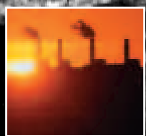
2003 ANNUAL REPORT

ON SOLID GROUND



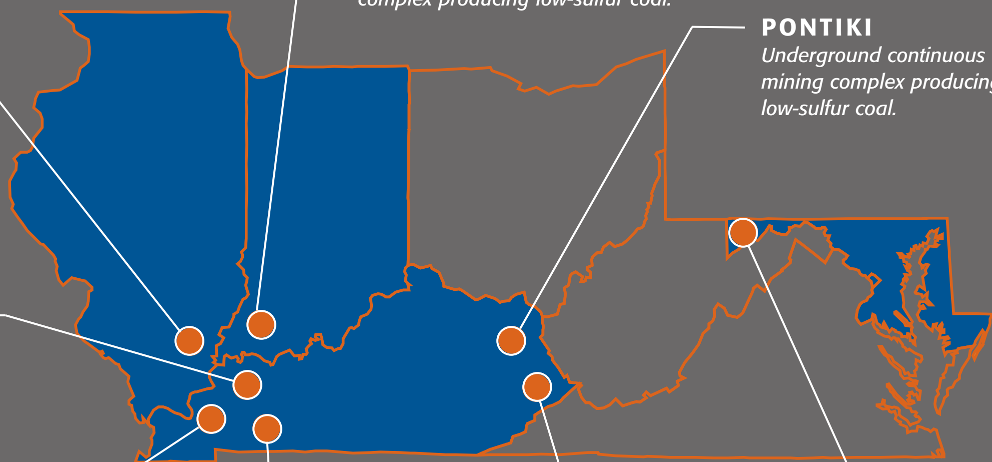
FIRM FOUNDATION. FOCUSED FUTURE.

ALLIANCE RESOURCE PARTNERS, L.P.

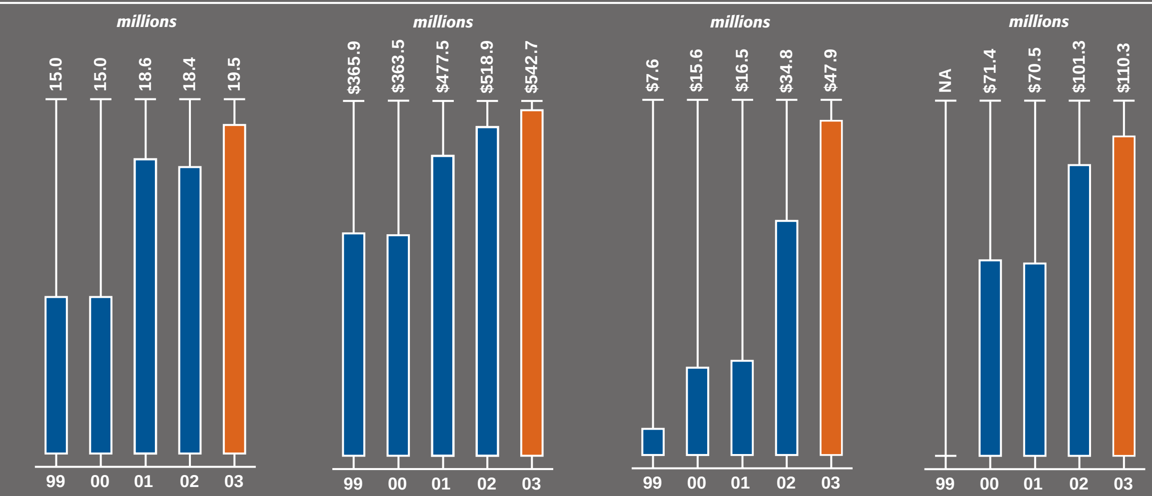
Alliance Resource Partners, L.P.

IS THE **nation's only** PUBLICLY TRADED MASTER LIMITED PARTNERSHIP INVOLVED IN THE **production** AND **marketing of coal.** WE HAVE BEEN A PUBLICLY TRADED PARTNERSHIP SINCE AUGUST 1999 AND ARE LISTED ON THE NASDAQ UNDER THE TICKER SYMBOL **"ARLP."**

WE OPERATE **seven active coal mining complexes** THROUGHOUT THE **eastern United States** AND SELL COAL FROM THREE OF THE FOUR **major coal-producing regions** OF THE COUNTRY.



TONS OF COAL SOLD* | **REVENUES*** | **NET INCOME*** | **CASH FLOW FROM OPERATIONS***



***Financial information for the year 1999 is pro forma, assuming the Partnership had been formed on January 1, 1999. Cash flow from operations is not available on a pro-forma basis.**
Net income for 2001 includes $7.9 million for the cumulative effect of the change in the method of estimating coal workers' black lung benefits liability effective January 1, 2001.

TO OUR FELLOW UNITHOLDERS:

Alliance Resource Partners continued to gain momentum throughout 2003, achieving record financial and operational performance for the third consecutive year – underscored by improvements of 5 percent in revenues, 7 percent in production, 9 percent in cash flow from operations and 38 percent in net income. This strong performance, fueled by the dedicated efforts of our entire organization and strategic initiatives to manage operating costs and increase capacity, again made Alliance the most profitable publicly traded coal company in America in 2003.

Clearly, as reinforced by our performance during 2003, we are **On Solid Ground** for continued growth and increased profitability.

Joseph W. Craft III
President and Chief Executive Officer

2003 FINANCIAL PERFORMANCE

For the fiscal year ended December 31, 2003, Alliance Resource Partners achieved net income of $47.9 million or $2.71 per basic limited partnership unit, compared to net income of $34.8 million or $2.31 per unit the prior year. Since 2000, our first full year as a publicly traded partnership, net income has increased at a compounded annual growth rate of 45 percent.

We realized record revenues of $542.7 million for 2003, compared to $518.9 million the previous year. Tons sold climbed by nearly 6 percent to a record 19.5 million tons, up from 18.4 million tons in 2002. Record levels of revenues and tons sold reflect the higher sales volume from improved production levels at essentially all of our active operations, partially offset by lower sales prices.

PARTNERSHIP UNITS

Alliance Resource Partners is the nation's only publicly traded master limited partnership involved in coal production and marketing. Our master limited partnership structure offers us flexibility and a low cost of capital, both of which we believe provide distinct advantages over many of our competitors. Our common units are traded on the NASDAQ National Market under the symbol "ARLP."

Our Board of Directors periodically reviews our distribution policy and declares distributions based primarily on earnings, cash flows, capital needs and the general outlook for the coal industry. As a reflection of our strong year-over-year cash flow growth and solid projections for

FINANCIAL HIGHLIGHTS

millions except per unit amounts	2003	2002
OPERATING DATA:		
Tons sold	19.5	18.4
Tons produced	19.2	18.0
Revenues per ton sold	$ 26.83	$ 27.17
Cost per ton sold[1]	$ 20.80	$ 21.63
FINANCIAL DATA:		
Revenues	$ 542.7	$ 518.9
Income from operations	$ 49.1	$ 33.2
Net income	$ 47.9	$ 34.8
Basic net income per LP unit[2]	$ 2.71	$ 2.31
Diluted net income per LP unit[2]	$ 2.62	$ 2.24
Total assets	$ 336.5	$ 316.9
Long-term debt, including current maturities	$ 180.0	$ 211.3
Net cash provided by operating activities	$ 110.3	$ 101.3

(1) See Note (6) on Page 27 of 2003 Form 10-K for cost per ton sold definition.

(2) The weighted average basic units outstanding for the years ended December 31, 2003 and 2002, were 17,580,734 and 15,405,311, respectively, and on a fully dilutive basis, were 18,162,839 and 15,842,708, respectively.

DOTIKI MINE: CHALLENGE MET

On February 11, 2004, an underground fire temporarily idled the Dotiki mine located near Providence, Kentucky, operated by our wholly owned Webster County Coal subsidiary. The early-morning fire originated from a diesel supply tractor that was located near two of the mine's six active mining areas.

Webster County Coal, working closely with industry experts from the Mine Safety and Health Administration (MSHA) and the Kentucky Department of Mines and Minerals (KDMM), quickly developed and implemented a state-of-the-art mine recovery plan. The jointly developed recovery plan utilized remote sensing techniques to ascertain the extent of the fire damage and to monitor the mine atmosphere. To establish a perimeter around the fire, 18 underground barriers or seals were pumped through bore holes drilled from the surface. Carbon dioxide and nitrogen were injected through these bore holes into the fire zone to remove oxygen and stabilize the mine atmosphere. Once the remote seal construction was completed and the mine atmosphere behind the seals was rendered inert, mine rescue teams from MSHA, KDMM and Alliance's Webster County Coal, White County Coal, Gibson County Coal and Warrior Coal subsidiaries entered the Dotiki mine, restored ventilation and constructed 32 permanent seals. These efforts effectively extinguished the

the future, our Board of Directors increased the quarterly cash distribution to unitholders for the second year in a row. Beginning with the fourth quarter of 2003, the quarterly cash distribution to unitholders was increased more than 7 percent to $0.5625 per unit or an annualized rate of $2.25 per unit, up from the previous $0.525 per unit or an annualized rate of $2.10 per unit.

With management beneficially owning approximately 45 percent of our units outstanding, management continues to be fully aligned with the interests of our unitholders. We reached a significant milestone on November 15, 2003, when 3,211,265 subordinated units, or one-half of Alliance's outstanding subordinated units held by our special general partner, were converted into common units in accordance with an early conversion financial test in the partnership agreement. At year-end 2003, our special general partner owned 4,444,045 common units and 3,211,266 subordinated units of the 17,903,793 total units outstanding. Assuming we continue to meet the financial test requirements of our partnership agreement, the remaining subordinated units will convert into common units in the fourth quarter of 2004.

During February and March 2003, we completed a secondary equity offering of 2,538,000 common units priced at $22.51 per unit. We used the net proceeds of approximately $53.9 million to finance the acquisition of Warrior Coal, as well as for working capital and general partnership purposes.

Largely as a result of our performance and an improving marketplace, the Partnership's common unit price continued to climb, providing a total return to unitholders in 2003 of approximately 51 percent year-over-year.

CORE STRENGTHS AND GROWTH STRATEGIES

Alliance Resource Partners, in pursuit of sustained cash flow growth and profitability, continues to build on its core strengths and strategies – strategic investments, highly productive workforce, geographic and product diversity, and long-term third-party relationships.

Strategic Investments

We remain committed to securing our future through strategic capital investments as the foundation for growth in both productivity and profits. During 2003, we invested a total of $55.7 million in existing assets and acquisitions. Our investment in existing assets included maintenance capital expenditures, efficiency projects and organic growth opportunities. We anticipate capital expenditures of approximately $46.5 million in 2004, primarily for maintenance capital expenditures as well as additional efficiency initiatives.

EFFICIENCY PROJECTS: We completed several efficiency projects during 2003 including construction of new mine shafts at Dotiki and our MC Mining facility and completion of a new slope at Warrior Coal. As a result of these projects, we enhanced mine ventilation, improved access for our miners and materials, and at Warrior Coal reduced the time required to transport coal from underground to our preparation plant.

We continue to invest in advanced coal preparation processes. At the Pattiki mine, we installed an ultra-fine processing circuit that substantially reduces ash levels and increases the thermal energy in the processed coal. As a result, the preparation plant's product recovery has improved more than 5 percent while operating and maintenance costs have decreased. At the Dotiki mine, we are developing and testing technology to improve the quality of coal before it is processed. This "Rock Avoidance System" uses gamma sensors, motion sensors and microprocessor controls to assist continuous miner operators in controlling out-of-seam dilution.

ORGANIC GROWTH: Throughout 2003, we continued efforts to optimize our existing assets and maximize operating capacity. At Pattiki, we completed the transition into an adjacent coal reserve area. Production capacity also was increased through the addition of mining units at MC Mining, Gibson County Coal and Warrior Coal.

WARRIOR COAL ACQUISITION: In addition to continuing investments in our existing assets, we continually evaluate potential growth opportunities through acquisitions. On February 14, 2003, we acquired Warrior Coal, LLC from ARH Warrior Holdings, Inc., a company indirectly owned by our management. The $29.7 million acquisition included a cash purchase price of $12.7 million and the repayment of $17.0 million in debt used to finance infrastructure capital projects to improve productivity and increase capacity. We funded the transaction with a portion of the net proceeds realized from the secondary equity offering mentioned previously.

mine fire and totally isolated the affected area of the Dotiki mine behind permanent seals.

Early estimates to recover the Dotiki mine using conventional methods ranged from a period of several months to one year. As a result of the cooperative efforts of and teamwork between MSHA, KDMM and Webster County Coal, as well as all the others who supported our mine recovery efforts, the Dotiki mine resumed production in an unprecedented 28 days after the fire incident occurred – mine recovery results never before seen in the coal mining industry. Alliance is committed to continuing work with MSHA's Technical Support Department to refine the mine recovery methods used at our Dotiki mine in order to benefit the entire coal industry.

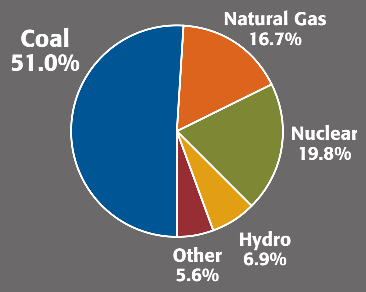
Even though the Dotiki mine returned to production in record time, we are particularly grateful that this occurred without injury to anyone involved in the around-the-clock firefighting and mine recovery operation. We are indebted to the heroic efforts of our employees and the hundreds of individuals responsible for this extraordinary safety achievement. We are especially appreciative for the support provided by our local communities, landowners, customers and suppliers during the difficult times in early 2004.

Warrior Coal is an underground mining complex that utilizes continuous mining units employing room-and-pillar mining techniques. Located near Madisonville, Kentucky, the complex is adjacent to our other western Kentucky operations. Warrior's coal production was approximately 2.4 million tons for 2003. Essentially all of this production was sold as feedstock for synfuel production to Synfuel Solutions Operating LLC, whose coal-synfuel production facility was moved from our Hopkins County complex to Warrior Coal.

HOPKINS COUNTY IDLED: We also idled two surface mines and closed a depleted underground mine at Hopkins County Coal. We reached this difficult decision after we were unable to secure any meaningful new sales commitments for our Hopkins County Coal production. Without firm sales commitments, we elected to idle our operations and halted production in June 2003. Although we were able to redeploy miners and equipment from the closed underground mine to Warrior Coal, the Hopkins County operations will remain idle until sufficient sales commitments for the complex's production are secured.

U.S. ELECTRICITY FUEL SOURCES

Electricity Generation by Fuel Source 2003



Source: Energy Information Administration Review

Productive Workforce

Our workforce is committed to optimizing our production capacity, improving operating efficiencies and reinforcing our position as a low-cost producer for the markets we serve. The efforts of our dedicated employees continue to deliver measurable results. Their efforts, coupled with the infrastructure investments completed over the last several years, have increased productivity and reduced operating costs at essentially all of our active mining complexes in 2003, and resulted in an approximate 4 percent reduction in cost per ton sold over the prior year.

As we seek to control costs and increase production, the safety of our workers, our facilities and the communities in which we operate remains our first and foremost priority. Our "non-fatal-days-lost" or NFDL rating for 2003, an industry measure of safety, was 54 percent below the industry average. The effectiveness of our safety training and procedures was underscored by the recent events at our Dotiki mine *(see sidebar).* The entire firefighting and mine recovery effort at Dotiki was accomplished in record time without injury.

Diversity

Ranking as the eighth largest coal producer in the eastern United States and approximately the 13th largest in the nation, Alliance produces a wide range of steam coals with varied sulfur and heat contents to meet the diverse specifications of our customers. In 2003, 31.2 percent of the coal we produced was low-sulfur, 17.2 percent was medium-sulfur and 51.6 percent was high-sulfur. Currently, we operate seven active coal mining complexes throughout the eastern United States in Illinois, Indiana, Kentucky and Maryland, and sell coal from three of the four major coal-producing regions of the country.

Our substantial coal reserve base provides additional support for sustained, long-term growth. At year-end 2003, we had approximately 418.4 million tons of proven and probable reserves. Our reserve estimates are based on geological data we gather through extensive, ongoing exploration drilling and in-mine channel sampling programs and reflect reserves that we currently believe can be economically and legally produced.

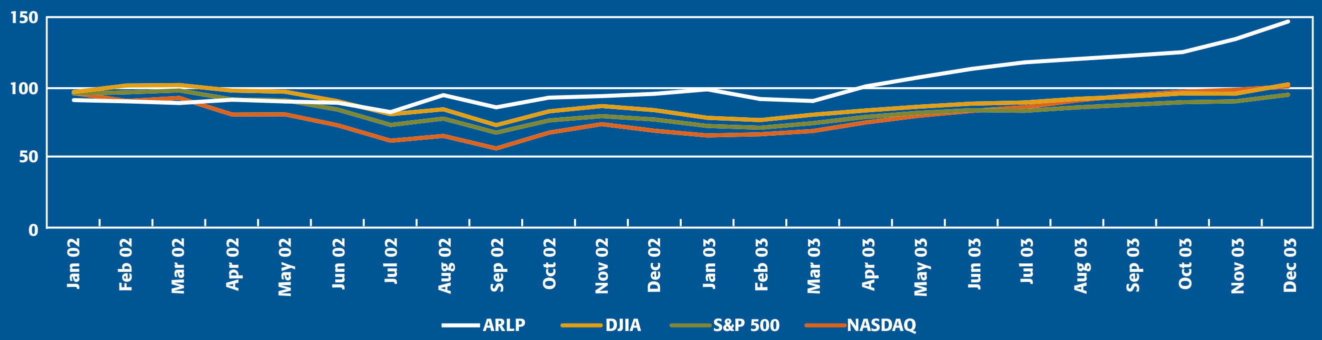
This strategic diversity in both geography and the coal types we produce delivers added stability to our production costs and cash flows, reducing our risk and limiting our exposure to a downturn in any single market segment.

Long-term Customer Relationships

We market coal to major U.S. utilities that use our coal for base-load electricity generation, as well as to other industrial users. Approximately 84 percent of both our sales tonnage and total coal sales were sold under long-term contracts with maturities ranging from 2003 to 2023. We continue to employ a strategy of maintaining a significant

MARKET PERFORMANCE COMPARISON

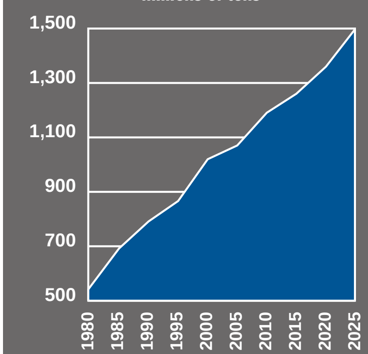
Trading History – Jan 02 to Dec 03
Trading data adjusted to reflect dividends or distributions



long-term contract position, which historically has reduced volatility during market cycles. This strategy has enhanced our stability and profitability by providing greater predictability of sales volumes and sales prices.

TVA AGREEMENT: In January 2004, we entered into a 20-year, 30-million-ton coal sales agreement to supply Illinois Basin coal to the Tennessee Valley Authority's (TVA) coal-fired power plants. On January 1, 2004, Webster County Coal's Dotiki mine began to provide approximately 1.0 million tons of coal to TVA, with annual shipments increasing to 1.5 million tons beginning in 2005. Our agreement with TVA contains periodic contract re-opening provisions addressing market price and other terms and conditions.

U.S. COAL DEMAND
millions of tons



Source: EIA Annual Energy Outlook 2003 Reference Guide

SALES CONTRACTS: We have also concluded multi-year coal sales contracts with several other customers beginning in 2004. We have commitments for substantially all of our anticipated 2004 coal production, which we now estimate at 20.2 million tons. For 2005, we currently estimate coal production levels similar to 2004, with approximately 86 percent of that volume committed under existing coal sales agreements and approximately 46 percent subject to market price negotiations.

OUTLOOK FOR THE FUTURE

The long-term market outlook for coal is as strong as ever, and coal continues to be the fuel of choice for base-load electricity generation nationwide. Current marketplace fundamentals are encouraging. Electricity generation, in large part, typically tracks GDP growth and the weather. Today's stronger economy and GDP growth in the 4-6 percent range are positive signs for industry growth and demand for coal. We expect higher per-ton sales prices in 2004, partially offset by slightly higher per-ton costs.

Going forward, the outlook for Alliance Resource Partners is positive and promising. We anticipate stable, improving demand for our product and are firmly positioned to take advantage of potential additional demand in the markets we serve. Capital investments in recent years give us excess production capacity to respond to increased marketplace demand from our existing infrastructure without significant additional capital investment.

ORGANIC GROWTH AND ACQUISITIONS: Historically, we have grown through a combination of organic growth and acquisitions, and we anticipate continuing that successful strategy. We plan to continue looking for acquisitions and other investments capable of generating consistent cash flow and earnings growth. Anticipated consolidation in our industry as well as other industries should provide opportunities for accretive transactions, and we intend to participate in those opportunities.

GOALS AND STRATEGIES: We will continue to focus strategically on our foundation – optimizing our capacity, reinforcing our position as a low-cost producer and capturing increased market share with our existing assets. We remain fully committed to delivering on our goal of sustained growth in earnings and cash flow.

I am extremely proud of our performance in 2003 and extend my utmost appreciation to all of our employees for their help in making this our best year ever. The entire Alliance organization is committed to excellence and to achieving superior results in the future. It is especially gratifying to be able to share our success with you, our unitholders. I want to thank each of our unitholders for your past support and continued confidence in our future.

Together, we look forward to focusing on a future of continued growth and progress at Alliance Resource Partners.

Joe Craft

Joseph W. Craft III
President and Chief
Executive Officer

April 2004

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

FORM 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2003

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 (STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION)	73-1564280 (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 $272,396,559 as of June 30, 2003, the last business day of the registrant's most recently completed second fiscal quarter, based on $27.25 per unit, the closing price of the common units as reported on the Nasdaq National Market on such date.

As of March 12, 2004, 14,692,527 common units and 3,211,266 subordinated units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: None

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FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K 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 respect 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 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 10.0% participation (excluding any applicable deductible) in our commercial insurance property program.

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;
- 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.

PART I

ITEM 1. BUSINESS

General

We are a diversified producer and marketer of coal to major United States utilities and industrial users. We began mining operations in 1971 and, since then, have grown through acquisitions and internal development to become what we believe to be the eighth largest coal producer in the eastern United States. At December 31, 2003, we had approximately 418.4 million tons of reserves in Illinois, Indiana, Kentucky, Maryland and West Virginia. In 2003, we produced 19.2 million tons of coal and sold 19.5 million tons of coal. The coal we produced in 2003 was 31.2% low-sulfur coal, 17.2% medium-sulfur coal and 51.6% high-sulfur coal. In 2003, approximately 89% 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 classify low-sulfur coal as coal with a sulfur content of less than 1%, medium-sulfur coal as coal with a sulfur content between 1% and 2%, and high-sulfur coal as coal with a sulfur content of greater than 2%.

At December 31, 2003, we operated seven underground mining complexes in Illinois, Indiana, Kentucky and Maryland. We have one surface operation that is currently idle. Our mining activities are organized into three operating regions: (a) the Illinois Basin operations, (b) the East Kentucky operations, and (c) the Maryland operations. We also host and operate a coal synfuel facility, supply the facility with coal feedstock, assist with the marketing of coal synfuel, and provide other services to the owner of the synfuel facility. We have no reportable segments because our operations solely consist of producing and marketing coal and providing rental and service fees associated with producing and marketing coal synfuel.

We and our subsidiary, Alliance Resource Operating Partners, L.P. (referred to as the intermediate partnership), are Delaware limited partnerships formed to acquire, own and operate certain coal production and marketing assets of Alliance Resource Holdings, Inc., (Alliance Resource Holdings) a Delaware corporation formerly known as Alliance Coal Corporation. We completed our initial public offering in August 1999, at which time Alliance Resource Holdings contributed certain assets in exchange for cash, common and subordinated units, general partner interests, the right to receive incentive distributions as defined in the partnership agreement, and the assumption of related indebtedness.

Our managing general partner, Alliance Resource Management GP, LLC, and our special general partner, Alliance Resource GP, LLC (collectively referred to as our general partners) own an aggregate 2% general partner interest in us. Our limited partners, including the general partners as holders of common units and subordinated units, own an aggregate 98% limited partner interest in us.

The coal production and marketing assets of Alliance Resource Holdings acquired by us, but not Alliance Resource Holdings, are referred to as our "Predecessor." All 1999 operating data contained herein includes our results and our Predecessor's results.

Our internet address is www.arlp.com, and we make available on our internet website our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K, and Form 4's for our Section 16 filers (and amendments and exhibits, such as press releases, to such filings) as soon as reasonably practicable after we electronically file with or furnish such material to the Securities and Exchange Commission. Our "Code of Ethics" for our chief executive officer and our senior financial officers is also posted on our website.

Recent Developments

Dotiki Mine Fire

On February 11, 2004 the Dotiki mine was temporarily idled following the occurrence of a mine fire. The fire originated from a diesel supply tractor located in an area near two of the mine's active mining areas. All employees were evacuated without injury. Working closely and cooperatively with federal and state mine safety agencies, which continuously had representatives on site, Dotiki personnel began implementing a plan to isolate and extinguish the fire. Fire fighting techniques initially focused on rendering the mine atmosphere inert by cutting off oxygen to the fire through a combination of temporarily sealing two main underground passageways and one of four mine portals, creating an initial set of temporary seals from the surface through boreholes and injecting nitrogen and carbon dioxide gases into the mine.

Once the mine atmosphere was rendered inert, recovery personnel re-entered the mine and created a second set of temporary seals to further contain the area of the mine impacted by the fire. Mine personnel then constructed permanent seals. With the injection of inert gases complete, the mine fire was effectively extinguished, and the affected area of the mine was totally isolated behind the permanent seals on or about March 4, 2004. Once the permanent seals were installed and the mine safely ventilated, Dotiki crews performed a thorough examination of the entire mine. Information obtained during these examinations indicated minimal impact to the mine outside of the permanently sealed fire area. All six mining units returned to production on March 8, 2004. We are unable to predict at this time when the mine will return to normal production levels.

The temporary idling of Dotiki will reduce earnings for the first quarter of 2004. At this time, we are unable to quantify the financial impact of the fire. We have commercial property insurance (including business interruption coverage) that we currently believe should cover a substantial portion of the financial loss. Assuming that is correct, Dotiki's losses recognized in the first quarter of 2004 should be substantially offset by an insurance settlement that would be recognized later in the year. There can be no assurance of the amount or timing of recovery, however, until the claim is resolved with the insurance underwriter. Our insurance program provides for a deductible of $3.5 million and a ten percent coinsurance. In addition to the losses associated with business interruption, we have currently identified approximately $6.0 million of out-of-pocket expenses that generally fall into the category of extra expenses, expedited expenses and other areas of coverage under the commercial property insurance policy. We expect that additional out-of-pocket costs will be identified in the future.

Transactions in 2003

Common Unit Offering

On February 14, 2003, we completed a public offering of 2,250,000 common units from which we received net proceeds of approximately $48.5 million before expenses, and on March 14, 2003, we received net proceeds of approximately $6.2 million before expenses from the exercise of the underwriters option to purchase an additional 288,000 common units. We used the net proceeds to fund the purchase of Warrior Coal, LLC (Warrior) and for working capital and general partnership purposes.

Warrior Acquisition

In February 2003, we acquired Warrior from an affiliate, ARH Warrior Holdings, Inc. (ARH Warrior Holdings), in accordance with the terms of an Amended and Restated Put and Call Option Agreement. We paid $12.7 million to ARH Warrior Holdings and repaid Warrior's borrowings of $17.0 million under a revolving credit agreement between an affiliate of ARH Warrior Holdings and Warrior. Please see "Item 8. Financial Statements and Supplementary Data – Note 3, Warrior Coal Acquisition."

Conversion of Subordinated Units

Our partnership agreement provides for the early conversion of one-half of the subordinated units if certain financial tests were satisfied before September 30, 2003. We satisfied the required financial tests for converting one-half of the subordinated units into common units as provided for under applicable provisions in our partnership agreement. Accordingly, in October 2003 the board of directors (and its conflicts committee) of our managing general partner approved management's determination that such conversion financial tests were satisfied. As a result, one-half of the outstanding subordinated units (i.e., 3,211,265 subordinated units) held by our special general partner converted into common units on November 15, 2003. The remaining 3,211,266 subordinated units are expected to convert on a one-for-one basis into common units in the fourth quarter of 2004, assuming we continue to meet the financial test requirements of our partnership agreement.

Management Buy-Out of Beacon Group Funds' Interests

Prior to May 2002, the majority of the outstanding equity interests in our general partners was owned by two investment funds controlled by The Beacon Group, LP (The Beacon Group) and its affiliates. In May 2002, our management purchased these interests, which consisted of:

- a 74.1% interest in our managing general partner for $4.8 million in cash; and

- a 91.3% interest in Alliance Resource Holdings, the parent of our special general partner (which owns 4,444,045 common units and 3,211,266 subordinated units) for approximately $103.4 million, consisting of approximately $46.7 million in cash and approximately $56.7 million in promissory notes.

As a result, our management now owns all of the interests in our managing general partner and Alliance Resource Holdings. The acquisitions were not funded or secured with any of our assets. In May 2003 management refinanced the remaining balance due on the promissory notes of $23.4 million with a commercial banking facility, secured by certain assets owned by subsidiaries of Alliance Resource Holdings. Some of the secured assets are leased to us by subsidiaries of Alliance Resource Holdings. A security and pledge agreement with The Beacon Group associated with the original promissory notes was cancelled in conjunction with the refinancing. The intermediate partnership and our subsidiary, Alliance Coal, LLC (Alliance Coal), have issued a parent guarantee on the reserve leases between SGP Land, LLC (SGP Land), a subsidiary of our special general partner, and us. Please see "Item 8. Financial Statements and Supplementary Data. – Note 16, Related Party Transactions."

Mining Operations

We produce a diverse range of steam coals with varying sulfur and heat contents, which enables us to satisfy the broad range of specifications required by our customers. The following chart summarizes our coal production by region for the last five years.

Operating Regions and Complexes	2003	2002	2001	2000	1999
			(tons in millions)		
Illinois Basin Operations:					
Dotiki, Gibson, Hopkins, Pattiki, Warrior Complexes	12.3	12.1	11.9	8.4	8.5
East Kentucky Operations:					
MC Mining, Pontiki Complexes	3.6	3.0	2.8	2.7	2.8
Maryland Operations:					
Mettiki Complex	3.3	2.9	2.7	2.6	2.8
Total	19.2	18.0	17.4	13.7	14.1

Illinois Basin Operations

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. We have approximately 1,075 employees in the Illinois Basin and currently operate four mining complexes. Additionally, we host a coal synfuel facility at one of our mining complexes.

Dotiki Complex. Webster County Coal, LLC operates Dotiki, which is an underground mining complex located near the city of Providence in Webster County, Kentucky. The complex was opened in 1966, and we purchased the mine in 1971. Our Dotiki complex utilizes continuous mining units employing room-and-pillar mining techniques. In 2004, Dotiki plans to increase the number of mining sections that operate with two continuous miners. The preparation plant currently has a throughput capacity of 1,000 tons of raw coal an hour which capacity will be expanded by approximately 30% in 2004, principally to accommodate a change in customer requirements for washed coal rather than raw coal. On February 11, 2004, the Dotiki mine was temporarily idled following the occurrence of a mine fire. We have successfully extinguished the fire and have totally isolated the affected area of the mine behind permanent seals. Production resumed on March 8, 2004. However, we are unable to predict at this time when Dotiki will return to normal production. For information on the fire at our Dotiki mine, please see "Recent Developments – Dotiki Mine Fire" above.

Production of high-sulfur coal from the complex is shipped via the CSX and PAL railroads and by truck on U.S. and state highways. Our primary customers for coal produced at Dotiki are Louisville Gas & Electric (LG&E), Seminole Electric Cooperative, Inc. (Seminole) and Tennessee Valley Authority (TVA), all of which purchase our coal pursuant to long-term contracts for use in their scrubbed generating units. In April 2003, Dotiki completed construction of a new mine shaft and ancillary facilities which provides new access to the coal reserves for miners and supplies.

Warrior Complex. Warrior Coal, LLC operates Warrior, an underground mining complex located near Madisonville, in Hopkins County, Kentucky, between and adjacent to our other western Kentucky operations. The Warrior complex was opened in 1985. Warrior utilizes continuous mining units employing room-and-pillar mining techniques producing high-sulfur coal. In September 2002, Warrior completed construction of a new shaft that provides new access to the coal reserves for miners and supplies. In April 2003, a continuous mining unit was added and a new slope was completed. The new slope provides improved ventilation and more efficient transportation of the coal from underground to the preparation plant. Warrior's preparation plant has a throughput capacity of 600 tons of raw coal an hour.

Production from Warrior in 2002 and into 2003 was shipped via truck on U.S. and state highways primarily to our Hopkins County Coal, LLC (Hopkins) complex for resale to our customer Synfuel Solutions Operating LLC (SSO). At our Hopkins complex, this coal was used as feedstock in the production of coal synfuel, as discussed under "Coal Synfuel" below. SSO's coal synfuel production facility was moved from Hopkins to Warrior in April 2003, and Warrior now sells substantially all of its production to SSO. Warrior's production can be shipped via the CSX and PAL railroads and by truck on U.S. and state highways. Additionally, Warrior now purchases supplemental production from Dotiki for resale to SSO. SSO continues to ship coal synfuel to electric utilities that have been purchasers of our coal. We maintain "back-up" coal supply agreements with these long-term customers for our coal, which automatically provide for the sale of our coal to them in the event they do not purchase coal synfuel from SSO.

Pattiki Complex. White County Coal, LLC operates Pattiki, which is an underground mining complex located near the city of Carmi, in White County, Illinois. We began construction of the complex in 1980 and have operated it since its inception. Our Pattiki complex utilizes continuous mining units employing room-and-pillar mining techniques. During 2001 and 2002, we extended Pattiki into adjacent coal reserves, through the construction of two new shafts and ancillary facilities. The preparation plant has a throughput capacity of 1,000 tons of raw coal an hour.

Production of high-sulfur coal from the complex is shipped via the CSX railroad. Our primary customers for coal produced at Pattiki are Ameren Energy Fuels & Services Company, Northern Indiana Public Service Company (NIPSCO), and Seminole for use in their generating units. NIPSCO and Seminole have scrubbed generating units.

Hopkins Complex. Hopkins County Coal, LLC owns Hopkins, a mining complex that is currently idle and located near the city of Madisonville in Hopkins County, Kentucky. We acquired the complex in January 1998. The complex has two inactive surface mines which utilize dragline mining. The preparation plant has a throughput capacity of 1,000 tons of raw coal an hour.

The Hopkins complex was idled in June 2003 because we were unable to secure sufficient sales commitments in the Illinois Basin region. The Hopkins complex will remain idle until sufficient sales commitments for the Illinois Basin region are secured. In April 2003, Hopkins depleted the coal reserves of its active underground mine.

During 2002 and into 2003, the majority of Hopkins high-sulfur production was sold to SSO, whose coal synfuel production facility was located at Hopkins. SSO's coal synfuel production facility was moved from Hopkins to Warrior in April 2003. Historically, Hopkins' production was shipped via the CSX and PAL railroads and by truck on U.S. and state highways.

Gibson Complex. Gibson County Coal, LLC operates Gibson, an underground mining complex located near the city of Princeton in Gibson County, Indiana. The mine began production in November 2000. Our Gibson complex utilizes continuous mining units employing room-and-pillar mining techniques. In February 2003, Gibson added a continuous mining unit. The preparation plant has a throughput capacity of 700 tons of raw coal an hour. We refer to the reserves mined at this location as the Gibson “North” reserves. We also control undeveloped reserves in Gibson County, which are not contiguous to the reserves currently being mined. We refer to these as the Gibson “South” reserves.

Production from Gibson is a low-sulfur coal, primarily shipped via truck approximately 10 miles on U.S. and state highways to Gibson’s principal customer, PSI Energy Inc. (PSI), a subsidiary of Cinergy Corporation. Gibson's production can also be trucked to our Mt. Vernon transloading facility for sale to utilities capable of receiving barge deliveries.

Coal Synfuel. We entered into long-term agreements with SSO to host and operate its coal synfuel facility currently located at Warrior, supply the facility with coal feedstock, assist SSO with the marketing of coal synfuel and provide other services. These agreements expire on December 31, 2007 and provide us with coal sales, 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. As discussed above, we sell most of the coal produced at Warrior to SSO, while Alliance Coal Sales, a division of Alliance Coal, assists SSO with the sale of its coal synfuel to our customers pursuant to a sales agency agreement. The term of each of these 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 revenues associated with the coal synfuel production facility cannot be assured. However, 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 to Warrior, agreements for providing certain of these services were assigned to Alliance Service, Inc. (Alliance Service), a wholly-owed subsidiary of Alliance Coal, in December 2002. Alliance Service is subject to federal and state income taxes.

For 2003, the incremental annual net income benefit from the combination of the various coal synfuel-related agreements was approximately $15.5 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 Internal Revenue Service (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.

East Kentucky Operations

Our East Kentucky mining operations are located in the Central Appalachia coal fields. Our East Kentucky mines produce low-sulfur coal. We have approximately 480 employees and operate two mining complexes in East Kentucky.

Pontiki Complex. Pontiki Coal, LLC owns Pontiki, an underground mining complex located near the city of Inez in Martin County, Kentucky. We constructed the mine in 1977. Pontiki owns the mining complex and leases the reserves, and Excel Mining, LLC (Excel), an affiliate of Pontiki, is responsible for conducting all mining operations. Substantially all of the coal produced at Pontiki meets or exceeds the compliance requirements of Phase II of the Clean Air Act amendments. Our Pontiki operation utilizes continuous mining units employing room-and-pillar mining techniques. The preparation plant has a throughput capacity of 800 tons of raw coal an hour.

Our primary customer for the low-sulfur coal produced at Pontiki is AEI Coal Sales Company, Inc. Production from the mine is shipped primarily to electric utilities located in the southeastern United States via the Norfolk Southern railroad or by truck via U.S. and state highways to various docks on the Big Sandy River in Kentucky.

MC Mining Complex. MC Mining, LLC owns MC Mining, an underground mining complex located near the city of Pikeville in Pike County, Kentucky. We acquired the mine in 1989. MC Mining owns the mining complex and leases the reserves, and Excel, an affiliate of MC Mining, is responsible for conducting all mining operations. The complex utilizes continuous mining units employing room-and-pillar mining techniques. In August 2003, MC Mining completed construction of a new shaft and added a continuous mining unit. The new mine shaft provides new access to the coal reserves for miners and supplies. The preparation plant has a throughput capacity of 800 tons of raw coal an hour.

Production from the mine is shipped via the CSX railroad or by truck via U.S. and state highways to various docks on the Big Sandy River. MC Mining sells its low-sulfur production primarily in the spot market.

Maryland Operations

Our Maryland mining operation is located in the Northern Appalachia coal fields. We have approximately 220 employees and operate one mining complex in Maryland.

Mettiki Complex. Mettiki Coal, LLC operates Mettiki, an underground longwall mining complex located near the city of Oakland in Garrett County, Maryland. We constructed Mettiki in 1977 and have operated it since its inception. The operation utilizes a longwall miner for the majority of the coal extraction as well as continuous mining units used to prepare the mine for future longwall mining. The preparation plant has a throughput capacity of 1,350 tons of raw coal an hour.

Our primary customer for the medium-sulfur coal produced at Mettiki is Virginia Electric and Power Company (VEPCO), which purchases the coal pursuant to a long-term contract for use in the scrubbed generating units at its Mt. Storm, West Virginia power plant, located less than 20 miles away. Our coal is trucked to Mt. Storm over a private haul road, which links to a state highway. Mettiki is also served by the CSX railroad.

Mettiki Coal (WV). Mettiki Coal (WV), LLC has approximately 23.3 million tons of undeveloped reserves in Grant and Tucker Counties, West Virginia close to Mettiki in Garrett County, Maryland. We currently do not conduct mining operations at Mettiki Coal (WV).

Other Operations

Mt. Vernon Transfer Terminal, LLC

The Mt. Vernon transfer terminal is a rail-to-barge loading terminal on the Ohio River at Mt. Vernon, Indiana. The terminal has a capacity of 8 million tons per year with existing ground storage. During 2003, the terminal loaded approximately 1.3 million tons for Pattiki and Dotiki customers and for third-party shippers.

Coal Brokerage

We buy coal from outside producers principally throughout the eastern United States, which we then resell, both directly and indirectly, to utility and industrial customers. We purchased and sold approximately 191,000 tons of outside coal from non-affiliates in 2003. We have a policy of matching our outside coal purchases and sales to minimize market risks associated with buying and reselling coal.

Additional Services

We develop and market additional services in order to establish ourselves as the supplier of choice for our customers. Examples of the kind of services we have offered to date include ash and scrubber sludge removal, coal yard maintenance, and arranging alternate transportation services. Revenues from these services represented less than one percent of our total revenues.

Coal Marketing and Sales

As is customary in the coal industry, we have entered into long-term contracts with many of our customers. These arrangements are mutually beneficial by contributing to both our customers' and our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2003, approximately 84% of both our sales tonnage and total coal sales, respectively, were sold under long-term contracts (contracts having a term of greater than one year) with maturities ranging from 2003 to 2023. Our total nominal commitment under significant long-term contracts was approximately 97.6 million tons at December 31, 2003, and is expected to be delivered as follows: 17.5 million tons in 2004, 16.4 million tons in 2005, 15.8 million tons in 2006, 8.3 million tons in 2007, 6.0 million tons in 2008, and 33.6 million tons thereafter during the remaining terms of the relevant coal supply agreements. The total commitment of coal under contract is an approximate number because, in some instances, our contracts contain provisions that could cause the nominal total commitment to increase or decrease by as much as 20%. The contractual time commitments for customers to nominate future purchase volumes under these contracts are sufficient to allow us to balance our sales commitments with prospective production capacity. In addition, the nominal total commitment can otherwise change because of price reopener provisions contained in certain of these long-term contracts.

The terms of long-term contracts are the results of both bidding procedures and extensive negotiations with each customer. As a result, the terms of these contracts vary significantly in many respects, including, among others, price adjustment features, price and contract reopener terms, permitted sources of supply, force majeure provisions, coal qualities, and quantities. Virtually all of our long-term contracts are subject to price adjustment provisions, which permit an increase or decrease periodically in the contract price to reflect changes in specified price indices or items such as taxes, royalties or actual production costs. These provisions, however, may not assure that the contract price will reflect every change in production or other costs. Failure of the parties to agree on a price pursuant to an adjustment or a reopener provision can lead to early termination of a contract. Some of the long-term contracts also permit the contract to be reopened to renegotiate terms and conditions other than the pricing terms, and where a mutually acceptable agreement on terms and conditions cannot be concluded, either party may have the option to terminate the contract. The long-term contracts typically stipulate procedures for quality control, sampling and weighing. Most contain provisions requiring us to deliver coal within stated ranges for specific coal characteristics such as heat, sulfur, ash, moisture, grindability, volatility and other qualities. Failure to meet these specifications can result in economic penalties or termination of the contracts. While most of the contracts specify the approved seams and/or approved locations from which the coal is to be mined, some contracts allow the coal to be sourced from more than one mine or location. Although the volume to be delivered pursuant to a long-term contract is stipulated, the buyers often have the option to vary the volume within specified limits.

Reliance on Major Customers

Our three largest customers in 2003 were Seminole, SSO, and VEPCO. Sales to these customers in the aggregate accounted for approximately 46% of our 2003 total revenues, and sales to each of these customers accounted for 10% or more of our 2003 total revenues.

In February 2002, a major customer of Pontiki, AEI Coal Sales Company, Inc., and numerous of its affiliates voluntarily filed for Chapter 11 bankruptcy protection. In May 2002, those companies emerged from bankruptcy proceedings under a joint plan of reorganization under a new name for their parent entity, Horizon Natural Resources Company (Horizon). We did not incur any losses associated with this bankruptcy filing. Subsequently, in November 2002, Horizon and its numerous affiliates again voluntarily filed for Chapter 11 bankruptcy protection. We believe that our payment terms with this customer protect us from any significant bad debt exposure and at December 31, 2003 we did not have any accounts receivable from this customer. Although Horizon has not indicated that it will reject Pontiki's coal supply agreement or other contracts and leases we have with Horizon, some action by Horizon is possible.

In May 2003, a significant customer of MC Mining voluntarily filed for Chapter 11 bankruptcy protection. We did not incur any losses associated with this bankruptcy filing. We believe that our payment terms with the customer protect us from any significant bad debt exposure and at December 31, 2003, we did not have any accounts receivable from this customer.

If any of our customers file for bankruptcy and reject their coal supply or other contracts, or if they otherwise default on their obligations to us, we may not be able to enter into new contracts on similar terms to replace the lost revenue, and our business, financial condition or results of operations could be adversely affected.

Competition

The United States coal industry is highly competitive with numerous producers in all coal producing regions. We compete with other large producers and hundreds of small producers in the United States. The largest coal company is estimated to have sold approximately 18% of the total 2003 tonnage sold in the United States market. We compete with other coal producers primarily on the basis of coal price at the mine, coal quality (including sulfur content), transportation cost from the mine to the customer, and the reliability of supply. Continued demand for our coal and the prices that we obtain are also affected by demand for electricity, environmental and government regulations, technological developments, and the availability and price of alternative fuel supplies, including nuclear, natural gas, oil, and hydroelectric power.

Transportation

Our coal is transported to our customers by rail, truck and barge. Depending on the proximity of the customer to the mine and the transportation available for delivering coal to that customer, transportation costs can range from 5% to 45% of the delivered cost of a customer's coal. As a consequence, the availability and cost of transportation constitute important factors in the marketability of coal. We believe our mines are located in favorable geographic locations that minimize transportation costs for our customers.

Our customers pay the transportation costs from the contractual F.O.B. point (free-on-board point), which is consistent with practice in the industry and is generally from the mine to the customer's plant. In 2003, the largest volume transporter of our coal shipments, including coal synfuel shipped by SSO, was the CSX railroad, which moved approximately 57% of our tonnage over its rail system. The practices of, and rates set by, the railroad serving a particular mine or customer might affect, either adversely or favorably, our marketing efforts with respect to coal produced from the relevant mine. At Gibson and Mettiki, a contractor operates a truck delivery system that transports the coal to our primary customer's power plant.

Regulation and Laws

The coal mining industry is subject to regulation by federal, state and local authorities on matters such as:

- employee health and safety;
- mine permits and other licensing requirements;
- air quality standards;
- water quality standards;
- storage of petroleum products and substances which are regarded as hazardous under applicable laws or which, if spilled, could reach waterways or wetlands;
- plant and wildlife protection;
- reclamation and restoration of mining properties after mining is completed;
- the discharge of materials into the environment;
- management of solid wastes generated by mining operations;
- storage and handling of explosives;
- wetlands protection;
- management of electrical equipment containing polychlorinated biphenyls (PCBs);
- surface subsidence from underground mining;
- the effects, if any, that mining has on groundwater quality and availability; and
- legislatively mandated benefits for current and retired coal miners.

In addition, the utility industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for our coal. The possibility exists that new legislation or regulations, or new interpretations of existing laws or regulations, may be adopted that may have a significant impact on our mining operations or our customers' ability to use coal, or may require us or our customers to change our or their operations significantly or to incur substantial costs.

We are committed to conducting mining operations in compliance with applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements, violations during mining operations are not unusual in the industry and, notwithstanding our compliance efforts, we do not believe these violations can be eliminated completely. None of the violations to date or the monetary penalties assessed at our operations have been material.

While it is not possible to quantify the costs of compliance with applicable federal and state laws, those costs have been and are expected to continue to be significant. Capital expenditures for environmental matters have not been material in recent years. We have accrued for the present value estimated cost of reclamation and mine closings, including the cost of treating mine water discharge, when necessary. The accruals for reclamation and mine closing costs are based upon permit requirements and the costs and timing of reclamation and mine closing procedures. Although management believes it has made adequate provisions for all expected reclamation and other costs associated with mine closures, future operating results would be adversely affected if we later determine these accruals to be insufficient. Compliance with these laws has substantially increased the cost of coal mining for all domestic coal producers.

Mining Permits and Approvals

Numerous governmental permits or approvals are required for mining operations. We may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production of coal may have upon the environment. All requirements imposed by any of these authorities may be costly and time consuming, and may delay or prevent commencement or continuation of mining operations in certain locations. Future legislation and administrative regulations may emphasize more heavily the protection of the environment and, as a consequence, our activities may be more closely regulated. Legislation and regulations, as well as future interpretations of existing laws, may require substantial increases in equipment and operating costs, or delays, interruptions or terminations of operations, the extent of any of which cannot be predicted.

Under some circumstances, substantial fines and penalties, including revocation of mining permits, may be imposed under the laws described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws. Regulations also provide that a mining permit can be refused or revoked if the permit applicant or permittee owns or controls, directly or indirectly through other entities, mining operations which have outstanding environmental violations. Although like other coal companies we have been cited for violations in the ordinary course of our business, we have never had a permit suspended or revoked because of any violation, and the penalties assessed for these violations have not been material.

Before commencing mining on a particular property, we must obtain mining permits and approvals by state regulatory authorities of a reclamation plan for restoring, upon the completion of mining, the mined property to its approximate prior condition, productive use or other permitted condition. Typically, we commence actions to obtain permits between 18 and 24 months before we plan to mine a new area. In our experience, permits generally are approved within 12 months after a completed application is submitted. Generally, we have not experienced material or significant difficulties in obtaining mining permits in the areas where our reserves are currently located. However, we cannot assure you that we will not experience difficulty in obtaining mining permits in the future.

In March 2000, we submitted a permit application to the West Virginia Department of Environmental Protection (WVDEP) requesting approval for the mining of approximately 3.1 million tons of coal deposits controlled by Mettiki Coal (WV), one of our subsidiaries, but contiguous with our Mettiki coal reserves in Maryland. In January 2002, the WVDEP denied the permit. We appealed the permit denial to the West Virginia Surface Mine Board (Surface Mine Board) and, in July 2002, the Surface Mine Board approved a permit that allowed us to mine approximately 1.2 million tons of coal from this coal deposit area in West Virginia. In February 2003, we submitted a revised permit application requesting approval for the mining of approximately 600,000 additional tons of this coal. In February 2004, we completed mining in this coal reserve area.

On October 15, 2003, the WVDEP issued a letter denying Mettiki Coal (WV)'s application for an underground mining permit for its proposed E-Mine. The E-Mine is a proposed longwall underground mine to be located primarily in Tucker County, West Virginia. The stated basis of WVDEP's denial was its belief that Mettiki Coal (WV)’s proposed E-Mine would result in the movement of acid mine drainage (AMD) outside the permit area from the post-mining mine pool, which would require long-term chemical treatment without a defined “end-point.” WVDEP takes the position that the applicable surface mining laws require reclamation of land and water resources, and that treatment for a period without a defined end-point is not an acceptable reclamation alternative. However, WVDEP previously issued a permit to Island Creek Coal Company to mine the same general reserve area without expressing such concerns. On November 14, 2003, Mettiki Coal (WV) appealed that decision to the Surface Mine Board. The appeal of the denial of this permit application is scheduled currently to be heard by the Surface Mine Board on April 6, 2004.

In order to expedite the WVDEP’s consideration of additional information that we believe addresses WVDEP’s basis for denial of the original permit application, Mettiki Coal (WV) prepared and submitted a new permit application on January 15, 2004. The new permit application addresses, among other issues, the stated concern for long-term material damage to the hydrologic balance outside the permit area by adding an alkaline recharge component to the hydrologic reclamation plan.

On January 22, 2004, the WVDEP notified Mettiki Coal (WV) that the new permit application was determined to be administratively complete. On February 6, 2004, the WVDEP notified Mettiki Coal (WV) of certain technical corrections that must be responded to before the new permit application review can be completed. Mettiki Coal (WV) submitted technical corrections to the WVDEP on February 17, 2004.

WVDEP's determination on the new permit application is expected within 30 days of an informal public conference to be held by the WVDEP on March 23, 2004.

In the event that WVDEP denies the new permit application, Mettiki Coal (WV) anticipates that it will vigorously pursue the appeal of the denial of the new mining permit application to the Surface Mine Board. The Surface Mine Board, a seven-member board, typically hears cases within several months after appeals are filed and rarely waits more than several weeks after hearing a case to render a final decision. Mettiki Coal (WV) has approximately $1.5 million of advance minimum royalties associated with the E-Mine reserves, which management believes are fully recoverable.

Mine Health and Safety Laws

Stringent safety and health standards have been imposed by federal legislation since 1969 when the Coal Mine Health and Safety Act of 1969 (CMHSA) was adopted. The Federal Mine Safety and Health Act of 1977, and regulations adopted pursuant thereto, significantly expanded the enforcement of health and safety standards and imposed comprehensive safety and health standards on numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations and other matters. The Mine Safety and Health Administration (MSHA) monitors compliance with these federal laws and regulations. In addition, as part of CMHSA and the Mine Safety and Health Act of 1977, the Black Lung Benefits Act requires payments of benefits by all businesses that conduct current mining operations to a coal miner with black lung disease and to some survivors of a miner who dies from this disease. Most of the states where we operate also have state programs for mine safety and health regulation and enforcement. In combination, federal and state safety and health regulation in the coal mining industry is perhaps the most comprehensive and rigorous system for protection of employee safety and health affecting any segment of any industry. Even the most minute aspects of mine operations, particularly underground mine operations, are subject to extensive regulation. This regulation has a significant effect on our operating costs. For example, new regulations governing exposures to diesel particulate matter in underground mines have recently increased our compliance costs, and new regulations that would effectively further limit coal dust and silica exposures are under consideration by MSHA. Our competitors in all of the areas in which we operate are subject to the same laws and regulations.

Black Lung Benefits Act (BLBA)

The Federal BLBA levies a tax on production of $1.10 per ton for underground-mined coal and $0.55 per ton for surface-mined coal, but not to exceed 4.4% of the applicable sales price, in order to compensate miners who are totally disabled due to black lung disease and some survivors of miners who died from this disease, and who were last employed as miners prior to 1970 or subsequently where no responsible coal mine operator has been identified for claims. In addition, BLBA provides that some claims for which coal operators had previously been responsible will be obligations of the government trust funded by the tax. The Revenue Act of 1987 extended the termination date of this tax from January 1, 1996, to the earlier of January 1, 2014, or the date on which the government trust becomes solvent. For miners last employed as miners after 1969 and who are determined to have contracted black lung, we self-insure the potential cost using actuarially determined estimates of the cost of present and future claims. We are also liable under state statutes for black lung claims.

The U.S. Department of Labor issued revised regulations effective January 2001 altering the claims process for federal black lung benefit recipients, which among other things:

- simplify administrative procedures for the adjudication of claims;
- propose preference for the miner's treating physician under certain circumstances;
- allow previously denied claims to be refiled and litigated under a different standard;

- limit the amount of evidence all parties may submit for consideration;
- create a rebuttable presumption that when a miner who is eligible for black lung benefits receives medical treatment for any pulmonary condition, the disorder is caused or aggravated by the miner's work; and
- expand the definition of pneumoconiosis and total disability.

The revised regulations are expected to result in an increase in the incidence and recovery of black lung claims. The amount of the increase in the incidence and recovery of black lung claims will be determined by the future application of the revised regulations in the numerous administrative and judicial processes involved in the adjudication of black lung claims. Concerning our requirement to maintain bonds to secure our black lung claim obligations, see the discussion of surety bonds below under "Surface Mining Control and Reclamation Act (SMCRA)". In addition, Congress and state legislatures regularly consider various items of black lung legislation, which, if enacted, could adversely affect our business, financial condition and results of operations.

Workers' Compensation

We are required to compensate employees for work-related injuries. Several states in which we operate consider changes in workers' compensation laws from time to time. We self-insure the potential cost using actuarially determined estimates of the cost of present and future claims. Concerning our requirement to maintain bonds to secure our workers' compensation obligations, see the discussion of surety bonds below under "Surface Mining Control and Reclamation Act (SMCRA)."

Coal Industry Retiree Health Benefits Act (CIRHBA)

The Federal CIRHBA was enacted to provide for the funding of health benefits for some United Mine Workers of America retirees. The act merged previously established union benefit plans into a single fund into which "signatory operators" and "related persons" are obligated to pay annual premiums for beneficiaries. The act also created a second benefit fund for miners who retired between July 21, 1992, and September 30, 1994, and whose former employers are no longer in business. Because of our union-free status, we are not required to make payments to retired miners under CIRHBA, with the exception of limited payments made on behalf of predecessors of MC Mining. However, in connection with the sale of the coal assets acquired by Alliance Resource Holdings in 1996, MAPCO Inc., now a wholly-owned subsidiary of The Williams Companies, Inc., agreed to retain, and be responsible for, all liabilities under CIRHBA.

Surface Mining Control and Reclamation Act (SMCRA)

The Federal SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of deep mining. The act requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of mining activities. In conjunction with mining the property, we reclaim and restore the mined areas by grading, shaping and preparing the soil for seeding. Upon completion of mining, reclamation generally is completed by seeding with grasses or planting trees for a variety of uses, as specified in the approved reclamation plan. We believe we are in compliance in all material respects with applicable regulations relating to reclamation.

SMCRA and similar state statutes require, among other things, that mined property be restored in accordance with specified standards and approved reclamation plans. The act requires us to restore the surface to approximate the original contours as contemporaneously as practicable with the completion of surface mining operations. The mine operator must submit a bond or otherwise secure the performance of these reclamation obligations. The earliest a reclamation bond can be released is five years after reclamation has been achieved. Federal law and some states impose on mine operators the responsibility for replacing certain water supplies damaged by mining operations and repairing or compensating for damage to certain structures occurring on the surface as a result of mine subsidence, a consequence of longwall mining and possibly other mining operations. The Federal Office of Surface Mining Reclamation and Enforcement is currently studying the adequacy of bonding requirements for treatment of long-term pollution discharges and whether other forms of financial assurances may be permitted. In addition, the Abandoned Mine Lands Program, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The maximum tax is $0.35 per ton on surface-mined coal and $0.15 per ton on underground-mined coal. We have accrued for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. In addition, states from time to time have increased and may continue to increase their fees and taxes to fund reclamation of orphaned mine sites and AMD control on a statewide basis, as West Virginia did in 2002.

Under SMCRA, responsibility for unabated violations, unpaid civil penalties and unpaid reclamation fees of independent contract mine operators and other third parties can be imputed to other companies which are deemed, according to the regulations, to have "owned" or "controlled" the third-party violator. Sanctions against the "owner" or "controller" are quite severe and can include being blocked from receiving new permits and revocation of any permits that have been issued since the time of the violations or, in the case of civil penalties and reclamation fees, since the time their amounts became due. We are not aware of any currently pending or asserted claims against us relating to the "ownership" or "control" theories discussed above. However, we cannot assure you that such claims will not develop in the future.

In 2002, a U.S. District Court reached a decision interpreting SMCRA to prohibit subsidence from underground mining on certain federal lands, near occupied dwelling, public or community building, public road, schools, churches, and cemeteries, or adversely affecting public parks or certain historic properties. The U.S. Court of Appeals, District of Columbia Circuit, reversed the district court decision as erroneous and in February 2004, the U.S. Supreme Court refused to hear an appeal of the Court of Appeals decision.

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, to pay federal and state workers' compensation, to pay certain black lung claims, and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. It has become increasingly difficult for us and for our competitors generally to secure new surety bonds without the posting of partial collateral. In addition, surety bond costs have increased while the market terms of surety bonds have generally become less favorable to us. Surety bonds issuers and holders may not continue to renew bonds or may demand additional collateral upon those renewals. Our failure to maintain, or inability to acquire, surety bonds that are required by state and federal laws would have a material adverse effect on us.

Clean Air Act (CAA)

The Federal CAA and similar state laws, which regulate emissions into the air, affect coal mining and processing operations primarily through permitting and emissions control requirements. The CAA also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants. For example, the CAA requires reduction of sulfur dioxide (SO_2) emissions from electric power generation plants in two phases. Only some facilities were subject to the Phase I requirements. Beginning in 2000, Phase II requires nearly all facilities to reduce emissions. The affected utilities are able to meet these requirements by:

- switching to lower sulfur fuels;
- installing pollution control devices such as scrubbers;
- reducing electricity generating levels; or
- purchasing or trading so-called pollution "credits."

Specific emissions sources receive these "credits" that utilities and industrial concerns can trade or sell to allow other units to emit higher levels of SO_2. In addition, the CAA required a study of utility power plant emissions of some toxic substances and their eventual regulation, if warranted. As a result of that study, EPA has proposed, but not yet finalized, alternative regulatory approaches to controlling mercury emissions from power plants. We cannot accurately predict the effect of such CAA controls on us in future years.

The CAA also indirectly affects coal mining operations by requiring utilities that currently are major sources of nitrogen oxides (NOx) in moderate or higher ozone non-attainment areas to install reasonably available control technology for NOx, which are precursors of ozone. In October 1998, the U.S. Environmental Protection Agency (EPA) issued a rule requiring 22 eastern states and the District of Columbia to make substantial reductions in NOx emissions by 2003. This deadline was recently extended by EPA to 2004. EPA expects that affected states will achieve reductions by requiring power plants to make substantial reductions in their NOx emissions. This in turn will require power plants to install reasonably available control technology and additional control measures. Installation of reasonably available control technology and additional measures required under EPA regulations will make it more costly to operate coal-fired plants and, depending on the requirements of individual state implementation plans and the development of revised new source performance standards, could make coal a less attractive fuel alternative in the planning and building of utility power plants in the future. Any reduction in coal's share of the capacity for power generation could have a material adverse effect on our business, financial condition and results of operations. The effect these regulations, or other requirements that may be imposed in the future, could have on the coal industry in general and on our business in particular cannot be predicted with certainty. We cannot assure you that the implementation of the CAA, the new National Ambient Air Quality Standards (NAAQS) discussed below, or any other current or future regulatory provision, will not materially adversely affect us.

In addition, EPA has already issued and is considering further regulations relating to fugitive dust and emissions of other coal-related pollutants such as fine particulates. For example, in July 1997 EPA adopted new, more stringent NAAQS for particulate matter, which may require some states to change existing implementation plans. Non-attainment designations for these NAAQS are expected to be made in 2004. Because coal mining operations and utilities emit particulate matter, our mining operations and utility customers are likely to be directly affected when the revisions to the NAAQS are implemented by the states. In conjunction with the mercury proposal noted above, EPA has also proposed an Interstate Air Quality Rule which would require coal-burning power plants in 29 eastern states and the District of Columbia to achieve greater reductions in NOx and SO_2 emissions by means of a "cap and trade" program. Congress may consider other controls on other air pollutants emitted by electric utilities. Such controls, if adopted, could adversely affect the market for coal.

EPA has filed suit against a number of our customers over implementation of new source performance standards and preconstruction review requirements for new sources and major modifications under the prevention of significant deterioration and non-attainment regulations. The issue raised in this litigation is what activities constitute routine maintenance, repair and replacement versus new construction. Some of our customers have agreed to or proposed settlements with EPA while others are preparing for or are engaged in litigation. These and other regulatory developments may restrict the size of our market, and the type of coal in demand. This in turn could adversely affect our ability to develop new mines, or could require us or our customers to modify existing operations.

Framework Convention On Global Climate Change (Kyoto Protocol)

The United States and more than 160 other nations are signatories to the Kyoto Protocol which is intended to limit or capture emissions of greenhouse gases, such as carbon dioxide. The purpose of the Kyoto Protocol is to establish a binding set of emissions targets for developed nations. The specific limits would vary from country to country. Under the terms of the Kyoto Protocol, the United States would be required to reduce emissions to 93% of 1990 levels over a five-year budget period from 2008 through 2012. The Clinton Administration signed the Kyoto Protocol in November 1998.

In March 2001, President Bush expressed his opposition to the Kyoto Protocol and stated he did not believe the government should impose mandatory carbon dioxide emission reductions on power plants. In February 2002, President Bush proposed voluntary actions to reduce greenhouse gas intensity in the United States. Greenhouse gas intensity measures the ratio of greenhouse gas emissions, such as carbon dioxide, to economic output. The President's climate change initiative calls for an 18% reduction in the ratio of greenhouse gas emissions to gross domestic product from 2002 to 2012, which is approximately equivalent to the reduction that has occurred over each of the past two decades. The United States has not ratified the Kyoto Protocol and it will not become binding until it is ratified by countries representing at least 55% of the total carbon dioxide emissions for 1990. As of December 31, 2003, countries representing 44.2% of 1990 carbon dioxide emissions had ratified the Kyoto Protocol.

While the United States has yet to adopt comprehensive federal legislation addressing greenhouse gas emissions, many states have proposed and adopted laws that have had the purpose or effect of decreasing greenhouse gas emissions. Such state initiatives have included state renewable energy portfolio standards, renewable energy incentives for producers of electricity, and carbon dioxide emission caps for newly constructed electricity generating facilities. Future federal and state initiatives to control greenhouse gas emissions could result in electric power generators switching to lower carbon sources of fuel, which would reduce the demand for our coal. These actions could have a material adverse effect on our business, financial condition and results of operations.

Clean Water Act (CWA)

The Federal CWA affects coal mining operations by imposing restrictions on effluent discharge into waters. Regular monitoring, as well as compliance with reporting requirements and performance standards, are preconditions for the issuance and renewal of permits governing the discharge of pollutants into water. Section 404 of CWA imposes permitting and mitigation requirements associated with the dredging and filling of wetlands and streams. The CWA and equivalent state legislation, where such equivalent state legislation exists, affect coal mining operations that impact wetlands and streams. Although permitting requirements have been tightened in recent years, we believe we have obtained all necessary wetlands permits required under CWA §404. However, mitigation requirements under existing and possible future wetlands permits may vary considerably. At this time we do not anticipate any increase in such requirements or in post-mining reclamation accrual requirements. For that reason, the setting of post-mine reclamation accruals for such mitigation projects is difficult to ascertain with certainty. We believe that we have obtained all permits required under the CWA as traditionally interpreted by the responsible agencies. Although more stringent permitting requirements may be imposed in the future, we are not able to accurately predict the impact, if any, of any such permitting requirements.

Each individual state is required to submit to EPA their biennial CWA §303(d) lists identifying all waterbodies not meeting state specified water quality standards. For each listed waterbody, the state is required to begin developing a Total Maximum Daily Load (TMDL) to:

- determine the maximum pollutant loading the waterbody can assimilate without violating water quality standards,
- identify all current pollutant sources and loadings to that waterbody,
- calculate the pollutant loading reduction necessary to achieve water quality standards, and
- establish a means of allocating that burden among and between the point and non-point sources contributing pollutants to the waterbody.

We are currently participating in stakeholders meetings and in negotiations with states and EPA to establish reasonable TMDLs that will accommodate expansion of our operations. These and other regulatory developments may restrict our ability to develop new mines, or could require our customers or us to modify existing operations, the extent of which we cannot accurately or reasonably predict.

Safe Drinking Water Act (SDWA)

The Federal SDWA and its state equivalents affect coal mining operations by imposing requirements on the underground injection of fine coal slurries, fly ash, and flue gas scrubber sludge, and by requiring permits to conduct such underground injection activities. The inability to obtain these permits could have a material impact on our ability to inject materials such as fine coal refuse, fly ash, or flue gas scrubber sludge into the inactive areas of some of our old underground mine workings.

In addition to establishing the underground injection control program, the Federal SDWA also imposes regulatory requirements on owners and operators of "public water systems." This regulatory program could impact our reclamation operations where subsidence, or other mining-related problems, require the provision of drinking water to affected adjacent homeowners. However, it is unlikely that any of our reclamation activities would fall within the definition of a "public water system." While we have several drinking water supply sources for our employees and contractors that are subject to SDWA regulation, the SDWA is unlikely to have a material impact on our operations.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)

The Federal CERCLA, also known as the "Superfund" law, and analogous state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. Some products used by coal companies in operations generate waste containing hazardous substances. We are currently unaware of any material liability associated with the release or disposal of hazardous substances from our past or present mine sites.

Resource Conservation and Recovery Act (RCRA)

The Federal RCRA and corresponding state laws regulating hazardous waste affect coal mining operations by imposing requirements for the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes. Many mining wastes are excluded from the regulatory definition of hazardous wastes, and coal mining operations covered by SMCRA permits are by statute exempted from RCRA permitting. RCRA also allows EPA to require corrective action at sites where there is a release of hazardous substances. In addition, each state has its own laws regarding the proper management and disposal of waste material. While these laws impose ongoing compliance obligations, we do not believe that these costs will have a material impact on our operations.

Coal Combustion By-Products

In 2000, EPA declined to impose hazardous waste regulatory controls on the disposal of some coal combustion by-products, including the practice of using coal combustion by-products (CCB) as mine fill. However, under pressure from environmental groups, EPA has continued evaluating the possibility of placing additional solid waste burdens on the disposal of these types of materials, and Congress has commissioned a

National Academy of Sciences study of CCB mine filling to be concluded in 2005. EPA's current semi-annual regulatory agent states that a rule on CCB mine filling is planned for proposal in July 2005.

While we cannot predict the ultimate outcome of the National Academy's study or EPA's assessment, we believe the beneficial uses of coal combustion by-products that we employ (such as the practice of placing by-products in abandoned mine areas) do not constitute poor environmental practices because, among other things, our CWA discharge permits for treated AMD contain parameters for pollutants of concern, such as metals, and those permits require monitoring and reporting of effluent quality data.

Other Environmental, Health And Safety Regulation

In addition to the laws and regulations described above, we are subject to regulations regarding underground and above ground storage tanks where we may store petroleum or other substances. Some monitoring equipment that we use is subject to licensing under the Federal Atomic Energy Act. Water supply wells located on our property are subject to federal, state and local regulation.

Also, the Safe Explosives Act (SEA), a portion of the Homeland Security Act of 2002, became law on November 25, 2002. The SEA covers all importers, manufacturers, dealers, and users of explosives. As regular users of explosives, mining companies are likely to be under special scrutiny in its enforcement. Knowing or willful violations of SEA may result in fines, imprisonment, or both. In addition, violations of SEA may result in revocation of user permits and seizure or forfeiture of explosive materials. The SEA became effective in two phases on January 24 and May 24, 2003.

The costs of compliance with these requirements should not have a material adverse effect on our business, financial condition or results of operations.

Employees

To conduct our operations, our managing general partner and its affiliates employ approximately 1,875 employees, including approximately 100 corporate employees and approximately 1,775 employees involved in active mining operations. Our work-force is entirely union-free. Relations with our employees are generally good.

ITEM 2. PROPERTIES

Coal Reserves

We must obtain permits from applicable state regulatory authorities before beginning to mine particular reserves. Applications for permits require extensive engineering and data analysis and presentation, and must address a variety of environmental, health, and safety matters associated with a proposed mining operation. These matters include the manner and sequencing of coal extraction, the storage, use and disposal of waste and other substances and other impacts on the environment, the construction of water containment areas, and reclamation of the area after coal extraction. We are required to post bonds to secure performance under our permits. As is typical in the coal industry, we strive to obtain mining permits within a time frame that allows us to mine reserves as planned on an uninterrupted basis. We begin preparing applications for permits for areas that we intend to mine sufficiently in advance of our planned mining activities to allow adequate time to complete the permitting process. Regulatory authorities have considerable discretion in the timing of permit issuance, and the public has rights to comment on and otherwise engage in the permitting process, including intervention in the courts. For the reserves set forth in the table below, except for the E-mine permit discussed above in "Item 1. Business; Regulations and Laws; Mining Permits and Approvals", we are not currently aware of matters which would significantly hinder our ability to obtain future mining permits on a timely basis.

Our reported coal reserves are those we believe can be economically and legally extracted or produced at the time of the filing of this Annual Report on Form 10-K and are in accordance with guidance from SEC Industry Guide No. 7. In determining whether our reserves meet this economical and legal standard, we take into account, among other things, our potential ability or inability to obtain a mining permit, the possible necessity of revising a mining plan, changes in estimated future costs, changes in future cash flows caused by changes in mining permits, variations in quantity and quality of coal, and varying levels of demand and their effects on selling prices.

At December 31, 2003, we had approximately 418.4 million tons of coal reserves. All of the estimates of reserves which are presented in this Annual Report on Form 10-K are of proven and probable reserves (as defined below). For information on location of our mines, please read "Mining Operations" under "Item 1. Business."

The following table sets forth reserve information, at December 31, 2003, about each of our mining complexes:

			Proven and Probable Reserves				Reserve Assignment	
			Pounds S02 per MMbtu					
Operations	Mine Type	Heat Content (Btus per pound)	<1.2	1.2-2.5	>2.5	Total	Assigned	Unassigned
			(tons in millions)					
Illinois Basin Operations								
Dotiki	Underground	12,500	-	-	100.4	100.4	100.4	-
Warrior	Underground	12,500	-	-	23.8	23.8	23.8	-
Pattiki	Underground	11,700	-	-	47.3	47.3	47.3	-
Hopkins	Underground	11,300	-	-	20.0	20.0	-	20.0
	/ Surface		-	-	9.7	9.7	9.7	-
Gibson (North)	Underground	11,600	-	26.5	7.2	33.7	33.7	-
Gibson (South)	Underground	11,600	-	46.5	36.2	82.7	-	82.7
Region Total			0.0	73.0	244.6	317.6	214.9	102.7
East Kentucky Operations								
Pontiki	Underground	12,800	12.1	12.2	-	24.3	24.3	-
MC Mining	Underground	12,800	24.2	-	-	24.2	24.2	-
Region Total			36.3	12.2	0.0	48.5	48.5	0.0
Maryland Operations								
Mettiki	Underground	12,200	-	15.8	13.2	29.0	13.2	15.8
Mettiki Coal (WV)	Underground	12,200	-	-	23.3	23.3	23.3	-
Region Total			0.0	15.8	36.5	52.3	36.5	15.8
Total			36.3	101.0	281.1	418.4	299.9	118.5
% of Total			8.7%	24.1%	67.2%	100.0%	71.7%	28.3%

Our reserve estimates are prepared from geological data assembled and analyzed by our staff of geologists and engineers. This data is obtained through our extensive, ongoing exploration drilling and in-mine channel sampling programs. Our drill spacing criteria adhere to standards as defined by the U.S. Geological Survey. The maximum acceptable distance from seam data points varies with the geologic nature of the coal seam being studied, but generally the standard for (a) proven reserves is that points of observation are no greater than ½ mile apart and are projected to extend as a ¼ mile wide belt around each point of measurement and (b) probable reserves is that points of observation are between ½ and 1 ½ miles apart and are projected to extend as a ½ mile wide belt that lies ¼ mile from the points of measurement.

Reserve estimates will change from time to time to reflect evolving market conditions, mining activities, additional analyses, new engineering and geological data, acquisition or divestment of reserve holdings, modification of mining plans or mining methods, and other factors. Weir International Mining Consultants performed an overview audit of all of our reserves at March 31, 1999 in conjunction with our initial public offering.

Reserves represent that part of a mineral deposit that can be economically and legally extracted or produced, and reflect estimated losses involved in producing a saleable product. All of our reserves are steam coal. The 36.3 million tons of reserves listed as <1.2 pounds of SO_2 per MMbtu are compliance coal.

Assigned reserves are those reserves that have been designated for mining by a specific operation.

Unassigned reserves are those reserves that have not yet been designated for mining by a specific operation.

BTU values are reported on an as shipped, fully washed, basis. Shipments that are either fully or partially raw will have a lower BTU value.

A permit application relating to 23.3 million tons of reserves controlled by Mettiki Coal (WV) has been submitted to the WVDEP. Please see “Item 1. Business; Regulation and Laws; Mining Permits and Approvals” above.

We control certain leases for coal deposits that are near, but not contiguous to, our primary reserve bases. The tons controlled by these leases are classified as non-reserve coal deposits and are not included in our reported reserves. These non-reserve coal deposits are as follows: Dotiki – 13.3 million tons, Pattiki – 3.2 million tons, Gibson (South) – 7.5 million tons, and Warrior – 2.2 million tons.

We lease almost all of our reserves and generally have the right to maintain leases in force until the exhaustion of minable and merchantable coal located within the leased premises or a larger coal reserve area. These leases provide for royalties to be paid to the lessor at a fixed amount per ton or as a percentage of the sales price. Many leases require payment of minimum royalties, payable either at the time of the execution of the lease or in periodic installments, even if no mining activities have begun. These minimum royalties are normally credited against the production royalties owed to a lessor once coal production has commenced.

The following table sets forth production data about each of our mining complexes:

Operations	Tons Produced 2003	2002	2001	Transportation	Equipment
	(tons in millions)				
Illinois Basin Operations					
Dotiki	4.9	4.5	4.6	CSX, PAL; truck; barge	CM
Warrior	2.4	1.6	1.7	CSX, PAL; truck	CM
Hopkins	0.8	2.2	2.0	CSX, PAL; truck	DL; CM
Pattiki	1.8	1.9	1.9	CSX; truck; barge	CM
Gibson (North)	2.4	1.9	1.7	Truck	CM
Region Total	12.3	12.1	11.9		
East Kentucky Operations					
Pontiki	2.0	1.7	1.7	NS; truck	CM
MC Mining	1.6	1.3	1.1	NS; truck	CM
Region Total	3.6	3.0	2.8		
Maryland Operations					
Mettiki	3.3	2.9	2.7	Truck; CSX	LW; CM
Region Total	3.3	2.9	2.7		
TOTAL	19.2	18.0	17.4		

CSX -- CSX Railroad
PAL -- Paducah & Louisville Railroad
NS -- Norfolk & Southern Railroad
CM -- Continuous Miner
DL -- Dragline with Stripping Shovel, Front End Loaders and Dozers
LW -- Longwall

ITEM 3. LEGAL PROCEEDINGS

We are subject to various types of litigation in the ordinary course of our business. Disputes with our customers over the provisions of long-term coal supply contracts arise occasionally and generally relate to, among other things, coal quality, quantity, pricing, and the existence of force majeure conditions. We are not currently involved in any litigation involving any of our long-term coal supply contracts. In August 2003, we settled a contract dispute with PSI as described under “Other” in “Item 8. Financial Statements and Supplementary Data. – Note 17. Commitments and Contingencies.” However, we cannot assure you that disputes will not occur or that we will be able to resolve those disputes in a satisfactory manner. We are not engaged in any litigation that we believe is material to our operations, including under the various environmental protection statutes to which we are subject. The information under “General Litigation” and "Other" under “Item 8. Financial Statements and Supplementary Data. – Note 17. Commitments and Contingencies” is incorporated herein by this reference.

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

None.

PART II

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

The common units representing limited partners' interests are listed on the Nasdaq National Market under the symbol "ARLP." The common units began trading on August 20, 1999. On March 11, 2004, the closing market price for the common units was $37.55 per unit. There were approximately 14,275 record holders and beneficial owners (held in street name) of common units at December 31, 2003.

The following table sets forth the range of high and low sales prices per common unit and the amount of cash distributions declared and paid with respect to the units, for the two most recent fiscal years:

	High	Low	Distributions Per Unit
1st Quarter 2002	$28.250	$21.710	$0.5000 (paid May 15, 2002)
2nd Quarter 2002	$24.700	$21.850	$0.5000 (paid August 14, 2002)
3rd Quarter 2002	$25.000	$17.000	$0.5000 (paid November 14, 2002)
4th Quarter 2002	$25.200	$20.000	$0.5250 (paid February 14, 2003)
1st Quarter 2003	$25.500	$21.490	$0.5250 (paid May 15, 2003)
2nd Quarter 2003	$27.999	$21.980	$0.5250 (paid August 14, 2003)
3rd Quarter 2003	$29.920	$25.480	$0.5250 (paid November 14, 2003)
4th Quarter 2003	$35.240	$28.000	$0.5625 (paid February 13, 2004)

We have also outstanding 3,211,266 subordinated units, all of which are held by our special general partner and for which there is no established public trading market. Originally we issued 6,422,531 subordinated units to our special general partner. In November 2003, 3,211,265 outstanding subordinated units converted to common units in accordance with our partnership agreement as explained below.

We will distribute to our partners (including holders of subordinated units), on a quarterly basis, all of our available cash. “Available cash”, as defined in our partnership agreement, generally means, with respect to any quarter, all cash on hand at the end of each quarter, plus working capital borrowings after the end of the quarter, less cash reserves in the amount necessary or appropriate in the reasonable discretion of our managing general partner to (a) provide for the proper conduct of our business, (b) comply with applicable law of any debt instrument or other agreement of ours or any of its affiliates, and (c) provide funds for distributions to unitholders and the general partners for any one or more of the next four quarters. If quarterly distributions of available cash exceed the minimum quarterly distribution (MQD) and certain target distribution levels as established in our partnership agreement, our managing general partner will receive distributions based on specified increasing percentages of the available cash that exceed the MQD and the target distribution levels. Our partnership agreement defines the MQD as $0.50 for each full fiscal quarter. Distributions of available cash to the holder of the subordinated units are subject to the prior rights of the holders of the common units to receive the MQD for each quarter during the subordination period and to receive any arrearages in the distribution of the MQD on the common units for prior quarters during the subordination period.

The subordination period will end if certain financial tests contained in the partnership agreement are met for three consecutive four-quarter periods but no sooner than September 30, 2004. During the first quarter after the end of the subordination period, all of the subordinated units will convert into common units. Our partnership agreement provides for the early conversion of one-half of the subordinated units if certain financial tests were satisfied before September 30, 2003. We satisfied the required financial tests for converting one-half of the subordinated units into common units as provided for under applicable provisions in the partnership agreement. Accordingly, in October 2003, the board of directors (and its conflicts committee) of our managing general partner approved management's determination that such conversion financial tests were satisfied. As a result, one-half of the outstanding subordinated units (i.e., 3,211,265 subordinated units) held by our special general partner converted into common units on November 15, 2003. The remaining 3,211,266 subordinated units are expected to convert on a one-for-one basis into common units in the fourth quarter of 2004, assuming we continue to meet the financial test requirements of the partnership agreement.

Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to such information as set forth in "Item 12. Security Ownership of Certain Beneficial Owners and Management" contained herein.

ITEM 6. SELECTED FINANCIAL DATA

On August 20, 1999, we completed our initial public offering whereby we became the successor to the business of our Predecessor. Our selected pro forma financial data for the year ended December 31, 1999 and our historical financial data below were derived from our audited consolidated financial statements as of December 31, 2003, 2002, 2001, 2000 and 1999, for the years ended December 31, 2003, 2002, 2001 and 2000 and the period from our commencement of operations (on August 20, 1999) to December 31, 1999, the audited combined financial statements of our Predecessor, as of August 19, 1999, and for the period from January 1, 1999 to August 19, 1999. 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 the assets that comprise Warrior on January 26, 2001.

(in millions, except per unit and per ton data)	Partnership						Predecessor
	Year Ended December 31,				Pro Forma Year Ended December 31, 1999 (1)	From Commencement of Operations (on August 20, 1999) to December 31, 1999	For the period from January 1, 1999 to August 19, 1999
	2003	2002	2001	2000			
Statements of Income:							
Sales and operating revenues							
Coal sales	$ 501.6	$ 479.5	$ 453.1	$ 347.2	$ 345.9	$ 128.8	$ 217.0
Transportation revenues (2)	19.5	19.0	18.2	13.5	19.1	4.9	14.2
Other sales and operating revenues	21.6	20.4	6.2	2.8	0.9	0.4	0.6
Total revenues	542.7	518.9	477.5	363.5	365.9	134.1	231.8
Expenses:							
Operating expenses	368.8	367.5	337.2	257.4	242.0	89.9	152.1
Transportation expenses (2)	19.5	19.0	18.2	13.5	19.1	4.9	14.2
Outside purchases	8.5	10.1	28.9	16.9	24.2	6.4	17.7
General and administrative	28.3	20.3	18.7	15.2	15.1	6.2	8.9
Depreciation, depletion and amortization	52.5	52.4	50.7	39.1	39.7	15.1	24.6
Interest expense	16.0	16.4	16.8	16.6	19.4	5.9	0.1
Unusual items (3)	-	-	-	(9.5)	-	-	-
Total expenses	493.6	485.7	470.5	349.2	359.5	128.4	217.6
Income from operations	49.1	33.2	7.0	14.3	6.4	5.7	14.2
Other income (expense)	1.4	0.5	0.8	1.3	1.2	0.6	0.5
Income before income taxes and cumulative effect of accounting change	50.5	33.7	7.8	15.6	7.6	6.3	14.7
Income tax expense (benefit)	2.6	(1.1)	(0.8)	-	-	-	4.5
Income before cumulative effect of accounting change	47.9	34.8	8.6	15.6	7.6	6.3	10.2
Cumulative effect of accounting change (4)	-	-	7.9	-	-	-	-
Net income	$ 47.9	$ 34.8	$ 16.5	$ 15.6	$ 7.6	$ 6.3	$ 10.2
General Partners' interest in net income (loss)	$ 0.3	$ (0.8)	$ (0.2)	$ 0.3	$ 0.2	$ 0.1	
Limited Partners' interest in net income	$ 47.6	$ 35.6	$ 16.7	$ 15.3	$ 7.4	$ 6.2	
Basic net income per limited partner unit	$ 2.71	$ 2.31	$ 1.09	$ 0.99	$ 0.48	$ 0.40	
Basic net income per limited partner unit before accounting change	$ 2.71	$ 2.31	$ 0.58	$ 0.99	$ 0.48	$ 0.40	
Diluted net income per limited partner unit	$ 2.62	$ 2.24	$ 1.07	$ 0.98	$ 0.48	$ 0.40	
Diluted net income per limited partner unit before accounting change	$ 2.62	$ 2.24	$ 0.57	$ 0.98	$ 0.48	$ 0.40	
Weighted average number of units outstanding-basic	17,580,734	15,405,311	15,405,311	15,405,311	15,405,311	15,405,311	
Weighted average number of units outstanding-diluted	18,162,839	15,842,708	15,684,550	15,551,062	15,405,311	15,405,311	
Balance Sheet Data:							
Working capital (deficit)	$ 16.4	$ (15.8)	$ 0.9	$ 38.6	$ -	$ 61.2	$ 11.2
Total assets	336.5	316.9	310.3	309.2	-	314.8	262.8
Long-term debt	180.0	195.0	211.3	226.3	-	230.0	1.8
Total liabilities	323.9	355.7	347.8	341.0	-	330.7	110.2
Net Parent investment	-	-	-	-	-	-	151.6
Partners' capital (deficit)	12.6	(38.8)	(37.6)	(31.8)	-	(15.9)	-
Other Operating Data:							
Tons sold	19.5	18.4	18.6	15.0	15.0	5.6	9.4
Tons produced	19.2	18.0	17.4	13.7	14.1	5.3	8.8
Revenues per ton sold (5)	$ 26.83	$ 27.17	$ 24.69	$ 23.33	$ 23.12	$ 23.07	$ 23.15
Cost per ton sold (6)	$ 20.80	$ 21.63	$ 20.69	$ 19.30	$ 18.75	$ 18.30	$ 19.01
Other Financial Data:							
Net cash provided by (used in) operating activities	$ 110.3	$ 101.3	$ 70.5	$ 71.4	$ -	$ (13.9)	$ 32.9
Net cash used in investing activities	(77.8)	(56.9)	(31.1)	(41.0)	-	(43.9)	(21.5)
Net cash provided by (used in) financing activities	(31.3)	(46.4)	(35.2)	(31.4)	-	65.8	(11.4)
Maintenance capital expenditures (7)	30.0	29.0	24.4	21.2	6.0	6.0	15.5

(1) The unaudited selected pro forma financial and operating data for the year ended December 31, 1999 is based on the historical financial statements of the partnership from our commencement of operations on August 20, 1999 through December 31, 1999, and our Predecessor for the period from January 1, 1999 through August 19, 1999. The pro forma results of operations reflect certain pro forma adjustments to the historical results of operations as if we had been formed on January 1, 1999. The pro forma adjustments include (a) pro forma interest on debt assumed by us and (b) the elimination of income tax expense as income taxes will be borne by the partners and not by us. The pro forma adjustments do not include

approximately $1.0 million of general and administrative expenses that we believe would have been incurred as a result of its being a public entity.

(2) During the fourth quarter of 2000, we adopted the Financial Accounting Standards Board Emerging Issues Task Force Issue No. 00-10 “Accounting for Shipping and Handling Fees and Costs” (EITF No. 00-10). We record the cost of transporting coal to customers through third party carriers and our corresponding direct reimbursement of these costs through customer billings. This activity is separately presented as transportation revenue and expense rather than offsetting these amounts in the consolidated and combined statements of income. There was no cumulative effect of the accounting change on net income and prior periods presented have been reclassified to comply with EITF No. 00-10.

(3) 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.

(4) 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.”

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

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

(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.

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

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. 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 2003, our total production was 19.2 million tons and our total sales were 19.5 million tons. The coal we produced in 2003 was approximately 31.2% low-sulfur coal, 17.2% medium-sulfur coal and 51.6% high-sulfur coal.

At December 31, 2003, we had approximately 418.4 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 2003, 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 2003 were Seminole, SSO, and VEPCO. In 2003, approximately 84% of our sales tonnage, including approximately 88% of our medium- and high-sulfur coal sales tonnage, was sold under long-term contracts. The balance of our sales were 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 2003, approximately 89% 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 2003, the incremental annual net income benefit from the combination of the various coal synfuel-related agreements was approximately $15.5 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 2003, we reported record net income of $47.9 million, an increase of 38.0% over 2002 net income of $34.8 million. We grew through a combination of internal expansion and an acquisition. We added continuous miner units at Gibson, Warrior and MC Mining and completed infrastructure investments such as new mine shafts at Dotiki and MC Mining and a new slope at Warrior. We acquired Warrior in February 2003. Tons produced increased 7.1% to 19.2 million tons. Tons sold increased 6.0% to 19.5 million tons.

The combination of adding mining units, realizing benefits from completed infrastructure projects and the absence of adverse geologic conditions encountered at Mettiki in the third quarter of 2002 contributed to lower operating expenses per ton sold. The lower operating expenses per ton sold was the primary factor in achieving record net income, offsetting the impact of lower sales prices.

For 2004, we have commitments for substantially all of our 2004 production. For our estimated 2005 production, approximately 84% is committed under existing coal sales agreements and approximately 49% is subject to market price negotiations.

In 2004, we will continue our efforts to maximize the cost reduction opportunities created by our increased production capacity. Dotiki plans to increase the number of operating sections that operate with two continuous miners and expand the throughput capacity of its preparation plant approximately 30%. With the infrastructure created by the capital investments we have made over the past three years, we could, with some additional capital investments, increase production approximately two million tons to respond to increases in market place demand.

On February 11, 2004, the Dotiki mine was temporarily idled following the occurrence of a mine fire. We have successfully extinguished the fire and have totally isolated the affected area of the mine behind permanent seals. Production resumed on March 8, 2004. At this time, we are unable to quantify the financial impact of the fire or to predict when Dotiki will return to normal production. The temporary idling of Dotiki will reduce earnings for the first quarter of 2004. We have commercial property insurance (including business interruption coverage) that we currently believe should cover a substantial portion of the financial loss. Assuming that is correct, Dotiki's losses recognized in the first quarter of 2004 should be substantially offset by an insurance settlement that would be recognized later in the year. There can be no assurance of the amount or timing of recovery, however, until the claim is resolved with the insurance underwriter. Our insurance program provides for a deductible of $3.5 million and a ten percent coinsurance. In addition to the losses associated with business interruption, we have currently identified approximately $6.0 million of out-of-pocket expenses that generally fall into the category of extra expenses, expedited expenses and other areas of coverage under the commercial property insurance policy. We expect that additional out-of-pocket costs will be identified in the future. Please see "Item 1. Business; Recent Developments; Dotiki Mine Fire."

Results of Operations

2003 Compared with 2002

	2003	2002	Per Ton Sold 2003	Per Ton Sold 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

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 idling 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.

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.

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" above concerning the increase in tons produced.

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.

2002 Compared with 2001

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.

	2002	2001	Per Ton Sold 2002	Per Ton Sold 2001
	(in thousands)			
Tons sold	18,370	18,569	NA	NA
Tons produced	17,970	17,354	NA	NA
Coal Sales	$479,515	$453,054	$ 26.10	$ 24.40
Other Sales and Operating Revenues	$ 20,385	$ 6,233	NA	NA
Operating Expenses and Outside Purchases	$377,644	$366,073	$ 20.56	$ 19.71

Coal sales. Coal sales for 2002 increased 5.8% to $479.5 million from $453.1 million for 2001. The increase of $26.4 million was primarily attributable to higher price sales contracts secured during the second half of 2001 for deliveries in 2002 and higher productivity and coal sales from Gibson. The higher priced sales contracts reflected a combination of factors including low coal stockpiles and supply shortages. These increases were partially offset by a decrease in the domestic coal brokerage market. Tons sold were comparable for 2002 and 2001 at 18.4 million tons and 18.6 million tons, respectively. Tons produced increased 3.5% to 18.0 million for 2002 compared to 17.4 million in 2001, primarily reflecting increased production at Gibson.

Other sales and operating revenues. Other sales and operating revenues increased to $20.4 million for 2002 from $6.2 million for 2001. The increase of $14.2 million was attributable to additional rental and service fees associated with increased volumes at a third-party coal synfuel production facility at Hopkins. Please see "Item 1. Business, Mining Operations, Illinois Basin Operations."

Operating expenses. Operating expenses increased 9.0% to $367.6 million in 2002 from $337.2 million in 2001. The increase of $30.4 million was primarily the result of increased operating expenses associated with increased tons sold from production, increased coal synfuel production and a period of higher costs at Dotiki and Warrior during the construction of infrastructure investments. Operating expenses increased on a cost-per-ton basis, reflecting the higher cost production periods at Dotiki and Warrior, the transition into higher cost-per-ton mining areas at Hopkins and production losses at Mettiki attributable to adverse geologic conditions.

Outside purchases. Outside purchases decreased to $10.1 million in 2002 from $28.9 million in 2001. The decrease of $18.8 million was primarily attributable to a decrease in the domestic coal brokerage market.

General and administrative. General and administrative expenses increased 8.5% to $20.3 million in 2002 compared to $18.7 million in 2001. The increase of $1.6 million was primarily attributable to higher expense accruals of $0.8 million associated with incentive compensation programs and various other increases in administrative compliance costs.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expenses increased 3.4% to $52.4 million for 2002 compared to $50.7 million for 2001. The increase of $1.7 million primarily resulted from additional depreciation expense associated with the new Gibson complex.

Interest expense. Interest expense decreased 2.5% to $16.4 million for 2002 from $16.8 million for 2001 primarily reflecting debt reduction due to scheduled debt payments.

Transportation revenues and expenses. Transportation revenues and expenses for 2002 increased 4.6% to $19.0 million from $18.2 million in 2001. The increase reflects increased shipments to a customer with above-average transportation costs. 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 $25.9 million to $33.7 million for 2002 from $7.8 million for 2001. The increase was primarily attributable to higher price sales contracts, increased volumes associated with the coal synfuel related agreements, and higher sales volume at Gibson partially offset by increased operating expense per ton sold, reflecting the higher cost production periods at Dotiki and Warrior during the construction of infrastructure investments, the transition into higher cost-per-ton mining areas at Hopkins and production losses at Mettiki attributable to adverse geologic conditions.

Income tax expense (benefit). Income tax benefit for 2002 was $1.1 million compared to an income tax benefit of $0.8 million in 2001. Although we are not a taxable entity for federal or state income tax purposes, Warrior was subject to federal and state income taxes prior to February 2003 when we purchased Warrior. Warrior had a net income tax benefit of $1.3 million in 2002 compared to $0.8 million in 2001. Additionally, 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, resulting in income tax expense of $0.2 million.

Cumulative effect of accounting change. Please see discussion above under “Workers’ Compensation and Pneumoconiosis (“Black Lung”) Benefits.”

Ongoing Acquisition Activities

Consistent with our business strategy, from time-to-time we engage in discussions with potential sellers regarding possible acquisitions 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 2003, we had rental expense of $1.0 million 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 $110.3 million in 2003, compared to $101.3 million in 2002. The increase in cash provided by operating activities was principally attributable to increased operating income.

Net cash used in investing activities was $77.8 million in 2003, compared to net cash used in investing activities of $56.9 million in 2002. The increased use of cash is principally attributable to purchasing of marketable securities of $23.1 million in 2003 compared to the receipt of proceeds from the maturity of marketable securities in 2002.

Net cash used in financing activities was $31.3 million for 2003, compared to net cash used in financing activities of $46.4 million for 2002. The decrease is primarily attributable to the proceeds received from our common unit offering during 2003 of $53.9 million partially offset by an increase of $5.6 million in distributions to our partners due to an increase in the quarterly distribution rate of $0.025 per unit to $0.525 per unit and the additional common units outstanding from the common unit offering, payment of Warrior's borrowings of $17.0 million under a revolving credit agreement and an increase in payments of $16.3 million on long-term debt. The quarterly distribution rate was increased to $0.5625 per unit for the quarter ended December 31, 2003. We expect to maintain this level of quarterly cash distribution during 2004.

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, 2003 (in thousands):

Contractual Obligations	**Total**	**Less than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**
Long-term debt	$ 180,000	$ -	$ 36,000	$ 36,000	$ 108,000
Operating leases	25,265	4,663	8,911	6,273	5,418
Other long-term obligations (excluding discount effect of $10.3 million for reclamation liability)	33,798	1,749	5,599	8,247	18,203
Capital projects	7,659	7,659	-	-	-
	$ 246,722	$ 14,071	$ 50,510	$ 50,520	$ 131,621

We expect to contribute $3.3 million to the defined benefit pension plan (Pension Plan) during 2004. We estimate that our combined interest and income tax cash requirements will be approximately $15.5 million and $2.4 million, respectively in 2004.

Capital Expenditures

Capital expenditures decreased to $55.7 million in 2003, compared to $67.3 million in 2002. The capital expenditures in 2003 of $55.7 million included $12.7 million for the Warrior acquisition. Excluding the Warrior acquisition, capital expenditures for 2003 decreased $24.3 million compared to capital expenditures for the 2002 period. The decrease is primarily attributable to the substantial completion of the extension into an adjacent reserve area at Pattiki in late 2002, new infrastructure projects at Warrior in 2002, and the new service shaft at Dotiki completed in April 2003. The majority of the capital expenditures associated with the Pattiki, Warrior and Dotiki projects were incurred during 2002.

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 $34.0 million. We also currently expect to fund our anticipated total capital expenditures for 2004 of $46.5 million, with cash generated from operations and borrowings under our revolving credit facility described below.

Notes Offering and Credit Facility

Concurrently with the closing of our initial public offering, our special general partner issued, and our intermediate partnership assumed the obligations with respect to, $180 million principal amount of 8.31% senior notes due August 20, 2014 (Senior Notes). On August 22, 2003, our intermediate partnership completed a new $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 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, 2003. 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, 2003, 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 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, 2003.

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, 2003, we had $15.6 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 an 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 $23.5 million for these costs at December 31, 2003 and 2002, respectively.

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 $28.2 million and $24.7 million for these costs at December 31, 2003 and 2002, respectively. A one-percentage-point reduction in the discount rate would have increased the liability at December 31, 2003 approximately $1.2 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 statues 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 $18.1 million and $16.6 million for these benefits at December 31, 2003 and 2002, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2003 by approximately $0.3 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.

Effective January 1, 2001, we changed our method of estimating black lung benefits to the service cost method described in Statement of Financial Accounting Standards ("SFAS") No. 106, "Employer's Accounting for Postretirement Benefits Other Than Pensions," which method is permitted under SFAS No. 112 "Employers' Accounting for Postemployment Benefits." In January 2001, governmental regulations regarding the federal black lung benefits claims approval process became effective. These new regulations specifically define the black lung disability as progressive and also expand the definition of pneumoconiosis to mandate consideration of diseases that are caused by factors other than exposure to coal dust. We believe the change to the SFAS No. 106 measurement methodology better matches black lung costs over the service lives of the miners who ultimately receive the black lung benefits and is more reflective of the enacted regulations, which place significant emphasis on coal miners' future years of employment in the coal industry. We previously accrued the black lung benefits liability at the present value of the actuarially determined current and future estimated black lung benefit payments utilizing the methodology prescribed under SFAS No. 5 "Accounting for Contingencies," which was also permitted by SFAS No. 112.

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, 2004, 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 $12,471,000, $6,559,000, and $6,503,000 for the years ended December 31, 2003, 2002, and 2001 respectively. The increase from 2002 to 2003 was primarily attributable to higher accruals related to common unit based incentive programs, 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 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 $3,460,000 for 2003 and $2.7 million in 2002 and 2001. Dotiki has recouped as earned royalties all advance minimum royalty payments made under these lease terms as of December 31, 2003.

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 $2,453,000, $2,127,000 and $2,838,000 for the years ended December 31, 2003, 2002, and 2001, respectively. Warrior has recouped as earned royalties all advance minimum royalty payments made in accordance with these lease terms except for $1,230,000 as of December 31, 2003.

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 $4,395,000, $3,922,000, and $2,347,000 for the years ended December 31, 2003, 2002 and 2001 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 $320,000 as of December 31, 2003.

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, $568,000, and $705,000 for the years ended December 31, 2003, 2002, and 2001, respectively. MC Mining has recouped as earned royalties all advance minimum royalty payments made under these lease terms as of December 31, 2003.

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 $684,000 during the years ended December 31, 2002 and 2001. 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 2003, 2002 and 2001.

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, 2003, we had $15.6 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, $48,200, and $8,800 in guarantee fees to our special general partner for the years ended December 31, 2003, 2002, and 2001, respectively.

Accruals of Other Liabilities

We had accruals for other liabilities, including current obligations, totaling $77.8 million and $75.8 million at December 31, 2003 and 2002. 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 $3,049,000 and $2,199,000 for the years ended December 31, 2003 and 2002, 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 9.0% and a discount rates of 6.75% and 7.25% for the years ended December 31, 2003 and 2002, 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, 2004, 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 10.2%, 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.

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 6.75% at December 31, 2002 to 6.25% at December 31, 2003.

We estimate that our Pension Plan expense and cash contributions will be approximately $2,640,000 and $3,300,000, respectively in 2004. 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, 2002 would have increased our pension expense for the year ended December 31, 2003 by approximately $140,000. Lowering the discount rate assumption by 0.5% (from 6.75% to 6.25%) at December 31, 2002 would have increased our pension expense for the year ended December 31, 2003 by approximately $357,000.

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, 2003.

Recent Accounting Pronouncements

On January 1, 2003, we adopted Statement of Financial Accounting Standards ("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. When the liability is initially recorded, a cost is capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value for each period, and the capitalized cost is depreciated over the useful life of the related asset. To settle the liability, the obligations for its recorded amount is paid or a gain or loss upon settlement is incurred. Since we have historically adhered to accounting principles similar to SFAS No. 143, this standard had no material effect on our consolidated financial statements upon adoption.

On January 1, 2003, we adopted Financial Accounting Standards Board Interpretation No. 45 “Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.” This interpretation elaborates on the disclosures to be made by a guarantor in its financial statements about its obligations under certain guarantees that it has issued. It also requires a guarantor to recognize, at the inception of a guarantee, a liability for the fair value of the obligations it has undertaken in issuing the guarantee. This interpretation had no material effect on our consolidated financial statements upon adoption.

Recent Accounting Issue

Extractive industry companies have historically classified leased coal interests and advance royalties as tangible assets, which is consistent with the classification of owned coal due to the similar rights of the leaseholder. SFAS No. 141, "Business Combinations," identifies mineral rights as an example of a contract-based intangible asset that should be considered for separate classification as the result of a business combination. Due to the potential for inconsistencies in applying the provisions of SFAS No. 141 (and SFAS No. 142, "Goodwill and Other Intangible Assets") in the extractive industries as they relate to mineral interests controlled by other than fee ownership, the Emerging Issues Task Force (EITF) has established a Mining Industry Working Group that is currently addressing this issue. Depending on the conclusions reached by the Mining Industry Working Group and the EITF, the classification of our leased coal interests and advance royalties in our consolidated balance sheets may be revised.

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.

- Several of our customers have had their credit rating down-graded, and two customers have filed for bankruptcy. While we have not received notice of, and otherwise are not aware of, the intent of any of these customers to default on their contractual obligations to us, the lowered credit ratings and the bankruptcy filing of these customers indicate that this is a possibility.

- Several coal companies that compete with us have filed for bankruptcy protection. If they emerge from bankruptcy with their debt burden reduced or eliminated, those companies may possess a significant competitive advantage over us.

- 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 facility at Warrior 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 the coal synfuel production facility 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.

- 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, including upon conversion of subordinated 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.

- 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.

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 18. 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 a $85 million revolving credit facility which replaces a $100 million credit facility. Borrowings under the new revolving 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. If interest rates would have increased by 100 basis points, interest expense for the year ended December 31, 2003 would have increased by approximately $250,000. We had no borrowings outstanding under the Credit Facility at December 31, 2003.

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, 2003, and 2002. The carrying amounts and fair values of financial instruments are as follows (in thousands):

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%		

Expected Maturity Dates as of December 31, 2002	**2003**	**2004**	**2005**	**2006**	**2007**	**Thereafter**	**Total**	**Fair Value December 31, 2002**
Senior Notes fixed rate	$ -	$ -	$ 18,000	$ 18,000	$ 18,000	$ 126,000	$ 180,000	$ 197,247
Weighted Average interest rate			8.31%	8.31%	8.31%	8.31%		
Term Loan-floating rate	$ 16,250	$ 15,000	$ -			$ -	$ 31,250	$ 31,250
Weighted Average interest rate	4.31%	4.31%						

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEPENDENT AUDITORS' REPORT

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, 2003 and 2002, the related consolidated statements of income, cash flows and Partners' capital (deficit) for each of the three years in the period ended December 31, 2003. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, 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.

As discussed in Note 4 to the consolidated financial statements, the Partnership changed its method of estimating coal workers pneumoconiosis benefits liability effective January 1, 2001.

/s/ Deloitte & Touche LLP

Tulsa, Oklahoma
March 12, 2004

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2003 AND 2002
(In thousands, except unit data)

	December 31, 2003	December 31, 2002
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 10,156	$ 9,028
Trade receivables, less allowance of $763 at December 31, 2003 and 2002	38,305	33,018
Marketable securities	23,615	470
Inventories	14,527	13,165
Advance royalties	1,108	5,232
Prepaid expenses and other assets	3,432	2,784
Total current assets	91,143	63,697
PROPERTY, PLANT AND EQUIPMENT, AT COST	474,357	446,629
LESS ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION	(251,567)	(216,777)
	222,790	229,852
OTHER ASSETS:		
Advance royalties	12,439	10,542
Coal supply agreements, net	5,445	8,167
Other long-term assets	4,637	4,674
	$ 336,454	$ 316,932
LIABILITIES AND PARTNERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 22,651	$ 23,330
Due to affiliates	13,546	1,286
Accrued taxes other than income taxes	10,375	8,105
Accrued payroll and related expenses	11,095	10,004
Accrued interest	5,402	5,361
Workers' compensation and pneumoconiosis benefits	5,905	5,275
Other current liabilities	5,739	9,877
Current maturities, long-term debt	-	16,250
Total current liabilities	74,713	79,488
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities	180,000	195,000
Pneumoconiosis benefits	17,633	16,067
Workers' compensation	22,819	19,949
Reclamation and mine closing	21,717	21,821
Due to affiliates	3,735	20,652
Other liabilities	3,280	2,717
Total liabilities	323,897	355,694
COMMITMENTS AND CONTINGENCIES		
PARTNERS' CAPITAL (DEFICIT):		
Common Unitholders 14,692,527 and 8,982,780 units outstanding, respectively	263,071	144,219
Subordinated Unitholder 3,211,266 and 6,422,531 units outstanding, respectively	58,411	112,916
General Partners	(305,034)	(290,472)
Unrealized loss on marketable securities	(102)	(150)
Minimum pension liability	(3,789)	(5,275)
Total Partners' capital (deficit)	12,557	(38,762)
	$ 336,454	$ 316,932

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001
(In thousands, except unit and per unit data)

	Year Ended December 31,		
	2003	2002	2001
SALES AND OPERATING REVENUES:			
Coal sales	$ 501,596	$ 479,515	$ 453,054
Transportation revenues	19,553	18,992	18,163
Other sales and operating revenues	21,598	20,385	6,233
Total revenues	542,747	518,892	477,450
EXPENSES:			
Operating expenses	368,835	367,567	337,223
Transportation expenses	19,553	18,992	18,163
Outside purchases	8,508	10,077	28,850
General and administrative	28,270	20,337	18,747
Depreciation, depletion and amortization	52,495	52,408	50,696
Interest expense (net of interest income and interest capitalized of $545, $1,353 and $2,056 for the Partnership's respective periods)	15,981	16,360	16,772
Total operating expenses	493,642	485,741	470,451
INCOME FROM OPERATIONS	49,105	33,151	6,999
OTHER INCOME	1,374	540	771
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	50,479	33,691	7,770
INCOME TAX EXPENSE (BENEFIT)	2,577	(1,094)	(836)
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	47,902	34,785	8,606
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	-	-	7,939
NET INCOME	$ 47,902	$ 34,785	$ 16,545
ALLOCATION OF NET INCOME:			
PORTION APPLICABLE TO WARRIOR COAL EARNINGS (LOSS) PRIOR TO ITS ACQUISITION ON FEBRUARY 14, 2003	$ (666)	$ (1,504)	$ (555)
PORTION APPLICABLE TO PARTNERS' INTEREST	48,568	36,289	17,100
NET INCOME	$ 47,902	$ 34,785	$ 16,545
GENERAL PARTNERS' INTEREST IN NET INCOME (LOSS)	$ 306	$ (778)	$ (213)
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 47,596	$ 35,563	$ 16,758
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 2.71	$ 2.31	$ 1.09
BASIC NET INCOME PER LIMITED PARTNER UNIT BEFORE ACCOUNTING CHANGE	$ 2.71	$ 2.31	$ 0.58
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 2.62	$ 2.24	$ 1.07
DILUTED NET INCOME PER LIMITED PARTNER UNIT BEFORE ACCOUNTING CHANGE	$ 2.62	$ 2.24	$ 0.57
PRO FORMA NET INCOME ASSUMING ACCOUNTING CHANGE IS APPLIED RETROACTIVELY	$ 47,902	$ 34,785	$ 8,606
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING - BASIC	17,580,734	15,405,311	15,405,311
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING - DILUTED	18,162,839	15,842,708	15,684,550

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001
(In thousands)

	Year Ended December 31,		
	2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 47,902	$ 34,785	$ 16,545
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	52,495	52,408	50,696
Cumulative effect of accounting change	-	-	(7,939)
Reclamation and mine closings	1,341	1,365	1,175
Coal inventory adjustment to market	687	48	233
Other	(353)	(1,014)	(890)
Changes in operating assets and liabilities:			
Trade receivables	(5,287)	(464)	6,395
Inventories	(2,049)	(104)	(584)
Advance royalties	2,227	(311)	(2,589)
Accounts payable	(679)	(4,144)	(37)
Due to affiliates	9,978	14,080	6,447
Accrued taxes other than income taxes	2,270	1,936	1,011
Accrued payroll and related benefits	1,091	1,348	1,322
Accrued pneumoconiosis benefits	1,566	1,452	903
Workers' compensation	3,500	2,568	1,493
Other	(4,377)	(2,647)	(3,716)
Total net adjustments	62,410	66,521	53,920
Net cash provided by operating activities	110,312	101,306	70,465
CASH FLOWS FROM INVESTING ACTIVITIES:			
Purchase of property, plant and equipment	(43,004)	(67,339)	(58,661)
Purchase of Warrior Coal	(12,661)	-	-
Proceeds from sale of property, plant and equipment	913	323	233
Purchase of marketable securities	(23,091)	-	(33,527)
Proceeds from the sale of marketable securities	-	10,085	60,840
Net cash used in investing activities	(77,843)	(56,931)	(31,115)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from common unit offering to public	53,927	-	-
Cash contribution by General Partners	9	-	-
Payments on Warrior Coal revolver	(17,000)	-	-
Borrowings under revolving credit and working capital facilities	31,600	66,400	1,100
Payments under revolving credit and working capital facilities	(31,600)	(66,400)	(1,100)
Payments on long-term debt	(31,250)	(15,000)	(3,750)
Distributions to Partners	(37,027)	(31,440)	(31,440)
Net cash used in financing activities	(31,341)	(46,440)	(35,190)
NET CHANGE IN CASH AND CASH EQUIVALENTS	1,128	(2,065)	4,160
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	9,028	11,093	6,933
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 10,156	$ 9,028	$ 11,093
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest	$ 15,960	$ 17,294	$ 18,162
Cash paid to taxing authorities	$ 2,681	$ -	$ -

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL (DEFICIT)
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001
(In thousands, except unit data)

	Number of Limited Partner Units							Total
	Common	Subordinated	Common	Subordinated	General Partners	Unrealized Gain (Loss)	Minimum Pension Liability	Partners' Capital (Deficit)
Balance at January 1, 2001	8,982,780	6,422,531	$149,642	$116,794	$(298,223)	$ -	$ -	$(31,787)
Comprehensive income:								
Net income (loss)	-	-	9,772	6,986	(213)	-	-	16,545
Unrealized loss	-	-	-	-	-	(74)	-	(74)
Minimum pension liability	-	-	-	-	-	-	(814)	(814)
Total comprehensive income	-	-	9,772	6,986	(213)	(74)	(814)	15,657
Capital contribution by affiliate (Note 3)	-	-	-	-	10,000	-	-	10,000
Distribution to Partners	-	-	(17,966)	(12,845)	(629)	-	-	(31,440)
Balance at December 31, 2001	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

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

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 are 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.

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 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 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, 2003 and 2002 and the results of their operations, cash flows and changes in partners' capital (deficit) for each of the three years in the period ended December 31, 2003. 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, 2003 and 2002, the estimated fair value of long-term debt was approximately $204.6 million and $228.5 million, respectively. The fair value of long-term debt is based on interest rates that 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 reclassified outstanding checks of $1,257,000 at December 31, 2003, to accounts payable in the consolidated balance sheets.

Marketable Securities—The Partnership currently classifies all marketable securities as available-for-sale securities. At December 31, 2003 and 2002, the cost of marketable securities are reported at fair value with unrealized gains and losses reported as a component of Partners' capital (deficit) until realized. The Partnership has restricted investments 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 20 years. Depreciable lives for mining equipment and processing facilities range from 2 to 20 years. Depreciable lives for land and land improvements and depletable lives for mineral rights range from 5 to 20 years. Depreciable lives for buildings, office equipment and improvements range from 2 to 20 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, 2003 and 2002, land and mineral rights include $2,178,000 representing 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.

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.

On June 2, 2003, the Partnership idled its Hopkins County Coal mining complex. Hopkins County Coal's two surface mines produced 1.6 million tons of coal in 2002 and were idled in response to soft market demand. The Partnership continues to evaluate the recoverability of the appropriate asset group and has concluded that there is 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.

Extractive industry companies have historically classified leased coal interests and advance royalties as tangible assets, which is consistent with the classification of owned coal due to the similar rights of the leaseholder. Statement of Financial Accounting Standards ("SFAS") No. 141, *Business Combinations*, identifies mineral rights as an example of a contract-based intangible asset that should be considered for separate classification as the result of a business combination. Due to the potential for inconsistencies in applying the provisions of SFAS No. 141 (and SFAS No. 142, *Goodwill and Other Intangible Assets*) in the extractive industries as they relate to mineral interests controlled by other than fee ownership, the Emerging Issues Task Force ("EITF") has established a Mining Industry Working Group that is currently addressing this issue. Depending on the conclusions reached by the Mining Industry Working Group and the EITF, the classification of our leased coal interests and advance royalties in our consolidated balance sheets may be revised.

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 $33,018,000 and $30,296,000 at December 31, 2003 and 2002, respectively. The aggregate amortization expense recognized for coal supply agreements was $2,722,000, $3,864,000 and $4,293,000 for the years ended December 31, 2003, 2002 and 2001, respectively. The estimated aggregate amortization expense for years 2004 and 2005 is approximately $2,723,000 per year.

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. Ongoing reclamation costs principally involve restoration of disturbed land and are expensed as incurred during the mining process.

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. Effective January 1, 2001, the Partnership changed its method of estimating the black lung benefits liability (Note 4).

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. 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.

Revenue Recognition—Revenues from coal sales are recognized when title passes to the customer as the coal is shipped. 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 (Note 13) using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* and the related Financial Accounting Standards Board Interpretation No. 28, *Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans*. 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.

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*, the following table provides pro forma results as if the fair value-based method had been applied to all outstanding and non-vested awards, including Long-Term Incentive Plan units, in each period presented (in thousands, except per unit data):

	Year Ended December 31,		
	2003	2002	2001
Net income, as reported	$47,902	$34,785	$16,545
Add: compensation expenses related to Long-Term Incentive Plan units included in reported net income	7,687	2,338	1,929
Deduct: compensation expense related to Long-Term Incentive Plan units determined under fair value method for all awards	(3,632)	(2,257)	(958)
Net income, pro forma	$51,957	$34,866	$17,516
General partners' interest in net income (loss), pro forma	386	(777)	(194)
Limited partners' interest in net income, pro forma	$51,571	$35,643	$17,710
Earnings per limited partner unit:			
Basic, as reported	$ 2.71	$ 2.31	$ 1.09
Basic, pro forma	$ 2.93	$ 2.38	$ 1.16
Diluted, as reported	$ 2.62	$ 2.24	$ 1.07
Diluted, pro forma	$ 2.84	$ 2.32	$ 1.14

Net Income Per Unit—Basic net income per limited partner unit is determined by dividing net income, after deducting the General Partners' 2% interest, by the weighted average number of outstanding Common Units and Subordinated Units. Warrior Coal's earnings (loss) prior to the Partnership's acquisition on February 14, 2003 was allocated entirely to the general partners. Diluted net income per unit is based on the combined weighted average number of Common Units, Subordinated Units and common unit equivalents outstanding (Note 11), which primarily include restricted units granted under the Long-Term Incentive Plan (Note 13).

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—On January 1, 2003, the Partnership adopted Financial Accounting Standards Board Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* ("FIN No. 45"). This interpretation elaborates on the disclosures to be made by a guarantor in its financial statements about its obligations under certain guarantees that it has issued. It also requires a guarantor to recognize, at the inception of a guarantee, a liability for the fair value of the obligations it has undertaken in issuing the guarantee. This interpretation had no material effect on the Partnership's consolidated financial statements upon adoption.

3. WARRIOR COAL ACQUISITION

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 had previously 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 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).

4. ACCOUNTING CHANGE

Effective January 1, 2001, the Partnership changed its method of estimating coal workers’ pneumoconiosis (“black lung”) benefits liability to the service cost method described in SFAS No. 106, *Employers’ Accounting for Postretirement Benefits Other Than Pensions*, which method is permitted under SFAS No. 112, *Employers’ Accounting for Postemployment Benefits*. The Partnership previously accrued the black lung benefits liability at the present value of the actuarially determined current and future estimated black lung benefit payments utilizing the methodology prescribed under SFAS No. 5, *Accounting for Contingencies*, which was also permitted by SFAS No. 112. In January 2001, governmental regulations regarding the black lung benefits claims approval process were enacted. These new regulations specifically define the black lung disability as progressive and also expand the definition of pneumoconiosis to mandate consideration of diseases that are caused by factors other than exposure to coal dust. The Partnership believes the change to the SFAS No. 106 measurement methodology better matches black lung costs over the service lives of the miners who ultimately receive the black lung benefits and is more reflective of the enacted regulations, which place significant emphasis on coal miners’ future years of employment in the coal industry.

The adjustment of $7,939,000 to apply retroactively the new method of estimating the black lung liability is included in net income for the year ended December 31, 2001. The effect of the change for the year ended December 31, 2001 was to decrease income before cumulative effect of a change in accounting principle $435,000 ($(0.03) per basic and diluted limited partner unit) and increase net income $7,504,000 ($0.48 and $0.47 per basic and diluted partner unit, respectively).

5. MARKETABLE SECURITIES

At December 31, 2003 and 2002, the cost of the certificates of deposit and U.S. Treasury securities approximated fair value and no effect of unrealized gains (losses) is reflected in Partners’ capital (deficit). The equity securities had a cumulative unrealized loss reflected in Partners’ capital (deficit) of $102,000 and $150,000 at December 31, 2003 and 2002, respectively.

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

	2003	2002
Certificates of deposit (maturing April 4, 2004)	$ 23,091	$ -
Equity securities	524	470
Total unrestricted marketable securities	$ 23,615	$ 470
Cash and cash equivalents	$ 1,809	$ 821
U.S. Treasury securities	-	963
Total restricted marketable securities	$ 1,809	$ 1,784

6. INVENTORIES

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

	2003	2002
Coal	$ 6,186	$ 4,436
Supplies	8,341	8,729
	$ 14,527	$ 13,165

7. PROPERTY, PLANT AND EQUIPMENT

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

	2003	2002
Mining equipment and processing facilities	$ 411,070	$ 367,396
Land and mineral rights	20,705	18,453
Buildings, office equipment and improvements	36,786	35,428
Construction in progress	5,796	25,352
	474,357	446,629
Less accumulated depreciation, depletion and amortization	(251,567)	(216,777)
	$ 222,790	$ 229,852

8. LONG-TERM DEBT

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

	2003	2002
Senior notes	$ 180,000	$ 180,000
Term loan through credit facility	-	31,250
	180,000	211,250
Less current maturities	-	(16,250)
	$ 180,000	$ 195,000

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 new $85 million revolving credit facility which expires September 30, 2006. The new 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 new 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 new 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, 2003. 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, 2003, 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. The Partnership was in compliance with the covenants of both the revolving credit facility and senior notes at December 31, 2003.

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, 2003, the Partnership had $15.6 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,	
2004	$ -
2005	18,000
2006	18,000
2007	18,000
2008	18,000
Thereafter	108,000
	$ 180,000

9. DISTRIBUTIONS OF AVAILABLE CASH AND CONVERSION OF SUBORDINATED UNITS

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.

Distributions of available cash to the holder of Subordinated Units are subject to the prior rights of holders of Common Units to receive the minimum quarterly distribution ("MQD") for each quarter during the subordination period and to receive any arrearages in the distribution of the MQD on the Common Units for the prior quarters during the subordination period. The MQD is $0.50 per unit ($2.00 per unit on an annual basis).

The Partnership satisfied the early conversion financial test for converting one-half of the Subordinated Units into Common Units as provided for under applicable provisions in the Partnership Agreement. On October 24, 2003, the Board of Directors (and its Conflicts Committee) of the Managing GP approved management's determination that such early conversion financial test was satisfied. As a result, one-half of the outstanding Subordinated Units (i.e., 3,211,265 Subordinated Units) held by the Special GP converted into Common Units on November 15, 2003. The remaining 3,211,266 Subordinated Units are expected to convert on a one-for-one basis into Common Units in the fourth quarter of 2004, assuming the Partnership continues to meet the financial test requirements of the Partnership Agreement.

If quarterly distributions of available cash exceed the MQD and target distributions levels as established in the Partnership Agreement, the Managing GP will receive distributions based on specified increasing percentages of the available cash that exceed the MQD and the target distribution levels. 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. No incentive distributions to the Managing GP have been made through December 31, 2003.

For each of the quarters ended December 31, 2000 through September 30, 2002, quarterly distributions of $0.50 per unit were paid to the common and subordinated unitholders. For each of the quarters ended December 31, 2002 through September 30, 2003, quarterly distributions of $0.525 per unit were paid to the common and subordinated unitholders. On January 26, 2004, the Partnership declared a quarterly distribution, for the period from October 1, 2003 to December 31, 2003, of $0.5625 per unit, totaling approximately $10,311,000, payable on February 13, 2004 to all unitholders of record on February 5, 2004.

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 from January 26, 2001, the date ARH Warrior Holdings acquired the assets that comprise Warrior Coal, to February 14, 2003, the date the Partnership acquired Warrior Coal, are included in income taxes. Components of income tax expense (benefit) are as follows (in thousands):

	Year Ended December 31,		
	2003	2002	2001
Current:			
Federal	$ 1,516	$ 310	$ 528
State	431	45	75
	1,947	355	603
Deferred:			
Federal	550	(1,269)	(1,256)
State	80	(180)	(183)
	630	(1,449)	(1,439)
Income tax expense (benefit)	$ 2,577	$ (1,094)	$ (836)

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,		
	2003	2002	2001
Income taxes at statutory rate	$ 17,668	$ 11,792	$ 2,719
Less: Income taxes at statutory rate on Partnership income not subject to income taxes	(15,855)	(12,606)	(3,206)
Increase/(decrease) resulting from:			
Depletion	-	(114)	(232)
State taxes, net of federal income tax benefit	313	(136)	(107)
Deferred tax assets retained by ARH Warrior Holdings	413	-	-
Other	38	(30)	(10)
Income tax expense (benefit)	$ 2,577	$ (1,094)	$ (836)

The tax effects of significant items comprising Warrior Coal's net deferred tax asset included in other long-term assets on the consolidated balance sheet at December 31, 2002 is as follows (in thousands):

Deferred tax assets:	
Accrued reclamation and mine closing	$ 1,259
Accrued expenses not currently deductible	308
Other	275
Deferred tax asset	1,842
Deferred tax liabilities:	
Differences between book and tax basis of property	1,055
Other	157
Deferred tax liability	1,212
Net deferred tax asset	$ 630

11. NET INCOME PER LIMITED PARTNER UNIT

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

	Year Ended December 31,		
	2003	2002	2001
Net income per limited partner unit	$ 47,596	$ 35,563	$ 16,758
Weighted average limited partner units - basic	17,581	15,405	15,405
Basic net income per limited partner unit	$ 2.71	$ 2.31	$ 1.09
Basic net income per limited partner unit before accounting change	$ 2.71	$ 2.31	$ 0.58
Weighted average limited partner units - basic	17,581	15,405	15,405
Units contingently issuable:			
Restricted units for Long-Term Incentive Plan	527	390	263
Directors' compensation units deferred	16	13	9
Supplemental Executive Retirement Plan	39	35	8
Weighted average limited partner units, assuming dilutive effect of restricted units	18,163	15,843	15,685
Diluted net income per limited partner unit	$ 2.62	$ 2.24	$ 1.07
Diluted net income per limited partner unit before accounting change	$ 2.62	$ 2.24	$ 0.57

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 $2,975,000, $2,959,000 and $2,795,000 for the years ended December 31, 2003, 2002 and 2001, 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.

The following sets forth changes in benefit obligations and plan assets for the years ended December 31, 2003 and 2002 and the funded status of the Pension Plan reconciled with amounts reported in the Partnership's consolidated financial statements at December 31, 2003 and 2002, respectively (dollars in thousands):

	2003	2002
Change in benefit obligations:		
Benefit obligations at beginning of year	$ 18,077	$ 13,202
Service cost	2,502	2,249
Interest cost	1,215	952
Actuarial loss	1,367	1,817
Benefits paid	(213)	(143)
Benefit obligation at end of year	22,948	18,077
Change in plan assets:		
Fair value of plan assets at beginning of year	12,432	10,508
Employer contribution	5,397	3,661
Actual return (loss) on plan assets	3,569	(1,594)
Benefits paid	(213)	(143)
Fair value of plan assets at end of year	21,185	12,432
Funded status	(1,763)	(5,645)
Unrecognized prior service cost	139	187
Unrecognized actuarial loss	3,789	5,275
Net amount recognized	$ 2,165	$ (183)
Amounts recognized in statement of financial position:		
Accrued benefit liability	$ (1,763)	$ (5,645)
Intangible asset	139	187
Accumulated other comprehensive income	3,789	5,275
Net amount recognized	$ 2,165	$ (183)
Weighted-average assumptions as of December 31:		
Discount rate	6.25 %	6.75 %
Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31:		
Discount rate	6.75 %	7.25 %
Expected return on plan assets	8.00 %	9.00 %
Weighted-average asset allocations as of December 31:		
Equity securities	86 %	85 %
Fixed income securities	13 %	13 %
Cash and cash equivalents	1 %	2 %
	100 %	100 %

(Continued)

	2003	2002	2001
Components of net periodic benefit cost:			
Service cost	$ 2,502	$ 2,249	$ 2,050
Interest cost	1,215	952	755
Expected return on plan assets	(1,115)	(1,050)	(888)
Prior service cost	48	48	48
Net loss	399	-	-
Net periodic benefit cost	$ 3,049	$ 2,199	$ 1,965
Effect on minimum pension liability	$ (1,486)	$ 4,461	$ 814

(Concluded)

The Partnership expects to contribute $3,300,000 to the Pension Plan in 2004.

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: (a) 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, 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 their 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 10.2%, 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 in 1998.

13. RESTRICTED UNIT-BASED COMPENSATION

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. The Compensation Committee additionally authorized the cash settlement of at least 40% of all awards under the LTIP that will vest at the end of the subordination period which will be no earlier than November 2004. During 2003 the Compensation Committee approved grants of 141,205 restricted units, which will vest September 30, 2005, subject to certain financial tests. During 2002 and 2001, the Compensation Committee approved grants of 133,885 and 129,200 restricted units, respectively, which vest at the end of the subordination period (Note 9). As of December 31, 2003, 18,125 restricted units have been forfeited. During 2003, 2002 and 2001, the Managing GP billed the Partnership approximately $7,687,000, $2,338,000 and $1,929,000, respectively, attributable to the LTIP. Effective January 1, 2004, the Compensation Committee approved additional grants of 103,425 restricted units, which will vest December 31, 2006, subject to certain financial tests.

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 4.25% 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 $10,332,000 and $10,510,000 at December 31, 2003 and 2002, respectively. Estimated payments of reclamation and mine closing costs as of December 31, 2003 are as follows (in thousands):

Year Ending December 31,	
2004	$ 1,749
2005	2,410
2006	3,189
2007	3,288
2008	4,959
Thereafter	18,203
Aggregate undiscounted reclamation and mine closing	33,798
Effect of discounting	10,332
Total reclamation and mine closing costs	23,466
Less current portion	(1,749)
Reclamation and mine closing costs	$ 21,717

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

	Year Ended December 31,		
	2003	2002	2001
Beginning balance	$ 23,456	$ 20,518	$ 16,018
Accretion expense	1,341	1,365	1,175
Payments	(1,054)	(865)	(571)
Allocation of liability associated with acquisition, mine development and change in assumptions	(277)	2,438	3,896
Ending balance	$ 23,466	$ 23,456	$ 20,518

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.

The Partnership changed its method of estimating black lung benefits liability effective January 1, 2001 to the service cost method (Note 4). 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 4.7% and 5.5% at December 31, 2003 and 2002, respectively.

The reconciliation of changes in benefit obligations at December 31, 2003 and 2002 is as follows (in thousands):

	2003	2002
Benefit obligations at beginning of year	$ 16,067	$ 14,615
Service cost	947	783
Interest cost	978	811
Actuarial loss	65	45
Benefits and expenses paid	(424)	(187)
Benefit obligations at end of year	$ 17,633	$ 16,067

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.

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 $12,471,000, $6,559,000 and $6,503,000 for the years ended December 31, 2003, 2002 and 2001, respectively. The increase from 2002 to 2003 was primarily attributable to higher accruals related to Common Unit-based incentive programs, which were impacted by the increased market value of the Partnership's Common Units, and a Short-Term Incentive Plan.

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 $3,460,000 for the year ended December 31, 2003 and $2.7 million during each of the two years in the period ended December 31, 2002. Webster County Coal has recouped as earned royalties all advance minimum royalty payments made under these lease terms as of December 31, 2003.

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 $2,453,000, $2,127,000 and $2,838,000 for the years ended December 31, 2003, 2002 and 2001, respectively. Warrior Coal has recouped as earned royalties all advance minimum royalty payments made in accordance with these lease terms except for $1,230,000 as of December 31, 2003.

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 $4,395,000, $3,922,000 and $2,347,000 for the years ended December 31, 2003, 2002 and 2001, 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 $320,000 as of December 31, 2003.

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, $568,000 and $705,000 for the years ended December 31, 2003, 2002 and 2001, respectively. MC Mining has recouped as earned royalties all advance minimum royalty payments made under these lease terms as of December 31, 2003.

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 $684,000 during the years ended December 31, 2002 and 2001. 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, 2003 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, 2003, the Partnership had $15.6 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. 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, $48,200 and $8,800 in guarantee fees to the Special GP for the years ended December 31, 2003, 2002 and 2001, respectively.

17. COMMITMENTS AND CONTINGENCIES

Commitments—The Partnership leases buildings and equipment under operating lease agreements which 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
2004	$ 2,595	$2,068	$ 4,663
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
Thereafter	5,405	13	5,418
	$ 18,380	$ 6,885	$ 25,265

Lease expense under all operating leases was $5,490,000, $4,707,000 and $4,740,000 for the years ended December 31, 2003, 2002 and 2001, respectively.

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.

Contractual Commitments—The Partnership had contractual commitments of approximately $7.7 million at December 31, 2003.

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 2003, the Partnership completed its annual property and casualty insurance renewal. Recent insurance carrier losses worldwide have created a tightening market reducing available capacity for underwriting property insurance. 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 limit of $7.5 million for each occurrence, excluding a $3.5 million deductible.

On October 15, 2003, the West Virginia Department of Environmental Protection (“WVDEP”) issued a letter denying Mettiki Coal (WV), LLC’s, one of the Partnership’s subsidiaries, application for an underground mining permit for its proposed E-Mine. The E-Mine is a proposed longwall underground mine to be located primarily in Tucker County, West Virginia. The stated basis of WVDEP’s denial was its belief that Mettiki Coal (WV)’s proposed E-Mine would result in the movement of acid mine drainage outside the permit area from the post-mining mine pool, which would require long-term chemical treatment without a defined “end-point.” WVDEP takes the position that the applicable surface mining laws require reclamation of land and water resources, and that treatment for a period without a defined end-point is not an acceptable reclamation alternative. However, WVDEP previously issued a permit to Island Creek Coal Company to mine the same general reserve area without expressing such concerns. On November 14, 2003, Mettiki Coal (WV) appealed that decision to the West Virginia Surface Mine Board (“Surface Mine Board”). The appeal of the denial of this permit application is scheduled currently to be heard by the Surface Mine Board on April 6, 2004.

In order to expedite the WVDEP’s consideration of additional information that we believe addresses WVDEP’s basis for denial of the original permit application, Mettiki Coal (WV) prepared and submitted a new permit application on January 15, 2004. The new permit application addresses, among other issues, the stated concern for long-term material damage to the hydrologic balance outside the permit area by adding an alkaline recharge component to the hydrologic reclamation plan.

On January 22, 2004, the WVDEP notified Mettiki Coal (WV) that the new permit application was determined to be administratively complete. On February 6, 2004, the WVDEP notified Mettiki Coal (WV) of certain technical corrections that must be responded to before the new permit application review can be completed. Mettiki Coal (WV) submitted technical corrections to the WVDEP on February 17, 2004. WVDEP’s determination on the new permit application is expected within 30 days of an informal public conference to be held by the WVDEP on March 23, 2004.

In the event that WVDEP denies the new permit application, Mettiki Coal (WV) anticipates that it will vigorously pursue the appeal of the denial of the new mining permit application to the Surface Mine Board. The Surface Mine Board, a seven-member board, typically hears cases within several months after appeals are filed and rarely waits more than several weeks after hearing a case to render a final decision. Mettiki Coal (WV) has approximately $1.5 million of advance minimum royalties associated with the E-Mine reserves, which management believes are fully recoverable.

In August 2003, the Partnership resolved a dispute with PSI Energy Inc. (“PSI”) concerning the procedures for and testing of a certain coal quality specification relating to the minimum Hardgrove Grindability Index (i.e., physical hardness of coal) of coal supplied by the Gibson County Coal mining complex. At that time, Gibson County Coal and PSI concluded a definitive settlement agreement that was consistent with a tentative settlement reached during mediation procedures that occurred in August 2002. As part of the settlement, the Partnership agreed with PSI to exchange mutual releases of any and all claims related to the contract dispute. The Partnership’s previously recorded accruals of approximately $800,000 relating to the dispute were consistent with the terms of the executed settlement agreement and certain other agreements.

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 D comprised less than four and two percent of total revenues in 2003 and 2002, respectively) are as follows (in thousands):

	Year Ended December 31,		
	2003	2002	2001
Customer A	$ 116,750	$ 113,094	$ 540
Customer B	78,724	72,224	63,241
Customer C	52,561	69,933	74,091
Customer D	21,382	5,415	59,279

Trade accounts receivable from these customers totaled approximately $17.2 million at December 31, 2003. 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. 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, C and D expire in 2007, 2006, 2010 and 2023, respectively.

19. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

A summary of the quarterly operating results for the Partnership is as follows (in thousands, except unit and per unit data):

	Quarter Ended			
	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003 (1)
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
Basic net income per limited partner unit	$ 0.81	$ 0.47	$ 0.59	$ 0.85
Diluted net income per limited partner unit	$ 0.79	$ 0.45	$ 0.57	$ 0.82
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

	Quarter Ended			
	March 31, 2002	June 30, 2002	September 30, 2002	December 31, 2002
Revenues	$ 125,388	$ 126,828	$ 132,780	$ 133,896
Operating income	15,038	17,660	7,976	8,837
Income before income taxes	11,553	13,836	3,556	4,746
Net income	11,400	14,012	4,126	5,247
Basic net income per limited partner unit	$ 0.71	$ 0.90	$ 0.31	$ 0.38
Diluted net income per limited partner unit	$ 0.69	$ 0.88	$ 0.30	$ 0.37
Weighted average number of units outstanding - basic	15,405,311	15,405,311	15,405,311	15,405,311
Weighted average number of units outstanding - diluted	15,841,062	15,842,657	15,844,316	15,842,783

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

(1) The Partnership's quarterly revenue was 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.

20. SUBSEQUENT EVENT

On February 11, 2004, Webster County Coal's Dotiki mine was temporarily idled following the occurrence of a mine fire. Dotiki has successfully extinguished the fire and has totally isolated the affected area of the mine behind permanent seals. Production resumed on March 8, 2004. At this time, the Partnership is unable to quantify the financial impact of the fire or to predict when Dotiki will return to normal production. The temporary idling of Dotiki will reduce earnings for the first quarter of 2004. The Partnership does have commercial property insurance (including business interruption coverage) that the Partnership currently believes will cover a substantial portion of the financial loss. Assuming that is correct, Dotiki's recognized losses in the first quarter of 2004 should be substantially offset by an insurance settlement that would be recognized later in the year. There can be no assurance of the amount or timing of recovery, however, until the claim is resolved with the insurance underwriter. The Partnership's insurance program provides for a deductible of $3.5 million and a ten percent coinsurance. In addition to the losses associated with business interruption, the Partnership has currently identified approximately $6.0 million of out-of-pocket expenses that generally fall into the category of extra expenses, expedited expenses and other areas of coverage under the commercial property insurance policy. The Partnership expects that additional out-of-pocket costs will be identified in the future.

* * * * * *

SCHEDULE II

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

	Balance At Beginning Of Year	Additions Charged To Income	Deductions	Balance At End Of Year
		(in thousands)		
2003				
Allowance for doubtful accounts	$ 763	$ -	$ -	$ 763
2002				
Allowance for doubtful accounts	$ 763	$ -	$ -	$ 763
2001				
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.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

An evaluation was carried out by management, including our chief executive officer and chief financial officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) and Rule 15d-15(e) under the Securities Exchange Act of 1934). Based upon this evaluation, the chief executive officer and the chief financial officer concluded that the design and operation of these disclosure controls and procedures were effective as of the end of the period covered by this report. During the quarterly period ended December 31, 2003, there have not been any changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) identified in connection with this evaluation that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Each of the chief executive officer and the chief financial officer of our managing general partner has furnished as Exhibit 32.1 and Exhibit 32.2, respectively, a certificate to the Securities and Exchange Commission as required by Section 906 of the Sarbanes-Oxley Act of 2002.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, PROMOTERS AND CONTROL PERSONS OF THE MANAGING GENERAL PARTNER

As is commonly the case with publicly-traded limited partnerships, we are managed and operated by our managing general partner. The following table shows information for the directors and executive officers of our managing general partner. Executive officers and directors are elected until death, resignation, retirement, disqualification, or removal.

Name	Age	Position With our Managing General Partner
Joseph W. Craft III	53	President, Chief Executive Officer and Director
Robert G. Sachse	55	Executive Vice President and Vice Chairman of the Board
Thomas L. Pearson	50	Senior Vice President – Law and Administration, General Counsel and Secretary
Charles R. Wesley	49	Senior Vice President – Operations
Brian L. Cantrell	44	Senior Vice President – Chief Financial Officer
Gary J. Rathburn	53	Senior Vice President – Marketing
Michael J. Hall	59	Director and Member of the Audit* and Conflicts Committees
John J. MacWilliams	48	Director

Preston R. Miller, Jr.	55	Director and Member of the Compensation* Committee
John P. Neafsey	64	Chairman of the Board and Member of Audit, Compensation and Conflicts Committees
John H. Robinson	53	Director and Member of Audit, Compensation and Conflicts* Committees

*Indicates Chairman of Committee

Joseph W. Craft III has been President, Chief Executive Officer and a Director since August 1996 and has indirect majority ownership of our managing general partner. Previously Mr. Craft served as President of MAPCO Coal Inc. since 1986. During that period, he also was Senior Vice President of MAPCO Inc. and had been previously that company's General Counsel and Chief Financial Officer. Before joining MAPCO, Mr. Craft was an attorney at Falcon Coal Corporation and Diamond Shamrock Coal Corporation. He is past Chairman of the National Coal Council, a Board and Executive Committee Member of the National Mining Association, and a Director of the Center for Energy and Economic Development. Mr. Craft holds a Bachelor of Science degree in Accounting and a Juris Doctor degree from the University of Kentucky. Mr. Craft also is a graduate of the Senior Executive Program of the Alfred P. Sloan School of Management at Massachusetts Institute of Technology.

Robert G. Sachse has been Executive Vice President and Vice Chairman since August 2000. Prior to his current position, Mr. Sachse was Executive Vice President and Chief Operating Officer of MAPCO Inc. from 1996 to 1998 when MAPCO merged with The Williams Companies. Following the merger, Mr. Sachse had a two year non-compete consulting agreement with The Williams Companies. Mr. Sachse held various positions while with MAPCO Coal Inc. from 1982 to 1991, and was promoted to President of MAPCO Natural Gas Liquids in 1992. Mr. Sachse holds a Bachelor of Science degree in Business Administration from Trinity University and a Juris Doctor degree from the University of Tulsa.

Thomas L. Pearson has been Senior Vice President – Law and Administration, General Counsel and Secretary since August 1996. Mr. Pearson previously was Assistant General Counsel of MAPCO Inc., and served as General Counsel and Secretary of MAPCO Coal Inc. from 1989 to 1996. Before joining the company, he was General Counsel and Secretary of McLouth Steel Products Corporation, Corporate Counsel for Midland-Ross Corporation, and an attorney for Arter & Hadden, a law firm in Cleveland, Ohio. Mr. Pearson's current and past business, charitable and education involvement includes Trustee of the Energy and Mineral Law Foundation, Vice Chairman, Legal Affairs Committee, National Mining Association, and Member, Dean's Committee, The University of Iowa College of Law. Mr. Pearson holds a Bachelor of Arts degree in History and Communications from DePauw University and a Juris Doctor degree from The University of Iowa.

Charles R. Wesley has been Senior Vice President – Operations since August 1996. He joined the company in 1974 when he began working for Webster County Coal Corporation as an engineering co-op student. In 1992, Mr. Wesley was named Vice President – Operations for Mettiki Coal Corporation. He has served the industry as past President of the West Kentucky Mining Institute and National Mine Rescue Association Post 11, and he has served on the Board of the Kentucky Mining Institute. Mr. Wesley holds a Bachelor of Science degree in Mining Engineering from the University of Kentucky.

Brian L. Cantrell was named Senior Vice President and Chief Financial Officer in October 2003. Prior to his current position, Mr. Cantrell was President of AFN Communications, LLC from November 2001 to October 2003 where he had previously served as Executive Vice President and Chief Financial Officer after joining AFN in September 2000. Mr. Cantrell's previous positions include Chief Financial Officer, Treasurer and Director with Brighton Energy, LLC from August 1997 to September 2000; Vice President – Finance of KCS Medallion Resources, Inc.; and Vice President – Finance, Secretary and Treasurer of Intercoast Oil and Gas Company. Mr. Cantrell is a Certified Public Accountant and holds a Master of Accountancy and Bachelor of Accountancy from the University of Oklahoma.

Gary J. Rathburn has been Senior Vice President – Marketing since August 1996. He joined MAPCO Coal Inc. as Manager of Brokerage Coals in 1980. Since that time, he has managed all phases of the marketing group involving transportation and distribution, international sales and the brokering of coal. Prior to joining the company, Mr. Rathburn was employed by Eastern Associated Coal Corporation in its International Sales and Brokerage groups. Active in many industry-related groups, he was a Director of The National Coal Association and Chairman of the Coal Exporters Association for several years. Mr. Rathburn holds a Bachelor of Arts degree in Political Science from the University of Pittsburgh and has participated in industry-related programs at the World Trade Institute, Princeton University and the Colorado School of Mines.

Michael J. Hall became a Director in March 2003. Mr. Hall is Vice President – Finance and Chief Financial Officer, Secretary and Treasurer of Matrix Service Company (Matrix) and serves on its Board of Directors. He assumed these positions when he joined Matrix in September 1998. Matrix is a company which provides general industrial construction and repair and maintenance services principally to the petroleum, petrochemical, power, bulk storage terminal, pipeline and industrial gas industries. Mr. Hall is responsible for all financial and administrative functions including accounting, financial reporting, auditing, finance, budgeting, tax, risk management, investor relations, human resources and information technology. Effective May 31, 2004, Mr. Hall will retire from his position of Vice President – Finance and Chief Financial Officer and will continue to serve on the Board of Directors of Matrix Service Company. Prior to working for Matrix, Mr. Hall was Vice President and Chief Financial Officer of Pexco Holdings, Inc., Vice President – Finance and Chief Financial Officer for Worldwide Sports & Recreation, Inc. an affiliated company of Pexco and worked for T.D. Williamson, Inc., as Senior Vice President, Chief Financial and Administrative Officer, and Director of Operations – Europe, Africa and Middle East Region. Mr. Hall holds a Bachelor of Science degree in Accounting from Boston College and a Master of Business Administration from Stanford University. Mr. Hall is chairman of the audit committee and a member of the conflicts committee.

John J. MacWilliams, is a Partner of The Tremont Group, LLC, a private equity investment firm founded in January 2003, located in Newton, MA., which has specialized expertise in the energy industry. Mr. MacWilliams is also a General Partner of The Beacon Group, LP, that he joined in 1993, and has served as a Director since June 1996. As part of the Beacon Group, he co-manages two private equity funds focusing on the energy industry. Mr. MacWilliams' previous positions include serving as a General Partner of JP Morgan Partners, Executive Director of Goldman Sachs International in London, Vice President for Goldman Sachs & Co.'s Investment Banking Division in New York, and as an attorney at Davis Polk & Wardwell in New York. He also is a Director of Compagnie Generale de Geophysique. Mr. MacWilliams holds a Bachelor of Arts degree from Stanford University, Master of Science degree from Massachusetts Institute of Technology, and a Juris Doctor degree from Harvard Law School.

Preston R. Miller, Jr., is a Partner of The Tremont Group, LLC, a private equity investment firm founded in January 2003, located in Newton, MA., which has a specialized expertise in the energy industry. Mr. Miller is a General Partner of The Beacon Group, LP that he joined in 1993 and has served as a Director since June 1996. As a part of The Beacon Group, he co-manages two private equity funds focusing on the energy industry. Mr. Miller's previous positions include serving as a General Partner of JP Morgan Partners from June 2000 through December 2002, and was with Goldman Sachs & Co.'s from January 1979 through January 1993, most recently as Vice President in the Structured Finance Group in New York City where he had global responsibility for coverage of the independent power industry, asset-backed power generation, and oil and gas financing. He also has a background in credit analysis, and was head of the revenue bond rating group at Standard & Poor's Corp. Mr. Miller holds a Bachelor of Arts degree from Yale University and a Master of Public Administration degree from Harvard University. Mr. Miller is the chairman of the compensation committee.

John P. Neafsey has served as Chairman since June 1996. Mr. Neafsey is President of JN Associates, an investment consulting firm formed in 1993. Mr. Neafsey served as President and CEO of Greenwich Capital Markets from 1990 to 1993 and a Director since its founding in 1983. Positions that Mr. Neafsey held during a 23-year career at The Sun Company include Executive Vice President responsible for Canadian operations, Sun Coal Company and Helios Capital Corporation; Chief Financial Officer; and other executive positions with numerous subsidiary companies. He is or has been active in a number of organizations, including the following: Director for The West Pharmaceutical Services Company and Constar, Inc. Trustee Emeritus and Presidential Counselor, Cornell University, and Overseer of Cornell-Weill Medical Center. Mr. Neafsey holds Bachelor and Master of Science degrees in Engineering and a Master of Business Administration degree from Cornell University. Mr. Neafsey is a Member of the audit, conflicts and compensation committees.

John H. Robinson became a Director in December 1999. Mr. Robinson is President and Chief Operating Officer of Metilinx Inc, a systems optimization software company. From 2000 to 2002, he was Executive Director of the Technology Services Division of Amey plc, a British support services business. Mr. Robinson served as Vice Chairman of Black & Veatch from 1997 to 2000. He began his career at Black & Veatch in 1973 and was a General Partner and Managing Partner prior to becoming Vice Chairman when the firm incorporated. Mr. Robinson is a Director of Coeur d'Alene Mining Corporation. Mr. Robinson holds Bachelor and Master of Science degrees in Engineering from the University of Kansas and is a graduate of the Owner-President-Management Program at the Harvard Business School. He is chairman of the conflicts committee and a member of the audit and compensation committees.

Audit Committee

The audit committee is comprised of three non-employee members of the board of directors (currently, Mr. Hall, Mr. Neafsey and Mr. Robinson). After reviewing the qualifications of the current members of the audit committee, and any relationships they may have with us that might affect their independence, the board of directors has determined that all current audit committee members are “independent” as that concept is defined in Section 10A of the Exchange Act, all current audit committee members are “independent” as that concept is defined in the applicable rules of the NASDAQ, all current audit committee members are financially literate, and Mr. Hall and Mr. Neafsey qualify as audit committee financial experts under the applicable rules promulgated pursuant to the Exchange Act.

Report of the Audit Committee

The audit committee of Alliance Resource Management GP, LLC, oversees our Partnership's financial reporting process on behalf of the board of directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls. The audit committee has the responsibility for the appointment, compensation and oversight of the work of our independent accountants and will assist the board of directors by conducting its own review of our:

- filings with the Securities and Exchange Commission (the "SEC") and the Securities Act of 1933 and the Securities Exchange Act of 1934 (the "Exchange Act") (i.e., Forms 10-K and 10-Q);

- press releases and other communications by the Partnership to the public concerning earnings, financial condition and results of operations, including changes in distribution policies or practices affecting the holders of Partnership units;

- systems of internal controls regarding finance and accounting that management and the board of directors have established; and

- auditing, accounting and financial reporting processes generally.

In fulfilling its oversight responsibilities, the audit committee reviewed and discussed with management the audited financial statements contained in this Annual Report on Form 10-K.

The Partnership's independent public accountants, Deloitte & Touche, LLP, are responsible for expressing an opinion on the conformity of the audited financial statements with generally accepted accounting principles. The audit committee reviewed with Deloitte & Touche, LLP their judgment as to the quality, not just the acceptability, of the Partnership's accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing standards.

The audit committee discussed with Deloitte & Touche, LLP the matters required to be discussed by SAS 61 (Codification of Statement on Auditing Standards, AU § 380), as may be modified or supplemented. The committee received written disclosures and the letter from Deloitte & Touche, LLP required by Independence Standards Board No. 1., *Independence Discussions with Audit Committees*, as may be modified or supplemented, and has discussed with Deloitte & Touche, LLP its independence from management and the Partnership.

Based on the reviews and discussions referred to above, the audit committee recommended to the board of directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2003 for filing with the SEC.

Members of the Audit Committee:

Michael J. Hall, Chairman

John P. Neafsey

John H. Robinson

Code of Ethics

We have adopted a Code of Ethics with which our chief executive officer and our senior financial officers (including our principal financial officer, and our principal accounting officer or controller), are expected to comply. The Code of Ethics is publicly available on our website under Investors Relations at www.arlp.com and is available in print to any unitholder who requests it. If any substantive amendments are made to the Code of Ethics or if there is a grant of a waiver, including any implicit waiver, from a provision of the code to our chief executive officer, chief financial officer or chief accounting officer or controller, we will disclose the nature of such amendment or waiver on our website or in a report on Form 8-K.

Communications with the Board

Unitholders or other interested parties can contact any director or committee of the board by writing to them c/o Senior Vice President – Law and Administration, General Counsel and Secretary, P. O. Box 22027, Tulsa, Oklahoma 74121-2027. Comments or complaints relating to our accounting, internal accounting controls or auditing matters will also be referred to members of the audit committee. The audit committee has procedures for receipt, retention and treatment of complaints received by us regarding accounting, internal accounting controls, or auditing matters; and for the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities and Exchange Act of 1934, as amended, requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC initial reports of ownership and reports or changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms they file. Based solely upon a review of the copies of the forms furnished to us, or written representations from certain reporting persons, we believe that during 2003 none of our officers and directors were delinquent with respect to any of the filing requirements under Rule 16(a) other than Mr. Sachse who did not timely file a Form 4 related to his purchase of 250 units on July 14, 2003, but has since filed a Form 4 with respect to this transaction.

Reimbursement of Expenses of our Managing General Partner and its Affiliates

Our managing general partner does not receive any management fee or other compensation in connection with its management of us. However, our managing general partner and its affiliates, including Alliance Resource Holdings, perform services for us and are reimbursed by us for all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits properly allocable to us, as well as all other expenses necessary or appropriate to the conduct of our business, and properly allocable to us. Our partnership agreement provides that our managing general partner will determine the expenses that are allocable to us in any reasonable manner determined by our managing general partner in its sole discretion.

ITEM 11. EXECUTIVE COMPENSATION

Executive Compensation

The following table sets forth certain compensation information for the chief executive officer and each of the four other most highly compensated executive officers of our managing general partner in excess of $100,000 in 2003, 2002 and 2001. We reimburse our managing general partner and its affiliates for expenses incurred on our behalf, including the cost of officer compensation allocable to us.

Summary Compensation Table

Name and Principal Position	Year	Annual Compensation: Salary	Annual Compensation: Bonus (1)	Annual Compensation: Other Annual Compensation (2)	Long-Term Compensation Restricted Stock Awards (3)	All Other Compensation (4)
Joseph W. Craft III,	2003	$334,828	$387,000	$3,400	$1,105,605	$62,694
President, Chief Executive Officer	2002	328,955	227,000	1,075	1,237,500	52,171
and Director	2001	314,700	130,000	5,250	781,875	50,562
Thomas L. Pearson,	2003	199,680	166,000	-	221,121	31,481
Senior Vice President-Law and	2002	196,178	83,000	1,750	222,750	32,631
Administration, General Counsel and Secretary	2001	192,000	63,000	1,167	140,738	31,914
Charles R. Wesley,	2003	215,665	234,500	-	343,966	37,115
Senior Vice President-Operations	2002	211,504	130,000	-	247,500	33,001
	2001	202,000	65,000	925	156,375	33,286
Gary J. Rathburn,	2003	173,680	171,000	-	227,263	30,602
Senior Vice President-Marketing	2002	170,634	90,000	2,285	233,750	29,884
	2001	167,000	70,000	3,000	140,738	26,702
Thomas M. Wynne	2003	153,600	150,000	-	159,699	17,448
Vice President-Operations	2002	144,462	60,000	-	178,750	16,102
	2001	135,308	40,000	-	112,938	10,194

(1) Amounts awarded under the Short-Term Incentive Plan. Please see "Short-Term Incentive Plan" below.

(2) Amounts reimbursed for income tax preparation and financial planning services.

(3) Awards under the Long-Term Incentive Plan. The amount represents the value of restricted units at the effective date of grant. The total number of restricted units and their aggregate market value as of December 31, 2003, were: Mr. Craft, 185,000 units valued at $6,360,300; Mr. Pearson, 34,200 units valued at $1,175,796; Mr. Wesley, 42,000 units valued at $1,443,960; Mr. Rathburn, 34,850 units valued at $1,198,143; Mr. Wynne 26,000 units valued at $893,880. Please see "Long-Term Incentive Plan" below.

(4) Amounts represent (a) our managing general partner's matching contributions to its 401(k) Plan, (b) our managing general partner's contribution to its Supplemental Executive Retirement Plan (SERP), and (c) in regard to Mr. Sachse only, our managing general partner's contribution to its Directors' Compensation Program.

Compensation of Directors

Under our managing general partner's Directors' Compensation Program (Directors' Plan) each non-employee director was paid an annual retainer of $21,500 during 2003, except Mr. MacWilliams and Mr. Miller who each received $10,750 in 2003. The annual retainer is payable in common units to be paid on a quarterly basis in advance determined by dividing the pro rata annual retainer payable on such date by the closing sales price per common unit averaged over the immediately preceding ten trading days. Each non-employee director is eligible to participate in a deferred compensation plan that is administered by the compensation committee. Prior to the beginning of each plan year, each non-employee director may elect to defer all or a portion of his compensation until he ceases to be a member of the board of directors. A new election must be made for each plan year. For compensation deferred by a director, a notional account is established and credited with "phantom" units equal to the number of common units deferred. In addition, when distributions are made with respect to common units, the notional account is credited with "phantom" distributions with respect to phantom units that are equal in amount to the distributions made with respect to common units. The board of directors may change or terminate the deferred compensation plan at any time; provided, however, that accrued benefits under the deferred benefit plan cannot be impaired. Effective January 1, 2004, the annual retainer was increased to $22,500.

In addition, each non-employee director is entitled to participate in the Long-Term Incentive Plan. Under the Long-Term Incentive Plan such directors receive annual grants of restricted units, which vest in accordance with the procedures described below. Please see "Long-Term Incentive Plan" below. Prior to the refinancing of the promissory notes in May 2003 between Alliance Resources Holdings and The Beacon Group, Mr. MacWilliams and Mr. Miller had declined compensation under the Directors' Plan and Long-Term Incentive Plans. Please see "Item 1. Business – Transactions in 2003."

Mr. Sachse has a consulting agreement with our managing general partner with an indefinite term, subject to termination by either party upon receipt of ninety-days advance written notice of termination. The consulting agreement provides that Mr. Sachse will serve as Executive Vice President of our managing general partner and devote his services on a part-time basis. In addition to compensation received under the Directors and Long-Term Incentive Plans described above, Mr. Sachse is entitled to receive an annual fee of $150,000, payable in arrears monthly. Mr. Sachse also is entitled to receive quarterly payments in arrears of $7,500, less the market value of 250 common units calculated by the closing sales price per common unit averaged over the immediately preceding ten trading days. Copies of Mr. Sachse's original consulting agreement and the letter agreement extending the term of the original agreement are exhibits hereto.

Employment Agreements

The executive officers of our managing general partner and some additional members of senior management will enter into employment agreements among the executive officer or member of senior management, on the one hand, and our managing general partner on the other. We reimburse our managing general partner for the compensation and benefits costs under these agreements. This summary of the terms of the employment agreements does not purport to be complete, but outlines their material provisions. A form of the agreements with each of Messrs. Craft, Pearson, Wesley and Rathburn is an exhibit hereto.

Each of the form of employment agreements had an initial term that expired on December 31, 2002, but automatically extend for successive one-year terms unless either party gives 12 months prior notice to the other party. The form of employment agreements provide for a base salary, subject to review annually, of $334,828, $199,680, $225,280 and $173,680 for Messrs. Craft, Pearson, Wesley and Rathburn, respectively. The employment agreements provide for continued salary payments, bonus and benefits for a period of three years, in the case of Mr. Craft, and 18 months, in the case of Messrs. Pearson, Wesley and Rathburn, following termination of employment, except in the case of a change of control of our managing general partner.

In the case of a "change of control" as defined in the agreements, in lieu of the continuation of salary and benefits, that executive will be entitled to a lump sum payment in an amount equal to three times base salary plus bonus, in the case of Mr. Craft, and two times base salary plus bonus in the case of Messrs. Pearson, Wesley and Rathburn. Unless the executive waives his or her right to the continuation of base salary and bonus, the agreements provide for a noncompetition period of 18 months. The noncompetition period does not apply after a change in control. Amounts paid by our managing general partner pursuant to the employment agreements will be reimbursed by us.

The executives who are subject to employment agreements also participate in the Short- and Long-Term Incentive Plans of our managing general partner described below along with other members of management.

They also are entitled to participate in the other employee benefit plans and programs that our managing general partner provides for its employees.

Long-Term Incentive Plan

Effective January 1, 2000, our managing general partner adopted the Long-Term Incentive Plan (LTIP) for certain employees and directors of our managing general partner and its affiliates who perform services for us. The summary of the LTIP contained herein does not purport to be complete, but outlines its material provisions.

The LTIP is administered by the compensation committee of our managing general partner's board of directors. Annual grant levels for designated participants are recommended by the president and chief executive officer of our managing general partner, subject to the review and approval of the compensation committee. We will reimburse our managing general partner for all costs incurred pursuant to the programs described below. Grants are made of either 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 a 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 our managing general partner in the open market at a price equal to the then prevailing price, or directly from Alliance Resource Holdings or any other third party, including units newly issued by us, or use units already owned by our managing general partner, or any combination of the foregoing. Our managing general partner is entitled to reimbursement by us for the cost incurred in acquiring these common units or in paying cash in lieu of common units upon vesting of the restricted units. If we issue new common units upon payment of the restricted units or unit options instead of purchasing them, the total number of common units outstanding will increase.

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 available with respect to which options and restricted units may be granted under the LTIP in the future. A copy of the amendment is an exhibit hereto. The compensation committee additionally authorized the cash settlement of at least 40% of all awards under the LTIP that will vest at the end of the subordination period, which will be no earlier than November 2004. During 2003 the compensation committee approved grants of 141,205 restricted units, which will vest September 30, 2005, subject to certain financial tests. During 2002 and 2001, the compensation committee approved grants of 133,885 and 129,200 restricted units, which vest at the end of the subordination period, which generally will not end before September 30, 2004. As of December 31, 2003, 18,125 units have been forfeited. Effective as of January 1, 2004, the compensation committee approved additional grants of 103,425 restricted units, which vest on December 31, 2006 subject to certain financial tests.

Restricted Units. Restricted units will vest over a period of time as determined by the compensation committee. However, if a grantee's employment is terminated for any reason prior to the vesting of any restricted units, those restricted units will be automatically forfeited, unless the compensation committee, in its sole discretion, provides otherwise. In addition, vested restricted units will not be payable before the end of the subordination period, which will generally not end before September 30, 2004.

The issuance of the common units pursuant to the restricted unit plan is intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation in respect of the common units. Therefore, no consideration will be payable by the plan participants upon receipt of the common units, and we receive no remuneration for these units. Following the subordination period, the compensation committee, in it discretion, may grant distribution equivalent rights with respect to restricted units.

Unit Options. We have not made any grants of unit options. The compensation committee, in the future, may decide to make unit option grants to employees and directors containing the specific terms as the committee determines. When granted, unit options will have an exercise price set by the compensation committee which may be above, below or equal to the fair market value of a common unit on the date of grant. Unit options, if any, granted during the subordination period will become exercisable upon, and in the same proportions as, the conversion of the subordinated units to common units, or at a later date as determined by the compensation committee in its sole discretion.

Our managing general partner's board of directors, in its discretion, may terminate the LTIP at any time with respect to any common units for which a grant has not previously been made. Our managing general partner's board of directors will also have the right to alter or amend the LTIP or any part of it from time to time, subject to unitholder approval as required by the exchange upon which the common units may be listed at that time; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the affected participant. In addition, our managing general partner may, in its discretion, establish such additional compensation and incentive arrangements as it deems appropriate to motivate and reward its employees. Our managing general partner is reimbursed for all compensation expenses incurred on our behalf.

Long-Term Incentive Plan – Awards in Last Fiscal Year

	Number of Units (1)	**Performance or Other Period Until Maturation or Payout (2)**
Joseph W. Craft III	45,000	33 Months
Thomas L. Pearson	9,000	33 Months
Charles R. Wesley	14,000	33 Months
Gary J. Rathburn	9,250	33 Months
Thomas M. Wynne	6,500	33 Months

(1) Units granted under the LTIP will vest September 30, 2005, subject to certain financial tests.

(2) The number of units granted is not subject to minimum thresholds, targets or maximum payout conditions.

Short-Term Incentive Plan

Our managing general partner maintains a STIP for management and other salaried employees. The STIP is designed to enhance the financial performance by rewarding management and selected salaried employees and those of our managing general partner with cash awards for our achieving an annual financial performance objective. The annual performance objective for each year is recommended by the president and chief executive officer of our managing general partner and approved by the compensation committee of its board of directors prior to or during January of that year. The STIP is administered by the compensation committee. Individual participants and payments each year are determined by and in the discretion of the compensation committee, and our managing general partner is able to amend the plan at any time. Our managing general partner is entitled to reimbursement by us for the costs incurred under the STIP.

Supplemental Executive Retirement Plan

Our managing general partner maintains a Supplemental Executive Rretirement Plan (SERP) for certain officers and key employees. The purpose of the SERP is to enhance our 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 our 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. Our managing general partner is able to amend or terminate the plan at any time. Our managing general partner is entitled to reimbursement by us for its costs incurred under the SERP.

Compensation Committee's Report on Executive Compensation

The compensation committee administers the executive compensation programs of our managing general partner and was established to fulfill two purposes: (a) to discharge the board of directors' responsibilities relating to compensation of our managing general partner's directors and executives, and (b) to produce an annual report on executive compensation for inclusion in our annual report on Form 10-K. All three members of the compensation committee of the board of directors (currently Mr. Miller, Mr. Neafsey and Mr. Robinson) are "non-employee directors" as defined under the Securities Exchange Act of 1934 and the Internal Revenue Code. The board of directors has assigned to the compensation committee the following functions:

- To review and approve corporate goals and objectives relative to our managing general partner's president and chief executive officer's (CEO) compensation, and evaluate the CEO's performance in light of those goals and objectives and to set the CEO's compensation level based on this evaluation.

- To review and approve corporate goals and objectives relative to our senior executive officers, including our named executive officers' compensation, evaluate our senior executive officers' performance in light of those goals and objectives, and to set the senior executive compensation levels based on this evaluation.

- To make recommendations to the board of directors with respect to incentive compensation plans and equity-based plans, including, without limitation, our managing general partner's short-term incentive plan (STIP), long-term incentive plan (LTIP), and supplemental executive retirement plan (SERP).

- To administer our managing general partner's LTIP and grant restricted units or other awards pursuant to such plan.

- To evaluate its own performance at least annually and report on such performance to the board of directors.

For the fiscal year ended December 31, 2003, the compensation committee's activities focused on the primary elements of the total direct compensation program for executive officers; the merits of continuing the LTIP; the guidelines for the STIP pertaining to eligibility, minimum thresholds, target objectives, target results, target payout groups, the respective percentage targets and the payout formula .

Overall Executive Compensation Program

The goals of our managing general partner's executive compensation program are to align compensation with our managing general partner's business objectives and performance and enable our managing general partner to attract, retain and motivate qualified executive officers that contribute to the long-term success of our managing general partner and its affiliates. The primary components of our managing general partner's executive compensation programs are:

- base salary;
- annual incentive bonus awards; and
- equity participation in the form of restricted units.

Executive officers are also entitled to customary benefits available to all of our managing general partner's employees, including group medical, dental, and life insurance and participation in our managing general partner's Profit Sharing and Savings Plan.

Base Salary

The compensation committee reviews and recommends the base salary of our managing general partner's named executive officers, as well as our other officers and key employees. When reviewing base salaries, the compensation committee considers the individual's performance, past performance of our managing general partner and the individual's contribution to that performance, the individual's level of responsibility and competitive pay practices. In general, base salaries are generally targeted at the middle of the competitive market place. This assessment considers relevant industry salary practices, the position's complexity and level of responsibility, its importance to our managing general partner in relation to other executive positions, and the competitiveness of an executive's total compensation. Subject to the committee's approval, the level of executive officer's base pay is determined on the basis of relative comparative compensation data and the CEO's assessment of the executive's performance, experience, demonstrated leadership, job knowledge and management skills.

Annual Incentive Bonus Awards

To provide annual incentive bonus awards, our managing general partner maintains the STIP. The purpose of the STIP is to enhance unitholder value by providing eligible employees, including executive officers of our managing general partner, with added incentive to achieve specific annual targets. The STIP also assists our managing general partner in attracting, retaining and motivating qualified personnel in order to allow our managing general partner to remain competitive with its industry peers. The targets are intended to be aligned with our managing general partner's mission so that bonus payments are made only if unitholder interests are advanced. These targets are established prior to the beginning of each fiscal year. Under the STIP and its related guidelines, our managing general partner's executive officers and other employees selected by the compensation committee are eligible for cash bonuses based upon the comparison of our actual performance results to an annual EBITDA target. EBITDA is defined as income before net interest expense, income taxes and depreciation, depletion and amortization.

Each executive officer of our managing general partner participating in the STIP was eligible to earn a cash bonus expressed as a percentage of such officer's base salary. The incentive bonus opportunities varied by each executive officer's level of responsibility. The maximum percentage of base salary payable as an incentive bonus was (i) up to 160 percent for our managing general partner's CEO, (ii) up to 120 percent for our managing general partner's senior vice presidents, (iii) up to 80 percent for our managing general partner's vice presidents, and (iv) up to specified percentages for other participants. For fiscal year 2003, we achieved our respective annual targets by varying amounts so that all of the 2003 STIP participants were eligible to receive a percentage of their salary as bonus awards at the discretion of the compensation committee and/or our CEO. Bonuses are payable in the first quarter of the following calendar year.

Equity Participation

Equity compensation in the form of restricted units is a key component of our managing general partner's executive compensation program. Under the LTIP administered by the compensation committee, annual grant levels for designated employees are recommended by the CEO. The grants are made either of (a) restricted units, which are "phantom units" that entitle a grantee to receive a common unit or an equivalent amount of cash upon the vesting of a phantom unit or (b) options to purchase common units. Restricted units are vested over a stated period from the grant date. The issuance of the common units pursuant to the LTIP is intended to serve as a means of incentive compensation performance and not primarily as an opportunity to participate in the equity participation with respect to our common units. Therefore, no consideration will be payable by the plan participants upon receipt of the common units. To date, the compensation committee has not granted any unit options under the LTIP.

CEO Executive Compensation

In determining Mr. Craft's compensation, the compensation committee considered our financial performance and peer group compensation data as well as Mr. Craft's leadership, decision-making skills, experience, knowledge, communication with the board of directors and strategic recommendations. The compensation committee did not place any particular relative weight on any one of these factors, but our financial performance is generally given the most weight. The committee's decisions regarding Mr. Craft's compensation are reported to and discussed with the board of directors meeting in executive session without Mr. Craft's participation. For fiscal year 2003, Mr. Craft served as CEO of our managing general partner. Effective June 1, 2002, Mr. Craft's annual salary was increased to $334,828 from $321,950, which adjustment was determined in the manner described above. The compensation committee honored Mr. Craft's request that his salary not be increased in 2003 even though a salary increase would have been warranted under the compensation adjustment procedure described above. Based on our record performance for 2003, Mr. Craft received a cash bonus (paid in fiscal year 2004) equal to approximately 116% of his base salary. Mr. Craft was awarded 28,000 restricted units under the LTIP, subject to certain vesting requirements. The number of restricted units granted to Mr. Craft was determined in the same manner as restricted units granted for our managing general partner's other executive officers as described above.

Conclusion

Based upon its review of our managing general partner's overall executive compensation program, the compensation committee has concluded that the program's structure is appropriate, competitive and effective to serve the purposes for which it was established. Moreover, the compensation committee believes that the total compensation opportunities provided to our managing general partner's executive officers creates a commonality of interest and alignment with the long-term interests of both our managing general partner and its unitholders.

Members of the Compensation Committee:

Preston R. (Jeff) Miller, Chairman

John H. Robinson

John P. Neafsey

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth certain information as of March 1, 2004, regarding the beneficial ownership of common and subordinated units held by (a) each person known by our managing general partner to be the beneficial owner of 5% or more of the common and subordinated units, (b) each director and executive officer of our managing general partner and (c) all directors and executive officers of our managing general partner as a group. Our managing general partner is owned by members of management. Our special general partner is a wholly-owned subsidiary of Alliance Resource Holdings. The address of Alliance Resource Holdings, our managing general partner and our special general partner is 1717 South Boulder Avenue, Tulsa, Oklahoma 74119.

Name of Beneficial Owner	Common Units Beneficially Owned (5)	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Units Beneficially Owned
Alliance Resource GP, LLC (1)	4,444,045	30.25%	3,211,266	100%	42.8%
Joseph W. Craft III (1)(4)	4,660,133	31.72%	3,211,266	100%	44.0%
Robert G. Sachse (1)	8,319	*	-	-	*
Thomas L. Pearson (1)	18,168	*	-	-	*
Charles R. Wesley (1)	27,845	*	-	-	*
Brian L. Cantrell (1)	-	*	-	-	*
Gary J. Rathburn (1)	15,703	*	-	-	*
Michael J. Hall (1)	169	*	-	-	*
John J. MacWilliams (2)	172	*	-	-	*
Preston R. Miller, Jr. (2)	172	*	-	-	*
John P. Neafsey (1)	14,847	*	-	-	*
John H. Robinson (3)	5,875	*	-	-	*
All directors and executive officers as a group (9 persons)	4,779,248	32.53%	3,211,266	100%	44.6%

* Less than one percent

(1) The address of Alliance Resource GP, LLC and Messrs. Craft, Sachse, Pearson, Wesley, Cantrell, Rathburn, Hall, and Neafsey is 1717 South Boulder Avenue, Tulsa, Oklahoma 74119.

(2) The address of Mr. MacWilliams and Mr. Miller is The Tremont Group, LLC., 275 Grove St., Suite 2-400, Newton, Massachusetts 02466.

(3) The address of Mr. Robinson is 121 West 48th Street, Suite 1006, Kansas City, Missouri 64112.

(4) Mr. Craft may be deemed to share beneficial ownership of 4,444,045 common units and 3,211,266 subordinated units held by Alliance Resource GP, LLC through Alliance Resource Holdings II, Inc., of which he is the sole director and majority shareholder. Alliance Resource Holdings II holds all of the outstanding shares of Alliance Resource Holdings, Inc., which holds all of the outstanding shares of Alliance Resource GP. Mr. Craft may be deemed to share beneficial ownership of 113,561 common units held be AMH II, LLC, of which he is the sole director and majority member. Mr. Craft may be deemed to share beneficial ownership of 10,921 common units held by Alliance Management Holdings, LLC, of which he is the sole director. Mr. Craft may also be deemed to share beneficial ownership of an additional 13,500 common units held by a private foundation for which he serves as a Trustee. Mr. Craft disclaims beneficial ownership of the common units held by the private foundation.

(5) The amounts set forth do not include any restricted units granted under the LTIP which vest at various dates ranging from the end of the subordination period, which generally will not end before September 30, 2004 through December 31, 2006, subject to certain financial tests.

Equity Compensation Plan Information

Plan Category	Number of units to be issued upon exercise/vesting of outstanding options, warrants and rights as of March 1, 2004	Weighted-average exercise price of outstanding options, warrants and rights	Number of units remaining available for future issuance under equity compensation plans as of March 1, 2004
Equity compensation plans approved by unitholders:			
Long-Term Incentive Plan	476,566	N/A	123,434
Equity compensation plans not approved by unitholders:			
Supplemental Executive Retirement Plan	44,986	N/A	35,014
Deferred Compensation Plan for Directors	14,835	N/A	35,165

For a description of our Supplemental Executive Retirement Plan and our Deferred Compensation Plan for Directors, please read "Supplemental Executive Retirement Plan" and "Compensation of Directors" under "Item 11. Executive Compensation."

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Certain Relationships and Related Transactions

Our special general partner owns 4,444,045 common units and 3,211,266 subordinated units representing an aggregate 42.6% limited partner interest in us. In addition, our general partners own, on a combined basis, an aggregate 2% general partner interest in us, the intermediate partnership and the subsidiaries. Our managing general partner's ability, as managing general partner, to control us together with our special general partner's ownership of 4,444,045 common units and 3,211,266 subordinated units, effectively gives our general partners the ability to veto some of our actions and to control our management.

Transactions Between the Partnership, Special General Partner and Alliance Resource Holdings

We lease a coal preparation plant and handling facilities at Gibson and lease coal reserves from our special general partner and its affiliates. Our special general partner guarantees our letters of credit. In accordance with the provisions of a put/call option agreement, we purchased Warrior from ARH Warrior Holdings in February 2003. Please see "Item 8. Financial Statements and Supplementary Data. - Note 16. Related Party Transactions" and "Liquidity and Capital Resources – Related Party Transactions" under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Other Related Party Transactions

JPMorgan Chase Bank (Chase) is paying agent, co-administrative agent and a lender under our Credit Facility. In 2003, 2002, and 2001, we made interest and principle payments to Chase on outstanding borrowings and paid Chase customary fees for their other services. We expect that these relationships will continue in 2004. The Beacon Group is an affiliate of Chase. Mr. MacWilliams and Mr. Miller are directors of both the Beacon Group and our managing general partner.

Omnibus Agreement

Concurrently with the closing of our initial public offering, we entered into an omnibus agreement with Alliance Resource Holdings and our general partners, which governs potential competition among us and the other parties to this agreement. The omnibus agreement was amended in May 2002. Pursuant to the terms of the amended omnibus agreement, Alliance Resource Holdings agreed, and caused its controlled affiliates to agree, for so long as management controls our managing general partner, not to engage in the business of mining, marketing or transporting coal in the U.S. unless it first offers us the opportunity to engage in a potential activity or acquire a potential business, and the board of directors of our managing general partner, with the concurrence of its conflicts committee, elects to cause us not to pursue such opportunity or acquisition. In addition, Alliance Resource Holdings has the ability to purchase businesses, the majority value of which is not mining, marketing or transporting coal, provided Alliance Resource Holdings offers us the opportunity to purchase the coal assets following their acquisition. The restriction does not apply to the assets retained and business conducted by Alliance Resource Holdings at the closing of our initial public offering. Except as provided above, Alliance Resource Holdings and its controlled affiliates are prohibited from engaging in activities in which they compete directly with us. In addition to its non-competition provisions, this agreement contains provisions which indemnify us against liabilities associated with certain assets and businesses of Alliance Resource Holdings which were disposed of or liquidated prior to consummating our initial public offering.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The firm of Deloitte & Touche LLP is our independent auditors. Fees paid to Deloitte & Touche LLP during the last two fiscal years were as follows:

> Audit Services. Fees for audit services provided during the years ended December 31, 2003 and 2002, were $240,000 and $377,000, respectively. Audit services consist primarily of the audit and quarterly reviews of the consolidated financial statements, but can also be related to statutory audits of subsidiaries required by governmental or regulatory bodies, attestation services required by statute or regulation, comfort letters, consents, assistance with and review of documents filed with the SEC, work performed by tax professionals in connection with the audit and quarterly reviews, and accounting and financial reporting consultations and research work necessary to comply with generally accepted accounting principles.
>
> Audit-Related Services. Fees for audit-related services provided during the years ended December 31, 2003 and 2002, were $36,000 and $21,000, respectively. Audit-related services consist primarily of audits of employee benefit plans, consultations concerning financial accounting and reporting standards, and attestation services associated with third-party compliance.
>
> Tax Services. Fees for tax services provided during the years ended December 31, 2003 and 2002, were $231,000 and $147,000, respectively. Tax services relate primarily to the preparation of federal and state tax returns but can also be related to tax advise, exclusive of tax services rendered in conjunction with the audit.
>
> All Other Fees. There were no other fees during the years ended December 31, 2003 and 2002.

The charter of the audit committee provides that the committee is responsible for the pre-approval of all auditing services and permitted non-audit services to be performed for us by our independent auditors, subject to the requirements of applicable law. In accordance with such law, the audit committee has delegated the authority to grant such pre-approvals to the audit committee chairman, which approvals are then reviewed by the full audit committee at is next regular meeting. Typically, however, the audit committee itself reviews the matters to be approved. The audit committee periodically monitors the services rendered by and actual fees paid to the independent auditors to ensure that such services are within the parameters approved by the audit committee.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(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, 2003, 2002 and 2001, 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)).

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 10.2 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.
* 10.18	First Amendment to the Alliance Resource Management GP, LLC 2000 Long-Term Incentive Plan.

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).

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 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).

10.29	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).
10.30	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).
*10.31	Assignment and Assumption Agreement dated April 1, 2003 between Synfuel Solutions Operating LLC, Hopkins County Coal, LLC, and Warrior Coal, LLC.
10.32	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).
10.33	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, 20002 File No. 000-26823).
10.34	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).
10.35	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).
10.36	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)).
10.37	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).
10.38	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).
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

* 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 March 12, 2004, 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 March 12, 2004, 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 March 12, 2004, 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 March 12, 2004, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 furnished herewith.

* Filed herewith.

(b) Reports on Form 8-K:

A Form 8-K was filed on October 27, 2003 to submit to the Securities and Exchange Commission a press release announcing earnings and operating results for the third quarter of 2003. The press release contains the following financial statements: (i) consolidated statement of income and operating data for the three-months and nine-months ended September 30, 2003 and 2002; (ii) consolidated balance sheets at September 30, 2003 and December 31, 2002; and (iii) consolidated condensed statements of cash flows for the nine-months ended September 30, 2003 and 2002.

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 March 12, 2004.

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 Joseph W. Craft III	President, Chief Executive Officer, and Director (Principal Executive Officer)	March 12, 2004
/s/ Brian L. Cantrell Brian L. Cantrell	Senior Vice President and Chief Financial Officer	March 12, 2004
/s/ Michael J. Hall Michael J. Hall	Director	March 12, 2004
/s/ John J. MacWilliams John J. MacWilliams	Director	March 12, 2004
/s/ Preston R. Miller, Jr. Preston R. Miller, Jr.	Director	March 12, 2004
/s/ John P. Neafsey John P. Neafsey	Director	March 12, 2004
/s/ John H. Robinson John H. Robinson	Director	March 12, 2004
/s/ Robert G. Sachse Robert G. Sachse	Executive Vice President and Director	March 12, 2004

UNITHOLDER INFORMATION

PUBLICLY-TRADED UNITS

Alliance Resource Partners, L.P. is a publicly traded master limited partnership.

Alliance Resource Partners, L.P. common units began trading on the NASDAQ National Market under the symbol "ARLP" in August 1999. As of December 31, 2003, there were 17,903,793 common and subordinated units outstanding.

CASH DISTRIBUTIONS

Alliance Resource Partners, L.P. expects to make Quarterly Distributions within 45 days after the end of each March, June, September and December to unitholders of record on the applicable record dates.

PARTNERSHIP TAX DETAILS

- Unitholders are partners in the Partnership and receive cash distributions. The cash distributions are generally not taxable as long as the unitholder's tax basis remains above zero.
- A partnership is generally not subject to federal or state income tax. The annual income, gains, losses, deductions or credits of the Partnership flow through to the unitholders, who are required to report their allocated share of these amounts on their individual tax returns, as though the unitholder had incurred these items directly.
- Unitholders of record will receive Schedule K-1 packages that summarize their allocated share of the Partnership's reportable tax items for the fiscal year.

It is important to note that cash distributions received should not be reported as taxable income. Only the amounts provided on the Schedule K-1 should be entered on each unitholder's 2003 tax return.

- Should you have questions regarding the Schedule K-1 contact:
  Alliance Resource Partners, L.P.
  K-1 Support
  P.O. Box 480927
  Denver, CO 80248
  (800) 485-6875
  Fax: (720) 931-7937

TRANSFER AGENT AND REGISTRAR

Unitholder requests regarding transfer of units, lost certificates, lost distribution checks or changes of address should be directed to:

American Stock Transfer
and Trust Company
Attn: Shareholder Services
59 Maiden Lane-Plaza Level
New York, NY 10038
(800) 937-5449

ADDITIONAL INVESTOR INFORMATION

Additional information about Alliance Resource Partners, L.P. can be obtained by contacting Investor Relations by e-mail at investorrelations@arlp.com, telephone at (918) 295-7674, visiting the Partnership's website at www.arlp.com, or writing to the Partnership's mailing address provided below.

PARTNERSHIP OFFICES

Alliance Resource Partners, L.P.
1717 South Boulder Avenue
Tulsa, OK 74119
(918) 295-7600

PARTNERSHIP MAILING ADDRESS

P.O. Box 22027
Tulsa, OK 74121-2027

INDEPENDENT AUDITORS

Deloitte & Touche, LLP
Two Warren Place
6120 South Yale Suite 1700
Tulsa, OK 74136

CONTACT

Brian L. Cantrell
Senior Vice President and
Chief Financial Officer
(918) 295-7674
brian.cantrell@arlp.com

OFFICERS AND DIRECTORS

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

Robert G. Sachse
Executive Vice President and Vice Chairman of the Board

Brian L. Cantrell
Senior Vice President and Chief Financial Officer

Thomas L. Pearson
Senior Vice President – Law and Administration, General Counsel and Secretary

Gary J. Rathburn
Senior Vice President – Marketing

Charles R. Wesley
Senior Vice President – Operations

Michael J. Hall
Director

John J. MacWilliams
Director

Preston R. Miller, Jr.
Director

John P. Neafsey
Chairman of the Board

John H. Robinson
Director

NASDAQ LISTED

ALLIANCE RESOURCE PARTNERS, L.P. common units are traded on the NASDAQ National Market under the ticker symbol "ARLP."

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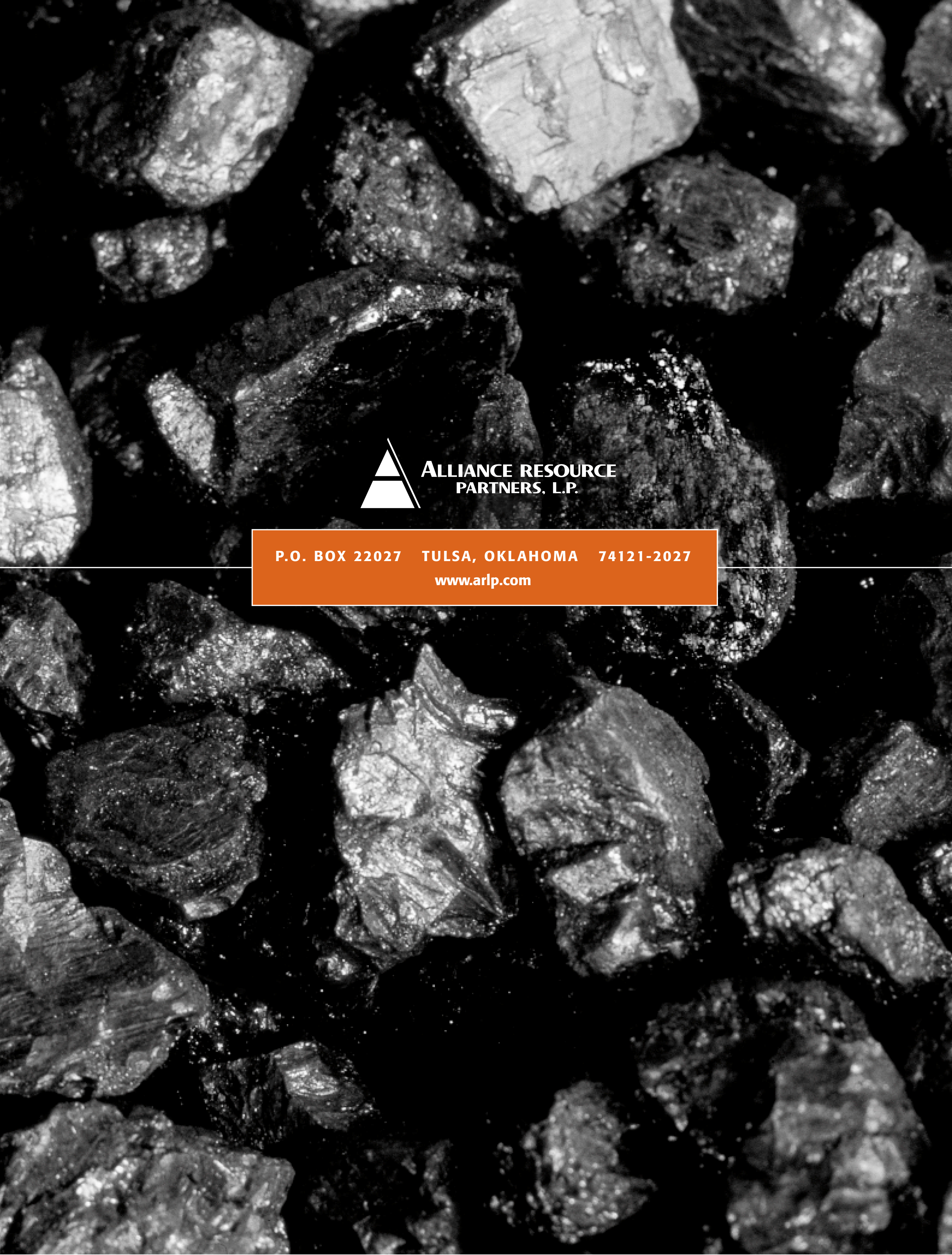

ALLIANCE RESOURCE PARTNERS, L.P.

P.O. BOX 22027 TULSA, OKLAHOMA 74121-2027

www.arlp.com