercise price.

The put option price of $12.7 million was paid to ARH Warrior Holdings in accordance with the terms of the Put/Call Agreement. In addition, we repaid Warrior s borrowings of $17.0 million under the revolving credit agreement between our special general partner and Warrior. The primary borrowings under the revolving credit agreement financed new infrastructure capital projects at Warrior that have contributed to improved productivity and significantly increased capacity. We funded the Warrior acquisition through a portion of the proceeds received from the issuance of 2,250,000 common units. Because the Warrior acquisition was between entities under common control, it has been accounted for at historical cost in a manner similar to that used in a pooling of interests.

Under the terms of the Put/Call Agreement, we assumed certain other obligations, including a mineral lease and sublease with SGP Land, a subsidiary of our special general partner, covering coal reserves that have been and will continue to be mined by Warrior. The terms and conditions of the mineral lease and sub-lease remain unchanged.

SGP Land

Dotiki has a mineral lease and sublease with SGP Land requiring annual minimum royalty payments of $2.7 million, payable in advance through 2013 or until $37.8 million of cumulative annual minimum and/or earned royalty payments have been paid. Dotiki paid royalties of $4,611,000, $3,460,000, and $2,700,000 for the years ended December 31, 2004, 2003 and 2002, respectively. Dotiki has recouped as earned royalties all advance minimum royalty payments made under these lease terms except for $805,000 as of December 31, 2004.

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Warrior has a mineral lease and sublease with SGP Land. Under the terms of the lease, Warrior has paid and will continue to pay in arrears an annual minimum royalty obligation of $2,270,000 until $15,890,000 of cumulative annual minimum and/or earned royalty payments have been paid. The annual minimum royalty periods are from October 1st through the end of the following September, expiring September 30, 2007. Warrior paid royalties of $2,561,000, $2,453,000, and $2,127,000 for the years ended December 31, 2004, 2003, and 2002, respectively. Warrior has recouped as earned royalties all advance minimum royalty payments made in accordance with these lease terms except for $636,000 as of December 31, 2004.

Under the terms of the mineral lease and sublease agreements described above, Dotiki and Warrior also reimbursed SGP Land for SGP Land s base lease obligations. We reimbursed SGP Land $5,428,000, $4,395,000, and $3,922,000 for the years ended December 31, 2004, 2003 and 2002 respectively, for the base lease obligations. Dotiki and Warrior have recouped as earned royalties all advance minimum royalty payments made in accordance with these terms except for $216,000 as of December 31, 2004.

In 2001, SGP Land, as successor in interest to an unaffiliated third party, entered into an amended mineral lease with MC Mining. Under the terms of the lease, MC Mining has paid and will continue to pay an annual minimum royalty obligation of $300,000 until $6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. MC Mining paid royalties of $479,000 and $568,000 for the years ended December 31, 2003 and 2002, respectively. The 2004 annual minimum royalty obligation of $300,000 was paid in January 2005. MC Mining has recouped as earned royalties all advance minimum royalty payments made under these lease terms as of December 31, 2004.

We also have an option to lease and/or sublease certain reserves from SGP Land, which reserves are contiguous to Hopkins. Under the terms of the option to lease and sublease, we paid option fees of $1,368,000 and $684,000 during the years ended December 31, 2004 and 2003, respectively. The 2003 option fee of $684,000 was paid in January 2004 and is included in the due to affiliates balance as of December 31, 2003. The anticipated annual minimum royalty obligation is $684,000, payable in advance through 2009.

Special General Partner

Effective January 2001, Gibson entered into a noncancelable operating lease arrangement with our special general partner for its coal preparation plant and ancillary facilities. Based on the terms of the lease, Gibson has paid and will continue to make monthly payments of approximately $216,000 through January 2011. Lease expense was $2,595,000 for 2004, 2003 and 2002.

We have previously entered into and have maintained agreements with two banks to provide letters of credit in an aggregate amount of $25.0 million to maintain surety bonds to secure our obligations for reclamation liabilities and workers compensation benefits. At December 31, 2004, we had $22.2 million in outstanding letters of credit. Our special general partner guarantees these letters of credit. Historically, we have compensated our special general partner a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. Our special general partner agreed to waive the guarantee fee in exchange for a parent guarantee from our intermediate partnership and Alliance Coal on the mineral lease and sublease with Dotiki and Warrior. We paid approximately $31,300 and $48,200 in guarantee fees to our special general partner for the years ended December 31, 2003 and 2002, respectively.

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Elk Creek and Tunnel Ridge

On October 21, 2004, we announced an agreement, subject to finalization of definitive agreements, to enter into two separate coal leases, which cumulatively will increase our coal reserve holdings by 25%. The Elk Creek reserves (Elk Creek) are located in Hopkins County, Kentucky, and the Tunnel Ridge reserves (Tunnel Ridge) are located in Ohio County, West Virginia and Washington County, Pennsylvania. These leases are estimated to contain approximately 100 million tons of high-sulfur coal reserves. The lessor for both leases is our special general partner. We also announced plans to immediately begin the development process for these properties, which includes obtaining the necessary mining permits and securing sufficient coal sales commitments to justify the capital investment needed to bring these properties into production.

The Elk Creek reserve area encompasses approximately 9,000 acres and is contiguous to our Hopkins County Coal complex. The Elk Creek coal reserves are currently estimated to include approximately 30 million tons of high-sulfur coal. The Elk Creek mine will be an underground mining complex, that mines the West Kentucky No. 9 and No. 11 coal seams. It will utilize continuous mining units and employ room-and-pillar mining techniques. We intend to use the existing coal handling and other surface facilities owned by Hopkins County Coal. We anticipate the Elk Creek complex will employ as many as 250 individuals and produce up to 3.2 million tons of coal annually. We estimate total capital expenditures to develop Elk Creek to be approximately $65.0 million. In December, 2004, the board of directors of our managing general partner approved the capital expenditures associated with Elk Creek. Coal supply commitments are currently being pursued. Construction of the Elk Creek mining complex began in the first quarter of 2005. We expect to fund these capital expenditures with available cash and marketable securities on hand, future cash generated from operations and borrowings available under our revolving credit facility.

In December 2000, Hopkins County Coal entered into an option agreement to lease and/or sublease the Elk Creek reserves from our special general partner. Under the terms of the option to lease and sublease, Hopkins County Coal paid an option fee of $645,000 during the year ended December 31, 2000, and paid option fees of $684,000 during each of the years ended December 31, 2001, 2002 and 2004. The 2003 option fee of $684,000 was paid in January 2004. Upon exercise of the option to lease or sublease, Hopkins County Coal is obligated to make an additional five annual advance minimum royalty payments of $684,000 per year, which royalty is fully recoupable against earned royalties. The earned royalty rate under the lease and/or sublease is $0.25 per ton.

In January 2005, we acquired 100% of the limited liability company member interests of Tunnel Ridge, LLC for approximately $500,000 and the assumption of reclamation liabilities from Alliance Resource Holdings, Inc., a company owned by our management. Tunnel Ridge, LLC controls through a coal lease agreement with the special general partner an estimated 70 million tons of high-sulfur coal in the Pittsburgh No. 8 coal seam. The Tunnel Ridge reserve area encompasses approximately 50,571 acres of land located in Ohio County, West Virginia and Washington County, Pennsylvania. Under the terms of the coal lease, beginning on January 1, 2005, Tunnel Ridge, LLC began paying our special general partner an advance minimum royalty of $3.0 million per year, which advance royalty payments will be fully recoupable against earned royalties. The earned royalty rate under the coal lease is the greater of $0.75 per ton or 3.0% of the per ton gross sales price f.o.b. barge. The term of the coal lease is the earlier of 30 years or until exhaustion of all mineable and merchantable coal with termination rights after the initial four years of the coal lease.

Tunnel Ridge, LLC also controls, under a separate lease agreement with our special general partner, the rights to approximately 900 acres of surface land and other tangible assets. Under the terms of the lease agreement, Tunnel Ridge, LLC shall pay our special general partner an annual lease payment of $240,000 beginning January 1, 2005. The lease agreement has an initial term of four years, which term may be extended by Tunnel Ridge, LLC at the same annual lease payment rate, to be consistent with the term of the coal lease.

We have initiated the permitting process of the Tunnel Ridge reserve area. We anticipate that the Tunnel Ridge operation will use a longwall miner for the majority of its coal extraction as well as continuous mining units used for preparation of the mine for future longwall mining. We estimate the Tunnel Ridge operation will be designed to produce up to six million tons of coal annually. We believe production from Tunnel Ridge may begin as early as 2008. We anticipate the Tunnel Ridge complex will employ as many as 300 individuals. We estimate total capital expenditures required to develop Tunnel Ridge to be approximately $200 million over a five-year period. We currently expect to fund these capital expenditures with available cash and marketable securities, future cash generated from operations and borrowings available under our revolving credit facility. A definitive commitment to develop Tunnel Ridge is dependent upon final approval by the board of directors of our managing general partner.

The Elk Creek and Tunnel Ridge transactions described above are related-party transactions and, as such, were reviewed by the board of directors of our managing general partner and its conflicts committee. Based upon these reviews, it was determined that these transactions reflect market-clearing terms and conditions customary in the coal industry. As a result, the board of directors of our managing general partner and its conflicts committee approved the Elk Creek and Tunnel Ridge transactions as fair and reasonable to us.

Accruals of Other Liabilities

We had accruals for other liabilities, including current obligations, totaling $101.1 million and $77.8 million at December 31, 2004 and 2003. These accruals were chiefly comprised of workers compensation benefits, black lung benefits, and costs associated with reclamation and mine closings. These obligations are self-insured. The accruals of these items were based on estimates of future expenditures based on current legislation, related regulations and other developments. Thus, from time to time, our results of operations may be significantly affected by changes to these liabilities. Please see Item 8. Financial Statements and Supplementary Data. - Note 14. Reclamation and Mine Closing Costs and Note 15. Pneumoconiosis (Black Lung) Benefits.

Pension Plan

We maintain a Pension Plan, which covers certain employees at the mining operations.

Our pension expense was approximately $2,751,000 and $3,049,000 for the years ended December 31, 2004 and 2003, respectively. The pension expense is based upon a number of actuarial assumptions, including an expected long-term rate of returns on our Pension Plan assets of 8.0% and 8.0% and discount rates of 6.25% and 6.75% for the years ended December 31, 2004 and 2003, respectively. Our actual return on plan assets was 11.9% and 25.9% for the years ended December 31, 2004 and 2003, respectively. Additionally, we base our determination of pension expense on an unsmoothed market-related valuation of assets equal to the fair value of assets, which immediately recognizes all investment gains or losses.

In developing our expected long-term rate of return assumption, we evaluated input from our investment manager, including their review of asset class return expectations by economists, and our actuary. At January 1, 2005, our expected long-term return assumption is at least 8.0%. Our advisors base the projected returns on broad equity and bond indices. Our expected long-term rate of return on Pension Plan assets is based on an asset allocation assumption of 80.0% with equity managers, with an expected long-term rate of return of 10.4%, and 20.0% with fixed income managers, with an expected long-term rate of return of 5.4%. The pension plan trustee regularly reviews our actual asset allocation in accordance with our investment guidelines and periodically rebalanced our investments to our targeted allocation when considered appropriate. The investment committee reviews our asset allocation with the compensation committee annually.

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The discount rate that we utilize for determining our future pension obligation is based on a review of currently available high-quality fixed-income investments that receive one of the two highest ratings given by a recognized rating agency. We have historically used the average monthly yield for December of an Aa-rated utility bond index as the primary benchmark for establishing the discount rate. The duration of the bonds that comprise this index is comparable to the duration of the benefit obligation in the Pension Plan. The discount rate determined on this basis decreased from 6.25% at December 31, 2003 to 5.75% at December 31, 2004.

We estimate that our Pension Plan expense and cash contributions will be approximately $3,240,000 and $2,700,000, respectively in 2005. Future actual pension expense and contributions will depend on future investment performance, changes in future discount rates and various other factors related to the employees participating in the Pension Plan.

Lowering the expected long-term rate of return assumption by 1.0% (from 8.0% to 7.0%) at December 31, 2003 would have increased our pension expense for the year ended December 31, 2004 by approximately $211,000. Lowering the discount rate assumption by 0.5% (from 6.25% to 5.75%) at December 31, 2003 would have increased our pension expense for the year ended December 31, 2004 by approximately $422,000.

Inflation

Inflation in the U.S. has been relatively low in recent years and did not have a material impact on our results of operations for the three years in the period ended December 31, 2004. However, in 2004 an increase in the cost of steel, power and fuel has increased, directly and indirectly, our materials, supplies and maintenance costs.

New Accounting Standards

In March 2004, the Financial Accounting Standard Board (FASB) issued Emerging Issues Task Force Issue No. 03-6 (EITF 03-6), Participating Securities and the Two-Class Method under FASB Statement No. 128. EITF 03-6 addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. EITF 03-6 provides that in any accounting period where our aggregate net income exceeds the aggregate distributions for such period, we are required to present earnings per unit as if all of the earnings for the periods were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed during a particular period from an economic probability standpoint. EITF 03-6 was effective for fiscal periods beginning after March 31, 2004, prior period net income per limited partner unit amounts are restated for comparative purposes. EITF 03-6 does not impact our overall net income or other financial results, however for periods in which aggregate net income exceeds our aggregate distributions for such period, it has the impact of reducing the earnings per limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights held by our managing general partner, even though we make cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. In accounting periods (either quarterly, year-to-date or annual) where aggregate net income does not exceed our aggregate distributions for such period, EITF 03-6 does not have any impact on our earnings per unit calculation. Refer to Item 8. Financial Statements and Supplementary Data. Note 21. Restatements .

In November 2004, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 151, *Inventory Costs*. SFAS No. 151 is an amendment of Accounting Research Bulletin (ARB) No. 43, chapter 4, paragraph 5 that deals with inventory pricing. SFAS No. 151 clarifies the accounting for abnormal amounts of

idle facility expenses, freight, handling costs, and spoilage. Under previous guidance, paragraph 5 of ARB No. 43, chapter 4, items such as idle facility expense, excessive spoilage, double freight, and rehandling costs might be considered to be so abnormal, under certain circumstances, as to require treatment as current period charges. This Statement eliminates the criterion of so abnormal and requires that those items be recognized as current period charges. Also, SFAS No. 151 requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. SFAS No. 151 is effective for fiscal years beginning after June 15, 2005. We are currently analyzing the requirements of SFAS No. 151 and believe that its adoption will not have any significant impact on our financial position, results of operations or cash flows.

In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment*. SFAS No. 123R is a revision of SFAS No. 123, *Accounting for Stock Based Compensation*, and supersedes APB 25. Among other items, SFAS No. 123R eliminates the use of APB 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements.

The effective date of SFAS No. 123R is the first reporting period beginning after June 15, 2005, and we expect to adopt SFAS No. 123R effective July 1, 2005. SFAS No. 123R permits companies to adopt its requirements using either a modified prospective method, or a modified retrospective method. Under the modified prospective method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS No. 123R for all share-based payments granted after that date, and based on the requirements of SFAS No. 123 for all unvested awards granted prior to the effective date of SFAS No. 123R. Under the modified retrospective method, the requirements are the same as under the modified prospective method, but also permits entities to restate financial statements of previous periods based on proforma disclosures made in accordance with SFAS No. 123. We are currently evaluating the appropriate transition method.

As permitted by SFAS No. 123, we currently account for share based payments to employees using the APB No. 25 intrinsic method and related FASB Interpretation No. 28 based upon the current market value of our common units at the end of each period. We have recorded compensation expense of $20,320,000, $7,687,000 and $2,338,000 for the years ended December 31, 2004, 2003 and 2002, respectively. SFAS No. 123R does not permit entities to continue to use the intrinsic method, we have not yet determined which model we will use to measure the fair value of restricted unit-based compensation upon the adoption of SFAS No. 123R.

RISK FACTORS

If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected and the trading price of our common units could decline.

Risks Inherent in Our Business

A substantial or extended decline in coal prices could negatively impact our results of operations.

A material portion of our net income and cash flow is dependent on the continued ability by us or others to realize benefits from state and federal tax credits. If the benefit to us from any of these tax credits is materially reduced, it could have a material adverse effect on our operations and might impair our ability to pay the distributions on our units.

Competition within the coal industry may adversely affect our ability to sell coal, and excess production capacity in the industry could put downward pressure on coal prices.

Newly constructed power plants may be fueled by natural gas. Any change in consumption patterns by utilities, away from the use of coal, could affect our ability to sell the coal we produce.

From time to time conditions in the coal industry may make it more difficult for us to extend existing or enter into new long-term contracts. This could affect the stability and profitability of our operations.

Some of our long-term contracts contain provisions allowing for the renegotiation of prices and, in some instances, the termination of the contract or the suspension of purchases by customers.

Some of our long-term contracts require us to supply all of our customers coal needs. If these customers coal requirements decline, our revenues under these contracts will also drop.

A substantial portion of our coal has a high-sulfur content. This coal may become more difficult to sell because the Clean Air Act may impact the ability of electric utilities to burn high-sulfur coal through the regulation of emissions.

We depend on a few customers for a significant portion of our revenues, and the loss of one or more significant customers could impact our ability to sell the coal we produce.

Litigation relating to disputes with our customers may result in substantial costs, liabilities and loss of revenues.

The term of each of the agreements associated with the coal synfuel agreements is subject to early cancellation provisions customary for transactions of these types, including the unavailability of synfuel tax credits, the termination of associated coal synfuel sales contracts, and the occurrence of certain force majeure events. Therefore, the continuation of the operating revenues associated with coal synfuel cannot be assured.

Coal mining is subject to inherent risks that are beyond our control and these risks may not be fully covered under our insurance policies. These risks include fires and explosions from methane, natural disasters like floods, mining and processing equipment failures, changes or variations in geologic conditions, inability to acquire mining rights or permits, employee injuries or fatalities, and labor-related interruptions.

Although none of our employees are members of unions, our work force may not remain union-free in the future.

Any significant increase in transportation costs or disruption of the transportation of our coal may impair our ability to sell coal.

We may not be able to grow successfully through future acquisitions, and we may not be able to effectively integrate the various businesses or properties we do acquire.

Our business will be adversely affected if we are unable to replace our coal reserves.

The estimates of our reserves may prove inaccurate, and unitholders should not place undue reliance on these estimates.

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Cash distributions are not guaranteed and may fluctuate with our performance. In addition, our managing general partner s discretion in establishing cash reserves may negatively impact a unitholder s receipt of cash distributions.

Our indebtedness may limit our ability to borrow additional funds, make distributions to unitholders or capitalize on business opportunities.

Risks Inherent in an Investment in the Partnership

The president and chief executive officer of our managing general partner effectively controls us through his ownership of a majority of the equity interests in our managing general partner and affiliates.

Unitholders have limited voting rights and do not control our managing general partner.

We may issue additional common units without the approval of common unitholders, which would dilute existing unitholders interests.

The issuance of additional common units will increase the risk that we will be unable to pay the full minimum quarterly distribution on all common units.

Cost reimbursements to our general partners may be substantial and will reduce our cash available for distribution.

Our managing general partner has a limited call right that may require unitholders to sell their common units at an undesirable time or price.

Unitholders may not have limited liability under some circumstances.

Our general partners and their affiliates, which are controlled by our management, may in some instances engage in activities that compete directly with us.

Regulatory Risks

We are subject to federal, state and local regulations on health, safety, environmental and numerous other matters. These regulations increase our costs of doing business, or discourage customers from buying our coal.

We have black lung benefits and workers compensation obligations that could increase if new legislation is enacted.

The Clean Air Act affects our customers and could significantly influence their purchasing decisions. New regulations under the Clean Air Act could also reduce demand for our coal.

The passage of state and federal legislation responsive to concerns over emissions of greenhouse gases such as carbon dioxide could result in a reduced use of coal by electric power generators. Any such reduction in use could adversely affect our revenues and results of operations.

We are subject to the Clean Water Act which imposes limitations, and monitoring and reporting obligations, on our discharge of pollutants into water. Those limitations and obligations may become more stringent and result in restricted operations and increased costs.

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We are subject to the Safe Drinking Water Act, which imposes various requirements on us through coal refuse disposal under the underground injection control program or regulation of our public drinking water systems.

We are subject to reclamation, mine closure and real property restoration regulatory obligations and must accrue for the estimated cost of complying with these regulations.

We could incur significant costs under federal and state Superfund and waste management statutes.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the IRS treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce distributions to our unitholders and our ability to make payments on our debt securities.

We have not requested an IRS ruling with respect to our tax treatment.

You may be required to pay taxes on income from us even if you receive no cash distributions.

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

Common unitholders, other than individuals who are U.S. residents, may experience adverse tax consequences from owning common units.

We have registered with the IRS as a tax shelter. This may increase the risk of an IRS audit of us or a common unitholder.

We treat a purchaser of common units as having the same tax benefits as the seller. The IRS may challenge this treatment, which could adversely affect the value of common units.

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

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We have significant long-term coal supply agreements. Virtually all of the long-term coal supply agreements are subject to price adjustment provisions, which permit an increase or decrease periodically in the contract price to principally reflect changes in specified price indices or items such as taxes, royalties or actual production costs. For additional discussion of coal supply agreements, please see Item 1. Business. Coal Marketing and Sales and Item 8. Financial Statements and Supplementary Data. Note 17. Concentration of Credit Risk and Major Customers.

Almost all of our Predecessor s transactions were, and all of our transactions are, denominated in U.S. dollars, and as a result, we do not have material exposure to currency exchange-rate risks.

At the current time, we do not have any interest rate, foreign currency exchange rate or commodity price-hedging transactions outstanding.

On August 22, 2003, our intermediate partnership completed an $85 million revolving credit facility which replaces a $100 million credit facility. Borrowings under the credit facility and the previous credit facility are and were at variable rates and, as a result, we have interest rate exposure. Our earnings are not materially affected by changes in interest rates. We had no borrowings outstanding under the Credit Facility during 2004 or at December 31, 2004.

The table below provides information about our market sensitive financial instruments and constitutes a forward-looking statement. The fair values of long-term debt are estimated using discounted cash flow analyses, based upon our current incremental borrowing rates for similar types of borrowing arrangements as of December 31, 2004, and 2003. The carrying amounts and fair values of financial instruments are as follows (in thousands):

Expected Maturity Dates as of December 31, 2004	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value December 31, 2004
Senior Notes fixed rate	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 90,000	$ 180,000	$ 197,278
Weighted Average interest rate	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%		

Expected Maturity Dates as of December 31, 2003	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value December 31, 2003
Senior Notes fixed rate	$	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 108,000	$ 180,000	$ 204,604
Weighted Average interest rate		8.31%	8.31%	8.31%	8.31%	8.31%		

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of the Managing

General Partner and the Partners of

Alliance Resource Partners, L.P.:

We have audited the accompanying consolidated balance sheets of Alliance Resource Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2004 and 2003, and the related consolidated statements of income, cash flows, and Partners capital (deficit) and comprehensive income for each of the three years in the period ended December 31, 2004. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial schedule are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 15, 2005 (August 15, 2005 as to the effect of the material weakness described in Management s Report on Internal Control Over Financial Reporting (as revised), expressed an unqualified opinion on management s assessment of the effectiveness of the Partnership s internal control over financial reporting and an adverse opinion on the effectiveness of the Partnership s internal control over financial reporting.

As discussed in Note 21 to the consolidated financial statements, net income per limited partner unit and the pro forma disclosure related to common unit-based compensation for each of the three years in the period ended December 31, 2004 have been restated.

Also, as discussed in Note 2 to the consolidated financial statements, the Partnership changed its method of determining net income per limited partner unit to conform to Emerging Issues Task Force Issue No. 03-6, Participating Securities and the Two-Class Method under FASB Statement No. 128, and, retroactively, restated the 2003 and 2002 financial statements for the change.

/s/ DELOITTE & TOUCHE LLP

Tulsa, Oklahoma

March 15, 2005

(August 15, 2005 as to the

effects of the restatements

discussed in Note 21)

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 2004 AND 2003

(In thousands, except unit data)

	December 31,	
	2004	**2003**
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 31,177	$ 10,156
Trade receivables, less allowance of $0 and $763 at December 31, 2004 and 2003	56,967	36,374
Other receivables	1,637	1,931
Marketable securities	49,397	23,615
Inventories	13,839	14,527
Advance royalties	3,117	1,108
Prepaid expenses and other assets	4,345	3,432
Total current assets	160,479	91,143
PROPERTY, PLANT AND EQUIPMENT, AT COST	526,468	474,357
LESS ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION	(292,900)	(251,567)
Total property, plant and equipment	233,568	222,790
OTHER ASSETS:		
Advance royalties	11,737	12,439
Coal supply agreements, net	2,723	5,445
Other long-term assets	4,277	4,637
Total other assets	18,737	22,521
TOTAL ASSETS	$ 412,784	$ 336,454
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 30,961	$ 22,651
Due to affiliates	10,338	13,546
Accrued taxes other than income taxes	10,742	10,375
Accrued payroll and related expenses	11,730	11,095
Accrued interest	5,402	5,402
Workers compensation and pneumoconiosis benefits	7,081	5,905
Other current liabilities	12,051	5,739
Current maturities, long-term debt	18,000	
Total current liabilities	106,305	74,713

LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities	162,000	180,000
Pneumoconiosis benefits	19,833	17,131
Workers compensation	25,994	23,321
Reclamation and mine closing	32,838	21,717
Due to affiliates	7,457	3,735
Other liabilities	3,170	3,280
Total long-term liabilities	251,292	249,184
Total liabilities	357,597	323,897
COMMITMENTS AND CONTINGENCIES		
PARTNERS CAPITAL:		
Limited Partners:		
Common Unitholders 18,130,440 and 14,692,527 units outstanding, respectively	363,658	263,071
Subordinated Unitholder -0- and 3,211,266 units outstanding, respectively		58,411
General Partners deficit	(303,295)	(305,034)
Unrealized loss on marketable securities	(54)	(102)
Minimum pension liability	(5,122)	(3,789)
Total Partners capital	55,187	12,557
TOTAL LIABILITIES AND PARTNERS CAPITAL	$ 412,784	$ 336,454

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

FOR THE YEARS ENDED DECEMBER 31, 2004, 2003, AND 2002

(In thousands, except unit and per unit data)

	Year Ended December 31,		
	2004	**2003**	**2002**
SALES AND OPERATING REVENUES:			
Coal sales	$ 599,399	$ 501,596	$ 479,515
Transportation revenues	29,817	19,553	18,992
Other sales and operating revenues	24,073	21,598	20,385
Total revenues	653,289	542,747	518,892
EXPENSES:			
Operating expenses	436,471	368,835	367,567
Transportation expenses	29,817	19,553	18,992
Outside purchases	9,913	8,508	10,077
General and administrative	45,400	28,270	20,337
Depreciation, depletion and amortization	53,664	52,495	52,408
Interest expense (net of interest income and interest capitalized of $852, $545 and $1,353 for the Partnership s respective periods)	14,963	15,981	16,360
Net gain from insurance settlement	(15,217)		
Total operating expenses	575,011	493,642	485,741
INCOME FROM OPERATIONS	78,278	49,105	33,151
OTHER INCOME	984	1,374	540
INCOME BEFORE INCOME TAXES	79,262	50,479	33,691
INCOME TAX EXPENSE (BENEFIT)	2,641	2,577	(1,094)
NET INCOME	$ 76,621	$ 47,902	$ 34,785
ALLOCATION OF NET INCOME:			
PORTION APPLICABLE TO WARRIOR COAL EARNINGS (LOSS) PRIOR TO ITS ACQUISITION ON FEBRUARY 14, 2003	$	$ (666)	$ (1,504)
PORTION APPLICABLE TO PARTNERS INTEREST	76,621	48,568	36,289
NET INCOME	$ 76,621	$ 47,902	$ 34,785
GENERAL PARTNERS INTEREST IN NET INCOME (LOSS)	$ 3,324	$ 306	$ (778)

LIMITED PARTNERS INTEREST IN NET INCOME	$ 73,297	$ 47,596	$ 35,563
BASIC NET INCOME PER LIMITED PARTNER UNIT (1)	$ 3.52	$ 2.61	$ 2.29
DILUTED NET INCOME PER LIMITED PARTNER UNIT (1)	$ 3.42	$ 2.53	$ 2.22
DISTRIBUTIONS PAID PER COMMON AND SUBORDINATED UNIT	$ 2.4875	$ 2.10	$ 2.00
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING BASIC	17,940,948	17,580,734	15,405,311
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING DILUTED	18,437,168	18,162,839	15,842,708

(1) As restated, see Note 21.

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31, 2004, 2003, AND 2002

(In thousands)

	Year Ended December 31,		
	2004	**2003**	**2002**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 76,621	$ 47,902	$ 34,785
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	53,664	52,495	52,408
Reclamation and mine closings	1,622	1,341	1,365
Coal inventory adjustment to market	488	687	48
Other	255	(353)	(1,014)
Changes in operating assets and liabilities:			
Trade receivables	(20,593)	(3,459)	(222)
Other receivables	294	(1,828)	(242)
Inventories	200	(2,049)	(104)
Advance royalties	(1,307)	2,227	(311)
Accounts payable	8,678	(679)	(4,144)
Due to affiliates	14,194	9,978	14,080
Accrued taxes other than income taxes	367	2,270	1,936
Accrued payroll and related benefits	635	1,091	1,348
Accrued pneumoconiosis benefits	2,702	1,064	1,452
Workers compensation	3,849	4,002	2,568
Other	3,386	(4,377)	(2,647)
Total net adjustments	68,434	62,410	66,521
Net cash provided by operating activities	145,055	110,312	101,306
CASH FLOWS FROM INVESTING ACTIVITIES:			
Purchase of property, plant and equipment	(54,713)	(43,004)	(67,339)
Purchase of Warrior Coal		(12,661)	
Proceeds from sale of property, plant and equipment	687	913	323
Purchase of marketable securities	(49,271)	(23,091)	
Proceeds from marketable securities	23,537		10,085
Proceeds from assumption of liability	2,112		
Net cash used in investing activities	(77,648)	(77,843)	(56,931)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from common unit offering to public		53,927	
Cash contribution by General Partners	3	9	
Payments on Warrior Coal revolving credit balance		(17,000)	
Borrowings under revolving credit and working capital facilities		31,600	66,400

Payments under revolving credit and working capital facilities		(31,600)	(66,400)
Payments on long-term debt		(31,250)	(15,000)
Distributions to Partners	(46,389)	(37,027)	(31,440)
Net cash used in financing activities	(46,386)	(31,341)	(46,440)
NET CHANGE IN CASH AND CASH EQUIVALENTS	21,021	1,128	(2,065)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	10,156	9,028	11,093
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 31,177	$ 10,156	$ 9,028
SUPPLEMENTAL CASH FLOW INFORMATION:			
CASH PAID FOR:			
Cash paid for interest	$ 15,229	$ 15,960	$ 17,294
Cash paid to taxing authorities	$ 2,150	$ 2,681	$
NON-CASH ACTIVITY:			
Market value of common units issued to Long-Term Incentive Plan participants upon vesting	$ 13,680	$	$

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL (DEFICIT) AND COMPREHENSIVE INCOME

FOR THE YEARS ENDED DECEMBER 31, 2004, 2003, AND 2002

(In thousands, except unit data)

	Number of Limited Partner Units		Limited Partners Capital		General Partners Capital (Deficit)	Unrealized Gain (Loss)	Minimum Pension Liability	Total Partners Capital (Deficit)
	Common	Subordinated	Common	Subordinated				
Balance at January 1, 2002	8,982,780	6,422,531	$ 141,448	$ 110,935	$ (289,065)	$ (74)	$ (814)	$ (37,570)
Comprehensive income:								
Net income (loss)			20,737	14,826	(778)			34,785
Unrealized loss						(76)		(76)
Minimum pension liability							(4,461)	(4,461)
Total comprehensive income			20,737	14,826	(778)	(76)	(4,461)	30,248
Distribution to Partners			(17,966)	(12,845)	(629)			(31,440)
Balance at December 31, 2002	8,982,780	6,422,531	144,219	112,916	(290,472)	(150)	(5,275)	(38,762)
Comprehensive income:								
Net income			31,346	16,250	306			47,902
Unrealized gain						48		48
Minimum pension liability							1,486	1,486
Total comprehensive income			31,346	16,250	306	48	1,486	49,436
Issuance of units to public	2,538,000		53,927					53,927
General Partners contribution					9			9
Retirement of common units contributed by Managing General Partner	(39,518)		(890)		890			
Subordinated units conversion to common units	3,211,265	(3,211,265)	57,268	(57,268)				
Warrior Coal purchase					(15,026)			(15,026)
Distribution to Partners			(22,799)	(13,487)	(741)			(37,027)
Balance at December 31, 2003	14,692,527	3,211,266	263,071	58,411	(305,034)	(102)	(3,789)	12,557
Comprehensive income:								
Net income			60,685	12,612	3,324			76,621
Unrealized gain						48		48
Minimum pension liability							(1,333)	(1,333)
Total comprehensive income			60,685	12,612	3,324	48	(1,333)	75,336
Issuance of units to Long-Term Incentive Plan participants upon	231,126		13,680					13,680

vesting								
General Partners contribution					3			3
Retirement of common units contributed by Managing General Partner	(4,479)		(265)		265			
Distribution to Partners			(36,548)	(7,988)	(1,853)			(46,389)
Subordinated units conversion to common units	3,211,266	(3,211,266)	63,035	(63,035)				
Balance at December 31, 2004	18,130,440		$ 363,658	$	$ (303,295)	$ (54)	$ (5,122)	$ 55,187

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2004, 2003, AND 2002

1. ORGANIZATION AND PRESENTATION

Alliance Resource Partners, L.P., a Delaware limited partnership (the Partnership) was formed in May 1999, to acquire, own and operate certain coal production and marketing assets of Alliance Resource Holdings, Inc., a Delaware corporation (ARH) (formerly known as Alliance Coal Corporation), consisting of substantially all of ARH s operating subsidiaries, but excluding ARH.

The Delaware limited partnerships, limited liability companies and corporation that comprise the Partnership s subsidiaries are as follows: Alliance Resource Partners, L.P., Alliance Resource Operating Partners, L.P. (the Intermediate Partnership), Alliance Coal, LLC (the holding company for operations), Alliance Land, LLC, Alliance Properties, LLC, Alliance Service, Inc., Backbone Mountain, LLC, Excel Mining, LLC, Gibson County Coal, LLC, Hopkins County Coal, LLC, MC Mining, LLC, Mettiki Coal, LLC, Mettiki Coal (WV), LLC, Mt. Vernon Transfer Terminal, LLC, Pontiki Coal, LLC, Warrior Coal, LLC, Webster County Coal, LLC, and White County Coal, LLC.

The Partnership completed its initial public offering (the IPO) in August 1999, issuing 7,750,000 Common Units (Common Units) at $19.00 per unit and received net proceeds of $133.7 million. Concurrently with the offering ARH contributed certain assets to the Partnership in exchange for cash, 0.01% general partner interest in each of the Partnership and the Intermediate Partnership, the right to receive incentive distributions as defined in the partnership agreement and the assumption of related indebtedness and 1,232,780 Common Units and 6,422,531 Subordinated Units, that converted into Common Units during November 2004 and 2003 (Note 9), held by Alliance Resource GP, LLC, a Delaware limited liability company and wholly-owned subsidiary of ARH (the Special GP). On February 14, 2003 and March 14, 2003, the Partnership issued 2,250,000 and 288,000 additional Common Units at a public offering price of $22.51 per unit and received net proceeds of $48.5 million and $6.2 million, respectively, before expenses of approximately $0.8 million, excluding underwriters fees. In November 2003, 3,211,265 outstanding Subordinated Units were converted to Common Units in accordance with the partnership agreement. In November 2004, the remaining 3,211,266 subordinated units converted to Common Units and the Partnership issued 231,126 additional Common Units pursuant to the Long-Term Incentive Plan (Note 13). If at any time not more than twenty percent of the then-issued and outstanding limited partner interests are held by persons other than the general partners and their affiliates, the managing general partner will have the right to acquire all, but not less than all, of the remaining limited partner interest held by unaffiliated persons.

On February 14, 2003, the Partnership acquired Warrior Coal, LLC (Warrior Coal) (Note 3). Because the Warrior Coal acquisition was between entities under common control, the acquisition was recorded at historical cost in a manner similar to that used in a pooling of interests. Accordingly, the consolidated financial statements and accompanying notes of the Partnership as of December 31, 2002 and for the year ended December 31, 2002 have been restated to reflect the combined historical results of operations, financial position and cash flows of the Partnership and Warrior Coal. ARH Warrior Holdings, Inc. (ARH Warrior Holdings), a subsidiary of ARH, acquired Warrior Coal on January 26, 2001.

The Partnership is managed by Alliance Resource Management GP, LLC, a Delaware limited liability company (the Managing GP), which holds a 0.99% and 1.0001% managing general partner interest in the Partnership and the Intermediate Partnership, respectively.

The accompanying consolidated financial statements include the accounts and operations of the limited partnerships, limited liability companies and corporation disclosed above and present the financial position as of December 31, 2004 and 2003 and the results of their operations, cash flows and changes in partners capital (deficit) and comprehensive income for each of the three years in the period ended December 31, 2004. All material intercompany transactions and accounts of the Partnership have been eliminated.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Estimates The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts and disclosures in the consolidated financial statements. Actual results could differ from those estimates.

Fair Value of Financial Instruments The carrying amounts for accounts receivable, marketable securities, and accounts payable approximate fair value because of the short maturity of those instruments. At December 31, 2004 and 2003, the estimated fair value of long-term debt was approximately $197.3 million and $204.6 million, respectively. The fair value of long-term debt is based on interest rates that management believes are currently available to the Partnership for issuance of debt with similar terms and remaining maturities.

Cash and Cash Equivalents Cash and cash equivalents include cash on hand and on deposit, including highly liquid investments with maturities of three months or less.

Cash Management The Partnership has presented bank overdrafts of $2,192,000 and $1,257,000 at December 31, 2004 and 2003, respectively, in accounts payable in the consolidated balance sheets.

Marketable Securities The Partnership currently classifies all marketable securities as available-for-sale securities. At December 31, 2004 and 2003, the cost of marketable securities are reported at fair value with unrealized gains and losses reported as a component of Partners capital until realized. The Partnership has restricted investments of $1,816,000 and $1,809,000 at December 31, 2004 and 2003, respectively, which are included in other assets in the consolidated balance sheets. The restricted marketable securities are held in escrow and secure reclamation bonds (Note 5).

Inventories Coal inventories are stated at the lower of cost or market on a first-in, first-out basis. Supply inventories are stated at the lower of cost or market on an average cost basis.

Property, Plant and Equipment Additions and replacements constituting improvements are capitalized. Maintenance, repairs, and minor replacements are expensed as incurred. Depreciation and amortization are computed principally on the straight-line method based upon the estimated useful lives of the assets or the estimated life of each mine, whichever is less ranging from 2 to 13 years. Depreciable lives for mining equipment and processing facilities range from 2 to 13 years. Depreciable lives for land and land improvements and depletable lives for mineral rights range from 5 to 13 years. Depreciable lives for buildings, office equipment and improvements range from 2 to 13 years. Gains or losses arising from retirements are included in current operations. Depletion of mineral rights is provided on the basis of tonnage mined in relation to estimated recoverable tonnage. At December 31, 2004 and 2003, land and mineral rights include $2,030,000 and $2,178,000, respectively, representing

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the carrying value of coal reserves attributable to properties where the Partnership is not currently engaged in mining operations or leasing to third parties, and therefore, the coal reserves are not currently being depleted. Management believes that the carrying value of these reserves will be recovered.

Mine Development Costs Mine development costs are capitalized and amortized over the estimated life of the mine.

Long-Lived Assets The Partnership reviews the carrying value of long-lived assets and certain identifiable intangibles whenever events or changes in circumstances indicate that the carrying amount may not be recoverable based upon estimated undiscounted future cash flows. The amount of an impairment is measured by the difference between the carrying value and the fair value of the asset.

In June 2003, the Partnership idled the active surface mine at its Hopkins County Coal mining complex in response to soft market demand. In October 2004, the surface mine was re-opened in response to incremental sales opportunities from existing customers as well as strong market demand for Illinois Basin region coal. While the Hopkins County Coal mining complex was idled the Partnership evaluated the recoverability of the appropriate asset group and concluded that there was no impairment loss.

Advance Royalties Rights to coal mineral leases are often acquired and/or maintained through advance royalty payments. Management assesses the recoverability of royalty prepayments based on estimated future production and capitalizes these amounts accordingly. Royalty prepayments expected to be recouped within one year are classified as a current asset. As mining occurs on those leases, the royalty prepayments are included in the cost of mined coal. Royalty prepayments estimated to be nonrecoverable are expensed.

In March 2004, the Financial Accounting Standards Board (FASB) issued Emerging Issues Task Force Issue No. 04-2, *Whether Mineral Rights Are Tangible or Intangible Assets*. In this Issue, the Task Force reached the consensus that mineral rights are tangible assets and amended Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Other Intangible Assets,* which previously classified mineral rights as intangible assets. Consistent with other extractive industry entities, the Partnership has historically included its related assets as tangible, therefore there was no material effect on the Partnership s consolidated financial statements upon adoption.

Coal Supply Agreements A portion of the acquisition costs from a business combination in 1996 was allocated to coal supply agreements. This allocated cost is being amortized on the basis of coal shipped in relation to total coal to be supplied during the respective contract terms. The amortization periods end on various dates from September 2002 to December 2005. Accumulated amortization for coal supply agreements was $35,740,000 and $33,018,000 at December 31, 2004 and 2003, respectively. The aggregate amortization expense recognized for coal supply agreements was $2,722,000, $2,722,000 and $3,864,000 for the years ended December 31, 2004, 2003 and 2002, respectively. The estimated aggregate amortization expense for 2005 is approximately $2,723,000.

Reclamation and Mine Closing Costs The liability for the estimated cost of future mine reclamation and closing procedures is recorded on a present value basis when incurred and the associated cost is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to sealing portals at underground mines and to reclaiming the final pits and support acreage at surface mines. Other costs common to both types of mining are related to removing or covering refuse piles and settling ponds, and dismantling preparation plants, other facilities and roadway infrastructure.

Workers Compensation and Pneumoconiosis (Black Lung) Benefits The Partnership is self-insured for workers compensation benefits, including black lung benefits. The Partnership accrues a workers compensation liability for the estimated present value of workers compensation and black lung benefits based on actuarial valuations.

Income Taxes The Partnership is not a taxable entity for federal or state income tax purposes; the tax effect of its activities accrues to the unitholders. Although publicly traded partnerships will, as a general rule, be taxed as corporations, the Partnership qualifies for an exemption because at least 90% of its income consists of qualifying income. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the Partnership agreement. The Partnership s subsidiary, Alliance Service, Inc. (Alliance Service), is subject to federal and state income taxes. Prior to the Partnership s acquisition of Warrior Coal, the financial results of Warrior Coal were subject to federal and state income taxes. The federal and state income taxes associated with Warrior Coal s financial results from January 26, 2001, the date of ARH Warrior Holdings acquisition of Warrior Coal, to February 14, 2003, the date of the Partnership s acquisition of Warrior Coal, are included in income taxes. The Partnership s tax counsel has provided an opinion that the Partnership, the Intermediate Partnership and the holding company will each be treated as a partnership. However, as is customary, no ruling has been or will be requested from the IRS regarding the Partnership s classification as a partnership for federal income tax purposes.

Revenue Recognition Revenues from coal sales are recognized when title passes to the customer as the coal is shipped. Some coal supply agreements provide for price adjustments based on variations in quality characteristics of the coal shipped. In certain cases, a customer s analysis of the coal quality is binding and the results of the analysis are received on a delayed basis. In these cases, the Partnership estimates the amount of the quality adjustment and adjusts the estimate to actual when the information is provided by the customer. Historically such adjustments have not been material. Non-coal sales revenues primarily consist of rental and service fees associated with agreements to host and operate a third-party coal synfuel facility and to assist with the coal synfuel marketing and other related services. These non-coal sales revenues are recognized as the services are performed. Transportation revenues are recognized in connection with the Partnership incurring the corresponding costs of transporting the coal to customers through third-party carriers since the Partnership is directly reimbursed for these costs through customer billings.

Common Unit-Based Compensation The Partnership accounts for the compensation expense of the non-vested restricted common units granted under the Long-Term Incentive Plan (LTIP) (Note 12) using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25) and the related Financial Accounting Standards Board Interpretation No. 28, *Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans* (FASB Interpretation No. 28). Compensation cost for the restricted common units is recorded on a pro-rata basis, as appropriate given the cliff vesting nature of the grants, based upon the current market value of the Partnership s common units at the end of each period.

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Consistent with the disclosure requirements of SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*, and amendment of SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS No. 123.   ), the following table demonstrates that compensation cost for the non vested restricted units granted under the LTIP is the same under the intrinsic value method and the provisions of SFAS No. 123 (in thousands, except per unit data):

	Year Ended December 31,		
	2004	**2003**	**2002**
Net income, as reported	$ 76,621	$ 47,902	$ 34,785
Add: compensation expenses related to Long-Term Incentive Plan units included in reported net income	20,320	7,687	2,338
Deduct: compensation expense related to Long-Term Incentive Plan units determined under fair value method for all awards	(20,320)	(7,687)	(2,338)
Net income, pro forma	76,621	47,902	34,785
General partners interest in net income (loss), pro forma	3,324	306	(778)
Limited partners interest in net income, pro forma	$ 73,297	$ 47,596	$ 35,563
Earnings per limited partner unit:			
Basic, as reported	$ 3.52	$ 2.61	$ 2.29
Basic, pro forma	$ 3.52	$ 2.61	$ 2.29
Diluted, as reported	$ 3.42	$ 2.53	$ 2.22
Diluted, pro forma	$ 3.42	$ 2.53	$ 2.22

Earnings per limited partner unit and diluted as reported and basic and diluted, pro forma for each of the three years in the period ended December 31, 2004. Refer to Note 21 to the consolidated financial statements for further discussion of this matter.

The total accrued liability associated with the Long-Term Incentive Plan as of December 31, 2004 and 2003 was $10,013,000 and $12,493,000, respectively, and is included in the current and long-term due to affiliates liabilities in the consolidated balance sheets. See New Accounting Standards discussion below concerning the impact of SFAS No. 123R, *Share-Based Payment*, on accounting for the Long-Term Incentive Plan.

Net Income Per Unit Basic net income per limited partner unit is determined by dividing Limited Partners   interest in net income (Note 11), by the weighted average number of outstanding Common Units and Subordinated Units. In periods when the Partnership   s aggregate net income exceeds the aggregate distributions, EITF 03-6 requires the Partnership to present earnings per unit as if all of the earnings for the periods were distributed (Refer to Notes 11 and 19). Warrior Coal   s earnings (loss) prior to the Partnership   s acquisition on February 14, 2003 was allocated entirely to the general partner. Diluted net income per unit is based on the combined weighted average number of Common Units, Subordinated Units and common unit equivalents outstanding, which primarily include restricted units granted under the Long-Term Incentive Plan (Note 13).

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Segment Reporting The Partnership has no reportable segments due to its operations consisting solely of producing and marketing coal and providing rental and service fees associated with producing and marketing coal synfuel, which meets the aggregation criteria of SFAS No. 131, *Disclosures About Segments of an Enterprise and Related Information*. The Partnership has disclosed major customer sales information (Note 18). The Partnership s geographic areas of operation are concentrated in the United States.

New Accounting Standards In March 2004, the FASB issued Emerging Issues Task Force Issue No. 03-6 (EITF 03-6), Participating Securities and the Two-Class Method under FASB Statement No. 128 . EITF 03-6 addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. EITF 03-6 provides that in any accounting period where the Partnership s aggregate net income exceeds the aggregate distributions for such period, the Partnership is required to present earnings per unit as if all of the earnings for the periods were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed during a particular period from an economic probability standpoint. EITF 03-6 was effective for fiscal periods beginning after March 31, 2004, prior period net income per limited partner unit amounts are restated for comparative purposes. EITF 03-6 does not impact the Partnership s overall net income or other financial results, however for periods in which aggregate net income exceeds the Partnership s aggregate distributions for such period, it has the impact of reducing the earnings per limited partner unit. This result occurs as a larger portion of the Partnership s aggregate earnings, as if distributed, is allocated to the incentive distribution rights held by the Managing GP, even though the Partnership makes cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. In accounting periods (either quarterly, year-to-date or annual) where aggregate net income does not exceed our aggregate distributions for such period, EITF 03-6 does not have any impact on the Partnership s earnings per unit calculation. See Note 21.

In November 2004, the FASB issued SFAS No. 151, *Inventory Costs*. SFAS No. 151 is an amendment of Accounting Research Bulletin (ARB) No. 43, chapter 4, paragraph 5 that deals with inventory pricing. SFAS No. 151 clarifies the accounting for abnormal amounts of idle facility expenses, freight, handling costs, and spoilage. Under previous guidance, paragraph 5 of ARB No. 43, chapter 4, items such as idle facility expense, excessive spoilage, double freight, and rehandling costs might be considered to be so abnormal, under certain circumstances, as to require treatment as current period charges. This Statement eliminates the criterion of so abnormal and requires that those items be recognized as current period charges. Also, SFAS No. 151 requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. SFAS No. 151 is effective for fiscal years beginning after June 15, 2005. The Partnership is analyzing the requirements of SFAS No. 151 and believes that its adoption will not have any significant impact on the Partnership s financial position, results of operations or cash flows.

In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment*. SFAS No. 123R is a revision of SFAS No. 123, *Accounting for Stock Based Compensation*, and supersedes APB 25. Among other items, SFAS No. 123R eliminates the use of APB 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements.

The effective date of SFAS No. 123R is the first reporting period beginning after June 15, 2005, and the Partnership expects to adopt SFAS No. 123R effective July 1, 2005. SFAS No. 123R permits companies to adopt its requirements using either a modified prospective method, or a modified retrospective method. Under the modified prospective method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS No. 123R for all share-based payments granted after that date, and based on the requirements of SFAS No. 123 for all unvested awards granted prior to the effective date of SFAS No. 123R. Under the modified retrospective method, the requirements are the same as under the modified prospective method, but also permits entities to restate financial statements of previous periods based on proforma disclosures made in accordance with SFAS No. 123. The Partnership is currently evaluating the appropriate transition method.

As permitted by SFAS No. 123, the Partnership currently accounts for share based payments to employees using the APB No. 25 intrinsic method and related FASB Interpretation No. 28 based upon the current market value of the Partnership s common units at the end of each period. The Partnership has recorded compensation expense of $20,320,000, $7,687,000 and $2,338,000 for the years ended December 31, 2004, 2003 and 2002, respectively. The Partnership has not yet determined which model it will use to measure the fair value of restricted unit-based compensation upon the adoption of SFAS No. 123R.

Reclassifications Certain reclassifications have been made to the 2003 balance sheet presentation of receivables, pneumoconiosis benefits and workers compensation long-term liabilities to conform to the 2004 classifications.

3. ACQUISITIONS

Warrior Coal

On February 14, 2003, Warrior Coal was acquired from an affiliate, ARH Warrior Holdings, a subsidiary of ARH, pursuant to an Amended and Restated Put and Call Option Agreement (Put/Call Agreement). Warrior Coal purchased the capital stock of Roberts Bros. Coal Co., Inc., Warrior Coal Mining Company, Warrior Coal Corporation and certain assets of Christian Coal Corp. and Richland Mining Co., Inc. in January 2001. The Managing GP originally declined the opportunity to purchase these assets as the Partnership had previously committed to major capital expenditures at two existing operations. As a condition to not exercising its right of first refusal, the Partnership requested that ARH Warrior Holdings enter into a put and call arrangement for Warrior Coal. ARH Warrior Holdings and the Partnership, with the approval of the Conflicts Committee of the Managing GP, entered into the Put/Call Agreement in January 2001. Concurrently, ARH Warrior Holdings acquired Warrior Coal in January 2001 for $10.0 million.

The Put/Call Agreement preserved the opportunity for the Partnership to acquire Warrior Coal during a specified time period. Under the terms of the Put/Call Agreement, ARH Warrior Holdings exercised its put option requiring the Partnership to purchase Warrior Coal at a put option price of approximately $12.7 million.

The option provisions of the Put/Call Agreement were subject to certain conditions (unless otherwise waived), including, among others, (a) the non-occurrence of a material adverse change in the business and financial condition of Warrior Coal, (b) the prohibition of any dividends or other distributions to Warrior Coal s shareholders, (c) the maintenance of Warrior Coal s assets in good working condition, (d) the prohibition on the sale of any equity interest in Warrior Coal except for the options contained in the Put/Call Agreement, and (e) the prohibition on the sale or transfer of Warrior Coal s assets except those made in the ordinary course of its business.

The Put/Call Agreement option prices reflected negotiated sale and purchase amounts that both parties determined would allow each party to satisfy acceptable minimum investment returns in the event either the put or call options were exercised. In January 2001 and in December 2002, the Partnership

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developed financial projections for Warrior Coal based on due diligence procedures it customarily performs when considering the acquisition of a coal mine. The assumptions underlying the financial projections made by the Partnership for Warrior Coal included, among others, (a) annual production levels ranging from 1.5 million to 1.8 million tons, (b) coal prices at or below the then current coal prices and (c) a discount rate of 12 percent. Based on these financial projections, as of the date of the acquisition and at December 31, 2002 and 2001, the Partnership believed that the fair value of Warrior Coal was equal to or greater than the put option exercise price.

The put option price of $12.7 million was paid to ARH Warrior Holdings in accordance with the terms of the Put/Call Agreement. In addition, the Partnership repaid Warrior Coal s borrowings of $17.0 million under the revolving credit agreement between the Special GP and Warrior Coal. The primary borrowings under the revolving credit agreement financed new infrastructure capital projects at Warrior Coal that have contributed to improved productivity and significantly increased capacity. The Partnership funded the Warrior Coal acquisition through a portion of the proceeds received from the issuance of 2,250,000 Common Units (Note 1). Because the Warrior Coal acquisition was between entities under common control, it has been accounted for at historical cost in a manner similar to that used in a pooling of interests.

Under the terms of the Put/Call Agreement, the Partnership assumed certain other obligations, including a mineral lease and sublease with SGP Land, LLC (SGP Land), a subsidiary of the Special GP, covering coal reserves that have been and will continue to be mined by Warrior Coal. The terms and conditions of the mineral lease and sub-lease remained unchanged (Note 16).

Lodestar

On July 15, 2003, Hopkins County Coal, LLC (Hopkins County Coal) executed an Asset Purchase Agreement with Lodestar Energy, Inc. (Lodestar), a coal company operating in Chapter 7 bankruptcy proceedings. Concurrently, Hopkins County Coal entered into various other agreements (collectively, the Asset Purchase Agreement and the various other agreements are referred to as the Lodestar Agreements) with several parties, including the Kentucky Environmental and Public Protection Cabinet (Cabinet) and Frontier Insurance Company (Frontier). Closing of the Lodestar Agreements was subject to the resolution of numerous contingencies and/or conditions. Under the terms of the relevant Lodestar Agreements, Hopkins County Coal principally acquired a mining pit, created by Lodestar s mining activities. The mining pit will be used for refuse disposal by the Partnership s Webster County Coal, LLC s Dotiki mine. The purchase price included a nominal monetary amount and the assumption of remedial reclamation activities under the various mining permits acquired by Hopkins County Coal from Lodestar. The Cabinet accepted these remedial activities in lieu of certain solid waste closure requirements applicable to residual landfills. Hopkins County Coal also received $2.1 million from Frontier in exchange for the assumption of the remedial activities associated with the mining pit. As a result of closing the Lodestar Agreements on June 2, 2004, Hopkins County Coal recorded the fair value of the asset retirement obligation of approximately $4.1 million with a corresponding asset that was reduced by the $2.1 million of cash received.

Elk Creek Tunnel Ridge

On October 21, 2004, the Partnership announced an agreement, subject to finalization of definitive agreements, to enter into two separate coal leases, the Elk Creek reserves (Elk Creek), which are located in Hopkins County, Kentucky, and the Tunnel Ridge reserves (Tunnel Ridge), which are located in Ohio County, West Virginia and Washington County, Pennsylvania. These leases are estimated to contain approximately 100 million tons of high-sulfur coal reserves. The lessor for both leases is the Special GP. The Partnership also announced plans to immediately begin the development process for these properties, which includes obtaining the necessary mining permits and securing sufficient coal sales commitments to justify the capital investment needed to bring these properties into production.

The Elk Creek reserve area encompasses approximately 9,000 acres and is contiguous to the Partnership s Hopkins County Coal complex. The Elk Creek coal reserves are currently estimated to include approximately 30 million tons of high-sulfur coal. The Elk Creek mine will be an underground mining complex, mining the West Kentucky No. 9 and No. 11 coal seams. It will utilize continuous mining units and employ room-and-pillar mining techniques. The mine intends to use the existing coal handling and other surface facilities owned by Hopkins County Coal. The Partnership anticipates that the Elk Creek complex will employ as many as 250 individuals and produce up to 3.2 million tons of coal annually. The Partnership is estimating total capital expenditures to develop Elk Creek to be approximately $65.0 million. Coal supply commitments are currently being pursued. Construction of the Elk Creek mining complex began in the first quarter of 2005. The Partnership expects to fund these capital expenditures with available cash and marketable securities on hand, future cash generated from operations and/or borrowings available under the revolving credit facility.

In December 2000, Hopkins County Coal entered into an option agreement to lease and/or sublease the Elk Creek reserves from the Partnership s Special GP. Under the terms of the option to lease and sublease, Hopkins County Coal paid an option fee of $645,000 during the year ended December 31, 2000, and paid option fees of $684,000 during each of the years ended December 31, 2001, 2002 and 2004. The 2003 option fee of $684,000 was paid in January 2004. Upon exercise of the option to lease or sublease, Hopkins County Coal is obligated to make an additional five annual advance minimum royalty payments of $684,000 per year, which royalty is fully recoupable against earned royalties. The earned royalty rate under the lease and/or sublease is $0.25 per ton.

In January 2005, the Partnership acquired 100% of the limited liability company member interests of Tunnel Ridge, LLC for approximately $500,000 and the assumption of reclamation liabilities from Alliance Resource Holdings, Inc., a company owned by management of the Partnership. Tunnel Ridge, LLC controls through a coal lease agreement with the Special GP an estimated 70 million tons of high-sulfur coal in the Pittsburgh No. 8 coal seam. The Tunnel Ridge reserve area encompasses approximately 50,571 acres of land located in Ohio County, West Virginia and Washington County, Pennsylvania. Under the terms of the coal lease, beginning on January 1, 2005, Tunnel Ridge, LLC shall pay the Special GP an advance minimum royalty of $3.0 million per year. The advance royalty payments will be fully recoupable against earned royalties. The earned royalty rate under the coal lease is the greater of $0.75 per ton or 3.0% of the per ton gross sales price f.o.b. barge. The term of the coal lease is the earlier of 30 years or until exhaustion of all mineable and merchantable coal. The Partnership has termination rights after the initial four years of the coal lease.

Tunnel Ridge, LLC also controls, under a separate lease agreement with the Special GP, the rights to approximately 900 acres of surface land and other tangible assets. Under the terms of the lease agreement, Tunnel Ridge, LLC shall pay to the Special GP an annual lease payment of $240,000 beginning January 1, 2005. The lease agreement has an initial term of four years, which may be extended by Tunnel Ridge, LLC, at the same annual lease payment rate, to be consistent with the term of the coal lease.

The Elk Creek and Tunnel Ridge transactions described above are related-party transactions and, as such, were reviewed by the Board of Directors of the Partnership s Managing GP and Conflicts Committee. Based upon these reviews, the Conflicts Committee determined that these transactions reflect market-clearing terms and conditions customary in the coal industry. As a result, the Board of Directors of the Partnership s Managing GP and its Conflicts Committee approved the Elk Creek and Tunnel Ridge transactions as fair and reasonable to the Partnership and its limited partners.

4. MINE FIRE INCIDENTS

Dotiki Mine Fire

On February 11, 2004, Webster County Coal, LLC s (Webster County Coal) Dotiki mine was temporarily idled for a period of twenty-seven calendar days following the occurrence of a mine fire that originated with a diesel supply tractor (the Dotiki Fire Incident). As a result of the firefighting efforts of the Mine Safety and Health Administration, Kentucky Department of Mines and Minerals, and Webster County Coal personnel, Dotiki successfully extinguished the fire and totally isolated the affected area of the mine behind permanent barriers. Initial production resumed on March 8, 2004. For the Dotiki Fire Incident, the Partnership had commercial property insurance that provided coverage for damage to property destroyed, interruption of business operations, including profit recovery, and expenditures incurred to minimize the period and total cost of disruption to operations.

On September 10, 2004, the Partnership filed a third and final proof of loss with the applicable insurance underwriters reflecting a settlement (the Dotiki Settlement) of all expenses, losses and claims incurred by Webster County Coal and other affiliates arising from or in connection with the Dotiki Fire Incident (the Dotiki Insurance Claim) in the aggregate amount of $27.0 million, inclusive of a $1.0 million self-retention, a $2.5 million deductible (collectively, the Dotiki Insurance Deductibles) and 10% co-insurance (the 2004 Co-Insurance). The 2004 Insurance Deductibles and 2004 Co-Insurance were allocated on a pro-rata basis to each of the three areas of insurance recoveries discussed below. In addition, the accounting for two net partial advance payments in the aggregate amount of $8.1 million and the final net payment of $13.05 million, exclusive of the 2004 Insurance Deductible and 2004 Co-Insurance, were subject to the accounting methodology described below. Specifically, the Partnership evaluated and accounted for the insurance recoveries in the following areas:

1. Expenses incurred as a result of the fire The Partnership incurred extra expenses, expediting expenses, and other costs associated with extinguishing the fire in an aggregate amount of approximately $7.1 million. With application of $5.6 million of the insurance recovery proceeds, the Partnership recorded net expenses of approximately $1.5 million.

2. Damage to Dotiki mine property The Partnership incurred damage to Dotiki s mine property (exclusive of any amounts relating to matters discussed in 1. above) of approximately $1.2 million, which property had a net book value of $138,000. Based on discussions with the underwriters culminating in the Dotiki Settlement, the Partnership recorded a net gain of approximately $785,000, reflecting the amount that the allocated insurance proceeds exceeded the net book value of the damaged property.

3. Dotiki mine business interruption costs and extra expense Based on the negotiations with the underwriters leading to the Dotiki Settlement, the Partnership recorded a net gain of approximately $14.4 million for the recovery of business interruption costs and extra expenses stemming from the Dotiki Fire Incident. This net gain amount reflects an offset of approximately $200,000 for professional services expenses incurred in resolving the business interruption portion of the Dotiki Settlement.

Pursuant to the accounting methodology described above, the Partnership recorded (a) an offset to operating expenses of approximately $5.9 million and (b) a combined net gain of approximately $15.2 million for damage to property destroyed, interruption of business operations (including profit recovery), and extra expenses incurred to minimize the period and total cost of disruption to operations associated with the Dotiki Fire Incident.

MC Mining Mine Fire

On December 26, 2004, MC Mining, LLC s (MC Mining) Excel No. 3 mine was temporarily idled following the occurrence of a mine fire (the MC Mining Fire Incident). The fire was discovered by mine personnel near the bottom of the Excel No. 3 mine slope late in the evening of December 25, 2004.

Under a firefighting plan developed by MC Mining, in cooperation with mine emergency response teams from the Mine Safety and Health Administration and Kentucky Office of Mine Safety and Licensing, the four portals at the Excel No. 3 mine were capped to deprive the fire of oxygen. A series of boreholes were then drilled into the fire area to further suppress the fire. As a result of these efforts, the mine atmosphere was rendered substantially inert, or without oxygen, and the Excel No. 3 mine fire was effectively suppressed. MC Mining then began construction of temporary and permanent barriers designed to completely isolate the mine fire area. When construction of the permanent barriers was completed, MC Mining began efforts to repair and rehabilitate the Excel No. 3 mine infrastructure. On February 21, 2005, the repair and rehabilitation efforts had progressed sufficiently to allow initial resumption of production. The Partnership anticipates that MC Mining may return to full production by the end of the first quarter of 2005, but there is no assurance that MC Mining s ability to produce will not continue to be adversely impacted by the MC Mining Fire Incident for a period of time. The boreholes continue to be used to monitor the mine atmosphere and to inject nitrogen into the area of the fire now isolated behind the permanent barriers.

The Partnership maintains commercial property (including business interruption) insurance policies, which are renewed annually in September and provide for self-retention and various applicable deductibles, including certain monetary and/or time element forms of deductibles, (collectively the 2005 Deductibles) and 10% co-insurance (2005 Co-Insurance), however, the Partnership cannot give any assurances as to the eventual timing or amount of any recovery of proceeds under these policies. The Partnership has made an initial estimate of certain costs primarily associated with activities relating to the suppression of the fire and the resumption of operations. Operating expenses for the 2004 fourth quarter increased by $4.1 million reflecting an initial estimate of certain minimum costs attributable to the MC Mining Fire Incident that are not reimbursable under the Partnership s insurance policies due to the application of the 2005 Deductibles and 2005 Co-Insurance. An increase in the amount of such costs is possible, but is not currently subject to a reasonable estimate at this time. In addition to these initial cost estimates, the Partnership expects to incur additional out-of-pocket costs that will generally fall into the categories of extra expenses, expediting expenses and other areas of coverage under the commercial insurance policies. These future out-of-pocket costs, which are not currently subject to reasonable estimation, will be expensed as incurred. The related estimated insurance recovery of these costs will be recorded, net of the 2005 Deductibles and 2005 Co-Insurance, as the Partnership determines that such recoveries are probable. Any recovery under the insurance policies of business interruption proceeds attributable to amounts in excess of actual costs incurred will be recorded as gains when the claims are settled with the insurance underwriters.

5. MARKETABLE SECURITIES

Marketable securities include or have historically included Federal home loan discount notes, bankers acceptances, certificates of deposits and equity securities. At December 31, 2004 and 2003, the cost of the bankers acceptances and certificates of deposit approximated fair value and no effect of unrealized gains (losses) is reflected in Partners capital. The Federal home loan discount notes and equity securities had a cumulative unrealized loss reflected in Partners capital of $54,000 and $102,000 at December 31, 2004 and 2003, respectively.

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Marketable securities consist of the following at December 31, (in thousands):

	2004	2003
Federal home loan discount notes	$ 39,414	$
Bankers acceptances	9,983	
Certificates of deposit		23,091
Equity securities		524
Total unrestricted marketable securities	$ 49,397	$ 23,615
Restricted cash and cash equivalents	$ 1,816	$ 1,809
Total restricted marketable securities (included in other long-term assets)	$ 1,816	$ 1,809

6. INVENTORIES

Inventories consist of the following at December 31, (in thousands):

	2004	2003
Coal	$ 4,822	$ 6,186
Supplies	9,017	8,341
	$ 13,839	$ 14,527

7. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consists of the following at December 31, (in thousands):

	2004	2003
Mining equipment and processing facilities	$ 448,571	$ 411,070
Land and mineral rights	22,281	20,705
Buildings, office equipment and improvements	46,281	36,786
Construction in progress	9,335	5,796
	526,468	474,357
Less accumulated depreciation, depletion and amortization	(292,900)	(251,567)

	$ 233,568	$ 222,790

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8. LONG-TERM DEBT

Long-term debt consists of the following at December 31, (in thousands):

	2004	2003
Senior notes	$ 180,000	$ 180,000
Less current maturities	(18,000)	
	$ 162,000	$ 180,000

The Intermediate Partnership has $180 million principal amount of 8.31% senior notes due August 20, 2014, payable in ten equal annual installments of $18 million beginning in August 2005 with interest payable semiannually. On August 22, 2003, the Intermediate Partnership completed a $85 million revolving credit facility which expires September 30, 2006. The revolving credit facility replaced a $100 million credit facility that would have expired August 2004. The Partnership paid in full all amounts outstanding under the original credit facility with borrowings of $20 million under the new revolving credit agreement. The interest rate on the revolving credit facility is based on either the (i) London Interbank Offered Rate or (ii) the Base Rate, which is equal to the greater of the JPMorgan Chase Prime Rate or the Federal Funds Rate plus ½ of 1%, plus, in either case, an applicable margin. The Partnership incurred certain costs aggregating $1.2 million associated with the revolving credit facility. These costs have been deferred and are being amortized as a component of interest expense over the term of the revolving credit facility. The Partnership had no borrowings outstanding under the revolving credit facility at December 31, 2004. Letters of credit can be issued under the revolving credit facility not to exceed $30 million; outstanding letters of credit reduce amounts available under the revolving credit facility. At December 31, 2004, the Partnership had letters of credit of $9.0 million outstanding under the revolving credit facility to secure the Partnership s obligations for reclamation liabilities and workers compensation benefits.

The senior notes and revolving credit facility are guaranteed by all of the subsidiaries of the Intermediate Partnership. The senior notes and revolving credit facility contain various restrictive and affirmative covenants, including the amount of distributions by the Intermediate Partnership and the incurrence of other debt exceeding $35 million. The senior note restrictions on distributions are consistent with the Partnership Agreement and the credit facility limit borrowings to fund distributions to $25,000,000. The Partnership was in compliance with the covenants of both the revolving credit facility and senior notes at December 31, 2004.

The Partnership previously entered into and has maintained agreements with two banks to provide additional letters of credit in an aggregate amount of $25.0 million to maintain surety bonds to secure its obligations for reclamation liabilities and workers compensation benefits. At December 31, 2004, the Partnership had $22.2 million in letters of credit outstanding under these agreements. The Special GP guarantees the letters of credit (Note 16).

Aggregate maturities of long-term debt are payable as follows (in thousands):

Year Ending December 31,	
2005	$ 18,000
2006	18,000
2007	18,000
2008	18,000
2009	18,000
Thereafter	90,000
	$ 180,000

9. DISTRIBUTIONS OF AVAILABLE CASH AND CONVERSION OF SUBORDINATED UNITS

The Partnership Agreement provides for the conversion of the Subordinated Units into Common Units after meeting certain financial tests. The Partnership satisfied, in two stages, the financial tests that resulted in the Subordinated Units being converted into Common Units. First, the Partnership satisfied certain financial tests that provided for the early conversion of one-half of the Subordinated Units (i.e. 3,211,265 Subordinated Units) to Common units in September 2003. Second, the Partnership satisfied the final conversion financial tests for converting the remaining Subordinated Units (i.e. 3,211,266 Subordinated Units) to Common Units in September 2004. The Board of Directors (and its Conflicts Committee) for the Managing GP approved management s determination that the early conversion financial tests and the final conversion financial tests were met. As a result, one-half of the Subordinated Units converted into Common Units on November 15, 2003 and the remaining one-half of the Subordinated Units converted into Common Units on November 2, 2004.

The Partnership will distribute 100% of its available cash within 45 days after the end of each quarter to unitholders of record and to the General Partners. Available cash is generally defined as all cash and cash equivalents of the Partnership on hand at the end of each quarter less reserves established by the Managing GP in its reasonable discretion for future cash requirements. These reserves are retained to provide for the conduct of the Partnership s business, the payment of debt principal and interest and to provide funds for future distributions.

As quarterly distributions of available cash exceed the minimum quarterly distribution (MQD) and target distributions levels as established in the Partnership Agreement, the Managing GP receives distributions based on specified increasing percentages of the available cash that exceed the MQD and the target distribution levels. The Partnership Agreement defines the MQD as $0.50 per unit ($2.00 per unit on an annual basis). The target distribution levels are based on the amounts of available cash from the Partnership s operating surplus distributed for a given quarter that exceed the MQD and common unit arrearages, if any.

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Under the quarterly incentive distribution provisions of the partnership agreement, the Managing GP is entitled to receive 15% of the amount the Partnership distributes in excess of $0.55 per unit, 25% of the amount the Partnership distributes in excess of $0.625 per unit, and 50% of the amount the Partnership distributes in excess of $0.75 per unit. During 2004 the Partnership allocated to the Managing GP incentive distributions of $1,828,000. There were no incentive distributions allocated to the Managing GP during the years ended December 31, 2003 and 2002. The following table summaries the quarterly per unit distribution paid during the respective quarter.

	Year		
	2004	2003	2002
First Quarter	$ 0.5625	$ 0.5250	$ 0.5000
Second Quarter	$ 0.6250	$ 0.5250	$ 0.5000
Third Quarter	$ 0.6500	$ 0.5250	$ 0.5000
Fourth Quarter	$ 0.6500	$ 0.5250	$ 0.5000

On January 27, 2005, the Partnership declared a quarterly distribution of $0.75 per unit, totaling approximately $14,797,000 (which includes the Managing GP s portion of incentive distributions), payable on February 14, 2005, to all unitholders of record on February 7, 2005.

10. INCOME TAXES

The Partnership s subsidiary, Alliance Service, is subject to federal and state income taxes. In conjunction with a decision to relocate the coal synfuel facility from Hopkins County Coal to Warrior Coal, agreements for a portion of the services provided to the coal synfuel producer were assigned to Alliance Service in December 2002. Alliance Service has no temporary differences between the financial reporting basis and the tax basis of its assets and liabilities. Prior to the Partnership s acquisition of Warrior Coal, the financial results of Warrior Coal were subject to federal and state income taxes. The federal and state income taxes associated with Warrior Coal s financial results prior to the Partnership s acquisition on February 14, 2003, are included in income taxes. Components of income tax expense (benefit) are as follows (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Current:			
Federal	$ 2,089	$ 1,516	$ 310
State	552	431	45
	2,641	1,947	355
Deferred:			
Federal		550	(1,269)
State		80	(180)
		630	(1,449)
Income tax expense (benefit)	$ 2,641	$ 2,577	$ (1,094)

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Reconciliations from the provision for income taxes at the U.S. federal statutory rate to the effective tax rate for the provision for income taxes are as follows (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Income taxes at statutory rate	$ 27,742	$ 17,668	$ 11,792
Less: Income taxes at statutory rate on Partnership income not subject to income taxes	(25,409)	(15,855)	(12,606)
Increase/(decrease) resulting from:			
Depletion			(114)
State taxes, net of federal income tax benefit	333	313	(136)
Deferred tax assets retained by ARH Warrior Holdings		413	
Other	(25)	38	(30)
Income tax expense (benefit)	$ 2,641	$ 2,577	$ (1,094)

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11. NET INCOME PER LIMITED PARTNER UNIT

A reconciliation of net income and weight average units used in computing basic and diluted earnings per unit is as follows (in thousands, except per unit data):

	Year Ended December 31,		
	2004	2003	2002
Net income	$ 76,621	$ 47,902	$ 34,785
Adjustments:			
Managing General Partner s incentive distributions	(1,828)		
General Partners 2% equity ownership	(1,496)	(972)	(726)
Portion applicable to Warrior loss prior to its acquisition on February 14, 2003		666	1,504
Limited partners interest in net income	73,297	47,596	35,563
Additional earnings allocation to general partner (a)	(10,211)	(1,723)	(355)
Net income available to limited partners (a)	63,086	45,873	35,208
Weighted average limited partner units - basic	17,941	17,581	15,405
Basic net income per limited partner unit (a)	$ 3.52	$ 2.61	$ 2.29
Weighted average limited partner units basic	17,941	17,581	15,405
Units contingently issuable:			
Restricted units for Long-Term Incentive Plan	434	527	390
Directors compensation units	16	16	13
Supplemental Executive Retirement Plan	46	39	35
Weighted average limited partner units, assuming dilutive effect of restricted units	18,437	18,163	15,843
Diluted net income per limited partner unit (a)	$ 3.42	$ 2.53	$ 2.22

(a) Basic and diluted net income per limited partner unit have been restated to reflect the application of EITF 03-6. The dilutive effect of EITF 03-6 on basic net income per limited partner unit was $0.57, $0.10 and $0.02 for years ended 2004, 2003 and 2002, respectively. The dilutive effect of EITF 03-6 on diluted net income per limited partner unit was $0.56, $0.09 and $0.02 for years ended 2004, 2003 and 2002, respectively. See Note 21 to the consolidated financial statements for further discussion of this matter.

The Partnership s net income for partners capital purposes is allocated to the general partners and limited partners in accordance with their respective partnership percentages, after giving effect to any priority income allocations for incentive distributions (Note 9), if any, to the Partnership s Managing GP, the holder of the incentive distribution rights pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. For purposes of computing basic and diluted net income per limited partner unit, in periods when the Partnership s aggregate net income exceeds the aggregate distributions for such periods, an increased amount of net income is allocated to the general partner for the additional pro forma priority income attributable to application of EITF 03-6. Warrior Coal s loss prior to its acquisition on February 14, 2003 was allocated to the general partners. For purposes of computing basic and diluted net income per limited partner unit, in periods when the Partnership s aggregate net income exceeds the aggregate distributions for such periods, an increased amount of net income is allocated to the general partner for the additional pro forma priority income attributable to application of EITF 03-6.

The Managing GP is entitled to receive incentive distributions if the amount the Partnership distributes with respect to any quarter exceeds levels specified in the Partnership Agreement. Under the quarterly incentive distribution provisions of the Partnership Agreement, generally, the Managing GP is entitled to receive 15% of the amount the Partnership distributes in excess of $0.55 per unit, 25% of the amount the Partnership distributes in excess of $0.625 per unit and 50% of the amount the Partnership distributes in excess of $0.75 per unit.

12. EMPLOYEE BENEFIT PLANS

Defined Contribution Plans The Partnership s employees currently participate in a defined contribution profit sharing and savings plan sponsored by the Partnership. This plan covers substantially all full-time employees. Plan participants may elect to make voluntary contributions to this plan up to a specified amount of their compensation. The Partnership makes matching contributions based on a percent of an employee s eligible compensation and for certain subsidiaries makes an additional nonmatching contribution also based on an employee s eligible compensation. Additionally, the Partnership contributes a defined percentage of eligible earnings for certain employees not covered by the defined benefit plan described below. The Partnership s expense for its plan was approximately $3,267,000, $2,975,000 and $2,959,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

Defined Benefit Plans Certain employees at the mining operations participate in a defined benefit plan (the Pension Plan) sponsored by the Partnership. The benefit formula is a fixed dollar unit based on years of service.

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The following sets forth changes in benefit obligations and plan assets for the years ended December 31, 2004 and 2003 and the funded status of the Pension Plan reconciled with amounts reported in the Partnership s consolidated financial statements at December 31, 2004 and 2003, respectively (dollars in thousands):

	2004	2003
Change in benefit obligations:		
Benefit obligations at beginning of year	$ 22,948	$ 18,077
Service cost	2,821	2,502
Interest cost	1,427	1,215
Actuarial loss	2,180	1,367
Benefits paid	(270)	(213)
Benefit obligation at end of year	29,106	22,948
Change in plan assets:		
Fair value of plan assets at beginning of year	21,185	12,432
Employer contribution		5,397
Actual return on plan assets	2,392	3,569
Benefits paid	(270)	(213)
Fair value of plan assets at end of year	23,307	21,185
Funded status	(5,799)	(1,763)
Unrecognized prior service cost	90	139
Unrecognized actuarial loss	5,122	3,789
Net amount recognized	$ (587)	$ 2,165
Amounts recognized in statement of financial position:		
Accrued benefit liability	$ (5,799)	$ (1,763)
Intangible asset	90	139
Accumulated other comprehensive income	5,122	3,789
Net amount recognized	$ (587)	$ 2,165
Weighted-average assumptions as of December 31:		
Discount rate	5.75%	6.25%
Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31:		
Discount rate	6.25%	6.75%
Expected return on plan assets	8.00%	8.00%
Weighted-average asset allocations as of December 31:		
Equity securities	88%	86%
Fixed income securities	11%	13%
Cash and cash equivalents	1%	1%
	100%	100%

(Continued)

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	2004	2003	2002
Components of net periodic benefit cost:			
Service cost	$ 2,821	$ 2,502	$ 2,249
Interest cost	1,427	1,215	952
Expected return on plan assets	(1,686)	(1,115)	(1,050)
Prior service cost	48	48	48
Net loss	141	399	
Net periodic benefit cost	$ 2,751	$ 3,049	$ 2,199
Effect on minimum pension liability	$ (1,333)	$ (1,486)	$ 4,461

Estimated future benefit payments as of December 31, 2004 are as follows (in thousands):

Year Ending December 31,	
2005	$ 460
2006	634
2007	806
2008	998
2009	1,219
2010-2014	10,322
	$ 14,439

The actuarial loss component of the change in benefit obligations for 2004 and 2003 was primarily attributable to reductions in the discount rate assumptions. The Partnership expects to contribute $2,700,000 to the Pension Plan in 2005.

The Compensation Committee (Compensation Committee) of the Board of Directors of the Managing GP maintains a Funding and Investment Policy Statement (Policy Statement) for the Pension Plan. The Policy Statement provides that the assets of the Pension Plan be invested in a diversified mix of domestic equity securities and international equity securities, domestic fixed income securities and cash equivalents with the goal of ensuring that the Pension Plan assets provide sufficient resources to meet or exceed benefit obligations. Investment options, which may be through mutual funds, collective funds, or direct investment in individual stock, bonds or cash equivalent investments, include (a) money market accounts, (b) U.S. Government bonds, (c) corporate bonds, (d) large, mid, and small capitalization stocks, and (e) international stocks. The Policy Statement imposes the following limitations, subject to exceptions authorized by the Compensation Committee under unusual market conditions: the maximum investment in any one stock should not exceed 10% of the total stock portfolio, the maximum investment in any one industry should not exceed 30% of the total stock portfolio, and the average credit quality of the bond portfolio should be at least AA with a maximum amount of non-investment grade debt of 10%. The Policy Statement s current asset allocation guidelines are as follows:

	Percentage of Total Portfolio

	Minimum	Target	Maximum
Domestic stocks	50%	70%	90%
Foreign stocks	0%	10%	20%
Fixed income/cash	5%	20%	40%

The expected long-term rate of return assumption is developed based on input from an independent investment manager, including its review of asset class return, expectations by economists, and an independent actuary. The Partnership s advisors base the projected returns on broad equity and bond indices. The Pension Plan s expected long-term rate of return is based on an asset allocation assumption of 80.0% with equity manager, with an expected long-term rate of return of 10.4%, and 20.0% with fixed income managers, with an expected long-term rate of return of 5.4%. The Pension Plan was established effective January 1, 1997 and the Partnership s initial contribution to the Pension Plan was made in 1998.

13. COMPENSATION PLANS

Effective January 1, 2000, the Managing GP adopted the Long-Term Incentive Plan (the LTIP) for certain employees and directors of the Managing GP and its affiliates who perform services for the Partnership. Annual grant levels and vesting provisions for designated participants are recommended by the President and Chief Executive Officer of the Managing GP, subject to the review and approval of the Compensation Committee. Grants are made either of restricted units, which are phantom units that entitle the grantee to receive a Common Unit or an equivalent amount of cash upon the vesting of the phantom unit, or options to purchase Common Units. Common Units to be delivered upon the vesting of restricted units or to be issued upon exercise of a unit option will be acquired by the Managing GP in the open market at a price equal to the then prevailing price, or directly from ARH or any other third party, including units newly issued by the Partnership, units already owned by the Managing GP, or any combination of the foregoing. The Partnership agreement provides that the Managing GP be reimbursed for all costs incurred in acquiring these Common Units or in paying cash in lieu of Common Units upon vesting of the restricted units.

The aggregate number of units reserved for issuance under the LTIP is 600,000. Effective January 1, 2004, the Compensation Committee approved an amendment to the LTIP clarifying that if an award is paid or settled in cash rather than through the delivery of units, then the units granted by such award shall be reloaded with respect to which options and restricted units may be granted under the LTIP in the future. In November 2004, the initial LTIP vesting requirements were met when the Partnership satisfied the final conversion financial tests for converting the remaining Subordinated Units into Common Units (Note 9). As a result, LTIP grants of 385,210 units vested in November 2004. The Partnership issued 231,126 Common Units to participants and paid cash to or on behalf of participants for the equivalent of 154,084 units to satisfy personal income tax obligations. During 2004 and 2003 the Compensation Committee approved grants of 102,785 and 141,205 restricted units, respectively, which will vest December 31, 2006 and September 30, 2005, subject to the satisfaction of certain financial tests. As of December 31, 2004, 2,765 restricted units outstanding LTIP grants have been forfeited. During 2004, 2003 and 2002, the Managing GP billed the Partnership approximately $20,320,000, $7,687,000, and $2,338,000, respectively, attributable to the LTIP. Effective January 1, 2005, the Compensation Committee approved additional grants of 57,195 restricted units, which will vest January 1, 2008, subject to the satisfaction of certain financial tests. As of December 31, 2004 there were 127,649 Common Units available for future issuance under the LTIP assuming all grants currently issued and outstanding for calendar year 2003, 2004 and 2005 are settled with common units.

Effective January 1, 1997, the Managing GP adopted a Supplemental Executive Retirement Plan (the SERP) for certain officers and key employees. The purpose of the SERP is to enhance the Partnership s ability to retain specific officers and key employees, by providing them with the deferred compensation benefits contained in the SERP. The intent of the SERP is to provide each participant with retirement benefits that are comparable in value to those of similar retirement programs administered by other companies, as well as to align each participant s supplemental benefits under the SERP with the interests of the Partnership s unitholders. All allocations made to participants under the SERP are made in the form of phantom units. The SERP is administered by the Compensation Committee. The Managing GP is able to amend or terminate the plan at any time. The Managing GP is entitled to reimbursement by the Partnership for its costs incurred under the SERP. During 2004, 2003 and 2002, the Managing GP billed the Partnership approximately $2,099,000, $626,000, and $64,000, respectively, attributable to the SERP. The increases from 2003 to 2004 and 2002 to 2003 are attributable to the increased market value of the Partnership s Common Units. The total accrued liability associated with the SERP plan as of December 31, 2004 and 2003 was $3,657,000 and $1,558,000, respectively, and is included in the long-term due to affiliates liability in the consolidated balance sheets.

14. RECLAMATION AND MINE CLOSING COSTS

The majority of the Partnership s operations are governed by various state statutes and the Federal Surface Mining Control and Reclamation Act of 1977, which establish reclamation and mine closing standards. These regulations, among other requirements, require restoration of property in accordance with specified standards and an approved reclamation plan. The Partnership has estimated the costs and timing of future reclamation and mine closing costs and recorded those estimates on a present value basis using discount rates ranging from 4.22% to 6.0%.

On January 1, 2003, the Partnership adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, which requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which it is incurred. Since the Partnership has historically adhered to accounting principles similar to SFAS No. 143, this standard had no material effect on the Partnership s consolidated financial statements upon adoption.

Discounting resulted in reducing the accrual for reclamation and mine closing costs by $28,760,000 and $10,332,000 at December 31, 2004 and 2003, respectively. Estimated payments of reclamation and mine closing costs as of December 31, 2004 are as follows (in thousands):

Year Ending December 31	
2005	$ 1,180
2006	2,327
2007	3,779
2008	558
2009	264
Thereafter	54,670
Aggregate undiscounted reclamation and mine closing	62,778
Effect of discounting	(28,760)
Total reclamation and mine closing costs	34,018
Less current portion	(1,180)
Reclamation and mine closing costs	$ 32,838

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The following table presents the activity affecting the reclamation and mine closing liability (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Beginning balance	$ 23,466	$ 23,456	$ 20,518
Accretion expense	1,622	1,341	1,365
Payments	(899)	(1,054)	(865)
Allocation of liability associated with acquisition, mine development and change in assumptions	9,829	(277)	2,438
Ending balance	$ 34,018	$ 23,466	$ 23,456

The reclamation and mine closing cost liability increase of $9,829,000 was primarily attributable to the Lodestar acquisition of $4,129,000 described in Note 3 and the initial land disturbances associated with new operations at Mettiki Coal, LLC and Mettiki Coal (WV), LLC of a combined $2,329,000. The liability also increased as the permitted refuse disposal areas were expanded at several existing operations and a comprehensive study related to water treatment costs was completed. Collectively, these reclamation issues also resulted in the effect of discounting increasing to $28,760,000 from $10,332,000.

15. PNEUMOCONIOSIS (BLACK LUNG) BENEFITS

Certain mine operating entities of the Partnership are liable under state statutes and the Federal Coal Mine Health and Safety Act of 1969, as amended, to pay black lung benefits to eligible employees and former employees and their dependents.

Pneumoconiosis (black lung) benefits liability is calculated using the service cost method. Under the service cost method the calculation of the actuarial present value of the estimated black lung obligation is based on an actuarial study performed by an independent actuary. Actuarial gains or losses are amortized over the remaining service period of active miners. The discount rate used to calculate the estimated present value of future obligations was 4.5% and 4.7% at December 31, 2004 and 2003, respectively.

The reconciliation of changes in benefit obligations at December 31, 2004 and 2003 is as follows (in thousands):

	2004	2003
Benefit obligations at beginning of year	$ 17,633	$ 16,067
Service cost	1,217	947
Interest cost	1,091	978
Actuarial loss	549	65
Benefits and expenses paid	(155)	(424)
Benefit obligations at end of year	$ 20,335	$ 17,633

The U.S. Department of Labor has issued revised regulations that will alter the claims process for the federal black lung benefit recipients. Both the coal and insurance industries have challenged certain provisions of the revised regulations through litigation, but the regulations were upheld, with some exceptions as to the retroactive application of the regulations. The revised regulations are expected to result in an increase in the incidence and recovery of black lung claims.

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16. RELATED PARTY TRANSACTIONS

Administrative Services The Partnership Agreement provides that the Managing GP and its affiliates be reimbursed for all direct and indirect expenses it incurs or payments it makes on behalf of the Partnership, including, but not limited to, management s salaries and related benefits (including the LTIP), and accounting, budget, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers compensation management, legal and information technology services. The Managing GP may determine in its sole discretion the expenses that are allocable to the Partnership. Total costs billed by the Managing GP and its affiliates to the Partnership were approximately $28,536,000, $12,471,000 and $6,559,000 for the years ended December 31, 2004, 2003 and 2002, respectively. The increase from 2003 to 2004 and 2002 to 2003 were primarily attributable to higher accruals for the LTIP, STIP and Supplemental Executive Retirement Plan (SERP). The expenses associated with LTIP and SERP were impacted by the market value of the Partnership s Common Units, which had a closing market price of $74.00, $34.38 and $24.22 at December 31, 2004, 2003 and 2002, respectively. The amounts billed by the managing GP include $24,242,000, $9,319,000 and $3,308,000 for the years ended December 31, 2004, 2003 and 2002, respectively, for the LTIP, STIP and SERP.

SGP Land Webster County Coal, LLC (Webster County Coal) has a mineral lease and sublease with SGP Land requiring annual minimum royalty payments of $2.7 million, payable in advance through 2013 or until $37.8 million of cumulative annual minimum and/or earned royalty payments have been paid. Webster County Coal paid royalties of $4,611,000, $3,460,000 and $2,700,000 for the years ended December 31, 2004, 2003 and 2002, respectively. Webster County Coal has recouped as earned royalties all advance minimum royalty payments made in accordance with these lease terms except for $805,000 as of December 31, 2004.

Warrior Coal has a mineral lease and sublease with SGP Land. Under the terms of the lease, Warrior Coal has paid and will continue to pay in arrears an annual minimum royalty obligation of $2,270,000 until $15,890,000 of cumulative annual minimum and/or earned royalty payments have been paid. The annual minimum royalty periods are from October 1 through the end of the following September 30, expiring September 30, 2007. Warrior Coal paid royalties of $2,561,000, $2,453,000 and $2,127,000 for the years ended December 31, 2004, 2003 and 2002, respectively. Warrior Coal has recouped as earned royalties all advance minimum royalty payments made in accordance with these lease terms except for $636,000 as of December 31, 2004.

Under the terms of the mineral lease and sublease agreements described above, Webster County Coal and Warrior Coal also reimburse SGP Land for SGP Land s base lease obligations. The Partnership reimbursed SGP Land $5,428,000, $4,395,000 and $3,922,000 for the years ended December 31, 2004, 2003 and 2002, respectively, for the base lease obligations. Webster County Coal and Warrior Coal have recouped as earned royalties all advance minimum royalty payments made in accordance with these terms except for $216,000 as of December 31, 2004.

In 2001, SGP Land, as successor in interest to an unaffiliated third party, entered into an amended mineral lease with MC Mining, LLC (MC Mining). Under the terms of the lease, MC Mining has paid and will continue to pay an annual minimum royalty obligation of $300,000 until $6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. MC Mining paid royalties of $479,000 and $568,000 for the years ended December 31, 2003 and 2002, respectively. The 2004 annual minimum royalty obligation of $300,000 was paid in January 2005. MC Mining has recouped as earned royalties all advance minimum royalty payments made under these lease terms as of December 31, 2004.

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The Partnership also has an option to lease and/or sublease certain reserves from SGP Land, which reserves are contiguous to the Partnership s Hopkins County Coal, LLC mining complex. Under the terms of the option to lease and sublease, the Partnership paid option fees of $1,368,000 and $684,000 during the years ended December 31, 2004 and 2002, respectively. The 2003 option fee of $684,000 was paid in January 2004 and is included in the due to affiliates balance as of December 31, 2003. The anticipated annual minimum royalty obligation is $684,000, payable in advance through 2009.

Special GP The Partnership has a noncancelable operating lease arrangement with the Special GP for the coal preparation plant and ancillary facilities at the Gibson County Coal, LLC mining complex. Based on the terms of the lease, the Partnership will make monthly payments of approximately $216,000 through January 2011. Lease expense incurred for each of the three years in the period ended December 31, 2004 was $2,595,000.

The Partnership previously entered into and has maintained agreements with two banks to provide letters of credit in an aggregate amount of $25.0 million (Note 8). At December 31, 2004, the Partnership had $22.2 million in outstanding letters of credit. The Special GP guarantees these letters of credit. Historically, the Partnership has compensated the Special GP for a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. During 2003 the Special GP agreed to waive the guarantee fee in exchange for a parent guarantee from the Intermediate Partnership and Alliance Coal, LLC on the mineral lease and sublease with Webster County Coal and Warrior Coal described above. Since the guarantee is made on behalf of entities within the consolidated partnership, the guarantee has no fair value under FIN No. 45 and does not impact the consolidated financial statements. The Partnership paid approximately $31,300 and $48,200 in guarantee fees to the Special GP for the years ended December 31, 2003 and 2002, respectively.

17. COMMITMENTS AND CONTINGENCIES

Commitments The Partnership leases buildings and equipment under operating lease agreements that provide for the payment of both minimum and contingent rentals. The Partnership also has a noncancelable lease with the Special GP (Note 16). Future minimum lease payments under operating leases are as follows (in thousands):

Year Ending December 31,	Affiliate	Others	Total
2005	$ 2,595	$ 2,071	$ 4,666
2006	2,595	1,650	4,245
2007	2,595	819	3,414
2008	2,595	264	2,859
2009	2,595	13	2,608
Thereafter	2,810		2,810
	$ 15,785	$ 4,817	$ 20,602

Lease expense under all operating leases was $6,112,000, $5,490,000 and $4,707,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

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In October 2002, the Partnership entered into a master equipment lease. The Partnership s credit facilities limit the amount of total operating lease obligations to $10 million payable in any period of 12 consecutive months. This master equipment lease is subject to this limitation on lease obligations. The Partnership entered into nine operating leases during 2003 under the master equipment lease with lease terms ranging from three to six years. The Partnership did not enter into any new equipment leases under the master equipment lease during 2004.

Contractual Commitments In connection with planned capital projects, the Partnership had contractual commitments of approximately $8.4 million at December 31, 2004.

General Litigation The Partnership is involved in various lawsuits, claims and regulatory proceedings, incidental to its business. The Partnership provides for costs related to litigation and regulatory proceedings, including civil fines issued as part of the outcome of such proceedings, when a loss is probable and the amount is reasonably determinable. Although the ultimate outcome of these matters cannot be predicted with certainty, in the opinion of management, the outcome of these matters, to the extent not previously provided for or covered under insurance, are not expected to have a material adverse effect on the Partnership s business, financial position or results of operations. Nonetheless, these matters or estimates that are based on current facts and circumstances, if resolved in a manner different from the basis on which management has formed its opinion, could have a material adverse effect on the Partnership s financial position or results of operations.

Other During September 2004, the Partnership completed its annual property and casualty insurance renewal. As a result, the Partnership and its affiliates retained a 10.0% participating interest along with its insurance carriers in the commercial property program. The aggregate maximum limit in the commercial property program is $75 million per occurrence of which the Partnership would be responsible for a maximum amount of $7.5 million for each occurrence, excluding a $3.5 million deductible.

Mettiki Coal (WV), LLC has proposed a long-wall underground mine extension (the E-Mine) to be located primarily in Tucker County, West Virginia, which will eventually replace the Partnership s Mettiki Coal, LLC s existing long-wall mine, D-Mine located in Garrett County, Maryland. The proposed mine, which will be either a long-wall or continuous mining operation, is approximately 10 miles from Mettiki Coal. In order to proceed with the development of the E-Mine, Mettiki Coal (WV) filed two separate permit applications with the West Virginia Department of Environmental Protection (WVDEP) concerning on-site disposal of scalp rock and underground mining, each requiring an associated water discharge permit. The Partnership was notified on April 16, May 13, May 26, and June 7, 2004, that WVDEP has issued the permits for on-site disposal of scalp rock, underground mining, water discharge related to the operation of the scalp rock disposal facility, and water discharge related to the operation of the underground mine, respectively.

The appeal periods for the scalp rock permit and the two water discharge permits related to the operation of the scalp rock disposal facility and underground mine have lapsed without any appeal being filed. Two appeals of the underground mining permit were filed on June 11 and 16, 2004, respectively. The West Virginia Surface Mine Board (SMB) consolidated the appeals and held an administrative initial hearing on October 19 and 20, 2004, December 7 and 8, 2004 and January 11 and February 7, 2005.

On March 8, 2005, the SMB issued a Final Order concluding consideration of the consolidated appeals without a decision, which Final Order held that the SMB was unable to take any action relating to the issuance of the underground permit by WVDEP because its vote did not obtain the concurrence of at least four SMB members as required by West Virginia law. Consequently, the ultimate decision by the WVDEP to issue the underground permit was affirmed by operation of West Virginia law. In the Final

Order, however, the SMB voted unanimously to require Mettiki Coal (WV) to increase the amount of a surety bond that serves as security for a portion of the reclamation plan approved by WVDEP as part of the underground permit. On March 8, 2005, Mettiki Coal (WV) filed an appeal of the Final Order with the Circuit Court of Tucker County, West Virginia, on the ground that the SMB was wrong in ordering Mettiki Coal (WV) to increase the surety bond for part of the reclamation plan approved by WVDEP when the SMB, as a result of not obtaining the concurrence of at least four members, failed to affirm the decision by WVDEP to issue a final order approving the underground permit issued by WVDEP on May 13, 2004. On March 10, 2005 the West Virginia Rivers Coalition, the West Virginia Highlands Conservancy, and Trout Unlimited West Virginia Council filed an appeal of the SMB s final order with the Circuit Court of Kanawha County, West Virginia. The appeal requests that the Circuit Court (a) grant a stay of the WVDEP s approval of the E-Mine permit pending a decision by the Circuit Court, (b) set a briefing schedule and oral argument of the appeal and (c) reverse and vacate the WVDEP s approval of the permit. Management believes the WVDEP s approval of the permit application will be ultimately upheld by the applicable Circuit Court in West Virginia.

On October 12, 2004, Pontiki Coal, LLC (Pontiki) was served with a complaint from ICG alleging a breach of contract and seeking declaratory relief to determine the parties rights under a coal sales agreement between Horizon Natural Resource Sales Company (Horizon Sales), as buyer, and Pontiki Coal Corporation, as seller, dated October 3, 1998, as amended on February 28, 2001 (the Agreement). ICG has represented that it acquired the rights and assumed the liabilities of the Agreement effective September 30, 2004 as part of an asset sale approved by the U.S. bankruptcy court supervising the bankruptcy proceedings of Horizon Sales and its affiliates. Pontiki is the successor-in-interest of Pontiki Coal Corporation as a result of a merger completed on August 4, 1999.

The complaint alleges that from January 2004 to August 2004, Pontiki failed to deliver a total of 138,111 tons of coal resulting in an alleged loss of profits for ICG of $4.1 million. The Partnership has been unable to confirm ICG s calculation of the alleged shortfall of coal deliveries. The Partnership is aware that certain deliveries under the Agreement have not been made during 2004 for reasons including, but not limited to, force majeure events at Pontiki and ICG s failure to provide transportation services for the delivery of coal as required under the Agreement. This litigation is in the preliminary stage and the Partnership does not believe that it is probable that a loss has been incurred. The Partnership also does not believe that this litigation has merit and intends to contest the litigation vigorously. The Partnership is unable, however, to predict the outcome of the litigation or reasonably estimate a range of possible loss given the current status of the litigation.

At certain of the Partnership s operations, property tax assessments for several years are under audit by the related tax authorities. The Partnership believes that it has recorded adequate liabilities based on reasonable estimates of any property tax assessments that may be ultimately assessed as a result of these audits.

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18. CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS

The Partnership has significant long-term coal supply agreements, some of which contain prospective price adjustment provisions designed to reflect changes in market conditions, labor and other production costs and, when the coal is sold other than FOB the mine, changes in transportation rates. Total revenues to major customers, including transportation revenues (Note 2), which exceed ten percent of total revenues (Customer C comprised less than nine percent of total revenues in 2004) are as follows (in thousands):

	Year Ended December 31,		
	2004	**2003**	**2002**
Customer A	$ 124,847	$ 116,750	$ 113,094
Customer B	89,887	78,724	72,224
Customer C	56,658	52,561	69,933

Trade accounts receivable from these customers totaled approximately $24.3 million at December 31, 2004. The Partnership s bad debt experience has historically been insignificant, however the Partnership established an allowance of $763,000 during 2001, due to the Partnership s total credit exposure to Enron Corp., which filed for bankruptcy protection during December 2001. The Partnership received $114,000 in 2004 for its claim against Enron and recognized as a recovery in 2004. Financial conditions of its customers could result in a material change to this estimate in future periods. The coal supply agreements with Customers A, B and C expire in 2007, 2006 and 2010, respectively.

19. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

A summary of the quarterly operating results for the Partnership, which includes the effect of the restatement discussed in Note 21 in all periods presented, is as follows (in thousands, except unit and per unit data):

	Quarter Ended			
	March 31, 2004 (1)	**June 30, 2004**	**September 30, 2004 (2)**	**December 31, 2004 (3)**
	All Periods Restated (5)			
Revenues	$ 157,824	$ 162,546	$ 158,261	$ 174,658
Operating income	22,493	27,180	29,337	14,231
Income before income taxes	18,964	23,589	25,867	10,842
Net income	18,225	22,861	25,321	10,214
As previously reported:				
Basic net income per limited partner unit (5)	$ 1.00	$ 1.22	$ 1.37	$ 0.51
Diluted net income per limited partner unit (5)	$ 0.97	$ 1.18	$ 1.33	$ 0.49
Restated:				
Basic net income per limited partner unit (5)	$ 0.87	$ 0.97	$ 1.06	$ 0.51

Diluted net income per limited partner unit (5)	$ 0.84	$ 0.94	$ 1.03	$ 0.49
Weighted average number of units outstanding - basic	17,903,793	17,903,793	17,903,793	18,051,606
Weighted average number of units outstanding - diluted	18,439,099	18,438,551	18,438,758	18,437,164

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	Quarter Ended			
	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003 (4)
	All Periods Restated (5)			
Revenues	$ 124,925	$ 133,471	$ 141,799	$ 142,552
Operating income	18,057	12,781	15,210	19,038
Income before income taxes	14,083	9,248	11,466	15,682
Net income	13,128	8,528	10,803	15,443
As previously reported:				
Basic net income per limited partner unit (5)	$ 0.81	$ 0.47	$ 0.59	$ 0.85
Diluted net income per limited partner unit (5)	$ 0.79	$ 0.45	$ 0.57	$ 0.82
Restated:				
Basic net income per limited partner unit (5)	$ 0.78	$ 0.47	$ 0.59	$ 0.78
Diluted net income per limited partner unit (5)	$ 0.75	$ 0.45	$ 0.57	$ 0.75
Weighted average number of units outstanding - basic	16,593,609	17,903,793	17,903,793	17,903,793
Weighted average number of units outstanding - diluted	17,176,824	18,485,741	18,487,787	18,486,098

Operating income in the above table represents income from operations before interest expense.

(1) The Partnership s March 31, 2004 quarterly results were impacted by extra expenses associated with extinguishing the Dotiki Fire Incident, in addition the Partnership recognized as an offset to operating expenses $2.9 million representing estimated insurance recoveries for expenses incurred as a result of the Dotiki Fire Incident (Note 4).

(2) The Partnership s September 30, 2004 quarterly results were impacted by an offset to operating expenses of $2.8 million due to the final settlement of insurance claims attributable to the Dotiki Fire Settlement and a net gain from insurance settlement of approximately $15.2 million attributable to the final settlement of insurance claims attributable to the Dotiki Fire Incident (Note 4).

(3) The Partnership s December 31, 2004 quarterly results were impacted by an accrual of $4.1 million reflecting the Partnership s initial estimate of certain minimum costs attributable to the MC Mining Fire Incident that are not reimbursable under the Partnership s insurance policies (Note 4).

(4) The Partnership s December 31, 2003 quarterly results were impacted by a contractual modification that resulted in a $2.0 million favorable pricing adjustment associated with coal feedstock sales to Synfuel Solutions Operating LLC for shipments made primarily in 2003 but prior to the fourth quarter of 2003. Additionally, operating expenses decreased due to the reversal of an expense accrual of $1.2 million established in 1998. The expense accrual was established in conjunction with the idling of Pontiki in 1998 that created an expectation of a probable increase in workers compensation costs associated with the terminated workforce. The expected anticipated increase in workers compensation claims did not emerge and, with limited exceptions, the statute of limitations expired in December 2003 for the filing or reopening of workers compensation claims associated with the employee terminations.

(5) As restated, see Note 21. The dilutive effect of EITF 03-6 on basic net income per limited partner unit was $0.13, $0.25 and $0.31 for the three months ended March 31, June 30, and September 30, 2004,

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respectively. There was no effect on basic net income per limited partner unit for the three months ended December 31, 2004 because the Partnership s aggregate distributions exceeded aggregate earnings for the period. The dilutive effect of EITF 03-6 on basic net income per limited partner unit was $0.03 and $0.07 for the three months ended March 31 and December 31, 2003, respectively. There was no effect on basic net income per limited partner unit for the three months ended June 30 and September 30, 2003 because the Partnership s aggregate distributions exceeded aggregate earnings for the periods. See Notes 2, 11 and 21 to the financial statements for further discussion of this matter.

20. SUBSEQUENT EVENT

On January 1, 2005 the Partnership acquired 100% of the limited liability company member interest of Tunnel Ridge, LLC from Alliance Resource Holdings, Inc., a company owned by management of the Partnership (Note 3).

21. RESTATEMENTS

Net Income Per Limited Partner Unit

Subsequent to the issuance of its consolidated financial statements for the year ended December 31, 2004, the Partnership determined that in periods in which aggregate net income exceeds the Partnership s aggregate distributions, the Partnership is required to present earnings per unit as if all the earnings for the period were distributed, regardless of the pro forma nature of the allocation or whether the earnings would actually have been distributed during the period. This requirement reflects a consensus reached by the FASB in Emerging Issues Task Force Issue No. 03-6 (EITF 03-6), Participating Securities and the Two-Class Method under FASB Statement No. 128 . EITF 03-6 addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. As a result, basic and diluted net income per limited partner unit for each of the three years in the period ended December 31, 2004 have been restated to reflect the pro forma distribution assumption required by EITF 03-6.

EITF 03-6 does not impact the Partnership s overall net income or other financial results, however, for periods in which aggregate net income exceeds the Partnership s aggregate distributions for such period, it will have the impact of reducing the earnings per limited partner unit. This result occurs as a larger portion of the Partnership s aggregate earnings, as if distributed, is allocated to the incentive distribution rights held by the Managing GP, even though the Partnership makes cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. In accounting periods in which aggregate net income does not exceed the Partnership s aggregate distributions for such period, EITF 03-06 does not have any impact on the Partnership s earnings per unit calculation.

Basic and diluted net income per limited partner unit is calculated by dividing net income after deducting the amount allocated to the general partners interests, (which includes the Managing GP s actual priority allocations paid and the pro forma priority allocations) by the weighted average number of outstanding limited partner units during the period. Partnership net income is first allocated to the Managing GP based on the amount of priority allocations. The remainder is then allocated between the limited partners and the general partner based on percentage ownership in the Partnership.

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The correction of the error decreased basic and diluted net income per limited partner unit as follows:

	Year Ended December 31,		
	2004	2003	2002
As Previously Reported:			
Basic net income per limited partner unit	$ 4.09	$ 2.71	$ 2.31
Diluted net income per limited partner unit	$ 3.98	$ 2.62	$ 2.24
After Application of EITF 03-6:			
Basic net income per limited partner unit	$ 3.52	$ 2.61	$ 2.29
Diluted net income per limited partner unit	$ 3.42	$ 2.53	$ 2.22
Difference:			
Basic net income per limited partner unit	$ (0.57)	$ (0.10)	$ (0.02)
Diluted net income per limited partner unit	$ (0.56)	$ (0.09)	$ (0.02)

Common Unit-Based Compensation

Subsequent to the issuance of the financial statements, the Partnership determined that the Partnership s pro forma limited partner unit based compensation disclosure was incorrect. The original disclosure assumed compensation expense for the non vested common units would be calculated utilizing a fair value model. The amounts have been restated to correctly calculate such common unit based compensation for non vested common units based on an intrinsic value model. The correction of the error affected the pro forma disclosure, which also considers the impact of EITF 03-06, as follows:

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As Previously Reported:

	Year Ended December 31,		
	2004	2003	2002
Net income, as reported	$ 76,621	$ 47,902	$ 34,785
Add: compensation expenses related to Long-Term Incentive Plan units included in reported net income	20,320	7,687	2,338
Deduct: compensation expense related to Long-Term Incentive Plan units determined under fair value method for all awards	(3,915)	(3,632)	(2,257)
Net income, pro forma	93,026	51,957	34,866
General partners interest in net income (loss), pro forma	3,652	386	(777)
Limited partners interest in net income, pro forma	$ 89,374	$ 51,571	$ 35,643
Earnings per limited partner unit:			
Basic, as reported	$ 4.09	$ 2.71	$ 2.31
Basic, pro forma	$ 4.98	$ 2.93	$ 2.38
Diluted, as reported	$ 3.98	$ 2.62	$ 2.24
Diluted, pro forma	$ 4.85	$ 2.84	$ 2.32

Restated:

	Year Ended December 31,		
	2004	2003	2002
Net income, as reported	$ 76,621	$ 47,902	$ 34,785
Add: compensation expenses related to Long-Term Incentive Plan units included in reported net income	20,320	7,687	2,338
Deduct: compensation expense related to Long-Term Incentive Plan units determined under fair value method for all awards	(20,320)	(7,687)	(2,338)
Net income, pro forma	76,621	47,902	34,785
General partners interest in net income (loss), pro forma	3,324	306	(778)
Limited partners interest in net income, pro forma	$ 73,297	$ 47,596	$ 35,563
Earnings per limited partner unit:			
Basic, as reported	$ 3.52	$ 2.61	$ 2.29
Basic, pro forma	$ 3.52	$ 2.61	$ 2.29
Diluted, as reported	$ 3.42	$ 2.53	$ 2.22
Diluted, pro forma	$ 3.42	$ 2.53	$ 2.22

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SCHEDULE II

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

YEARS ENDED DECEMBER 31, 2004, 2003, AND 2002

	Balance At Beginning Of Year	Additions Charged To Income	Deductions	Balance At End Of Year
		(in thousands)		
2004				
Allowance for doubtful accounts	$ 763	$	$ 763	$
2003				
Allowance for doubtful accounts	$ 763	$	$	$ 763
2002				
Allowance for doubtful accounts	$ 763	$	$	$ 763

The Partnership established an allowance of $763,000 during 2001 due to the Partnership s total credit exposure to Enron Corp. which filed for bankruptcy protection during December 2001. In 2004, the Partnership collected approximately $114,000 from the sale to a third-party of a bankruptcy claim relating to this receivable to a third-party. The remaining balance of $649,000 was written-off.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

The Partnership s management, including the Partnership s Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of its disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this annual report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, solely due to the material weakness described below under the heading Management s Report on Internal Control Over Financial Reporting, the Partnership s disclosure controls and procedures were not effective as of the end of the period covered by this annual report.

Management s Report on Internal Control Over Financial Reporting (as revised)

Management of Alliance Resource Partners, L.P. and its subsidiaries (the Partnership, we or us) is responsible for establishing and maintaining adequate internal control over financial reporting. The Partnership s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

A material weakness is a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. A significant deficiency is a control deficiency, or combination of control deficiencies, that adversely affects the Partnership s ability to initiate, authorize, record, process, or report external financial information reliably in accordance with generally accepted accounting principles such that there is more than a remote likelihood that a misstatement of the Partnership s annual or interim financial statements that is more than inconsequential will not be prevented or detected.

Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Partnership;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures are being made in accordance with authorizations of the Partnership s management and directors; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

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

Management of the Partnership has revised its assessment of the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2004 originally included in Management s Report on Internal Control Over Financial Reporting in the Partnership s annual report on Form 10-K filed on March 15, 2005, in which management concluded that the Partnership s internal control over financial reporting was effective. Subsequent to filing its annual report on Form 10-K on March 15, 2005, the Partnership identified misstatements in its annual financial statements for each of the three years in the period ended December 31, of which the misstatements in 2004 and 2003 were material. The Partnership has restated those annual financial statements as discussed in Item 8. Financial Statements and Supplementary Data; Notes to Consolidated Financial Statements for the years ended December 31, 2004, 2003 and 2002; Note 21. Restatements . Management has concluded that these misstatements resulted from a control deficiency that represents a material weakness. As a result, management has revised its assessment of the effectiveness of the Partnership s internal control over financial reporting because a material weakness resulted in the following:

The Partnership s control to determine that the principles in Emerging Issues Task Force (EITF) 03-6: Participating Securities and the Two-Class Method under FASB Statement No. 128 (EITF 03-6) was applicable to the Partnership s determination of basic and diluted net income per limited partner unit calculations was not effective as of December 31, 2004. In August 2005, the Partnership determined that EITF 03-6 was applicable to the Partnership s determination of basic and diluted net income per limited partner unit calculations. Consequently, the Partnership has restated its annual consolidated financial statements for each of three years in the period ended December 31, 2004, including the quarterly disclosures therein.

The Partnership s control to disclose pro forma information required under Statement of Financial Accounting Standards (SFAS) No. 148, Accounting for Stock-Based Compensation-Transition and Disclosure, an Amendment of FASB Statement No. 123 (SFAS 148) was not effective as of December 31, 2004. The Partnership had assumed that compensation expense for the non-vested common units granted would be different under the intrinsic method of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees, and a fair value model under the provisions of the SFAS No. 123, Accounting for Stock-Based Compensation . In August 2005, the Partnership determined that its pro forma limited partner common unit based compensation disclosure was incorrect. Consequently, a restatement to the pro forma information required under SFAS 148 was required to correctly calculate such common unit based compensation expense for non vested common units based on an intrinsic value model for each of the three years in the period ended December 31, 2004 and represented a material change to the pro forma disclosures of earnings per limited partner unit for the years ended December 31, 2004 and 2003. The Partnership has restated its annual financial statements for each of three years in the period ended December 31, 2004, 2003 and 2002 including the quarterly disclosures therein.

In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework. Based on its revised assessment and those criteria, management concluded that the Partnership did not maintain effective internal control over financial reporting as of December 31, 2004 due to the material weakness described above.

The Partnership s Independent Registered Public Accounting Firm, Deloitte & Touche LLP, has audited and issued a report on management s revised assessment of the Partnership s internal control over financial reporting. The report of Deloitte & Touche LLP appears below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of the Managing

General Partner and the Partners of

Alliance Resource Partners, L.P.

We have audited management s assessment, included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting, that Alliance Resource Partners, L.P. and subsidiaries (the Partnership) did not maintain effective internal control over financial reporting as of December 31, 2004, because of the effect of the material weakness identified in management s assessment based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Partnership s internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our report dated March 15, 2005, we expressed an unqualified opinion on management s assessment that the Partnership maintained effective internal control over financial reporting and an unqualified opinion on the effectiveness of internal control over financial reporting. As described in the following paragraph, the Partnership subsequently identified material misstatements in its 2002, 2003, and 2004 annual financial statements and related note disclosures and the interim financial statements for the three months ended March 31, 2005 and 2004 and related note disclosures, which caused such annual and interim financial statements to be restated. Management subsequently revised its assessment due to the identification of a material weakness, described in the following paragraph, in connection with the financial statement restatement. Accordingly, our opinion on the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2004 expressed herein is different from that expressed in our previous report.

A material weakness is a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weakness has been identified and included in management s assessment: there was a deficiency in design of the internal controls over the financial reporting process for the application of accounting principles generally accepted in the United States of America for two specific financial disclosure areas:

1) In August 2005, the Partnership determined that the principles in Emerging Issues Task Force (EITF) 03-6: Participating Securities and the Two-Class Method under FASB Statement No. 128 (EITF 03-6) was applicable to the Partnership s determination of basic and diluted net income per limited partner unit calculations. EITF 03-6 guidance was effective for fiscal periods beginning after March 31, 2004. This issue required the restatement of the net income per limited partner unit amounts for each of the three years in the period ended December 31, 2004 and the restatement was material for the year ended December 31, 2004.

2) The Partnership previously disclosed pro forma information required under Statement of Financial Accounting Standards (SFAS) No. 148, Accounting for Stock-Based Compensation-Transition and Disclosure, an Amendment of FASB Statement No. 123 (SFAS 148) assuming

compensation expense for the non-vested common units granted would be calculated under a fair value model under the provisions of the SFAS No. 123, Accounting for Stock-Based Compensation . In August 2005, the Partnership determined its pro forma limited partner common unit based compensation disclosure was incorrect since it should be based on an intrinsic value model. Consequently, a restatement to the pro forma information table required under SFAS 148 was required for each of the three years in the period ended December 31, 2004 and represented a material change to the pro forma disclosures of net income per limited partner unit for 2004 and 2003.

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This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements as of and for the year ended December 31, 2004 (as restated), of the Partnership and this report does not affect our report on such restated financial statements.

In our opinion, management s revised assessment that the Partnership did not maintain effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, the Partnership has not maintained effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and consolidated financial statement schedule as of and for the year ended December 31, 2004, of the Partnership and our report dated March 15, 2005 (August 15, 2005 as to the effects of the restatements discussed in Note 21) expressed an unqualified opinion on those financial statements and financial statement schedule, and included explanatory paragraphs relating to an accounting change and to the restatements discussed in Note 21.

/s/ DELOITTE & TOUCHE LLP

Tulsa, Oklahoma

March 15, 2005

(August 15, 2005 as to the

effects of the material

weakness described in

Management s Annual

Report on Internal Control

over Financial Reporting)

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) Financial Statements.

The response to this portion of Item 15 is submitted as a separate section herein under Part II, Item 8. - Financial Statements and Supplementary Data.

(a)(2) Financial Statement Schedules.

Schedule II Valuation and Qualifying Accounts Years ended December 31, 2004, 2003 and 2002, is set forth under Part II Item 8. - Financial Statements and Supplementary Data. All other schedules are omitted because they are not applicable or the information is shown in the financial statements or notes thereto.

(a)(3) and (c) The exhibits listed below are filed as part of this annual report.

3.1 Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 3.1 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).

3.2 Amended and Restated Agreement of Limited Partnership of Alliance Resource Operating Partners, L.P. (Incorporated by reference to Exhibit 3.2 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).

3.3 Certificate of Limited Partnership of Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 3.6 of the Registrant s Registration Statement on Form S-1 filed with the Commission on May 20, 1999 (Reg. No. 333-78845)).

3.4 Certificate of Limited Partnership of Alliance Resource Operating Partners, L.P. (Incorporated by reference to Exhibit 3.8 of the Registrant s Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).

3.5 Certificate of Formation of Alliance Resource Management GP, LLC (Incorporated by reference to Exhibit 3.7 of the Registrant s Registration Statement on Form S-1/A filed with the Commission on July 23, 1999 (Reg. No. 333-78845)).

3.6 Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC (Incorporated by reference to Exhibit 3.4 of the Registrant s Registration Statement on Form S-3 filed with the Commission on April 1, 2002 (Reg. No. 333-85282)).

3.7 Amendment No. 1 to Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC (Incorporated by reference to Exhibit 3.5 of the Registrant s Registration Statement on Form S-3 filed with the Commission on April 1, 2002 (Reg. No. 333-85282)).

3.8 Amendment No. 2 to Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC (Incorporated by reference to Exhibit 3.6 of the Registrant s Registration Statement on Form S-3 filed with the Commission on April 1, 2002 (Reg. No. 333-85282)).

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4.1 Form of Common Unit Certificate (Included as Exhibit A to the Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.)

10.1 Credit Agreement, dated as of August 22, 2003, among Alliance Resource Operating Partners, L.P., JPMorgan Chase Bank (as paying agent), Citicorp USA, Inc. and JPMorgan Chase Bank (as co-administrative agents) and lenders named therein. (Incorporated by reference to Exhibit 10.41 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, File No. 000-26823).

10.2 Note Purchase Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC and the purchasers named therein. (Incorporated by reference to Exhibit 10.20 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).

10.3 Letter of Credit Facility Agreement dated as of June 29, 2001, between Alliance Resource Partners, L.P. and Bank of Oklahoma, National Association. (Incorporated by reference to Exhibit 10.20 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).

10.4 Amendment One to Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of Oklahoma, National Association. (Incorporated by reference to Exhibit 10.33 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 000-26823).

10.5 Promissory Note Agreement dated as of July 31, 2001, between Alliance Resource Partners, L.P. and Bank of Oklahoma, N. A. (Incorporated by reference to Exhibit 10.21 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).

10.6 Guarantee Agreement, dated as of July 31, 2001, between Alliance Resource GP, LLC and Bank of Oklahoma, N.A. (Incorporated by reference to Exhibit 10.22 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).

10.7 Letter of Credit Facility Agreement dated as of August 30, 2001, between Alliance Resource Partners, L.P. and Fifth Third Bank. (Incorporated by reference to Exhibit 10.23 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).

10.8 Amendment No. 1 to Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Fifth Third Bank. (Incorporated by reference to Exhibit 10.9 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, File No. 000-26823).

10.9 Guarantee Agreement, dated as of August 30, 2001, between Alliance Resource GP, LLC and Fifth Third Bank. (Incorporated by reference to Exhibit 10.24 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).

10.10 Letter of Credit Facility Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association. (Incorporated by reference to Exhibit 10.25 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).

10.11 First Amendment to the Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association. (Incorporated by reference to Exhibit 10.32 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 000-26823).

10.12 Promissory Note Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, N.A. (Incorporated by reference to Exhibit 10.26 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).

10.13 Guarantee Agreement, dated as of October 2, 2001, between Alliance Resource GP, LLC and Bank of the Lakes, N.A. (Incorporated by reference to Exhibit 10.27 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).

10.14 Guaranty Fee Agreement dated as of July 31, 2001, between Alliance Resource Partners, L.P. and Alliance Resource GP, LLC. (Incorporated by reference to Exhibit 10.28 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).

10.15 Contribution and Assumption Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC, Alliance Resource Partners, L.P., Alliance Resource Operating Partners, L.P. and the other parties named therein. (Incorporated by reference to Exhibit 10.3 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).

10.16 Omnibus Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC and Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 10.4 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).

10.17 Amended and Restated Alliance Resource Management GP, LLC 2000 Long-Term Incentive Plan. (Incorporated by reference to Exhibit 10.17 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, File No. 000-26823).

10.18 First Amendment to the Alliance Resource Management GP, LLC 2000 Long-Term Incentive Plan. (Incorporated by reference to Exhibit 10.18 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, File No. 000-26823).

10.19 Alliance Resource Management GP, LLC Short-Term Incentive Plan. (Incorporated by reference to Exhibit 10.12 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).

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10.20 Alliance Resource Management GP, LLC Supplemental Executive Retirement Plan. (Incorporated by reference to Exhibit 99.2 of the Registrant s Registration Statement on Form S-8 filed with the Commission on April 1, 2002 (Reg. No. 333-85258)).

10.21 Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors. (Incorporated by reference to Exhibit 99.3 of the Registrant s Registration Statement on Form S-8 filed with the Commission on April 1, 2002 (Reg. No. 333-85258)).

10.22 Restated and Amended Coal Supply Agreement, dated February 1, 1986, among Seminole Electric Cooperative, Inc., Webster County Coal Corporation and White County Coal Corporation. (Incorporated by reference to Exhibit 10.9 of the Registrant s Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).

10.23 Amendment No. 1 to the Restated and Amended Coal Supply Agreement effective April 1, 1996, between MAPCO Coal Inc., Webster County Coal Corporation, White County Coal Corporation, and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.14 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2000, File No. 000-26823).

10.24 Amendment No. 2 to the Restated and Amended Coal Supply Agreement effective February 28, 2002 between Webster County Coal, LLC, White County Coal, LLC, and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.32 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002, File No. 000-26823).

10.25 Amendment No. 3 to the Restated and Amended Coal Supply Agreement effective January 1, 2003 between Webster County Coal, LLC, White County Coal, LLC, Alliance Coal, LLC, and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.39 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2003, File No. 000-26823).

10.26 Interim Coal Supply Agreement effective May 1, 2000, between Alliance Coal, LLC and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.15 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2000, File No. 000-26823).

10.27 Agreement for Supply of Coal to the Mt. Storm Power Station, dated January 15, 1996, between Virginia Electric and Power Company and Mettiki Coal Corporation. (Incorporated by reference to Exhibit 10. (t) to MAPCO Inc. s Annual Report on Form 10-K, filed April 1, 1996, File No. 1-5254).

10.28 Memorandum of Understanding dated January 17, 2005 between VEPCO and Mettiki. (Incorporated by reference to Exhibit 10.2 of the Registrants Form 8-K filed with the Commission on January 19, 2005, File No. 000-26823).

10.29 Amendment No. 1 dated January 17, 2005 between VEPCO and Mettiki to the Coal Supply Agreement. (Incorporated by reference to Exhibit 10.2 of the Registrants Form 8-K filed with the Commission on January 19, 2005, File No. 000-26823).

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10.30	Coal Feedstock Supply Agreement dated October 26, 2001, between Synfuel Solutions Operating LLC and Hopkins County Coal, LLC (Incorporated by reference to Exhibit 10.27 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2001, File No. 000-26823).
10.31	First Amendment to Coal Feedstock Supply Agreement dated February 28, 2002, between Synfuel Solutions Operating LLC and Hopkins County Coal, LLC (Incorporated by reference to Exhibit 10.28 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2001, File No. 000-26823).
10.32	Second Amendment to Coal Feedstock Supply Agreement dated April 1, 2003, between Synfuel Solutions Operating LLC and Warrior Coal, LLC. (Incorporated by reference to Exhibit 10.40 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File No. 000-26823).
10.33	Assignment and Assumption Agreement dated April 1, 2003 between Synfuel Solutions Operating LLC, Hopkins County Coal, LLC, and Warrior Coal, LLC. (Incorporated by reference to Exhibit 10.31 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, File No. 000-26823).
10.34	Amended and Restated Put and Call Option Agreement dated February 12, 2001 between ARH Warrior Holdings, Inc. and Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 10.17 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2000, File No. 000-26823).
10.35	Letter Agreement dated January 31, 2003 between ARH Warrior Holdings, Inc. and Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 10.34 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002 File No. 000-26823).
10.36	Consulting Agreement for Mr. Sachse dated January 1, 2001. (Incorporated by reference to Exhibit 10.18 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2000, File No. 000-26823).
10.37	Extension of Consulting Agreement with Mr. Sachse, dated September 30, 2003. (Incorporated by reference to Exhibit 10.42 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, File No. 000-26823).
10.38	Form of Employee Agreements for Messrs. Craft, Pearson, Wesley and Rathburn. (Incorporated by reference to Exhibit 10.6 of the Registrant s Registration Statement on Form S 1/A filed with the Commission on August 9, 1999 (Reg. No. 333-78845)).
10.39	Security and Pledge Agreement dated as of May 8, 2002 by and among Alliance Resource Holdings II, Inc., AMH II, LLC, Alliance Resource Holdings, Inc., Alliance Resource GP, LLC, the Management Investors as identified therein, The Beacon Group Energy Investment Fund, L.P., MPC Partners, LP and three individuals as Sellers identified therein, and JPMorgan Chase Bank as collateral agent. (Incorporated by reference to Exhibit 99.2 of the Registrant s Form 8-K filed with the Commission on May 9, 2002, File No. 000-26823).

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10.40	Form of Promissory Note made by Alliance Resource Holdings, Inc. dated as of May 8, 2002. (Incorporated by reference to Exhibit 99.3 of the Registrant s Form 8-K filed with the Commission on May 9, 2002, File No. 000-26823).
10.41	Amended and Restated Charter for the Audit Committee of the Board of Directors dated March 10, 2005. (Incorporated by reference to Exhibit 10.41 of the Registrant s Annual Report on Form 10-K filed with the commission on March 15, 2005).
18.1	Preferability Letter on Accounting Change. (Incorporated by reference to Exhibit 18.1 of the Registrant s Amended Quarterly Report on Form 10-Q/A for the quarter ended March 31, 2001, File No. 000-26823).
21.1	List of Subsidiaries (Incorporated by reference to Exhibit 10.41 of the Registrant s Annual Report on Form 10-K filed with the commission on March 15, 2005).
* 23.1	Consent of Deloitte & Touche LLP regarding Form S-3 and Form S-8, Registration No. 333-85282 and No. 333-85258, respectively.
* 31.1	Certification of Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated August 15, 2005, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 furnished herewith.
* 31.2	Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated August 15, 2005, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 furnished herewith.
* 32.1	Certification of Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated August 15, 2005, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 furnished herewith.
* 32.2	Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated August 15, 2005, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 furnished herewith.

* Filed herewith.

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Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, in Tulsa, Oklahoma, on August 15, 2005.

ALLIANCE RESOURCE PARTNERS, L.P.

By: Alliance Resource Management GP, LLC
its managing general partner

/s/ Joseph W. Craft III

Joseph W. Craft III
President, Chief Executive Officer and Director

/s/ Brian L. Cantrell

Brian L. Cantrell
Senior Vice President and Chief Financial Officer

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

Signature	Title	Date
/s/ Joseph W. Craft III	President, Chief Executive Officer,	August 15, 2005
Joseph W. Craft III	and Director (Principal Executive Officer)	
/s/ Brian L. Cantrell	Senior Vice President and	August 15, 2005
Brian L. Cantrell	Chief Financial Officer	
/s/ Michael J. Hall	Director	August 15, 2005
Michael J. Hall		
/s/ John J. MacWilliams	Director	August 15, 2005
John J. MacWilliams		
/s/ Preston R. Miller, Jr.	Director	August 15, 2005
Preston R. Miller, Jr.		

/s/ John P. Neafsey John P. Neafsey	Director	August 15, 2005
/s/ John H. Robinson John H. Robinson	Director	August 15, 2005
/s/ Robert G. Sachse Robert G. Sachse	Executive Vice President and Director	August 15, 2005