2002 ANNUAL REPORT

ARLP

Planning For Growth

BUILDING A FOUNDATION FOR SUSTAINABLE CASH FLOW GROWTH

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."

IN 2002, WE EXPERIENCED A

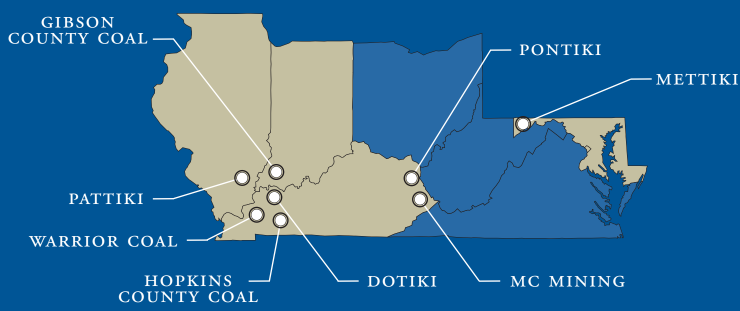
38%

INCREASE IN NET CASH PROVIDED BY OPERATING ACTIVITIES TO

$87.6

MILLION.

WE OPERATE EIGHT COAL MINING COMPLEXES THROUGHOUT THE EASTERN UNITED STATES.



Another solid year

FINANCIAL HIGHLIGHTS

(millions except per unit amounts)	2002	2001
Operating Data:		
Tons sold	**18.3**	17.0
Tons produced	**16.4**	15.7
Revenues per ton sold	**$ 27.25**	$ 25.19
Cost per ton sold(1)	**$ 21.81**	$ 21.03
Financial Data:		
Revenues	**$ 517.7**	$ 446.3
Income from operations	**$ 36.0**	$ 8.4
Net income	**$ 36.3**	$ 17.1
Basic net income per LP unit(2)	**$ 2.31**	$ 1.09
Diluted net income per LP unit(2)	**$ 2.24**	$ 1.07
Total assets	**$ 288.4**	$ 290.9
Long-term debt	**$ 195.0**	$ 211.3
Net cash provided by operating activities	**$ 87.6**	$ 63.7
EBITDA(3)	**$ 100.0**	$ 79.4

(1) See Note (6) on Page 25 of 2002 Form 10-K for Cost per ton sold definition.

(2) The weighted average basic units outstanding for the years ended December 31, 2002 and 2001, was 15,405,311 and on a fully dilutive basis, was 15,842,708 and 15,684,550, respectively.

(3) See Note (7) and (8) on Page 25 of 2002 Form 10-K for EBITDA definition and reconciliation to Net Income.

IN 2002, WE EARNED RECORD EBITDA(3) OF

$100.0

MILLION, AN INCREASE OF

26%

FOR THE YEAR.

IN 2002, WE RECORDED RECORD NET INCOME OF

$36.3

MILLION, AN INCREASE OF

112%

FOR THE YEAR.

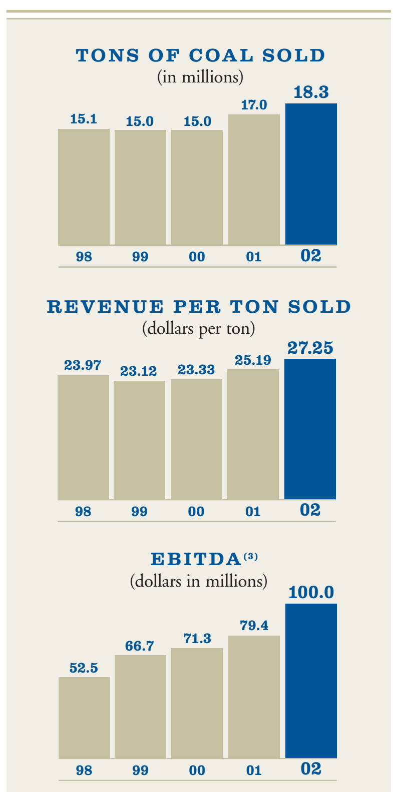
ABOUT THE COVER A variety of sophisticated mapping tools – timing maps, design maps, topographic maps and projection maps – help in the planning, budgeting and surface design of our mining operations.

DEAR FELLOW UNITHOLDERS,

Alliance Resource Partners, L.P. continued to build on its solid record of growing production levels and profits in 2002. During 2002, our record results – and the percent improvement from the prior year – included:

- Tons of coal sold of 18.3 million – an increase of 7%,
- Tons of coal produced of 16.4 million – an increase of 4%,
- Revenues of $517.7 million – an increase of 16%,
- EBITDA[3] (income before net interest expense, income taxes, depreciation, depletion and amortization) of $100.0 million – an increase of 26%,
- Cash flow provided by operating activities of $87.6 million – an increase of 37%, and
- Net income of $36.3 million – an increase of 112%.

These financial and operational results were achieved despite a challenging business environment, both from a general economy and coal industry perspective. Even with the persistence of global political and economic uncertainties into 2003, I believe the Partnership is well positioned to continue delivering superior results going forward.



Key to our success in 2002 were three factors: continued strategic investments, long-term relationships with our customers, and a committed workforce. As can be expected, these factors will be equally instrumental to our continued success in the years ahead.

DURING 2002, we continued to invest in our future through strategic capital expenditures designed to grow our production capacity and improve our productivity. During the course of the year, we benefited from prior year capital investments at our Gibson County Coal and eastern Kentucky operations. In the Illinois Basin, the extension of the Pattiki mine into an adjacent coal reserve area was substantially completed, and construction of a new mine shaft at the Dotiki mine was initiated. This strategic investment plan continued into 2003 as we announced the recently completed acquisition of Warrior Coal and the addition of a fourth production unit at our Gibson County operation. Plans are also under way for a new production shaft and the addition of a continuous mining unit at our MC Mining complex in eastern Kentucky, both of which are scheduled to come on line in the third quarter of 2003.

In 2002, approximately 88% of our sales were made under long-term contracts with maturities ranging from 2002 to 2012. Long-term contracts are those that have a term greater than one year. These long-term contracts contribute to both our customers' and the Partnership's stability and profitability by providing greater predictability of sales volumes and sales prices. In addition to these coal sales agreements, we also benefited from long-term synfuel agreements with Synfuel Solutions Operating LLC (SSO). These agreements expire on December 31, 2007, and provide us with coal sales, rental and service fees from SSO based on the tonnages placed through the synfuel facility that has been located at our Hopkins County Coal mine complex and which is currently being relocated to our recently acquired Warrior Coal operation. We believe these long-term contracts represent our level of commitment to our customers and the value we place on these relationships.

LETTER TO UNITHOLDERS (continued)

SINCE OUR BEGINNING IN THE EARLY 1970s, one of our core strengths has been the team spirit and commitment of our employees. The teamwork and the efforts of all 1,745 employees of the Partnership are focused on serving our valued customers as a low-cost producer of coal. Our employees are proud of their proven track record in this area. During calendar year 2002, the Partnership's production costs per ton, exclusive of coal synfuel operating and sales-related expenses, were essentially flat compared to last year – we believe this compares favorably to our industry competitors. As we look forward to 2003, we believe the recent strategic capital investments made by the Partnership and the determination and dedication of our employees will result in greater productivity and lower costs.

WE INCREASED OUR QUARTERLY CASH DISTRIBUTION

5%

TO AN ANNUALIZED RATE OF

$2.10

PER UNIT.

During the course of the last year, several other milestones were reached. On May 9, 2002, the Partnership announced that members of management had purchased the remaining interests, which they did not already own, of its managing general partner and its special general partner. As a result of this transaction, management beneficially owns approximately 45% of the total common and subordinated outstanding units of the Partnership, bringing further alignment of management's and our unitholders' common interests.

In late January 2003, we announced a 5% increase in our quarterly cash distribution with respect to the fourth quarter of 2002. This marked the first cash distribution increase in our short history as a publicly-traded master limited partnership. Using the increased annual cash distribution rate of $2.10 per unit and the closing market price of $22.39 on March 31, 2003, the distribution equates to an annual pre-tax yield of approximately 9.4%. As indicated by the announcement of the increase in our quarterly cash distribution, we are focused on increasing, on a sustainable basis, our distributable cash flow.

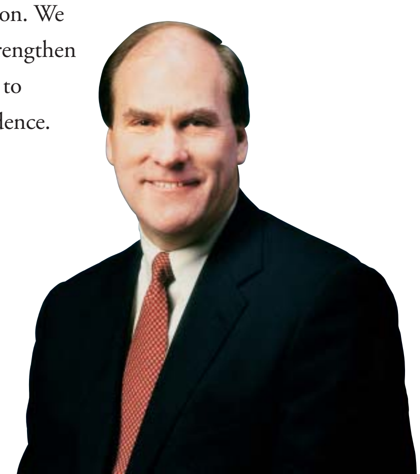
The headframe support structure is under construction at the Dotiki mine.

Our business strategy is to increase our profitability and maximize our distributions to unitholders through productivity improvements, increased market share, strategic investments – whether organic or through accretive acquisitions – in mining operations and/or reserves, and developing strategic relationships with our customers and other third parties in order to capture opportunities created by the significant changes that have occurred and are continuing to occur in the energy industry.

During February and March 2003, we completed a public offering, including the underwriters' option to purchase additional units, of 2,538,000 common units with total net proceeds to the Partnership of approximately $54.7 million before expenses. A portion of the proceeds was used to fund the purchase of the Warrior Coal operations. As a result of this offering and our financial performance in 2002, we are well positioned to continue the implementation of our strategy.

In late December 2002, Paul R. Tregurtha completed his three-year commitment to serve on the managing general partner's Board of Directors. I wish to thank Mr. Tregurtha for sharing his invaluable wisdom and experience in our developing years as a publicly-traded master limited partnership. I welcome Michael J. Hall of Tulsa, Oklahoma, who was elected to fill the vacancy created by Mr. Tregurtha's retirement from our Board of Directors.

ON BEHALF OF OUR BOARD OF DIRECTORS, I want to personally thank and congratulate our employees for their outstanding performance in 2002! And on behalf of our employees, I want to thank you, the Partnership's unitholders, for your support of, and investment in, the Alliance Resource organization. We are committed to continually strengthen and grow our business in order to reward your support and confidence.



JOSEPH W. CRAFT III
President and
Chief Executive Officer

PARTNERSHIP SUMMARY

ALLIANCE RESOURCE PARTNERS, L.P. (NASDAQ: ARLP) is the nation's only publicly-traded master limited partnership involved in the production and marketing of coal. We sell coal to major United States utilities and industrial users. We were formed in 1999 to acquire, own and operate certain coal production and marketing assets of Alliance Resource Holdings, Inc., a Delaware corporation formerly known as Alliance Coal Corporation, whose predecessor's mining operations began in 1971. We have grown through acquisitions and internal development to become the eighth largest coal producer in the eastern United States.

During 2002, we operated seven mining complexes in Illinois, Indiana, Kentucky and Maryland. We added our eighth operation in February 2003 when we acquired Warrior Coal, LLC, which is located in western Kentucky. Seven of our mining complexes are underground and one has both surface and underground mines. Through these operations, we sell a diversity of coals in three of the four major coal-producing regions of the United States. This product and geographic diversity allows us to limit our exposure if there is a downturn in any single market segment.

We have developed long-standing customer relationships and signed long-term contracts with large, solvent power generators that use coal for electricity generation. In 2002, approximately 88% of our sales were made under long-term contracts with maturities ranging from 2002 to 2012. Our total nominal commitment under significant long-term contracts was approximately 71 million tons at December 31, 2002. The Partnership has also entered into long-term agreements to supply coal feedstock and other services through December 2007 to a coal synfuel facility currently located at our Hopkins County mine in western Kentucky. Additionally, replacement coal supply agreements with each coal synfuel customer have been put in place that automatically provide for the sale of our coal directly to the customer in the event they do not receive coal synfuel. The Partnership's strategy of maintaining a significant long-term contract position has historically provided us with less volatility during active market cycles. For 2003, we currently have commitments for nearly 90% of the 19.1 to 19.9 million tons of coal we are expecting to sell.

A screening tower used in sizing coal is being constructed at our recently acquired Warrior Coal operation.

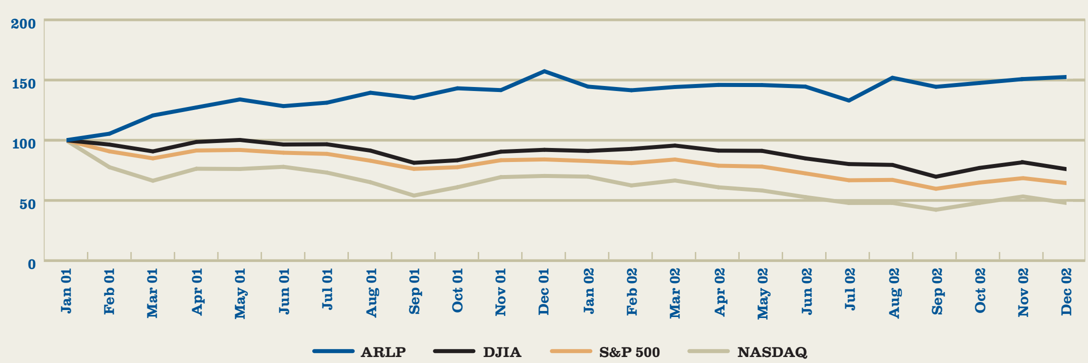
WE SELL A DIVERSITY OF COALS IN

3 OUT OF 4

OF THE MAJOR COAL-PRODUCING REGIONS OF THE UNITED STATES.

FINANCIAL HIGHLIGHTS For the year ended December 31, 2002, we had record revenues of $517.7 million and record

MARKET PERFORMANCE COMPARISON
Trading History – Jan 01 to Dec 02



NOTE: Trading data adjusted to reflect dividends or distributions

PARTNERSHIP SUMMARY (continued)

When completed, the overland belt will move coal from the Warrior Slope to nearby preparation facilities.

net income of $36.3 million.

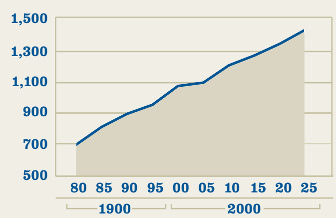
At December 31, 2002, we had approximately 416.5 million tons of reserves in Illinois, Indiana, Kentucky, Maryland and West Virginia. In 2002, we produced 16.4 million tons of coal and sold 18.3 million tons of coal.

In 2002, the Partnership's capital expenditures totaled $51.5 million, including maintenance capital expenditures of approximately $29.0 million. The remaining capital expenditures related primarily to the previously announced extension of the Pattiki mine into an adjacent coal reserve area and a new mine shaft at the Dotiki mine. Both of these projects are expected to be completed in the second quarter of 2003. Alliance is estimating full-year 2003 capital expenditures of approximately $68.0 million, including approximately $30.0 million associated with the acquisition of Warrior Coal, which closed in February 2003. As a result of the Warrior Coal acquisition, the annual maintenance capital for the Partnership is expected to increase to approximately $32.0 million in 2003. The balance of the capital expenditures in 2003 relate to the completion of the Dotiki mine construction project mentioned above and adding a fourth unit of production at the Gibson County mine and MC Mining. As a result of the capital expenditures program in 2002 and the acquisition of Warrior Coal in the first quarter of 2003, the Partnership expects depreciation expense to increase approximately $7.0 million in 2003.

At December 31, 2002, we had 15,405,311 units outstanding. At March 31, 2003, we had 17,903,793 units outstanding. The net increase of 2,498,482 units reflects our issuance during the first quarter of 2003 of 2,538,000 common units and our retirement of 39,518 common units previously owned by our managing general partner. Our managing general partner contributed the 39,518 common units to us to maintain its level of general partner interests. For the year ended December 31, 2002, the weighted average units outstanding was 15,405,311 and 15,842,708 on a basic and dilutive basis, respectively. For the quarter ended March 31, 2003, the weighted average units outstanding was 16,593,609 and 17,176,824 on a basic and dilutive basis, respectively. The increase in the weighted average basic units outstanding reflects the net common unit issuance in February and March 2003. The increase in the weighted average dilutive units outstanding reflects the net common unit issuance plus additional unit grants under various benefit and compensation plans. For the quarter ended June 30, 2003, the weighted average units outstanding will be 17,903,793 and 18,487,536 on a basic and dilutive basis, respectively, assuming no additional retirements or issuance of units during the second quarter of 2003.

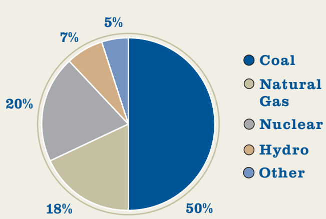
For the first three quarters of 2002, the Partnership paid quarterly cash distributions to its unitholders at $0.50 per unit, an annualized rate of $2.00 per unit. For the fourth quarter of 2002, the Partnership declared a quarterly cash distribution of $0.525 per unit, an annualized rate of $2.10. This distribution was paid on February 14, 2003, to all unitholders of record as of February 3, 2003. The quarterly distributions for 2002 were declared and paid on all of the Partnership's common and subordinated units. The Partnership's distributions to unitholders are generally not taxable to the extent of the unitholder's tax basis. However, each unitholder is allocated a share of income, gains, losses and deductions. The majority of the distributions are not subject to current income taxes, resulting in a significant enhancement of the after-tax yield on the Partnership's units.

U.S. COAL DEMAND
(in millions of tons)



SOURCE: EIA Annual Energy Outlook 2003 Reference Guide

U.S. ELECTRICITY FUEL SOURCES
Electricity Generation by Fuel Source 2002



SOURCE: Energy Information Administration Review

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, 2002

OR

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

FOR THE TRANSITION PERIOD FROM _____________TO_____________

COMMISSION FILE NO.: 0-26823

ALLIANCE RESOURCE PARTNERS, L.P.

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

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

1717 SOUTH BOULDER AVENUE, SUITE 600, TULSA, OKLAHOMA 74119
(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES AND ZIP CODE)

(918) 295-7600
(REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE)

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

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

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).

Yes [X] No [ ]

The aggregate value of the common units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $176,108,377 as of June 28, 2002, the last business day of the registrant’s most recently completed second fiscal quarter, based on $23.74 per unit, the closing price of the common units as reported on the Nasdaq National Market on such date.

As of March 18, 2003, 11,481,262 common units and 6,422,531 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;
- fluctuations 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 15.48% participation (excluding any applicable deductible) in the 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 the eighth largest coal producer in the eastern United States. At December 31, 2002, we had approximately 416.5 million tons of reserves in Illinois, Indiana, Kentucky, Maryland and West Virginia. In 2002, we produced 16.4 million tons of coal and sold 18.3 million tons of coal. The coal we produced in 2002 was 29.9% low-sulfur coal, 17.7% medium-sulfur coal and 52.4% high-sulfur coal. In 2002, 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, 2002, we operated seven mining complexes in Illinois, Indiana, Kentucky and Maryland. Six of these mining complexes are underground and one has multiple surface operations and a single underground mine. 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 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% of the limited partner interests 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.

Recent Developments

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.

Warrior operates 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 initially in 1985. Warrior utilizes continuous mining units employing room-and-pillar mining techniques producing high-sulfur coal. Warrior's preparation plant has a throughput capacity of 700 tons of raw coal an hour. In 2002, Warrior had approximately 170 employees and produced some 1.6 million tons of coal, leaving approximately 22.8 million tons of proven and probable reserves at December 31, 2002. Since 2001, Warrior has invested approximately $17.0 million in non-partnership capital in new infrastructure. We plan to add an additional continuous mining unit, early in the second quarter 2003, to supplant other operations in the Illinois Basin that will be depleting. Warrior’s production level for 2003 is expected to increase to 2.6 million tons.

Production from Warrior in 2002 and into 2003 has been shipped via truck on U.S. and state highways primarily to Hopkins for resale to our customer Synfuel Solutions Operating LLC (SSO) for use as feedstock in the production of coal synfuel, as discussed under "Hopkins Complex" and "Coal Synfuel" below. Following the planned move of SSO's coal synfuel production facility to Warrior in the second quarter of 2003, it is expected that Warrior will sell substantially all of its production to SSO. At that time, we anticipate Warrior will purchase supplemental production from our neighboring Hopkins County Coal, LLC (Hopkins) and Webster County Coal, LLC (Dotiki) complexes for resale to SSO. SSO advises it plans 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.

Because we acquired Warrior in 2003, the remainder of this 2002 Annual Report on Form 10-K excludes further discussion of Warrior, except as otherwise noted.

Management Buy-out of Beacon Group Funds’ Interests

Prior to May 8, 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. On May 8, 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 1,232,780 common units and 6,422,531 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.

The promissory notes require two installment payments, including a $30.9 million payment due on March 1, 2004 and a $25.8 million payment due on March 1, 2005. In September 2002, management prepaid approximately $29.9 million due under the first promissory note with borrowings from a commercial bank facility. Our management expects to pay off the remaining balance under the promissory notes from borrowings from commercial lending institutions, cash generated from operations of Alliance Resource Holdings, and/or from quarterly distributions paid by us on the common and subordinated units held by our special general partner.

Management's payment obligations under the promissory notes are secured under a security and pledge agreement by a pledge to The Beacon Group's funds of all of the outstanding capital stock of Alliance Resource Holdings and other equity interests in affiliated entities owned directly or indirectly by our management.

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 production by region for the last five years.

Operating Region and Complexes	2002	2001	2000	1999	1998
			(tons in millions)		
Illinois Basin Operations:					
Dotiki, Gibson, Hopkins, Pattiki Complexes	10.5	10.2	8.4	8.5	7.9
East Kentucky Operations:					
MC Mining, Pontiki Complexes	3.0	2.8	2.7	2.8	2.5
Maryland Operations:					
Mettiki Complex	2.9	2.7	2.6	2.8	3.0
Total	16.4	15.7	13.7	14.1	13.4

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.

Illinois Basin Operations

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. We have approximately 975 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. 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 and PAL railroads and by truck on U.S. and state highways. Our primary customers for coal produced at Dotiki are and Louisville Gas & Electric (LG&E), Seminole Electric Cooperative, Inc. (Seminole), Tennessee Valley Authority (TVA) and Western Kentucky Energy Corp., all of which purchase our coal pursuant to long-term contracts for use in their scrubbed generating units. During August 2001, Dotiki began construction of a new mine shaft and ancillary facilities, which are expected to be operational during the second quarter of 2003 and will provide a new access to the coal reserves for miners and supplies.

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. This extension involves capital expenditures of approximately $30 million principally expended during the 2000-2002 period and is expected to allow Pattiki to continue and expand its existing productive capacity for the next 15 years. 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 Seminole and TVA, both of which purchase our coal pursuant to long-term contracts for use in their scrubbed generating units.

Hopkins Complex. Hopkins County Coal, LLC operates a mining complex located near the city of Madisonville in Hopkins County, Kentucky. We acquired the complex in January 1998. The complex has three surface mines, one of which is currently idle, and one underground mine. The underground mine is expected to be depleted in the first quarter of 2003. The surface operations utilize dragline mining and the underground operation utilizes a continuous mining unit employing room-and-pillar mining techniques. 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 and PAL railroads and by truck on U.S. and state highways. As discussed below, we sell most of Hopkins' production to SSO, whose coal synfuel production facility is located currently at Hopkins. SSO has in turn sold coal synfuel to utilities that have been purchasers of our coal. . We have maintained "back-up" coal supply agreements with these customers, which automatically provide for the sale of our coal to these customers in the event they do not purchase coal synfuel from SSO.

Gibson Complex. Gibson County Coal, LLC (Gibson) operates 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. 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, shipped via truck approximately 10 miles on U.S. and state highways to Gibson's primary customer, PSI Energy Inc. (PSI), a subsidiary of Cinergy Corporation. We are involved in a contract dispute with PSI concerning the procedures for and testing of a certain coal quality specification. Please read "Item 3. Legal Proceedings" and "Item 8. Financial Statements and Supplementary Data – Note 15. Commitments and Contingencies."

Coal Synfuel. We entered into long-term agreements with SSO to host and operate its coal synfuel facility currently located at Hopkins, 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 in "Mining Operations; Illinois Basin; Hopkins Complex," we sell most of the coal produced at Hopkins to SSO, while Alliance Coal Sales, a division of Alliance Coal, LLC (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 operating 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. Hopkins purchased approximately 1.4 million tons of coal from Warrior in 2002, which was resold to SSO as feedstock for coal synfuel production. 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.

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 430 employees and operate two mining complexes in East Kentucky.

Pontiki Complex. Pontiki Coal, LLC (Pontiki) owns 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.

Production from the mine is shipped via the Norfolk Southern railroad or by truck via U.S. and state highways to various docks on the Big Sandy River in Kentucky.   Pontiki ships its low-sulfur production primarily to electric utilities located in the southeastern United States.

MC Mining Complex. MC Mining, LLC (MC Mining) owns an underground mining complex located near the city of Pikeville in Pike County, Kentucky. MC Mining was acquired in 1989. When we began production in late 1996, MC Mining was operated by an unaffiliated contract mining company. During 2000, the contract mining agreement was terminated, and MC Mining entered into an intercompany support services agreement with Excel. Selected employees of the contractor and other qualified individuals were hired by Excel, which is responsible for conducting all mining operations. The complex 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.

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 225 employees and operate one mining complex in Maryland.

Mettiki Complex. Mettiki Coal, LLC (Mettiki) operates 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 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 18.9 million tons of undeveloped recoverable reserves in Grant and Tucker Counties, West Virginia close to Mettiki in Garrett County, Maryland. We currently do not conduct mining operations at Mettiki (WV).

Other Operations

Mt. Vernon Transfer Terminal, LLC

The Mt. Vernon terminal is a rail-to-barge loading terminal on the Ohio River at Mt. Vernon, Indiana. The terminal has a capacity of 5.5 million tons per year with existing ground storage. The terminal was used from 1983 through 1998 for shipments from Pattiki and Dotiki under our coal supply agreements with Seminole. Seminole now transports these shipments to its generating units directly by the CSX railroad. During 2002, the terminal loaded approximately 1.2 million tons for Pattiki and Dotiki customers other than Seminole.

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 502,000 tons of outside coal from non-affiliates in 2002. 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-half of 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. Our utility customers secure a fuel supply for their power plants for years into the future. Our long-term contracts contribute to both our customers' and our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2002, approximately 88% 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 2002 to 2012. Our total nominal commitment under significant long-term contracts was approximately 71.4 million tons at December 31, 2002 and is expected to be delivered as follows: 14.2 million tons in 2003, 12.5 million tons in 2004, 11.6 million tons in 2005, 11.6 million tons in 2006, 4.4 million tons in 2007, and 17.1 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 2002 were Seminole, SSO and VEPCO. Sales to these customers in the aggregate accounted for approximately 49% of our 2002 total revenues, and sales to each of these customers accounted for more than 10% of our 2002 total revenues.

In February 2002, a major customer of our Pontiki Complex, 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, 2002 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, that is possible. 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 2002 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 10% to 50% 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.

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 2002, the largest volume transporter of our coal production was the CSX railroad, which moved approximately 39% 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 our Gibson and Mettiki complexes, 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 commencement or continuation of mining operations. 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.

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 (West Virginia DEP) requesting approval for the mining of approximately 3.1 million tons of coal deposits controlled by Mettiki (WV) but contiguous with our Mettiki Coal Reserves in Maryland. In January 2002, the West Virginia DEP denied the permit. We appealed the permit denial to the West Virginia Surface Mining Board (Mining Board) and, in July 2002, the Mining Board approved a permit that currently allows 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 an additional 600,000 tons of this West Virginia coal deposit. We cannot assure you that this revised permit application will be approved.

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.

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 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 has recently increased our compliance costs. 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 medical treatment for any pulmonary condition 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. 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.

Because the revised regulations are expected to result in an increase in the incidence and recovery of black lung claims, both the coal and insurance industries challenged certain provisions of the revised regulations through litigation. A federal judge upheld these regulations in August 2001. In June 2002, the U.S. Court of Appeals, District of Columbia Circuit, affirmed in part, reversed in part, and remanded to the District Court for further proceedings consistent with its opinion. 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.

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.

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. 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 the 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 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 acid mine drainage 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.

Our underground mining operations could be adversely affected by a recent decision which interprets SMCRA to prohibit subsidence from underground mining on certain federal lands, near occupied dwellings, public or community buildings, public roads, schools, churches, and cemeteries, or adversely affecting public parks or certain historic properties. The U.S. District Court's decision has been stayed until the U.S. Court of Appeals, District of Columbia Circuit, has ruled on the appeal filed by the United States and by the National Mining Association, both of which claim that the District Court misinterpreted the statute, which exempts subsidence from such prohibitions applicable only to surface mines. If the decision is not overturned by the U.S. Court of Appeals or Congress, and depending on how the decision is interpreted and applied by the regulatory authorities, it could effectively increase our permitting and mining costs, restrict our ability to mine certain reserves, and limit the use of longwall mining technologies.

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, to pay federal and state workers' compensation, and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. It has become increasingly difficult for us 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 requires a study of utility power plant emissions of some toxic substances and their eventual regulation, if warranted. We cannot accurately predict the effect of these provisions of the CAA 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 nonattainment 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 mercury, nickel, dioxin and 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. These NAAQS are currently expected to be implemented by 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. Both Congress and EPA are considering additional controls on other air pollutants emitted by electric utilities. Any 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 nonattainment regulations. This issue addresses 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 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, 2002, countries representing 44% 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 in 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. 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. 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." Accordingly, 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 affects 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 exempted from regulation under RCRA by statute. 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 wastes regulatory controls on the disposal of some coal combustion by-products, including the practice of using coal combustion by-products as mine fill. However, EPA is currently evaluating the possibility of placing additional solid waste burdens on the disposal of these types of materials, but it may be several years before these standards will be developed.

While we cannot predict the ultimate outcome of 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 acid mine drainage 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 becomes 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 1,745 employees, including approximately 100 corporate employees and approximately 1,645 employees involved in active mining operations. With the acquisition of Warrior completed in February 2003, our total number of employees will increase to approximately 1,920 employees. 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, 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. 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, 2002, we had approximately 416.5 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, 2002, about each of our mining complexes:

Operations	Mine Type	Heat Content (Btus per pound)	Proven and Probable Reserves Pounds SO2 per MMbtu <1.2	1.2 - 2.5	>2.5	Total	Reserve Assignment Assigned	Unassigned
			(tons in millions)					
Illinois Basin Operations								
Dotiki	Underground	12,500	-	-	100.7	100.7	100.7	-
Pattiki	Underground	11,700	-	-	49.6	49.6	49.6	-
Hopkins	Underground	11,300	-	-	20.7	20.7	0.7	20.0
	/ Surface		-	-	10.9	10.9	10.9	-
Gibson (North)	Underground	11,600	-	34.9	-	34.9	34.9	-
Gibson (South)	Underground	11,600	-	55.0	44.9	99.9	-	99.9
Region Total			-	89.9	226.8	316.7	196.8	119.9
East Kentucky Operations								
Pontiki	Underground	12,800	13.4	12.2	-	25.6	25.6	-
MC Mining	Underground	12,800	26.2	-	-	26.2	26.2	-
Region Total			39.6	12.2	-	51.8	51.8	-
Maryland Operations								
Mettiki	Underground	13,000	-	15.8	13.3	29.1	13.3	15.8
Mettiki (WV)	Underground	13,000	-	-	18.9	18.9	18.9	-
			-	15.8	32.2	48.0	32.2	15.8
Total			39.6	117.9	259.0	416.5	280.8	135.7
% of Total			9.5%	28.3%	62.2%	100.0%	67.4%	32.6%

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 mining activities, additional analysis, 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 39.6 million tons of reserves listed as <1.2 pounds of SO2 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 18.9 million tons of reserves controlled by Mettiki (WV) has been submitted to the West Virginia DEP. We are in the process of responding to various comments submitted by the West Virginia DEP concerning the permit application. In regard to a different permit application concerning other coal deposits and reserves, please read “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 – 14.1 million tons, Pattiki – 3.5 million tons, Gibson (North) – 4.1 million tons, and Gibson (South) – 4.3 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 2002	2001	2000	Transportation	Equipment
	(tons in millions)				
Illinois Basin Operations					
Dotiki	4.5	4.6	3.9	CSX, PAL; truck; barge	CM
Pattiki	1.9	1.9	2.3	CSX; truck; barge	CM
Hopkins	2.2	2.0	2.1	CSX, PAL; truck	DL; CM
Gibson (North)	1.9	1.7	0.1	Truck	CM
Region Total	10.5	10.2	8.4		
East Kentucky Operations					
Pontiki	1.7	1.7	1.9	NS; truck	CM
MC Mining	1.3	1.1	0.8	NS; truck	CM
Region Total	3.0	2.8	2.7		
Maryland Operations					
Mettiki	2.9	2.7	2.6	Truck; CSX	LW; CM
Total	16.4	15.7	13.7		

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. Other than the contract dispute with PSI described under “Other” in “Item 8. Financial Statements and Supplementary Data. – Note 15. Commitments and Contingencies,” we are not involved in any litigation involving any of our long-term coal supply contracts. 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” under “Item 8. Financial Statements and Supplementary Data. – Note 15. 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 18, 2003, the closing market price for the common units was $21.88 per unit. There were approximately 10,120 record holders and beneficial owners (held in street name) of common units at December 31, 2002.

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

	High	Low	Distributions Per Unit
1st Quarter 2001	$22.50	$16.63	$0.50 (paid May 15, 2001)
2nd Quarter 2001	$29.99	$20.63	$0.50 (paid August 14, 2001)
3rd Quarter 2001	$25.20	$21.73	$0.50 (paid November 14, 2001)
4th Quarter 2001	$27.45	$22.65	$0.50 (paid February 14, 2002)
1st Quarter 2002	$28.25	$21.71	$0.50 (paid May 15, 2002)
2nd Quarter 2002	$24.70	$21.85	$0.50 (paid August 14, 2002)
3rd Quarter 2002	$25.00	$17.00	$0.50 (paid November 14, 2002)
4th Quarter 2002	$25.20	$20.00	$0.525 (paid February 14, 2003)

We have also issued 6,422,531 subordinated units, all of which are held by the special general partner, for which there is no established public trading market.

We will distribute to our partners (including holders of subordinated units), on a quarterly basis, all of our available cash. “Available cash” generally means, with respect to any quarter, all cash on hand at the end of each quarter less cash reserves in the amount necessary or appropriate in the reasonable discretion of the 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. Available cash is defined in our partnership agreement. Our partnership agreement defines the minimum quarterly distribution (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 (testing period), 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. Early conversion of a portion of the subordinated units may occur if the testing period is satisfied before September 30, 2003. We are now in the testing period and, if we continue to meet the requirements, 50% of the subordinated units will convert into common units before the end of the subordination period, which will generally not occur before September 30, 2003, and the remainder will convert in the fourth quarter of 2004. Our ability to meet these requirements is subject to a number of economic and operational contingencies. See “Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Inherent in Our Business” and “Forward Looking Statements” at the beginning of this report.

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, 2002, 2001, 2000 and 1999, for the years ended December 31, 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, and as of and for the year ended December 31, 1998.

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

	Partnership					Predecessor	
	Year Ended December 31,			Pro Forma Year Ended December 31,	From Commencement of Operations (on August 20, 1999) to December 31,	For the period from January 1, 1999 to August 19,	Year Ended December 31,
	2002	2001	2000	1999 (1)	1999	1999	1998
Statements of Income:							
Sales and operating revenues							
Coal sales	$ 478.4	$ 422.0	$ 347.2	$ 345.9	$ 128.8	$ 217.0	$ 357.4
Transportation revenues (2)	19.0	18.1	13.5	19.1	4.9	14.2	41.4
Other sales and operating revenues	20.3	6.2	2.8	0.9	0.4	0.6	4.5
Total revenues	517.7	446.3	363.5	365.9	134.1	231.8	403.3
Expenses							
Operating expenses	333.1	308.0	257.4	242.0	89.9	152.1	237.6
Transportation expenses (2)	19.0	18.1	13.5	19.1	4.9	14.2	41.4
Outside purchases	46.7	31.8	16.9	24.2	6.4	17.7	51.2
General and administrative	19.4	17.7	15.2	15.1	6.2	8.9	15.3
Depreciation, depletion and amortization	47.2	45.5	39.1	39.7	15.1	24.6	39.8
Interest expense	16.3	16.8	16.6	19.4	5.9	0.1	0.2
Unusual items (3)	-	-	(9.5)	-	-	-	5.2
Total expenses	481.7	437.9	349.2	359.5	128.4	217.6	390.7
Income from operations	36.0	8.4	14.3	6.4	5.7	14.2	12.6
Other income (expense)	0.5	0.8	1.3	1.2	0.6	0.5	(0.1)
Income before income taxes and cumulative effect of accounting change	36.5	9.2	15.6	7.6	6.3	14.7	12.5
Income tax expense	0.2	-	-	-	-	4.5	3.8
Income before cumulative effect of accounting change	36.3	9.2	15.6	7.6	6.3	10.2	8.7
Cumulative effect of accounting change (4)	-	7.9	-	-	-	-	-
Net income	$ 36.3	$ 17.1	$ 15.6	$ 7.6	$ 6.3	$ 10.2	$ 8.7
Basic net income per limited partner unit	$ 2.31	$ 1.09	$ 0.99	$ 0.48	$ 0.40		
Basic net income per limited partner unit before accounting change	$ 2.31	$ 0.58	$ 0.99	$ 0.48	$ 0.40		
Diluted net income per limited partner unit	$ 2.24	$ 1.07	$ 0.98	$ 0.48	$ 0.40		
Diluted net income per limited partner unit before accounting change	$ 2.24	$ 0.57	$ 0.98	$ 0.48	$ 0.40		
Weighted average number of units outstanding-basic	15,405,311	15,405,311	15,405,311	15,405,311	15,405,311		
Weighted average number of units outstanding-diluted	15,842,708	15,684,550	15,551,062	15,405,311	15,405,311		
Balance Sheet Data:							
Working capital (deficit)	$ (16.1)	$ (2.3)	$ 38.6	$ -	$ 61.2	$ 11.2	$ 7.1
Total assets	288.4	290.9	309.2	-	314.8	262.8	261.1
Long-term debt	195.0	211.3	226.3	-	230.0	1.8	1.7
Total liabilities	335.0	337.8	341.0	-	330.7	110.2	108.3
Net Parent investment	-	-	-	-	-	151.6	152.8
Partners' capital (deficit)	(46.6)	(46.9)	(31.8)	-	(15.9)	-	-
Other Operating Data:							
Tons sold	18.3	17.0	15.0	15.0	5.6	9.4	15.1
Tons produced	16.4	15.7	13.7	14.1	5.3	8.8	13.4
Revenues per ton sold (5)	$ 27.25	$ 25.19	$ 23.33	$ 23.12	$ 23.07	$ 23.15	$ 23.97
Cost per ton sold (6)	$ 21.81	$ 21.03	$ 19.30	$ 18.75	$ 18.30	$ 19.01	$ 20.14
Other Financial Data:							
Net cash provided by (used in) operating activities	87.6	63.7	71.4	-	(13.9)	32.9	50.5
Net cash used in investing activities	(41.3)	(26.2)	(41.0)	-	(43.9)	(21.5)	(35.6)
Net cash provided by (used in) financing activities	(46.4)	(35.2)	(31.4)	-	65.8	(11.4)	(14.9)
EBITDA (7)	$ 100.0	$ 79.4	$ 71.3	$ 66.7	$ 27.3	$ 39.4	$ 52.5
Adjusted EBITDA (8)	$ 100.0	$ 71.5	$ 61.8	$ 66.7	$ 27.3	$ 39.4	$ 57.7
Maintenance capital expenditures (9)	29.0	24.4	21.2	6.0	6.0	15.5	17.2

(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 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, and the net loss incurred during the temporary closing of one of our mining complexes in the second half of 1998.

(4) Represents the cumulative effect of the change in the method of estimating coal workers' pneumoconiosis ("black lung") benefits liability effective January 1, 2001. 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 3. 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) EBITDA is defined as income before net interest expense, income taxes and depreciation, depletion and amortization. EBITDA should not be considered as an alternative to net income, income from operations, cash flows from operating activities or any other measure of financial performance presented in accordance with generally accepted accounting principles. EBITDA has not been adjusted for the cumulative effect of an accounting change. EBITDA is not intended to represent cash flow and does not represent the measure of cash available for distribution. The Partnership’s method of computing EBITDA may not be the same method used to compute similar measures reported by other companies, or EBITDA may be computed differently by the Partnership in different contexts (i.e., public reporting versus computation under financing agreements). The table below shows how the Partnership calculated EBITDA.

(8) Adjusted EBITDA has been adjusted for the cumulative effect of an accounting change or unusual items, as applicable. The table below shows how the Partnership calculated Adjusted EBITDA.

(in millions)	Partnership					Predecessor	
	Year Ended December 31,			Pro Forma Year Ended December 31,	From Commencement of Operations (on August 20, 1999) to December 31,	For the period from January 1, 1999 to August 19,	Year Ended December 31,
	2002	2001	2000	1999 (1)	1999	1999	1998
Net income	$ 36.3	$ 17.1	$ 15.6	$ 7.6	$ 6.3	$ 10.2	$ 8.7
Interest expense	16.3	16.8	16.6	19.4	5.9	0.1	0.2
Income taxes	0.2	-	-	-	-	4.5	3.8
Depreciation, depletion and amortization	47.2	45.5	39.1	39.7	15.1	24.6	39.8
EBITDA	100.0	79.4	71.3	66.7	27.3	39.4	52.5
Cumulative effect of accounting change	-	(7.9)	-	-	-	-	-
Unusual items	-	-	(9.5)	-	-	-	5.2
Adjusted EBITDA	$ 100.0	$ 71.5	$ 61.8	$ 66.7	$ 27.3	$ 39.4	$ 57.7

(9) Our maintenance capital expenditures, as defined under the terms of our partnership agreement, are defined as 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.

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 operations and our Predecessor should be read in conjunction with the historical financial statements and notes thereto included elsewhere in this

Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see "Item 8. Financial Statements and Supplementary Data. - Note 1. Organization and Presentation and Note 2. Summary of Significant Accounting Policies."

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. 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 the Partnership 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 the Partnership's 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 $19.3 million and $16.5 million for these costs at December 31, 2002 and 2001, 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 actuarial study performed by an independent actuary. 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 $24.5 million and $22.1 million for these costs at December 31, 2002 and 2001, respectively. A one-percentage-point reduction in the discount rate would have increased the liability at December 31, 2002 approximately $0.9 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 $16.6 million and $15.1 million for these benefits at December 31, 2002 and 2001, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2002 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 recently 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.

Business

We are a diversified producer and marketer of coal to major U.S. utilities and industrial users. In 2002, our total production was 16.4 million tons and our total sales were 18.3 million tons. The coal we produced in 2002 was approximately 29.9% low-sulfur coal, 17.7% medium-sulfur coal and 52.4% high-sulfur coal.

At December 31, 2002, we had approximately 416.5 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 adjacent properties that we currently intend to acquire or lease as our mining operations approach these areas.

In 2002, approximately 87% of our sales tonnage was consumed by electric utilities with the balance consumed by cogeneration plants and industrial users. Our largest customers in 2002 were Seminole, SSO, and VEPCO. In 2002, approximately 88% of our sales tonnage, including approximately 86% 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 2002, 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 Hopkins, 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. Therefore, the continuation of the operating 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, a wholly-owned subsidiary of Alliance Coal, in December 2002. Alliance Service is subject to federal and state income taxes.

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. We believe this gives us a transportation cost advantage compared to many of our competitors.

Results Of Operations

2002 Compared with 2001

Coal sales. Coal sales for 2002 increased 13.4% to $478.4 million from $422.0 million for 2001. The increase of $56.4 million was primarily attributable to higher price sales contracts secured during the second half of last year, increased tons associated with coal feedstock for coal synfuel production, and higher productivity and sales from Gibson. These increases were partially offset by a decrease in the domestic coal brokerage market. Tons sold increased 7.6% to 18.3 million for 2002 from 17.0 million in 2001. Tons produced increased 4.5% to 16.4 million for 2002 from 15.7 million for 2001.

Transportation revenues. Transportation revenues for 2002 increased 5.0% to $19.0 million from $18.1 million for 2001. The increase of $0.9 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.

Other sales and operating revenues. Other sales and operating revenues increased to $20.3 million for 2002 from $6.2 million for 2001. The increase of $14.1 million is attributable to additional rental and service fees associated with increased volumes at a third-party coal synfuel production facility at Hopkins. See the discussion above under “Business.”

Operating expenses. Operating expenses increased 8.2% to $333.1 million for 2002 from $308.0 million for 2001. The increase of $25.1 million is primarily the result of increased operating costs associated with increased sales volumes and coal synfuel production.

Transportation expenses. See “Transportation Revenues” above concerning the increase in transportation expenses.

Outside purchases. Outside purchases increased to $46.7 million for 2002 from $31.8 million for 2001. The increase of $14.9 million is primarily the result of outside purchases necessary to fulfill feedstock contract commitments at Hopkins, offset by a decrease in the activity in the domestic coal brokerage market.

General and administrative. General and administrative expenses increased 9.5% to $19.4 million for 2002 from $17.7 million for 2001. The increase of $1.7 million was primarily attributable to higher accruals related to the Short-Term Incentive Plan, combined with additional restricted units granted under the Long-Term Incentive Plan.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expenses increased 3.9% to $47.2 million for 2002 from $45.5 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 2.8% to $16.3 million for 2002 from $16.8 million for 2001. The decrease of $0.5 million primarily reflects debt reduction due to scheduled debt payments.

Income taxes. 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. Income taxes were not incurred in 2001. In 2003, income taxes are estimated to be between $1.3 million and $1.8 million.

EBITDA (income before net interest expense, income taxes, depreciation, depletion and amortization) increased 26.0% to $100.0 million for 2002 compared with $79.4 million for 2001. The 2001 results include the benefit of a cumulative effect of accounting change totaling $7.9 million related to a change in the method of estimating the black lung benefits liability. Excluding the benefit of the accounting change during 2001, EBITDA for 2002 increased $28.5 million or 40.1%. The $28.5 million increase in EBITDA, after excluding the effect of the accounting change, is primarily attributable to higher price sales contracts, increased volumes associated with coal synfuel related agreements, and higher sales volume at Gibson. For an explanation of EBITDA and a reconciliation of EBITDA to net income, please read footnotes 7 and 8 to "Item 6. Selected Financial Data."

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

2001 Compared with 2000

Coal sales. Coal sales for 2001 increased 21.5% to $422.0 million from $347.2 million for 2000. The increase of $74.8 million was primarily attributable to higher price sales contracts and volumes reflecting increased utility demand, increased activity in the domestic coal brokerage market due to favorable spot price levels and additional revenues from the new Gibson Complex, which opened in late 2000. Tons sold increased 13.3% to 17.0 million for 2001 from 15.0 million in 2000. Tons produced increased 14.9% to 15.7 million for 2001 from 13.7 million for 2000.

Transportation revenues. Transportation revenues for 2001 increased 33.9% to $18.1 million from $13.5 million for 2000. The increase of $4.6 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.

Other sales and operating revenues. Other sales and operating revenues increased to $6.2 million for 2001 from $2.8 million for 2000. The increase of $3.4 million is attributable to additional service fees associated with increased volumes at a third party coal synfuel production facility at Hopkins. See the discussion immediately above under “Business.”

Operating expenses. Operating expenses increased 19.7% to $308.0 million for 2001 from $257.4 million for 2000. The increase of $50.6 million resulted from increased sales volumes as well as additional operating expenses associated with a full year of operation at Gibson, which opened in late 2000, and difficult mining conditions encountered at several operations. Those difficult mining conditions placed an undue burden on equipment scheduled for replacement, resulting in unanticipated equipment failures and higher maintenance costs.

Transportation expenses. See “Transportation Revenues” above concerning the increase in transportation expenses.

Outside purchases. Outside purchases increased to $31.8 million for 2001 from $16.9 million for 2000. The increase of $14.9 million resulted from increased activity in the domestic coal brokerage market due to improved profit margins on spot coal sales, which resulted in increased volumes at higher purchase prices. The higher brokerage volumes are largely attributable to short-term opportunities in the domestic coal brokerage markets, which are not expected to be material in the future.

General and administrative. General and administrative expenses increased 16.8% to $17.7 million for 2001 from $15.2 million for 2000. The increase of $2.5 million was primarily attributable to higher accruals related to the Short-Term Incentive Plan, combined with additional restricted units granted under the Long-Term Incentive Plan. The Long-Term Incentive Plan accrual is impacted by the increased market value of our common units.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expenses increased 16.1% to $45.5 million for 2001 from $39.1 million for 2000. The increase of $6.4 million primarily resulted from additional depreciation expense associated with a full year of operation at Gibson, which opened in late 2000.

Interest expense. Interest expense was comparable for 2001 and 2000 at $16.8 million and $16.6 million, respectively.

Cumulative effect of accounting change. Effective January 1, 2001, we changed our method of estimating our black lung benefits liability. See the discussion above under “Workers’ Compensation and Pneumoconiosis (“Black Lung”) Benefits.”

EBITDA (income before net interest expense, income taxes, depreciation, depletion and amortization) increased 11.3% to $79.4 million for 2001 compared with $71.3 million for 2000. Excluding the net benefits of the change in accounting method in 2001 and the unusual items in 2000, EBITDA for 2001 was $71.4 million, compared to $61.8 million for 2000. The $9.6 million increase was primarily attributable to higher price sales contracts and volumes reflecting increased utility demand during 2001 and a full year of operations at Gibson, which opened in late 2000, and the increased revenue from the third party coal synfuel facility at Hopkins. For an explanation of EBITDA and a reconciliation of EBITDA to net income, please read footnotes 7 and 8 to “Item 6. Selected Financial Data.”

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

Outlook

Ongoing Acquisition Activities

Consistent with our business strategy, from time-to-time we engage in discussions with potential sellers regarding the possible purchase by us of coal production and marketing assets.

Sarbanes-Oxley Act and New SEC Rules

Several regulatory and legislative initiatives were introduced in 2002 in response to developments during 2001 and 2002 regarding accounting issues at large public companies, resulting in disruptions in the capital markets and ensuing calls for action to prevent repetition of those events. We support the actions called for under these initiatives and believe these steps will ultimately be successful in accomplishing the stated objectives. However, implementation of reforms in connection with these initiatives will add to the costs of doing business for all publicly-traded entities, including us. These costs will have an adverse impact on future income and cash flow, especially in the near term as legal, financial and consultant costs are incurred to analyze the new requirements, formalize current practices and implement required changes to ensure that we maintain compliance with these new rules. We are not able to estimate the magnitude of increase in our costs that will result from such reforms.

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 MQD 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. We had no equipment leased under the master equipment lease at December 31, 2002. Selected pieces of equipment will be leased in 2003 when the lease terms are considered favorable. Our credit facilities limit the amount of total operating lease obligations to $10 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 $87.6 million in 2002, compared to $63.7 million in 2001. The increase in cash provided by operating activities was principally attributable to operating income and working capital changes during 2002 compared to 2001.

Net cash used in investing activities was $41.3 million in 2002, compared to net cash used in investing activities of $26.2 million in 2001. The increased use of cash is principally attributable to reduced liquidation of marketable securities, net of purchases, during 2002 compared to 2001.

Net cash used in financing activities was $46.4 million for 2002, compared to net cash used in financing activities of $35.2 million for 2001. Cash used in financing activities during 2002 and 2001 was a direct result of eight quarterly distributions of $0.50 per unit on common and subordinated units outstanding. The quarterly cash distribution was increased to $0.525 per unit with respect to the fourth quarter of 2002, which was paid in February 2003. We expect to maintain this level of quarterly cash distribution during 2003. Additionally, during 2002 and 2001, we made scheduled debt payments of $15.0 million and $3.75 million, respectively.

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, 2002:

Contractual Obligations	Total	Less than 1 year	2-3 years	4-5 years	After 5 years
Long-Term Debt	$ 211,250	$ 16,250	$ 33,000	$ 36,000	$ 126,000
Operating Leases	24,633	3,375	6,777	6,268	8,213
Other Long-Term Obligations (excluding discount effect of $12.4 million for reclamation liability)	31,754	1,186	6,428	2,430	21,710
Capital projects	6,010	6,010	-	-	-
Pension liability	5,645	5,300	345	-	-
	$ 279,292	$ 32,121	$ 46,550	$ 44,698	$ 155,923

Capital Expenditures

Capital expenditures decreased to $51.5 million in 2002, compared to $53.7 million in 2001. The decrease is principally attributable to capital expenditures related to capital for a new service shaft at Dotiki and extension into the Pattiki II coal reserve, offset by the completion of Gibson during 2001.

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. The operation utilizes continuous mining units employing room-and-pillar mining techniques producing high-sulfur coal. Since January 2002, substantially all of the coal produced by Warrior has been sold to Hopkins for subsequent resale to SSO for use as feedstock in the production of coal synfuel. Since 2001, Warrior invested in new infrastructure capital projects that are expected to improve Warrior's productivity and significantly increase Warrior's annual production capacity. We plan to transfer an additional continuous mining unit to Warrior in the second quarter of 2003, to supplant other operations of the Partnership that will be depleting.

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 an affiliate of ARH Warrior Holdings 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.

As a result of the Warrior acquisition, we currently project that our average annual maintenance capital expenditures will increase to $32 million, which figure includes capital equipment that may be leased under the master equipment lease discussed above. We also currently expect to fund our anticipated capital expenditures, with the exception of the Warrior acquisition described above, with cash generated from operations and borrowings under our revolving credit facility described below.

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 $250 million of debt or equity securities. At March 15, 2003, we had approximately $192.9 million available under this registration statement.

Notes Offering and Credit Facility

Concurrently with the closing of our initial public offering, the special general partner issued and the intermediate partnership assumed the obligations with respect to $180 million principal amount of 8.31% senior notes due August 20, 2014 (Senior Notes). The special general partner also entered into, and the intermediate partnership assumed the obligations under, a $100 million credit facility (Credit Facility). The Credit Facility consists of three tranches, including a $50 million term loan facility, a $25 million working capital facility, and a $25 million revolving credit facility. We had borrowings outstanding of $31.3 million and $46.3 million under the term loan facility and no borrowings outstanding under either the working capital facility or the revolving credit facility at December 31, 2002, and 2001, respectively. The interest rates on the term loan facility at December 31, 2002, and 2001, were 4.31% and 3.40%, respectively. The Credit Facility expires August 2004. The Senior Notes and Credit Facility are guaranteed by all of the subsidiaries of the intermediate partnership. The Senior Notes and Credit Facility contain various restrictive and affirmative covenants, including the amount of distributions by the 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, 2002 and 2001.

We have entered into agreements with three banks to provide letters of credit in an aggregate amount of $35.0 million to maintain surety bonds to secure its obligations for reclamation liabilities and workers' compensation benefits. At December 31, 2002, we had $21.6 million in letters of credit outstanding. The special general partner guarantees the letters of credit.

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 it incurs or payments it makes on our behalf; including, but not limited to, management's salaries and related benefits, 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 $6,559,000, $6,503,000, and $3,899,000 for the years ended December 31, 2002, 2001 and 2000, respectively.

Warrior Coal 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 at a price significantly greater than the price paid by ARH Warrior Holdings. 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 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, under which the put option period was extended through February 28, 2003. In addition, we repaid Warrior's borrowings of $17.0 million under the revolving credit agreement between the special general partner and Warrior. The primary borrowings under the revolving credit agreement financed new infrastructure capital projects at Warrior that are expected to improve productivity and significantly increase capacity. We funded the Warrior acquisition through a portion of the proceeds received from the issuance of 2,250,000 common units. Based upon our current financial projections, we continue to believe that the fair value of Warrior is equal to or greater than the put option exercise price. Because the Warrior acquisition was between entities under common control, it will be 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, LLC (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.

During 2002 and 2001, we provided management and administrative services to Warrior under an administrative service agreement. Under this agreement, we recognized approximately $929,000 and $1,019,000 as a reduction of general and administrative expenses during the years ended December 31, 2002 and 2001, respectively.

During 2001, we entered into an agreement with Warrior to perform certain reclamation procedures for us. The total estimated cost of the reclamation procedures covered by this agreement is $475,000 of which approximately $97,000 and $160,000 was paid to Warrior for the years ended December 31, 2002 and 2001, respectively.

During 2002 and 2001, we made coal purchases of approximately $36,700,000 and $3,135,000, respectively, from Warrior. Accounts payable to Warrior of $3,400,000 and $1,876,000 is included in the amount due to affiliates at December 31, 2002 and 2001, respectively. During 2002, we made coal sales of approximately $3.5 million to Warrior. Accounts receivable from Warrior of $1.4 million offsets a portion of the amount due to affiliates at December 31, 2002.

SGP Land

We have 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. We paid annual minimum royalties of $2.7 million during each of the three years in the period ended December 31, 2002.

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 anticipated annual minimum royalty obligation is $684,000, payable in advance, from 2003 through 2009.

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 $568,000 and $705,000 for the years ended December 31, 2002 and 2001, respectively.

Special General Partner

Effective January 2001, Gibson entered into a noncancelable operating lease arrangement with the Special GP 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 incurred for the three years in the period ended December 31, 2002 was $2,595,000.

We have entered into agreements with three banks to provide letters of credit in an aggregate amount of $35.0 million to maintain surety bonds to secure our obligations for reclamation liabilities and workers' compensation benefits. At December 31, 2002, we had $21.6 million in outstanding letters of credit. Our special general partner guarantees these letters of credit, and as a result we have agreed to compensate our special general partner a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. We paid approximately $48,200 and $8,800 in guarantee fees to our special general partner for the years ended December 31, 2002 and 2001, respectively.

Accruals of Other Liabilities

We had accruals for other liabilities, including current obligations, totaling $70.8 million and $61.0 million at December 31, 2002 and 2001. 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. See "Item 8. Financial Statements and Supplementary Data. - Note 12. Reclamation and Mine Closing Costs” and “Note 13. Pneumoconiosis ("Black Lung") Benefits."

Pension Plan

We maintain a defined benefit pension plan (Pension Plan), which covers certain employees at the mining operations.

Our pension expense was approximately $2,200,000 and $2,000,000 for the years ended December 31, 2002 and 2001, respectively. The pension expense is based upon a number of actuarial assumptions, including an expected long-term rate of return on our Pension Plan assets of 9.0% and a discount rate of 7.25% and 7.50% for the years ended December 31, 2002 and 2001, 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. Historically, we have assumed that our investment managers will generate long-term returns of at least 9.0%. Effective January 1, 2003, we adjusted our assumption of long-term return to 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 10.7%, and 20.0% with fixed income managers, with an expected long-term rate of return of 5.3%. We regularly review our actual asset allocation and periodically rebalance our investments to our targeted allocation when considered appropriate.

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 7.25% at December 31, 2001 to 6.75% at December 31, 2002.

We estimate that our Pension Plan expense and cash contributions will be approximately $3,180,000 and $5,300,000, respectively in 2003. 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 9.0% to 8.0%) at December 31, 2001 would have increased our pension expense for the year ended December 31, 2002 by approximately $120,000. Lowering the discount rate assumption by 0.5% (from 7.25% to 6.75%) at December 31, 2001 would have increased our pension expense for the year ended December 31, 2002 by approximately $130,000.

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, 2002.

Recent Accounting Pronouncements

Effective January 1, 2002, we adopted Statement of Financial Accounting Standards ("SFAS") No. 142 "Goodwill and Intangible Assets." This standard discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. This standard had no material effect on our consolidated financial statements upon adoption.

In August 2001, the Financial Accounting Standards Board ("FASB") issued 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 obligation for its recorded amount is paid or a gain or loss upon settlement is incurred. Since we historically adhered to accounting principles similar to SFAS No. 143 in accounting for reclamation and mine closing costs, we do not believe that adoption of SFAS No. 143, effective January 1, 2003, will have a material impact on our financial statements.

Effective January 1, 2002, the Partnership adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This standard had no material effect on our consolidated financial statements upon adoption.

In November 2002, the FASB issued 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. The initial recognition and initial measurement provisions of the interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. We do not believe this interpretation will have a material effect on our financial statements upon adoption.

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 one customer recently 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 recently 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.

- Most 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 Hopkins 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.

- Any loss of the benefit from state tax credits may affect adversely our ability to pay distributions.

- Coal mining is subject to inherent risks that are beyond our control and these risks may not be fully covered under our insurance policies.

- 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 may 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 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

- Under our management’s buy-out agreement with The Beacon Group, under some circumstances The Beacon Group may assume control of the business and affairs of our general partner.

- 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 an affiliate.

- 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

- A recent federal district court decision, currently on appeal, extends prohibitions previously applicable only to surface mines to underground mines, which could limit our ability to conduct underground mining operations.

- Federal and state laws require bonds to secure our obligations related to (a) the statutory requirement that we return mined property to its approximate original condition and (b) workers compensation. Due to problems in the surety industry, like other mine operators we may have difficulty maintaining our surety bonds for mine reclamation as well as workers’ compensation and black lung benefits. At December 31, 2002, we had $58.8 million of surety bonds in place. Our failure to maintain, or inability to acquire, surety bonds that are required by state and federal law would have a material adverse effect on us.

- 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.

- 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, see “Item 1. Business. – Coal Marketing and Sales” and “Item 8. Financial Statements and Supplementary Data. – Note 16. 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.

We do not engage in any interest rate, foreign currency exchange rate or commodity price-hedging transactions.

The intermediate partnership assumed obligations under the Credit Facility. Borrowings under the Credit Facility are at variable rates and, as a result, we have interest rate exposure.

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, 2002, and 2001. The carrying amounts and fair values of financial instruments are as follows (in thousands):

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%						

Expected Maturity Dates as of December 31, 2001	2002	2003	2004	2005	2006	Thereafter	Total	Fair Value December 31, 2001
Senior Notes-fixed rate	$ -	$ -	$ -	$ 18,000	$ 18,000	$ 144,000	$ 180,000	$ 180,000
Weighted Average interest rate				8.31%	8.31%	8.31%		
Term Loan-floating rate	$ 15,000	$ 16,250	$ 15,000	$ -		$ -	$ 46,250	$ 46,250
Weighted Average interest rate	3.40%	3.40%	3.40%					

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, 2002 and 2001, the related consolidated statements of income, cash flows and Partners' capital (deficit) for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 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 7, 2003, except for Note 19,
as to which the date is March 14, 2003

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2002 AND 2001
(In thousands, except unit data)

	December 31, 2002	December 31, 2001
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 9,000	$ 9,176
Trade receivables, less allowance of $763 at December 31, 2002 and 2001	30,793	31,124
Due from affiliates	1,369	-
Marketable securities (at cost, which approximates fair value)	-	10,085
Inventories	12,023	11,600
Advance royalties	5,231	5,353
Prepaid expenses and other assets	2,680	2,020
Total current assets	61,096	69,358
PROPERTY, PLANT AND EQUIPMENT, AT COST	413,889	367,050
LESS ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION	(206,471)	(169,960)
	207,418	197,090
OTHER ASSETS:		
Advance royalties	9,486	9,756
Coal supply agreements, net	8,167	12,031
Other long-term assets	2,240	2,670
	$ 288,407	$ 290,905
LIABILITIES AND PARTNERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 19,770	$ 25,237
Due to affiliates	4,706	2,595
Accrued taxes other than income taxes	7,615	5,660
Accrued payroll and related expenses	9,319	8,284
Accrued interest	5,361	5,402
Workers' compensation and pneumoconiosis benefits	5,254	4,194
Other current liabilities	8,899	5,324
Current maturities, long-term debt	16,250	15,000
Total current liabilities	77,174	71,696
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities	195,000	211,250
Pneumoconiosis benefits	16,067	14,615
Workers' compensation	19,710	18,409
Reclamation and mine closing	18,139	15,387
Due to affiliates	6,152	3,624
Other liabilities	2,718	2,865
Total liabilities	334,960	337,846
COMMITMENTS AND CONTINGENCIES		
PARTNERS' CAPITAL (DEFICIT):		
Common Unitholders 8,982,780 units outstanding	144,219	141,448
Subordinated Unitholder 6,422,531 units outstanding	112,916	110,935
General Partners	(298,413)	(298,510)
Minimum pension liability	(5,275)	(814)
Total Partners' capital (deficit)	(46,553)	(46,941)
	$ 288,407	$ 290,905

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001, AND 2000
(In thousands, except unit and per unit data)

	Year Ended December 31,		
	2002	**2001**	**2000**
SALES AND OPERATING REVENUES:			
Coal sales	$ 478,383	$ 421,996	$ 347,209
Transportation revenues	18,992	18,090	13,511
Other sales and operating revenues	20,367	6,214	2,749
Total revenues	517,742	446,300	363,469
EXPENSES:			
Operating expenses	333,112	307,977	257,365
Transportation expenses	18,992	18,090	13,511
Outside purchases	46,738	31,840	16,874
General and administrative	19,408	17,728	15,176
Depreciation, depletion and amortization	47,218	45,451	39,141
Interest expense (net of interest income and interest capitalized of $1,139, $1,928, and $3,015 for the Partnership's respective periods)	16,338	16,805	16,563
Unusual items	-	-	(9,466)
Total operating expenses	481,806	437,891	349,164
INCOME FROM OPERATIONS	35,936	8,409	14,305
OTHER INCOME	528	752	1,276
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	36,464	9,161	15,581
INCOME TAX EXPENSE	175	-	-
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	36,289	9,161	15,581
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	-	7,939	-
NET INCOME	$ 36,289	$ 17,100	$ 15,581
GENERAL PARTNERS' INTEREST IN NET INCOME	$ 726	$ 342	$ 312
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 35,563	$ 16,758	$ 15,269
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 2.31	$ 1.09	$ 0.99
BASIC NET INCOME PER LIMITED PARTNER UNIT BEFORE ACCOUNTING CHANGE	$ 2.31	$ 0.58	$ 0.99
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 2.24	$ 1.07	$ 0.98
DILUTED NET INCOME PER LIMITED PARTNER UNIT BEFORE ACCOUNTING CHANGE	$ 2.24	$ 0.57	$ 0.98
PRO FORMA NET INCOME ASSUMING ACCOUNTING CHANGE IS APPLIED RETROACTIVELY	$ 36,289	$ 9,161	$ 14,907
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING - BASIC	15,405,311	15,405,311	15,405,311
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING - DILUTED	15,842,708	15,684,550	15,551,062

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001, AND 2000
(In thousands)

	Year Ended December 31,		
	2002	2001	2000
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 36,289	$ 17,100	$ 15,581
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	47,218	45,451	39,141
Cumulative effect of accounting change	-	(7,939)	-
Impairment of transloading facility	-	-	2,439
Reclamation and mine closings	1,328	943	1,074
Coal inventory adjustment to market	21	212	579
Other	445	(257)	391
Changes in operating assets and liabilities:			
Trade receivables	331	4,774	(2,842)
Inventories	(444)	(970)	9,709
Advance royalties	392	(2,235)	(3,011)
Accounts payable	(5,467)	(321)	6,181
Due to affiliates	3,270	5,149	264
Accrued taxes other than income taxes	1,955	797	289
Accrued payroll and related benefits	1,035	1,309	(1,836)
Accrued pneumoconiosis benefits	1,452	903	(4)
Workers' compensation	2,361	1,661	1,052
Other	(2,607)	(2,926)	2,366
Total net adjustments	51,290	46,551	55,792
Net cash provided by operating activities	87,579	63,651	71,373
CASH FLOWS FROM INVESTING ACTIVITIES:			
Purchase of property, plant and equipment	(51,524)	(53,714)	(46,151)
Proceeds from sale of property, plant and equipment	124	183	210
Purchase of marketable securities	-	(33,527)	(72,523)
Proceeds from the sale of marketable securities	10,085	60,840	77,464
Net cash used in investing activities	(41,315)	(26,218)	(41,000)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under revolving credit and working capital facilities	66,400	1,100	29,500
Payments under revolving credit and working capital facilities	(66,400)	(1,100)	(29,500)
Payments on long-term debt	(15,000)	(3,750)	-
Distributions to Partners	(31,440)	(31,440)	(31,440)
Net cash used in financing activities	(46,440)	(35,190)	(31,440)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(176)	2,243	(1,067)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	9,176	6,933	8,000
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 9,000	$ 9,176	$ 6,933
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest	$ 17,059	$ 18,070	$ 19,043

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, 2002, 2001, AND 2000
(In thousands, except unit data)

	Number of Limited Partner Units						Total
	Common	Subordinated	Common	Subordinated	General Partners	Minimum Pension Liability	Total Partners' Capital (Deficit)
Balance at January 1, 2000	8,982,780	6,422,531	$158,705	$123,273	$ (297,906)	$ -	$ (15,928)
Net income	-	-	8,903	6,366	312	-	15,581
Distribution to Partners	-	-	(17,966)	(12,845)	(629)	-	(31,440)
Balance at December 31, 2000	8,982,780	6,422,531	149,642	116,794	(298,223)	-	(31,787)
Comprehensive income:							
Net income	-	-	9,772	6,986	342	-	17,100
Minimum pension liability	-	-	-	-	-	(814)	(814)
Total comprehensive income	-	-	9,772	6,986	342	(814)	16,286
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	(298,510)	(814)	(46,941)
Comprehensive income:							
Net income	-	-	20,737	14,826	726	-	36,289
Minimum pension liability	-	-	-	-	-	(4,461)	(4,461)
Total comprehensive income	-	-	20,737	14,826	726	(4,461)	31,828
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	$ (298,413)	$(5,275)	$ (46,553)

See notes to consolidated financial statements.

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), which assets consisted of substantially all of ARH's operating subsidiaries. Collectively, the coal production and marketing assets and the operating subsidiaries of ARH acquired by the Partnership, but excluding ARH and certain excluded assets and subsidiaries, are referred to as the "Predecessor."

The Delaware limited partnerships and 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, 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 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 other than underwriters fees (Note 19).

Consistent with guidance provided by the Emerging Issues Task Force in Issue No. 87-21, "Change of Accounting Basis in Master Limited Partnership Transactions," the Partnership maintained the historical cost basis of the $121 million of net assets contributed by ARH to the Partnership.

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, 2002 and 2001 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, 2002. 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, 2002 and 2001, the estimated fair value of long-term debt was approximately $228.5 million and $226.3 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 $3,352,000 at December 31, 2001, to accounts payable in the consolidated balance sheets.

Marketable Securities – At December 31, 2001, the Partnership had an investment in a Federal Agency Note, which matured February 1, 2002 and was classified as an available-for-sale security. At December 31, 2001, the cost of marketable securities approximated fair value and no effect of unrealized gains (losses) is reflected in Partners' capital (deficit).

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, 2002 and 2001, 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. During 2000, the Partnership recorded an impairment loss of approximately $2,439,000 relating to certain transloading facility assets, associated with Seminole Electric Cooperative, Inc.'s ("Seminole") termination of a long-term contract for transloading of coal from rail to barge. Because this facility's revenues were primarily attributable to the Seminole long-term contract, the carrying value of the transloading facility and associated equipment, net of salvage value, was recorded as an impairment and is included as an unusual item in 2000 in the accompanying consolidated statements of income.

Advance Royalties – Rights to coal mineral leases are often acquired 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.

Coal Supply Agreements – The Predecessor purchased the coal operations of MAPCO Inc. effective August 1, 1996, in a business combination using the purchase method of accounting. A portion of the acquisition costs 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 $30,296,000 and $26,432,000 at December 31, 2002 and 2001, respectively. The aggregate amortization expense recognized for coal supply agreements was $3,864,000, $4,293,000 and $3,555,000 for the years ended December 31, 2002, 2001 and 2000, respectively. The estimated aggregate amortization expense for years 2003 through 2005 is approximately $2,722,000 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 3).

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.

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 restricted common units granted under the Long-Term Incentive Plan (Note 11) using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" and the related FASB 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.

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 (a total of 15,405,311 units as of December 31, 2002 and 2001). Diluted net income per unit is based on the combined weighted average number of Common Units, Subordinated Units and common unit equivalents outstanding, which primarily include restricted units granted under the Long-Term Incentive Plan (Note 11).

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. The Partnership has disclosed major customer sales information (Note 16). The Partnership's geographic areas of operation are concentrated in the United States.

New Accounting Standards – On January 1, 2002, the Partnership adopted Statement of Financial Accounting Standards ("SFAS") No. 142 "Goodwill and Intangible Assets." This standard discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. This standard had no material effect on the Partnership's consolidated financial statements upon adoption.

In August 2001, the Financial Accounting Standards Board ("FASB") issued 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 obligation for its recorded amount is paid or a gain or loss upon settlement is incurred. Since the Partnership has historically adhered to accounting principles similar to SFAS No. 143 in accounting for its reclamation and mine closing costs, the Partnership does not believe that adoption of SFAS No. 143, effective January 1, 2003, will have a material impact on its consolidated financial statements.

On January 1, 2002, the Partnership adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets. This standard had no material effect on the Partnership's consolidated financial statements upon adoption.

In November 2002, the FASB issued 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. The initial recognition and initial measurement provisions of the interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. The Partnership does not believe this interpretation will have a material effect on the Partnership's consolidated financial statements upon adoption.

3. 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 recently 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). Assuming the retroactive application of the service cost method of estimating the black lung liability, the pro forma net income for the year ended December 31, 2000, would have been approximately $14,907,000 or $0.95 per basic limited partner unit and $0.94 per diluted limited partner unit, respectively, as compared to reported net income of $15,581,000 or $0.99 per basic limited partner unit and $0.98 per diluted limited partner unit.

4. UNUSUAL ITEMS

The Partnership was involved in litigation with Seminole with respect to Seminole's termination of a long-term contract for the transloading of coal from rail to barge through the Mt. Vernon terminal in Indiana. The final resolution between the parties, reached in conjunction with an arbitrator's decision rendered during the third quarter of 2000, included both cash payments and amendments to an existing coal supply contract. The Partnership recorded income of $12,141,000, which was net of litigation expenses of approximately $881,000 and an impairment charge of $2,439,000 relating to the facility's assets. Additionally, during the third quarter of 2000, the Partnership recorded an expense of $2,675,000, consisting of $675,000 relating to a settlement and $2,000,000 attributable to contingencies associated with third-party claims arising out of the Partnership's mining operations. The net effect of these unusual items was $9,466,000 recorded in the year ended December 31, 2000.

5. INVENTORIES

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

	2002	2001
Coal	$ 4,190	$ 4,184
Supplies	7,833	7,416
	$ 12,023	$ 11,600

6. PROPERTY, PLANT AND EQUIPMENT

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

	2002	2001
Mining equipment and processing facilities	$ 344,062	$ 299,480
Land and mineral rights	17,720	17,691
Buildings, office equipment and improvements	33,414	29,359
Construction in progress	18,693	20,520
	413,889	367,050
Less accumulated depreciation, depletion and amortization	(206,471)	(169,960)
	$ 207,418	$ 197,090

7. LONG-TERM DEBT

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

	2002	2001
Senior notes	$ 180,000	$ 180,000
Term loan through credit facility	31,250	46,250
	211,250	226,250
Less current maturities	(16,250)	(15,000)
	$ 195,000	$ 211,250

The senior notes are payable in ten annual installments of $18 million beginning in August 2005 and bear interest at 8.31%, payable semiannually.

The Intermediate Partnership has a $100 million credit facility that consists of three tranches, including a $50 million term loan facility, a $25 million working capital facility and a $25 million revolving credit facility. The working capital facility can be used to provide working capital and, if necessary, to fund distributions to unitholders. The revolving credit facility can be used for general business purposes, including capital expenditures and acquisitions. The rate of interest charged is adjusted quarterly based on a pricing grid, which is a function of the ratio of the Partnership's debt to cash flow. The credit facility provides the Partnership the option of borrowing at either (1) the London Interbank Offered Rate ("LIBOR") or (2) the "Base Rate" which is equal to the greater of (a) the Chase Prime Rate, or (b) the Federal Funds Rate plus ½ of 1%, plus, in either option, an applicable margin. The interest rates on the term loan facility at December 31, 2002 and 2001 were 4.31% and 3.40%, respectively. In accordance with the pricing grid, a commitment fee ranging from 0.375% to 0.500% per annum is paid quarterly on the unused portion of the working capital and revolving credit facilities. There were no amounts outstanding under the Partnership's working capital facility or revolving credit facility as of December 31, 2002 and 2001. The credit facility expires in August 2004.

The senior notes and credit facility are guaranteed by all subsidiaries of the Intermediate Partnership. The senior notes and credit facility contain various restrictive and affirmative covenants, including limitations on 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 credit facility and senior notes at December 31, 2002 and 2001.

The Partnership entered into agreements with three banks to provide letters of credit in an aggregate amount of $35.0 million. At December 31, 2002, the Partnership had $21.6 million in letters of credit outstanding. The Special GP guarantees the letters of credit (Note 14).

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

Year Ending December 31,	
2003	$ 16,250
2004	15,000
2005	18,000
2006	18,000
2007	18,000
Thereafter	126,000
	$ 211,250

8. DISTRIBUTIONS OF AVAILABLE CASH

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). Upon expiration of the subordination period, which will generally not occur before September 30, 2004, all Subordinated Units will be converted on a one-for-one basis into Common Units and will then participate, on a pro rata basis with all other Common Units in future distributions of available cash. However, under certain circumstances, up to 50% of the Subordinated Units may convert into Common Units on or after September 30, 2003. Common Units will accrue arrearages with respect to distributions for any quarter during the subordination period, but Subordinated Units will not accrue any arrearages with respect to distributions for any quarter.

If quarterly distributions of available cash exceed the MQD or the target distributions levels, the General Partners will receive distributions based on specified increasing percentages of the available cash that exceed the MQD or 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 distributions for the MQD and common unit arrearages, if any.

For each of the quarters ended December 31, 1999 through September 30, 2002, quarterly distributions of $0.50 per unit were paid to the common and subordinated unitholders. On January 28, 2003, the Partnership declared a quarterly distribution, for the period from October 1, 2002 to December 31, 2002, of $0.525 per unit, totaling approximately $8,088,000 on its outstanding Common and Subordinated Units, payable on February 14, 2003 to all unitholders of record on February 3, 2003.

9. 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 (Note 14), 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. Components of income tax expense are as follows (in thousands):

	Year Ended December 31, 2002
Current:	
Federal	$ 153
State	22
	$ 175

10. 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,		
	2002	2001	2000
Net income per limited partner unit	$ 35,563	$ 16,758	$ 15,269
Weighted average limited partner units - basic	15,405	15,405	15,405
Basic net income per limited partner unit	$ 2.31	$ 1.09	$ 0.99
Basic net income per limited partner unit before accounting change	$ 2.31	$ 0.58	$ 0.99
Weighted average limited partner units - basic	15,405	15,405	15,405
Units contingently issuable:			
Restricted units for Long-Term Incentive Plan	390	263	142
Directors' compensation units deferred	13	9	4
Supplemental Executive Retirement Plan	35	8	-
Weighted average limited partner units, assuming dilutive effect of restricted units	15,843	15,685	15,551
Diluted net income per limited partner unit	$ 2.24	$ 1.07	$ 0.98
Diluted net income per limited partner unit before accounting change	$ 2.24	$ 0.57	$ 0.98

11. EMPLOYEE BENEFIT PLANS

Long-Term Incentive Plan – 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, 2002, 2001 and 2000 the Compensation Committee approved grants of 133,885, 129,200 and 142,100 restricted units, respectively, which vest at the end of the subordination period, which will generally not end before September 30, 2004. As of December 31, 2002, 15,050 units have been forfeited. During 2002, 2001 and 2000, the Managing GP billed the Partnership approximately $2,338,000, $1,929,000 and $538,000, respectively, attributable to the LTIP. The Partnership has recorded this amount as compensation expense in accordance with variable plan accounting. Effective January 1, 2003, the Compensation Committee approved additional grants of 139,705 restricted units, which will vest September 30, 2005, subject to certain financial tests.

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 contributions based on matching 75% of employee contributions up to 3% of their annual compensation as well as an additional nonmatching contribution of ¾ of 1% of their 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 $2,565,000, $2,430,000 and $2,050,000 for the years ended December 31, 2002, 2001 and 2000, respectively.

Defined Benefit Plans – Certain employees at the mining operations participate in a defined benefit 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, 2002 and 2001 and the funded status of the plans reconciled with amounts reported in the Partnership's consolidated financial statements at December 31, 2002 and 2001, respectively (dollars in thousands):

	2002	2001
Change in benefit obligations:		
Benefit obligations at beginning of year	$ 13,202	$ 10,135
Service cost	2,249	2,050
Interest cost	952	755
Actuarial loss	1,817	384
Benefits paid	(143)	(122)
Benefit obligation at end of year	18,077	13,202
Change in plan assets:		
Fair value of plan assets at beginning of year	10,508	9,500
Employer contribution	3,661	1,500
Actual loss on plan assets	(1,594)	(370)
Benefits paid	(143)	(122)
Fair value of plan assets at end of year	12,432	10,508
Funded status	(5,645)	(2,694)
Unrecognized prior service cost	187	235
Unrecognized actuarial loss	5,275	814
Net amount recognized	$ (183)	$ (1,645)
Amounts recognized in statement of financial position:		
Accrued benefit liability	$ (5,645)	$ (2,694)
Intangible asset	187	235
Accumulated other comprehensive income	5,275	814
Net amount recognized	$ (183)	$ (1,645)
Weighted-average assumptions as of December 31:		
Discount rate	6.75 %	7.25 %
Expected return on plan assets	9.00 %	9.00 %

	2002	2001	2000
Components of net periodic benefit cost:			
Service cost	$ 2,249	$ 2,050	$ 1,971
Interest cost	952	755	596
Expected return on plan assets	(1,050)	(888)	(737)
Prior service cost	48	48	48
Net gain	-	-	(49)
Net periodic benefit cost	$ 2,199	$ 1,965	$ 1,829
Effect on minimum pension liability	$ 4,461	$ 814	$ -

12. 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 a 6% discount rate.

Discounting resulted in reducing the accrual for reclamation and mine closing costs by $12,429,000 and $12,184,000 at December 31, 2002 and 2001, respectively. Estimated payments of reclamation and mine closing costs as of December 31, 2002 are as follows (in thousands):

Year Ending December 31,	
2003	$ 1,186
2004	2,702
2005	3,726
2006	2,430
2007	-
Thereafter	21,710
Aggregate undiscounted reclamation and mine closing	31,754
Effect of discounting	12,429
Total reclamation and mine closing costs	19,325
Less current portion	1,186
Reclamation and mine closing costs	$ 18,139

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

	Year Ended December 31,		
	2002	**2001**	**2000**
Beginning balance	$ 16,465	$ 16,018	$ 14,796
Accrual	1,131	943	1,074
Payments	(709)	(454)	(764)
Allocation of liability associated with acquisition and mine development	2,438	(42)	912
Ending balance	$ 19,325	$ 16,465	$ 16,018

13. 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 3). 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 5.5% at December 31, 2002 and 2001, respectively.

The reconciliation of changes in benefit obligations at December 31, 2002 and 2001 is as follows (in thousands):

	2002	2001
Benefit obligations at beginning of year, including cumulative effect of accounting change of $7,939 effective January 1, 2001 (Note 3)	$ 14,615	$ 13,712
Service cost	783	464
Interest cost	811	705
Actuarial loss	45	-
Benefits paid	(187)	(266)
Benefit obligations at end of year	$ 16,067	$ 14,615

The Partnership previously accrued the black lung benefits liability based upon the actuarially computed present and future claims. The cost due to change in the estimate of black lung benefits charged to operations for the year ended December 31, 2000 was $123,000.

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.

14. 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, 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 $6,559,000, $6,503,000, and $3,899,000 for the years ended December 31, 2002, 2001 and 2000, respectively.

Warrior Coal Acquisition – On February 14, 2003, the Partnership acquired Warrior Coal, LLC ("Warrior Coal") from an affiliate, ARH Warrior Holdings, Inc. ("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 at a price significantly greater than the price paid by ARH Warrior Holdings. 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 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, as amended to extend the put option period through February 28, 2003. 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 are expected to improve productivity and significantly increase 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 19). Based on the Partnership's current financial projections, the Partnership continues to believe that the fair value of Warrior Coal is equal to or greater than the put option exercise price. Because the Warrior Coal acquisition was between entities under common control, it will be 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.

During 2002 and 2001, the Partnership provided management and administrative services to Warrior Coal under an administrative service agreement. Under this agreement, the Partnership recognized approximately $929,000 and $1,019,000 as a reduction of general and administrative expenses during the years ended December 31, 2002 and 2001, respectively.

During 2001, the Partnership entered into an agreement with Warrior Coal to perform certain reclamation procedures for the Partnership. The total estimated cost of the reclamation procedures covered by this agreement is $475,000 of which approximately $97,000 and $160,000 was paid to Warrior Coal for the years ended December 31, 2002 and 2001, respectively.

During 2002 and 2001, the Partnership made coal purchases of approximately $36,700,000 and $3,135,000, respectively, from Warrior Coal. Accounts payable to Warrior Coal of $3,400,000 and $1,876,000 is included in the amount due to affiliates at December 31, 2002 and 2001, respectively. During 2002, the Partnership made coal sales of approximately $3.5 million to Warrior Coal. Accounts receivable from Warrior Coal of $1.4 million offset a portion of the amount due to affiliates at December 31, 2002.

SGP Land – The Partnership 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. The Partnership paid annual minimum royalties of $2.7 million during each of the three years in the period ended December 31, 2002.

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 anticipated annual minimum royalty obligation is $684,000, payable in advance, from 2003 through 2009.

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 $568,000 and $705,000 for the years ended December 31, 2002 and 2001, respectively.

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, 2002 was $2,595,000.

The Partnership entered into agreements with three banks to provide letters of credit in an aggregate amount of $35.0 million to maintain surety bonds to secure its obligations for reclamation liabilities and workers' compensation benefits. At December 31, 2002, the Partnership had $21.6 million in outstanding letters of credit. The Special GP guarantees these letters of credit, and as a result the

Partnership has agreed to compensate the Special GP for a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. The Partnership paid approximately $48,200 and $8,800 in guarantee fees to the Special GP for the years ended December 31, 2002 and 2001, respectively.

15. 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 14). Future minimum lease payments under operating leases are as follows (in thousands):

Year Ending December 31,	Affiliate	Others	Total
2003	$ 2,595	$ 780	$ 3,375
2004	2,595	792	3,387
2005	2,595	795	3,390
2006	2,595	627	3,222
2007	2,595	451	3,046
Thereafter	8,000	213	8,213
	$ 20,975	$ 3,658	$ 24,633

Lease expense under all operating leases was $4,235,000, $4,224,000, $1,409,000, for the years ended December 31, 2002, 2001 and 2000, 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. There was no equipment leased under the master equipment lease at December 31, 2002.

Contractual Commitments – In connection with the expansion of an existing mine into adjacent coal reserves and construction of a new mine shaft at another existing mine, the Partnership has remaining contractual commitments of approximately $6.0 million at December 31, 2002.

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. The Partnership also recorded an expense of $2,675,000 consisting of $675,000 relating to a settlement and $2,000,000 attributable to contingencies associated with third-party claims arising out of its mining operations, which is reflected in "Unusual items" in the accompanying consolidated statements of income for the year ended December 31, 2000. In the opinion of management, the outcome of such matters to the extent not previously provided for or covered under insurance, will not have a material adverse effect on the Partnership's business, financial position or results of operations, although management cannot give any assurance to that effect.

Other – During September 2002, the Partnership completed its annual property insurance and casualty renewal. In general, 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 increased the deductible for commercial property insurance from $1.0 million to $3.5 million and, in addition, retained a participating interest along with its insurance carriers in the commercial property program at various levels up to 15.48%. The aggregate maximum limit in the commercial property program is $50.0 million per occurrence of which the Partnership would be responsible for a maximum limit of $7.7 million for each occurrence. While the Partnership does not have a significant history of material insurance claims, the ultimate amount of occurrences incurred and claims made, if any, are dependent on future developments. The Partnership cannot assure that it will not experience significant insurance claims in the future, which as a result of the Partnership's participation in the commercial property program, could have a material adverse effect on its business, financial condition and results of operations.

The Partnership is involved in 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 its Gibson County Coal mining complex. Gibson County Coal and PSI have had on-going discussions since March 2001 concerning the procedures for and testing of coal supplied by the Gibson County Coal mining complex, and have been unable to resolve their differences to-date. During March and April 2002, PSI withheld approximately $234,000 in payments due to Gibson County Coal. PSI has not withheld any additional payments and has verbally advised that it does not intend to withhold any future payments until this dispute is resolved. PSI claimed damages of $2,220,000 at December 31, 2002.

During April 2002, Gibson County Coal and PSI agreed to proceed with mediation in an effort to resolve this contractual dispute. The mediation of the dispute occurred in August 2002 during which the parties concluded an outline of a tentative settlement, subject to the negotiation of a definitive settlement agreement. The parties are in the process of negotiating such settlement agreement, but no assurance can be provided that a final settlement can be reached. In the event the final settlement agreement and certain other agreements cannot be concluded, the parties will proceed with either additional mediation efforts or resort to arbitration. Gibson County Coal continues to strongly disagree with PSI's position.

16. 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 (Customers D and E comprise less than one percent and seven percent of total revenues in 2002, respectively) are as follows (in thousands):

	Year Ended December 31,		
	2002	2001	2000
Customer A	$ 113,094	$ 540	$ -
Customer B	69,933	74,091	58,498
Customer C	72,224	63,241	67,234
Customer D	1,047	47,492	61,007
Customer E	32,491	32,614	38,713

Trade accounts receivable from these customers totaled approximately $17.2 million at December 31, 2002. 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, C, D and E expire in 2006 and Customer B in 2010.

17. 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, 2002	June 30, 2002	September 30, 2002	December 31, 2002
Revenues	$ 125,051	$ 126,829	$ 132,171	$ 133,691
Operating income	14,738	18,019	9,268	10,249
Income before income taxes	11,220	14,220	4,801	6,223
Net income	11,220	14,220	4,801	6,048
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

	Quarter Ended			
	March 31, 2001 (1)	June 30, 2001	September 30, 2001	December 31, 2001
Revenues	$ 106,752	$ 110,722	$ 117,894	$ 110,932
Operating income	8,456	4,012	11,943	803
Net income (loss)	12,375	(46)	7,816	(3,045)
Basic net income (loss) per limited partner unit	$ 0.79	$ (0.01)	$ 0.50	$ (0.19)
Basic net income (loss) per limited partner unit before accounting change	$ 0.28	$ (0.01)	$ 0.50	$ (0.19)
Diluted net income (loss) per limited partner unit	$ 0.77	$ (0.01)	$ 0.49	$ (0.19)
Diluted net income (loss) per limited partner unit before accounting change	$ 0.28	$ (0.01)	$ 0.49	$ (0.19)
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	15,680,594	15,681,411	15,678,013	15,708,968

(1) The Partnership changed its method of estimating black lung benefits liability effective January 1, 2001. The cumulative effect of this change resulted in the reduction of this liability and a corresponding increase in net income of $7,939,000 for the quarter (Note 3).

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

18. REGISTRATION STATEMENT

The Partnership filed a shelf registration statement on April 1, 2002 to register common units representing limited partner interests and debt securities, including guarantees. The Partnership, exclusive of its investment in all of its wholly-owned operating subsidiaries, has no independent assets or operations. If a series of debt securities is guaranteed, such series will be guaranteed by all of the Partnership's operating subsidiaries on a full and unconditional and joint and several basis.

19. SUBSEQUENT EVENTS

On February 14, 2003, the Partnership completed a public offering of 2,250,000 common units and received net proceeds of approximately $48.5 million, before expenses other than underwriters fees, and on March 14, 2003, 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. The Partnership used the net proceeds to fund the purchase of Warrior Coal and for working capital and general partnership purposes.

The Partnership acquired Warrior Coal on February 14, 2003 pursuant to the terms of an Amended and Restated Put/Call Agreement with ARH Warrior Holdings, a subsidiary of ARH. The Partnership paid the put option price of $12.7 million and repaid Warrior Coal's borrowings of $17.0 million under the revolving credit agreement between the Special GP and Warrior Coal. Because the Warrior Coal acquisition is between entities under common control, it will be accounted for at historical cost in a manner similar to that used in a pooling of interests.

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

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS 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 the 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	52	President, Chief Executive Officer and Director
Robert G. Sachse	54	Executive Vice President and Vice Chairman of the Board
Thomas L. Pearson	49	Senior Vice President - Law and Administration, General Counsel and Secretary
Charles R. Wesley	48	Senior Vice President - Operations
Gary J. Rathburn	52	Senior Vice President - Marketing
Michael J. Hall	58	Director and Member of the Audit* and Conflicts Committees
John J. MacWilliams	47	Director
Preston R. Miller, Jr.	54	Director and Member of the Compensation* Committee
John P. Neafsey	63	Chairman of the Board and Member of Audit, Compensation and Conflicts Committees
John H. Robinson	52	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. He held various positions 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 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.

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 of Matrix Service Company and serves on its Board of Directors. 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, a General Partner of The Beacon Group, LP, has served as a Director since June 1996. 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., a General Partner of The Beacon Group, LP, has served as a Director since June 1996. Mr. Miller's previous positions include serving as a General Partner of JP Morgan Partners and as Vice President for Goldman Sachs & Co.’s 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 our Compensation Committee.

John P. Neafsey has served as Chairman since June 1996. Mr. Neafsey is President of JN Associates, an investment consulting firm. 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 Longhorn Partners Pipeline, 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 Executive Director 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 a Member of our Audit, Compensation, and Conflicts Committees.

The position of Chairman of the Conflicts Committee of our managing general partner is currently open because of the retirement of Mr. Paul Tregurtha from the Board of Directors in December 2002. We expect that one of the current committee members will be elected as Chairman of the Conflicts Committee.

The Chief Financial Officer position of our managing general partner is currently open and an executive search is underway to find an individual to fill this position. Until this position is filled, the responsibilities of the Principle Financial Officer is jointly shared by Messrs. Joseph W. Craft and Cary P. Marshall, Vice President – Corporate Finance and Treasurer. The responsibilities of the Principle Accounting Officer are performed by Dale G. Wilkerson, Vice President and Controller.

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 it, or written representations from certain reporting persons, we believe that during 2002 none of our officers and directors was 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 for a purchase on October 2, 2002, but has since filed a Form 4 with respect to this transaction.

Reimbursement of Expenses of the Managing General Partner and its Affiliates

The 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 the managing general partner will determine the expenses that are allocable to us in any reasonable manner determined by the 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, the former Chief Financial Officer, and each of the four other most highly compensated executive officers of our managing general partner in excess of $100,000 in 2002, 2001 and 2000. 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

		Annual Compensation			Long Term Compensation	
Name and Principal Position	**Year**	**Salary**	**Bonus (1)**	**Other Annual Compensation (2)**	**Restricted Stock Awards (3)**	**All Other Compensation (4)**
Joseph W. Craft III,	2002	$328,955	$227,000	$1,075	$1,237,500	$52,171
President, Chief Executive Officer	2001	314,700	130,000	5,250	781,875	50,562
and Director	2000	292,950	94,200	-	678,150	63,695
Thomas L. Pearson,	2002	196,178	83,000	1,750	222,750	32,631
Senior Vice President-Law and	2001	192,000	63,000	1,167	140,738	31,914
Administration, General Counsel and Secretary	2000	177,000	45,000	1,550	122,067	43,856
Michael L. Greenwood (5)	2002	180,267	-	-	222,750	93,250
Senior Vice President-Chief	2001	162,650	50,000	-	140,738	24,531
Financial Officer and Treasurer	2000	151,400	45,000	-	122,067	26,009
Charles R. Wesley,	2002	211,504	130,000	-	247,500	33,001
Senior Vice President-Operations	2001	202,000	65,000	925	156,375	33,286
	2000	187,000	47,600	1,500	135,630	32,802
Gary J. Rathburn,	2002	170,634	90,000	2,285	233,750	29,884
Senior Vice President-Marketing	2001	167,000	70,000	3,000	140,738	26,702
	2000	152,000	45,000	1,500	122,067	28,008

Robert G. Sachse (6)	2002	180,392	-	-	61,875	25,470
Executive Vice President,	2001	180,265	-	-	39,096	21,976
Vice Chairman and Director	2000	62,981	-	-	-	5,149

(1) Amounts awarded under the Short-Term Incentive Plan. 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, 2002, were: Mr. Craft, 140,000 units valued at $3,390,800; Mr. Pearson, 25,200 units valued at $610,344; Mr. Greenwood, 25,200 units valued at $610,344; Mr. Wesley, 28,000 units valued at $678,160; Mr. Rathburn, 25,600 units valued at $620,032; Mr. Sachse 4,500 units valued at $108,990. Units granted under the Long-Term Incentive Plan do not vest until the end of the subordination period, which will generally not end before September 30, 2004. See "Long-Term Incentive Plan" below.

(4) Amounts represent (a) the managing general partner's matching contributions to its 401(k) Plan, (b) the managing general partner's contribution to its Supplemental Executive Retirement Plan (SERP), (c) in regard to Mr. Greenwood only, a payment of $85,050 in accordance with the terms of the SERP and (d) in regard to Mr. Sachse only, the managing general partner's contribution to its Directors Compensation Program.

(5) Mr. Greenwood separated from service effective May 17, 2002. Under the terms of his severance agreement he continued to receive compensation during 2002.

(6) Mr. Sachse was hired effective August 14, 2000; therefore his 2000 compensation information is for the period from August 14, 2000 to December 31, 2000.

Compensation Of Directors

Under the managing general partner's Directors Compensation Program (Directors Plan) each non-employee Director is paid an annual retainer of $21,500. 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 may elect to defer all or a portion of his or her compensation under the Deferred Compensation Plan for Directors.

In addition, each non-employee director participates in the Long-Term Incentive Plan. The directors restricted units vest in accordance with the procedures described below. Messrs. MacWilliams and Miller have declined compensation under the Directors and Long-Term Incentive Plans.

Mr. Sachse has a consulting agreement with the managing general partner for a term of three years, commencing August 14, 2000. The consulting agreement provides that Mr. Sachse will serve as Executive Vice President of the 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. A copy of the consulting agreement with Mr. Sachse is an exhibit hereto.

Employment Agreements

The executive officers of the 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 the managing general partner on the other. We reimburse the 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, $215,280 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 the 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 the 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 the 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 the managing general partner provides for its employees.

Long-Term Incentive Plan

Effective January 1, 2000, the managing general partner adopted the Long-Term Incentive Plan (LTIP) for certain employees and directors of the 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 the managing general partner's Board of Directors. Annual grant levels for designated participants are recommended by the President and CEO of the managing general partner, subject to the review and approval of the Compensation Committee. We will reimburse the 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 the 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 the managing general partner, or any combination of the foregoing. The 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, 2002, 2001 and 2000, the Compensation Committee approved initial grants of 133,885, 129,200 and 142,100 restricted units, vesting at the end of the subordination period, which generally will not end before September 30, 2004. As of December 31, 2002, 15,050 units have been forfeited. Effective as of January 1, 2003, the Compensation Committee approved additional grants of 139,705 restricted units, which vest September 30, 2005, 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.

The 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. The 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, the managing general partner may, in its discretion, establish such additional compensation and incentive arrangements as it deems appropriate to motivate and reward its employees. The 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	8,100	33 Months
Michael L. Greenwood	8,100	33 Months
Charles R. Wesley	9,000	33 Months
Gary J. Rathburn	8,500	33 Months
Robert G. Sachse	2,250	33 Months

(1) Units granted under the LTIP will vest at the end of 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 not sooner than September 30, 2004.

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

Short-Term Incentive Plan

Effective January 1, 1999, the managing general partner adopted a Short-Term Incentive Plan (STIP) for management and other salaried employees. The STIP is designed to enhance the financial performance by rewarding management and our salaried employees and those of the 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 CEO of the 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 the managing general partner is able to amend the plan at any time. The managing general partner is entitled to reimbursement by us for the costs incurred under the STIP.

Supplemental Executive Retirement Plan

Effective January 1, 1997, the managing general partner adopted a supplemental executive retirement 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. The managing general partner is able to amend or terminate the plan at any time. The managing general partner is entitled to reimbursement by us for its costs incurred under the SERP.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth certain information as of March 1, 2003, regarding the beneficial ownership of common and subordinated units held by (a) each person known by the 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 the managing general partner and (c) all directors and executive officers of the managing general partner as a group. The managing general partner is owned by members of management. The special general partner is a wholly-owned subsidiary of Alliance Resource Holdings. The address of Alliance Resource Holdings, the managing general partner and the 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)	1,232,780	11.01%	6,422,531	100%	43.4%
Joseph W. Craft III (1) (4)	1,449,223	12.94%	6,422,531	100%	44.7%
Robert G. Sachse (1)	6,302	*	-	-	*
Thomas L. Pearson (1)	17,151	*	-	-	*
Charles R. Wesley (1)	53,392	*	-	-	*
Gary J. Rathburn (1)	14,793	*	-	-	*
John J. MacWilliams (2)	-	*	-	-	*
Preston R. Miller, Jr. (2)	-	*	-	-	*
John P. Neafsey (1)	13,729	*	-	-	*
John H. Robinson (3)	4,685	*	-	-	*
All directors and executive officers as a group (9 persons)	1,559,275	13.93%	6,422,531	100%	45.3%

* Less than one percent.

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

(2) The address of Messrs. MacWilliams and Miller is The Beacon Group, LP, 275 Grove St., Suite 2-400, Newton, Massachusetts 02466.

(3) The address of Mr. Robinson is 11 Grosvenor Crescent, London, England SW1X 7EE.

(4) Mr. Craft may be deemed to share beneficial ownership of 1,232,780 common units and 6,422,531 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 115,695 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 11,667 common units held by Alliance Management Holdings, LLC, of which he is the sole director and majority member. 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.

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, 2003	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, 2003
Equity compensation plans approved by unitholders:			
Long-Term Incentive Plan	514,790	N/A	85,210
Equity compensation plans not approved by unitholders:			
Supplemental Executive Retirement Plan	38,405	N/A	41,595
Deferred Compensation Plan for Directors	15,498	N/A	34,502

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

The special general partner owns 1,232,780 common units and 6,422,531 subordinated units representing an aggregate 42.6% limited partner interest in us. In addition, the general partners own, on a combined basis, an aggregate 2% general partner interest in us, the intermediate partnership and the subsidiaries. The managing general partner's ability, as managing general partner, together with the special general partner's ownership of 1,232,780 common units and 6,422,531 subordinated units, effectively gives the 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 purchase coal from affiliates, lease a coal preparation plant and handling facilities at Gibson, lease coal reserves from our special general partner and its affiliates, provide general and administrative services to an affiliate, and receive reclamation services at Dotiki from an affiliate. 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 in February 2003. See "Item 8. Financial Statements and Supplementary Data. - Note 14. 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

J.P. Morgan Chase & Co. (Chase) is paying agent, co-administrative agent and a lender under our Credit Facility. In 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 2003. The Beacon Group is an affiliate of Chase. Messrs. MacWilliams and Miller are General Partners of the Beacon Group and Directors of the managing general partner.

Omnibus Agreement

Concurrent with the closing of our initial public offering, we entered into an omnibus agreement with Alliance Resource Holdings and the 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 the 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 the 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. CONTROLS AND PROCEDURES

Within the 90-day period prior to filing of this report, an evaluation was carried out by management, including our chief executive officer and principal accounting officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-14(c) under the Securities Exchange Act of 1934). Based upon this evaluation, the chief executive officer and the principal accounting officer concluded that the design and operation of these disclosure controls and procedures were effective.

Subsequent to this evaluation on March 14, 2003 through the date of this filing on Form 10-K for the year ended December 31, 2002, there have been no significant changes in the Partnership's internal controls or in other factors that could significantly affect these controls, including any significant deficiencies or material weaknesses of internal controls that would require corrective action.

Each of the chief executive officer and the principal accounting officer of our managing general partner has furnished a certificate to the Securities and Exchange Commission as required by Section 906 of the Sarbanes-Oxley Act of 2002.

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, 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 16, 1999, among Alliance Resource GP, LLC, JP Morgan Chase Bank (formerly The Chase Manhattan Bank) (as paying agent), Deutsche Bank AG, New York Branch (as documentation agent), Citicorp USA, Inc. and JP Morgan Chase Bank (as co-administrative agents) and the lenders named therein. (Incorporated by reference to Exhibit 10.1 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).

10.2 Amendment No. 1 dated December 7, 2001, to the Credit Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC, JP Morgan Chase Bank (formerly The Chase Manhattan Bank) (as paying agent), Deutsche Bank AG, New York Branch (as documentation agent), Citicorp USA, Inc. and JP Morgan Chase Bank (as co-administrative agents) and the lenders named therein. (Incorporated by reference to Exhibit 10.2 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 000-26823).

10.3 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).

10.4 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).

10.5 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 10.32 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 000-26823).

10.6 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).

10.7 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).

10.8 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).

*10.9 Amendment No. 1 to Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Fifth Third Bank.

10.10 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).

10.11 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).

10.12 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 10.33 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 000-26823).

10.13 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).

10.14 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).

10.15 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).

10.16 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).

10.17 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).

10.18 Alliance Resource Management GP, LLC 2000 Long-Term Incentive Plan (as amended). (Incorporated by reference to Exhibit 10.11 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).

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

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 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).

10.26 Contract for Purchase and Sale of Coal, dated January 31, 1995, between Tennessee Valley Authority and Webster County Coal Corporation. (Incorporated by reference to Exhibit 10.10 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).

10.27 Assignment/Transfer Agreement between Andalex Resources, Inc., Hopkins County Coal LLC, Webster County Coal Corporation and Tennessee Valley Authority, dated January 23, 1998, with Exhibit A – Contract for Purchase and Sale of Coal between Tennessee Valley Authority and Andalex Resources, Inc., dated January 31, 1995. (Incorporated by reference to Exhibit 10.11 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).

10.28 Contract for Purchase and Sale of Coal, dated July 7, 1998, between Tennessee Valley Authority and Webster County Coal Corporation. (Incorporated by reference to Exhibit 10.12 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).

10.29 Contract for Purchase and Sale of Coal, dated July 7, 1998, between Tennessee Valley Authority and White County Coal Corporation. (Incorporated by reference to Exhibit 10.13 of the Registrant's Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).

10.30 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).

10.31 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).

10.32 Amendment No. 1 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).

10.33 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).

*10.34 Letter Agreement dated January 31, 2003 between ARH Warrior Holdings, Inc. and Alliance Resource Partners, L.P.

10.35 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).

10.36	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, respecitvely.

* Filed herewith

(b) Reports on Form 8-K:

A Form 8-K was filed on November 14, 2002 to submit to the Securities and Exchange Commission the certifications of the Partnership's Chief Executive Officer and Principal Accounting Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

A Form 8-K/A was also filed on December 23, 2002 to correct a typographical error in the Principal Accounting Officer certification filed on November 14, 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 19, 2003.

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/ Dale G. Wilkerson
Dale G. Wilkerson
Vice President and Controller
(Principal Accounting 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 19, 2003
/s/ Dale G. Wilkerson Dale G. Wilkerson	Vice President and Controller (Principal Accounting Officer)	March 19, 2003
/s/ Michael J. Hall Michael J. Hall	Director	March 19, 2003
/s/ John J. MacWilliams John J. MacWilliams	Director	March 19, 2003
/s/ Preston R. Miller, Jr. Preston R. Miller, Jr.	Director	March 19, 2003
/s/ John P. Neafsey John P. Neafsey	Director	March 19, 2003
/s/ John H. Robinson John H. Robinson	Director	March 19, 2003
/s/ Robert G. Sachse Robert G. Sachse	Executive Vice President and Director	March 19, 2003

CERTIFICATION

I, Joseph W. Craft III certify that:

1. I have reviewed this Annual Report on Form 10-K of Alliance Resource Partners, L.P.;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:
    a. designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
    b. evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
    c. presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
    b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 19, 2003

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

CERTIFICATION

I, Dale G. Wilkerson certify that:

1. I have reviewed this Annual Report on Form 10-K of Alliance Resource Partners, L.P.;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:
    a. designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
    b. evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
    c. presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
    b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 19, 2003

/s/ Dale G. Wilkerson
Dale G. Wilkerson
Vice President and Controller
(Principal Accounting
Officer)

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, 2002, there were 15,405,311 common and subordinated units outstanding. As of March 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 2002 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 fredric@arlp.com, telephone at (918) 295-7642, 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

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John H. Robinson
Director

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

NASDAQ LISTED

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