ALLIANCE RESOURCE PARTNERS LP
Form 10-K
March 16, 2006
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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, 2005

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	**(IRS EMPLOYER**
INCORPORATION OR ORGANIZATION)	**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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. x Yes ¨ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ¨ Yes x No

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. x Yes ¨ 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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchance Act. (check one)

Large Accelerated Filer x Accelerated Filer ¨ Non-Accelerated Filer ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ¨ 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 $749,107,920 as of June 30, 2005, the last business day of the registrant s most recently completed second fiscal quarter, based on the reported closing price of the common units as reported on the Nasdaq National Market on such date.

As of March 16, 2006, 36,426,306 common 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, fo 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:

- increased competition in coal markets and our ability to respond to the competition;
- fluctuation in coal prices, which could adversely affect our operating results and cash flows;
- risks associated with the expansion of our operations and properties;
- 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 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;
- greater than expected increases in raw material costs;
- greater than expected shortage of skilled labor;
- 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;
- risks associated with major mine-related accidents, such as mine fires, or interruptions;
- results of litigation;
- difficulty maintaining our surety bonds for mine reclamation as well as workers compensation and black lung benefits;
- a loss or reduction of the direct or indirect benefit from certain state and federal tax credits, including non-conventional source fuel tax credits; and
- difficulty obtaining commercial property insurance, and risks associated with our 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.

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PART I

ITEM 1. BUSINESS

General

We are a diversified producer and marketer of coal to major United States utilities and industrial users. We began mining operations in 1971 and, since then, have grown through acquisitions and internal development to become what we believe to be the fifth largest coal producer in the eastern United States. At December 31, 2005, we had approximately 549.0 million tons of reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. In 2005, we produced 22.3 million tons of coal and sold 22.8 million tons of coal. The coal we produced in 2005 was 30.0% low-sulfur coal, 14.8% medium-sulfur coal and 55.2% high-sulfur coal. In 2005, approximately 89.8% 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, 2005, we operated seven underground complexes in Illinois, Indiana, Kentucky and Maryland. Our surface mine located in Kentucky depleted its entire reserve area in December 2005 and its production eventually will be replaced by an underground mine that is expected to emerge from mine development during the second quarter of 2006. We also are developing an underground mine in West Virginia that will replace production from our underground mine in Maryland, which is expected to deplete its reserves in November 2006. Our mining activities are conducted in three geographic regions commonly referred to in the coal industry as the Illinois Basin, Central Appalachia and Northern Appalachia regions. We have grown historically, and expect to grow in the future through expansion of our operations by adding and developing mines and coal reserves in existing, adjacent or neighboring properties.

In 2002, we entered into long-term agreements to host and operate a coal synfuel production facility currently based at Warrior Coal, LLC (Warrior), located in the Illinois Basin region, to supply the facility with coal feedstock, to assist with the marketing of coal synfuel and to provide other services to the owner of the synfuel facility.

In 2005, Gibson County Coal, LLC (Gibson County Coal), and Mettiki Coal, LLC (Mettiki Coal), entered into similar long-term coal synfuel agreements. At Gibson, in the Illinois Basin region, we host a coal synfuel facility, supply the facility with coal feedstock, and assist with the marketing of coal synfuel. At Mettiki, in the Northern Appalachia region, we supply a coal synfuel facility located at the power plant of Mettiki s primary customer with coal feedstock.

We and our subsidiary, Alliance Resource Operating Partners, L.P. (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, own an aggregate 98% limited partner interest in us.

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

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Recent Developments

Allegheny Coal Lease and Coal Sales Agreement. On December 29, 2005, we announced that our newly formed subsidiary, Penn Ridge Coal, LLC (Penn Ridge), had entered into a coal lease and sales agreement with affiliates of Allegheny Energy, Inc. (Allegheny), to pursue development of Allegheny s Buffalo coal reserve in Washington County, Pennsylvania. Under this coal lease and sales agreement, an affiliate of Allegheny has agreed to lease to Penn Ridge the Buffalo coal reserve in exchange for lease payments consisting of fixed production royalties on coal sales proceeds. The lease term is fifteen years, and it commenced on December 28, 2005. The Buffalo coal reserve lease encompasses approximately 19,800 acres and is estimated to include approximately 55 million tons of coal in the Pittsburgh No. 8 seam and 300 acres of surface land located near Avella, Pennsylvania. We anticipate that the Penn Ridge operation will be capable of producing annually up to 5.0 million tons of coal and may employ as many as 270 persons. We are estimating total capital expenditures required to develop Penn Ridge to be approximately $165.0 million over a five-year period. We expect to immediately begin the development process for the Penn Ridge mine, which includes obtaining the necessary permits. We anticipate production from Penn Ridge commencing between 2009 and 2010. In conjunction with the Buffalo coal reserve lease, Penn Ridge also entered into a ten-year, 20 million ton coal sales agreement with affiliates of Allegheny at market based prices. Upon commencement of initial production, Penn Ridge will supply annually up to two million tons of coal produced from the Buffalo coal reserve for use in Allegheny s power plants. The Buffalo coal reserve area is north of and contiguous to our Tunnel Ridge reserve area, which is located in Washington County, Pennsylvania and Ohio County, West Virginia. When combined with our Tunnel Ridge reserves, we control an estimated 125 million tons of coal in the Pittsburgh No. 8 seam.

LG&E Coal Sales Agreement. On December 21, 2005, we announced that our subsidiary, Alliance Coal, LLC (Alliance Coal), has entered into a new six-year, 23.5 million ton coal sales agreement, effective January 1, 2006, with Louisville Gas and Electric Company (LG&E). At the end of the primary six-year term, the parties have the option to extend the new agreement for an incremental 16.0 million tons of coal over an additional four years. Under the new agreement, beginning January 1, 2006, Alliance Coal will ship annually up to 4.0 million tons of coal directly to LG&E or as feedstock for synfuel produced for the benefit of LG&E. Since 2001, Alliance Coal, LLC and its affiliates have supplied annually approximately 2.4 million tons of Illinois Basin coal to LG&E, either directly or as synfuel feedstock, under existing coal supply agreements. The new agreement represents an increase of approximately 1.6 million tons over coal shipments historically supplied by Alliance Coal s subsidiaries, Hopkins County Coal, LLC, Webster County Coal, LLC, and Warrior Coal, LLC.

New Mine Safety Rules. As a result of recent coal mining accidents in West Virginia and Kentucky, the U.S. Department of Labor s Mine Safety Health Administration as well as West Virginia and several other states, including Kentucky, Pennsylvania and Illinois, have imposed, or are considering imposing, stringent new mine safety and accident reporting requirements and increased civil and criminal penalties for violations of mine safety laws. Please read Mine Health and Safety Laws.

Mining Operations

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

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(tons in millions)				
Regions and Complexes					
Illinois Basin:					
Dotiki, Warrior, Pattiki, Hopkins and Gibson Complexes	15.7	13.6	12.3	12.1	11.9
Central Appalachia:					
Pontiki and MC Mining Complexes	3.3	3.6	3.6	3.0	2.8
Northern Appalachia:					
Mettiki Complex	3.3	3.2	3.3	2.9	2.7
Total	22.3	20.4	19.2	18.0	17.4

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Illinois Basin Operations

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. We have approximately 1,440 employees in the Illinois Basin and currently operate five mining complexes. Additionally, we host a coal synfuel facility at two of our mining complexes.

Dotiki Complex. Webster County Coal, LLC (Webster County Coal) operates Dotiki, which is an underground mining complex located near the city of Providence in Webster County, Kentucky. The complex was opened in 1966, and we purchased the mine in 1971. Our Dotiki complex utilizes continuous mining units employing room-and-pillar mining techniques. In 2004, the preparation plant throughput capacity was increased to 1,300 tons of raw coal an hour. Capacity was increased principally to accommodate a change in customer requirements for washed coal rather than raw coal.

On February 11, 2004, the Dotiki mine was temporarily idled following the occurrence of a mine fire. The fire was successfully extinguished and the affected area of the mine was totally isolated behind permanent barriers. Production resumed on March 8, 2004. For information on the fire at our Dotiki complex, please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Production of high-sulfur coal from the Dotiki 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 LG&E, Seminole Electric Cooperative, Inc. (Seminole) and Tennessee Valley Authority (TVA), all of which purchase our coal pursuant to long-term contracts for use in their scrubbed generating units.

Warrior Complex. Warrior Coal, LLC (Warrior) operates the Cardinal mine, an underground mining complex located near Madisonville, in Hopkins County, Kentucky, between and adjacent to our other western Kentucky operations. The Warrior complex was opened in 1985 and acquired by us in February 2003. Warrior utilizes continuous mining units employing room-and-pillar mining techniques producing high-sulfur coal. During 2005, Warrior increased mining capacity with the addition of one continuous miner unit. Warrior s preparation plant has a throughput capacity of 600 tons of raw coal an hour.

Warrior sells substantially all of its production to Synfuel Solutions Operating, LLC (SSO) for feedstock in the production of coal synfuel, as discussed below. SSO s coal synfuel production facility was moved from Hopkins County Coal, LLC (Hopkins) to Warrior in April 2003. Warrior s production can be shipped via the CSX and PAL railroads and by truck on U.S. and state highways. Additionally, Warrior purchased supplemental production from a third-party supplier for resale to SSO and will continue to purchase tons from the third-party supplier through June 2007. SSO continues to ship coal synfuel to electric utilities that have been purchasers of our coal. We maintain back-up coal supply agreements with these long-term customers for our coal, which automatically provide for the sale of our coal to them in the event they do not purchase coal synfuel from SSO.

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

For 2005, the incremental annual net income benefit from the combination of the various coal synfuel-related agreements associated with the facility located at Warrior was approximately $18.9 million, assuming that coal pricing would not have increased without the availability of synfuel. The continuation of the incremental net income benefit associated with SSO s coal synfuel facility cannot be assured. Pursuant to our agreement with SSO, we are not obligated to make retroactive adjustments or reimbursements if SSO s tax credits are disallowed.

In June 2003, the Internal Revenue Service (IRS) suspended the issuance of private letter rulings on the significant chemical change requirement to qualify for synfuel tax credits and announced that it was reviewing the test procedures and results used by taxpayers to establish that a significant chemical change had occurred. In October 2003, the IRS completed its review and concluded that the test procedures and results were scientifically valid if applied in a consistent and unbiased manner. The IRS has resumed issuing private letter rulings under its existing guidelines. SSO has advised us that its private letter ruling could be reviewed by the IRS as part of a tax audit, similar to the IRS reviews of other synfuel procedures.

Pattiki Complex. White County Coal, LLC (White County Coal) 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. 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 have been Northern Indiana Public Service Company and Seminole for use in their scrubbed generating units. Pattiki production is also shipped via rail to our Mt. Vernon transloading facility for sale to utilities capable of receiving barge deliveries. In 2006, Pattiki expects to ship a significant portion of its production to TVA and Tampa Electric and transfer its Seminole shipments to Dotiki and Warrior.

Hopkins Complex. During 2005, Hopkins County Coal, LLC s (Hopkins County Coal) production was from its Newcoal surface mine that depleted its reserves in December 2005. Hopkins County Coal is developing an underground mine, referred to as the Elk Creek mine, which is described below. Hopkins County Coal is located near the city of Madisonville in Hopkins County, Kentucky. We acquired the complex in January 1998. The Newcoal surface mine was idled in June 2003 because we were unable to secure sufficient sales commitments in the Illinois Basin region. In October 2004, the surface mine was re-opened in response to incremental sale opportunities from existing customers as well as strong market demand for Illinois Basin region coal.

The surface operation utilized dragline mining and the existing preparation plant has a throughput capacity of 1,000 tons of raw coal an hour. In conjunction with the development of the Elk Creek mine, Hopkins County Coal is constructing a new preparation plant with a throughput capacity of 1,200 tons of coal an hour. The new preparation plant will provide significant operating efficiencies. Hopkins production has the ability to be shipped via the CSX and PAL railroads and by truck on U.S. and state highways.

On October 23, 2005, Hopkins exercised an option to lease the Elk Creek reserves. The Elk Creek coal reserves consist of approximately 36.0 million tons of high-sulfur coal. The Elk Creek mine will be an underground mining complex, using continuous mining units employing room-and-pillar mining techniques. We intend to utilize the existing coal handling and other surface facilities at Hopkins to process and ship coal produced from the Elk Creek mine. Elk Creek is expected to emerge from mine development in the second quarter of 2006. When the Elk Creek mine reaches full production capacity we expect annual production to be approximately 3.8 million tons.

Gibson Complex. Gibson County Coal operates Gibson, an underground mining complex located near the city of Princeton in Gibson County, Indiana. The mine began production in November 2000. Our Gibson complex utilizes continuous mining units employing room-and-pillar mining techniques. 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, that historically has been primarily shipped via truck approximately 10 miles on U.S. and state highways to Gibson s principal customer, PSI Energy Inc. (PSI), a subsidiary of Cinergy Corporation. Gibson s production is also trucked to our Mt. Vernon transloading facility for sale to utilities capable of receiving barge deliveries.

In January 2005, Gibson entered into long-term agreements with PC Indiana Synthetic Fuel #2, L.L.C. (PCIN) to host its coal synfuel facility, supply the facility with coal feedstock, assist PCIN with the marketing of coal synfuel and provide other services. The synfuel facility commenced operations at Gibson in May 2005. A significant portion of Gibson s production is sold to PCIN. The agreements expire on December 31, 2007 and provide us with coal sales, rental and service fees from PCIN based on the synfuel facility throughput tonnages. These amounts are dependent on the ability of PCIN 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 synfuel tax credits, the termination of associated coal synfuel sales contracts, and the occurrence of certain force majeure events. Therefore, revenues associated with the coal synfuel production facility cannot be assured. However, we have entered into 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 PCIN.

For 2005, the incremental annual net income benefit from the combination of the various coal synfuel related agreements associated with the facility located at Gibson was approximately $3.0 million, assuming that coal pricing would not have increased without the availability of synfuel. This estimated incremental net income cannot be assured. Pursuant to our agreement with PCIN, we are not obligated to make retroactive adjustments or reimbursements if PCIN s tax credits are disallowed.

We have initiated the permitting process for the Gibson South reserves and are actively evaluating its development. Capital expenditures required to develop the Gibson South reserves are estimated to be approximately $100 million. Assuming sufficient sales commitments are obtained and the permitting process progresses as anticipated, initial production could commence in 2008 or 2009. When the Gibson South mine reaches full production capacity, we expect annual production to be approximately 3.1 million tons. Definitive development commitment for Gibson South is dependent upon final approval by the board of directors of our managing general partner.

Central Appalachian Operations

Our Central Appalachian mining operations are located in the Central Appalachia coal fields. Our Central Appalachian mines produce low-sulfur coal. We have approximately 530 employees in Central Appalachian and operate two mining complexes producing low sulfur coal.

Pontiki Complex. Pontiki Coal, LLC (Pontiki Coal) owns Pontiki, an underground mining complex located near the city of Inez in Martin County, Kentucky. We constructed the mine in 1977. Pontiki owns the mining complex and leases the reserves, and Excel Mining, LLC (Excel), an affiliate of Pontiki, is responsible for conducting all mining operations. Substantially all of the coal produced at Pontiki in 2005 met or exceeded 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. In February 2005 construction efforts began that allowed Pontiki to migrate its mining units into a new coal seam. The first mining unit in the new coal seam emerged from mine development in the fourth quarter of 2005. Beginning in 2006, production will still be low sulfur, but because of changes in geology and the migration of some of Pontiki s mining units into the Van Lear coal seam, may no longer meet the compliance requirements of Phase II of the Clean Air Act.

Our primary customer for the low-sulfur coal produced at Pontiki is ICG, LLC (ICG), the successor-in-interest of certain assets of Horizon Natural Resources Company. In November 2005, we settled a contract dispute in which ICG alleged we failed to deliver 138,111 tons of coal. Please read Item 13. Legal Proceedings and Item 8. Financial Statements and Supplementary Data Note 18. Commitments and Contingencies. Production from the mine is shipped primarily to electric utilities located in the southeastern United States via the Norfolk Southern railroad or by truck via U.S. and state highways to various docks on the Big Sandy River in Kentucky.

MC Mining Complex. MC Mining, LLC (MC Mining) owns an underground mining complex located near the city of Pikeville in Pike County, Kentucky. We acquired the mine in 1989. MC Mining owns the mining complex and leases the reserves, and Excel, an affiliate of MC Mining, is responsible for conducting all mining operations. On December 26, 2004, MC Mining was temporarily idled following the occurrence of a mine fire. The fire was successfully extinguished and the affected area of the mine was totally isolated behind permanent barriers. Initial production resumed on February 21, 2005. For more information on the fire at our MC Mining mine, please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Substantially all of the coal produced at MC Mining in 2005 met or exceeded the compliance requirements of Phase II of the Clean Air Act amendments. 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.

Northern Appalachia Operations

Our Northern Appalachia mining operation is located in the Northern Appalachia coal fields. We have approximately 230 employees and operate one mining complex in Northern Appalachia.

Mettiki Complex. Mettiki Coal operates an underground longwall mining complex, which is sometimes referred to as the D-Mine, 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. In response to strong market demand, Mettiki s production capacity was increased through two small-scale third party mining operations.

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

In June 2005 and subsequently amended in August 2005, Mettiki entered into an agreement with Mt. Storm Coal Supply, LLC, or Mt. Storm Coal Supply, to supply its coal synfuel facility, located at the Mt. Storm power plant, with coal feedstock. For 2005, the incremental annual net income benefit from the coal feedstock agreements was approximately $2.2 million, assuming that coal pricing would not increase without the availability of synfuel. The continuation of this agreement cannot be assured because the non-conventional source fuel tax credits are subject to a pro-rata phase-out or reduction based on the annual average wellhead price per barrel for all domestic crude oil (the reference price) as determined by the Secretary of the Treasury. We have entered into a back up coal supply agreement with VEPCO for sale of our coal in the event VEPCO does not purchase coal synfuel from Mt. Storm Coal Supply. Pursuant to our agreement with Mt. Storm Coal Supply, we are not obligated to make retroactive adjustments or reimbursements if Mt. Storm Coal Supply s tax credits are disallowed.

Mettiki Coal (WV). Mettiki Coal (WV), LLC is developing an underground longwall mine in Tucker County, West Virginia known as the Mountain View Mine (also known as the E-Mine), which will eventually replace Mettiki Coal s D-Mine. We anticipate the active D-Mine will deplete its coal reserves in November 2006, at which time the longwall mining system will be relocated from D-Mine to Mettiki Coal (WV) s Mountain View Mine. Longwall production is expected to commence in January 2007.

Penn Ridge Coal. Penn Ridge Coal, LLC (Penn Ridge) has entered into a coal lease and sales agreement with affiliates of Allegheny, to pursue development of Allegheny s Buffalo coal reserve in Washington County, Pennsylvania. The Buffalo coal reserve lease is estimated to include approximately 55 million tons of coal in the Pittsburgh No. 8 seam. Definitive development commitment for Penn Ridge is dependent upon final approval of the board of directors of our managing general partner.

Tunnel Ridge. Tunnel Ridge, LLC (Tunnel Ridge) controls, through a coal lease agreement with our special general partner, approximately 70 million tons of high-sulfur coal in the Pittsburgh No. 8 coal seam. Definitive development commitment for Tunnel Ridge is dependent upon final approval of the board of directors of our managing general partner.

Other Operations

Mt. Vernon Transfer Terminal, LLC

The Mt. Vernon Transfer Terminal, LLC (Mt. Vernon) leases land and operates a coal loading terminal on the Ohio River at Mt. Vernon, Indiana. Coal is delivered to Mt. Vernon by both rail and truck. The terminal has a capacity of 8 million tons per year with existing ground storage. During 2005, the terminal loaded approximately 2.1 million tons for Pattiki and Gibson customers and for third-party shippers.

Coal Brokerage

As markets allow, we buy coal from non-affiliated producers principally throughout the eastern United States, which we then resell, both directly and indirectly, primarily to utility customers. We purchased and sold approximately 6,000 tons of coal from non-affiliated producers in 2005. We have a policy of matching our outside coal purchases and sales to minimize market risks associated with buying and reselling coal. Purchased coal that is delivered to our operations and commingled with our production is not classified as brokerage coal.

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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 have historically represented less than one percent of our total revenues.

Reportable Segments

Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations , and Note 20. Segment Information under Item 8. Financial Statements And Supplementary Data for information concerning our reportable segments.

Coal Marketing and Sales

As is customary in the coal industry, we have entered into long-term coal supply agreements with many of our customers. These arrangements are mutually beneficial to us and our customers by providing greater predictability of sales volumes and sales prices. In 2005, approximately 86.0% and 81.7% of our sales tonnage and total coal sales, respectively, were sold under long-term contracts (contracts having a term of one year or greater) with maturities ranging from 2005 to 2023. Our total nominal commitment under significant long-term contracts for existing operations was approximately 117.6 million tons at December 31, 2005, and is expected to be delivered as follows: 20.2 million tons in 2006, 16.5 million tons in 2007, 14.7 million tons in 2008, 13.9 million tons in 2009, 13.9 million tons in 2010, and 38.4 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 2005 were SSO, TVA and Mt. Storm Coal Supply. Sales to these customers in the aggregate accounted for approximately 36.4% of our 2005 total revenues, and sales to each of these customers accounted approximately 10% or more of our 2005 total revenues.

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 21% of the total 2005 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.

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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 4% to 41% 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.

Typically, our customers pay the transportation costs from the contractual F.O.B. point (free-on-board point), which is the standard practice in the industry and is generally from the mine to the customer s plant. In 2005, the largest volume transporter of our coal shipments, including coal synfuel shipped by SSO, was the CSX railroad, which moved approximately 44.5% of our tonnage over its rail system. The practices of, and rates set by, the railroad serving a particular mine or customer might affect, either adversely or favorably, our marketing efforts with respect to coal produced from the relevant mine. At Gibson and Mettiki, independent contractors operate truck delivery systems that transport the coal to Gibson and Mettiki s primary customer s power plants.

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;
- storage and handling of explosives;
- wetlands protection;
- surface subsidence from underground mining; and

the effects, if any, that mining has on groundwater quality and availability.

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.

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 have had a material impact on our operations or financial condition.

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

Mining Permits and Approvals

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

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

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

Our subsidiary, Mettiki Coal (WV), LLC (Mettiki Coal (WV)), is developing an underground longwall mining operation in Tucker County, West Virginia (which we refer to as the Mountain View Mine or E-Mine), which will eventually replace Mettiki s existing longwall mining operation at the D-Mine located in Garrett County, Maryland. The Mountain View Mine is located approximately 10 miles from Mettiki. In order to proceed with development of the Mountain View Mine, Mettiki Coal (WV) submitted various permit applications to the West Virginia Department of Environmental Protection (WVDEP) including an application for approval to conduct underground mining. WVDEP issued the required permits in the Spring of 2004. Certain complainants appealed WVDEP s decision issuing the underground mining permit to the West Virginia Surface Mine Board (SMB), which held administrative hearings on the matter in late 2004 and early 2005. On March 8, 2005, the SMB on a divided 3-3 vote issued a final order concluding consideration of the appeal without effectively rendering a decision, which, by operation of West Virginia law, resulted in the affirmation of WVDEP s decision to issue the underground mining permit. The complainants appealed the SMB decision, but subsequently voluntarily agreed to withdraw the appeal, which was dismissed with prejudice by the Tucker County circuit court in West Virginia on April 26, 2005.

On April 19, 2005, these same complainants submitted a letter to the U.S. Department of Interior s Office of Surface Mining, Reclamation and Enforcement (OSM), and the OSM s regional field office in Charleston, West Virginia (CHFO), requesting federal monitoring and inspection of the Mountain View Mine and alleging that operations at the mine would create acid mine drainage with no defined end point. By written notice, dated April 21, 2005, the CHFO advised WVDEP that it would review the complainants allegation that the Mountain View Mine would cause material harm to the hydrological balance within and outside of the permit area. Following its initial review, on September 15, 2005, the CHFO notified WVDEP that it intended to initiate a formal investigation into the issuance of the underground mining permit for the Mountain View Mine. WVDEP requested an informal review of the CHFO decision by the OSM. By two letters, both dated October 21, 2005, OSM reversed the decision of the CHFO concluding that the CHFO and OSM lacked statutory authority to review the WVDEP s issuance of the underground mining permit, and the Department of the Interior ordered that this was the Department s final decision on the matter raised in the complainants letter dated April 19, 2005. The Mountain View Mine is not currently subject to any pending or threatened agency or third-party claims. However, on March 8, 2006, these same complainants requested that the Director of OSM evaluate West Virginia s State Program pursuant to 30 C.F.R. §§ 733 et seq., but acknowledged a similar request had been made on April 19, 2005, which request had been previously rejected by the Department of Interior s final decision on October 21, 2005.

Mine Health and Safety Laws

Stringent safety and health standards have been imposed by federal legislation since 1969 when the Coal Mine Health and Safety Act of 1969 (CMHSA) was adopted. The Federal Mine Safety and Health Act of 1977, and regulations adopted pursuant thereto, significantly expanded the enforcement of health and safety standards and imposed comprehensive safety and health standards on numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations and other matters. The Mine Safety and Health Administration (MSHA) monitors compliance with these federal laws and regulations. In addition, as part of 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, and this regulation has a significant effect on our operating costs. Our competitors in all of the areas in which we operate are subject to the same laws and regulations.

Recent mining accidents involving fatalities in West Virginia and Kentucky have received national attention and prompted responses at the state and national level that have resulted in increased scrutiny of current industry safety practices and procedures at all mining operations. On January 26, 2006, West Virginia Governor Joe Manchin signed into law a bill imposing stringent new mine safety and accident reporting requirements and increased civil and criminal penalties for violations of mine safety laws. Other states, including Illinois, Pennsylvania and Kentucky, have proposed or passed similar bills and resolutions addressing mine safety practices. In addition, several mine safety bills have been introduced in Congress that would mandate similar improvements in mine safety practices; increase or add civil and criminal penalties for non-compliance with such laws or regulations; and expand the scope of federal oversight, inspection, and enforcement activities. On February 7, 2006, MSHA announced the promulgation of new emergency rules on mine safety. These rules address mine safety equipment, training, and emergency reporting requirements. Unlike most MSHA rules, these emergency rules will become effective immediately upon their publication in the *Federal Register*. Implementing and complying with these new laws and regulations could adversely affect our results of operation and financial position.

Black Lung Benefits Act

The Federal Black Lung Benefits Act (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 are or will become 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.

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 operation. Effective January 2001, new Federal Black Lung regulations took effect. These regulations relax the stringent award criteria established under the previous regulations potentially allowing more new Federal claims to be awarded and allowing previously denied claimants to re-file under the new criteria. The new regulations may also increase black lung related medical costs by broadening the scope of conditions for which medical costs are reimbursable, and increase legal costs by shifting more of the burden of proof to the employer.

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

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

Surface Mining Control and Reclamation Act

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

SMCRA and similar state statutes require, among other things, that mined property be restored in accordance with specified standards and approved reclamation plans. The act requires us to restore the surface to approximate the original contours as contemporaneously as practicable with the completion of surface mining operations. The mine operator must submit a bond or otherwise secure the performance of these reclamation obligations. Federal law and some states impose on mine operators the responsibility for replacing certain water supplies damaged by mining operations and repairing or compensating for damage to certain structures occurring on the surface as a result of mine subsidence, a consequence of longwall mining and possibly other mining operations. 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. The Abandoned Mine Lands Tax is set to expire June 30, 2006, and there are various legislative proposals that are under consideration by Congress to extend the tax. We have accrued 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 or orphaned mine sites and AMD control on a statewide basis.

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.

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, to pay federal and state workers compensation, to pay certain black lung claims, and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. It has become increasingly difficult for us and for our competitors generally to secure new surety bonds without the posting of partial collateral. In addition, surety bond costs have increased while the market terms of surety bonds have generally become less favorable to us. It is possible that surety bonds issuers may refuse 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.

Air Emissions

The Federal Clean Air Act (CAA), and similar state and local laws and regulations, which regulate emissions into the air, affect coal mining operations. The CAA directly impacts our coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, on sources that emit various hazardous and non-hazardous air pollutants. The CAA also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants. There have been a series of recent federal rulemakings that are focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technology and additional measures required under the U.S. Environmental Protection Agency (EPA) laws and regulations will make it more costly to operate coal-fired power plants and, depending on the requirements of individual state implementation plans, could make coal a less attractive fuel alternative in the planning and building of power plants in the future. Any reduction in coal s share of power generating capacity could have a material adverse effect on our business, financial condition and results of operations.

The EPA s Acid Rain Program, provided in Title IV of the CAA, regulates emissions of sulfur dioxide from electric generating facilities. Sulfur dioxide is a by-product of coal combustion. Affected facilities purchase or are otherwise allocated sulfur dioxide emissions allowances, which must be surrendered annually in an amount equal to a facility s sulfur dioxide emissions in that year. Affected facilities may sell or trade excess allowances to other facilities that require additional allowances to offset their sulfur dioxide emissions. In addition to purchasing or trading for additional sulfur dioxide allowances, affected power facilities can satisfy the requirements of EPA s Acid Rain Program by switching to lower sulfur fuels, installing pollution control devices such as flue gas desulfurization systems, or scrubbers, or by reducing electricity generating levels.

EPA has promulgated rules, referred to as the NOx SIP Call, that require coal-fired power plants in 21 eastern states and Washington D.C. to make substantial reductions in nitrogen oxide emissions in an effort to reduce the impacts of ozone transport between states. Additionally, in March 2005, EPA issued the final Clean Air Interstate Rule, or CAIR, which will permanently cap nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. beginning in 2009 and 2010, respectively. CAIR requires these states to achieve the required emission reductions by requiring power plants to either participate in an EPA-administered cap-and-trade program that caps emission in two phases, or by meeting an individual state emissions budget through measures established by the state.

In March 2005, EPA finalized the Clean Air Mercury Rule (CAMR), which establishes a two-part, nationwide cap on mercury emissions from coal-fired power plants beginning in 2010. While currently the subject of extensive controversy and litigation, if fully implemented, CAMR would permit states to implement their own mercury control regulations or participate in an interstate cap-and-trade program for mercury emission allowances.

EPA has adopted new, more stringent national air quality standards for ozone and fine particulate matter. As a result, some states will be required to amend their existing state implementation plans to attain and maintain compliance with the new air quality standards. For example, in December 2004, EPA designated specific areas in the United States as in non-attainment with the new national ambient air quality standard for fine particulate matter. In November 2005, EPA published proposed rules addressing how states would implement plans to bring applicable non-attainment regions into compliance with the new air quality standard. Under EPA s proposed rulemaking, states would have until April 2008 to submit their implementation plans to EPA for approval. Because coal mining operations and coal-fired electric generating facilities emit particulate matter, our mining operations and our customers could be affected when the new standards are implemented by the applicable states.

In June 2005, EPA announced final amendments to its regional haze program originally developed in 1999 to improve visibility in national parks and wilderness areas. As part of the new rules, affected states must develop implementation plans by December 2007 that, among other things, identify facilities that will have to reduce emissions and comply with stricter emission limitations. This program may restrict construction of new coal-fired power plants where emissions are projected to reduce visibility in protected areas. In addition, this program may require certain existing coal-fired power plants to install emissions control equipment to reduce haze-causing emissions such as sulfur dioxide, nitrogen oxide, and particulate matter. Demand for our coal could be affected when these new standards are implemented by the applicable states.

The Department of Justice, on behalf of EPA, has filed lawsuits against a number of coal-fired electric generating facilities, including some of our customers, alleging violations of the new source review provisions of the CAA. EPA has alleged that certain modifications have been made to these facilities without first obtaining certain permits issued under the new source review program. Several of these lawsuits have settled, but others remain pending. Depending on the ultimate resolution of these cases, demand for our coal could be affected.

Carbon Dioxide Emissions

The Kyoto Protocol to the United Nations Framework Convention on Climate Change calls for developed nations to reduce their emissions of greenhouse gases to five percent below 1990 levels by 2012. Carbon dioxide, which is a major by product of the combustion of coal and other fossil fuels, is subject to the Kyoto Protocol. The Kyoto Protocol went into effect on February 16, 2005 for those nations that ratified the treaty.

In 2002, the United States withdrew its support for the Kyoto Protocol. With the Kyoto Protocol now effective, there will likely be increasing international pressure on the United States to adopt mandatory restrictions on carbon dioxide emissions. The United States Congress has considered bills in the past that would regulate domestic carbon dioxide emissions, but such bills have not yet received sufficient Congressional approvals. Several states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired electric generating facilities. For example, in December 2005, seven northeastern states agreed to implement a regional cap-and-trade program to stabilize carbon dioxide emissions from regional power plants beginning in 2009.

While higher prices for natural gas and oil, and improved efficiencies and new technologies for coal-fired electric power generation have helped to increase demand for our coal, it is possible that future federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, which could have a material adverse effect on our business, financial condition and results of operations.

Water Discharge

The Federal Clean Water Act (CWA), and similar state and local laws and regulations affect 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 the CWA imposes permitting and mitigation requirements associated with the dredging and filling of wetlands and streams. The CWA and equivalent state legislation, where such equivalent state legislation exists, affect coal mining operations that impact wetlands and streams. Although permitting requirements have been tightened in recent years, we believe we have obtained all necessary wetlands permits required under CWA Section 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.

Recent federal district court decisions in West Virginia, and related litigation filed in federal district court in Kentucky, have created uncertainty regarding the future ability to obtain certain general permits authorizing the construction of valley fills for the disposal of overburden from mining operations. A July 2004 decision by the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Bulen* enjoined the Huntington District of the U.S. Army Corps of Engineers from issuing further permits pursuant to Nationwide Permit 21, which is a general permit issued by the U.S. Army Corps of Engineers to streamline the process for obtaining permits under Section 404 of the Clean Water Act. The Fourth Circuit Court of Appeals issued a decision on November 23, 2005, vacating the district court decision in *Bulen* and remanding the case to the lower court for further argument. A similar lawsuit has been filed in federal district court in Kentucky that seeks to enjoin the issuance of permits pursuant to Nationwide Permit 21 by the Louisville District of the U.S. Army Corps of Engineers. We do not operate any mines located within the Southern District of West Virginia and currently only utilize Nationwide Permit 21 at one location in Indiana. In the event current or future litigation contesting the use of Nationwide Permit 21 is successful, we may be required to apply for individual discharge permits pursuant to Section 404 of the CWA in areas where it would have otherwise utilized Nationwide Permit 21. Such a change could result in delays in obtaining required mining permits to conduct operations, which could in turn result in reduced production, cash flow and profitability.

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On September 22, 2005, environmental groups led by the Ohio Valley Environmental Coalition filed suit in the Federal District Court for the Southern District of West Virginia challenging the Army Corps of Engineers (Corps of Engineers) authority to issue CWA Section 404 discharge permits for certain mountaintop mining projects. The case, styled *Ohio Valley Environmental Coalition v. United States Army Corps of Engineers* alleges that the Corps of Engineers generally acted arbitrarily and capriciously in issuing certain Section 404 permits to operators engaged in mountaintop mining operations. On February 1, 2006, the plaintiffs moved to amend their pleadings to seek a preliminary injunction that would void the Corps of Engineers approval of three particular CWA Section 404 permits issued to operators. Although our mining operations are not implicated in this particular litigation, it is possible that similar litigation affecting the Corps of Engineers ability to issue CWA permits could adversely affect our results of operation and financial position.

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

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

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

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

Hazardous Substances and Wastes

The Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), or 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.

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

In 2000, EPA declined to impose hazardous waste regulatory controls on the disposal of some coal combustion by-products, including the practice of using coal combustion by-products (CCB) as mine fill. However, under pressure from environmental groups, EPA has continued evaluating the possibility of placing additional solid waste burdens on the disposal of these types of materials. On March 1, 2006, the National Academy of Sciences released a report commissioned by Congress that studied CCB mine filling practices and recommended federal regulatory oversight of CCB mine filling under either SMCRA or the non-hazardous waste provisions of RCRA. It is unclear at this time how federal regulators will view this report and whether they will propose federal regulations under either SMCRA or RCRA. Assuming federal regulations are proposed in the future, it is not possible at this time to assess how such regulations would impact our operations. However, we believe the beneficial uses of coal combustion by-products that we employ (such as the practice of placing by-products in abandoned mine areas) do not constitute poor environmental practices because, among other things, our CWA discharge permits for treated AMD contain parameters for pollutants of concern, such as metals, and those permits require monitoring and reporting of effluent quality data.

Other Environmental, Health And Safety Regulation

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

The Federal Safe Explosives Act, or the SEA, applies to all users of explosives. 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 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 2,300 employees, including approximately 100 corporate employees and approximately 2,200 employees involved in active mining operations. Our work-force is entirely union-free. Relations with our employees are generally good.

ITEM 1A. RISK FACTORS

Risks Inherent in an Investment in us

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

The prices we receive for our production depends upon factors beyond our control, including:

- the supply of and demand for domestic and foreign coal;
- weather conditions;
- the proximity to, and capacity of, transportation facilities;

worldwide economic conditions;

domestic and foreign governmental regulations and taxes;

the price and availability of alternative fuels; and

the effect of worldwide energy conservation measures.

A substantial or extended decline in coal prices could materially and adversely affect us by decreasing our revenues to the extent we are not otherwise protected pursuant to the specific terms of our coal supply agreements.

A material amount of our net income and cash flow is dependent on our continued ability to realize direct or indirect benefits from federal income tax credits such as non-conventional source fuel tax credits. If the benefit to us from any of these tax credits is materially reduced, it could negatively impact our results of operations and reduce our cash available for distributions. The non-conventional source fuel tax credit is scheduled to expire on December 31, 2007.

In 2005, we derived a material amount of our net income under long-term agreements with SSO. These agreements are dependent on the ability of the synfuel facility s owner to use certain qualifying federal income tax credits available to the facility and are subject to early cancellation in certain circumstances, including in the event that these synfuel tax credits become unavailable to the owner. In 2005, the benefit of this synfuel tax credit was approximately $24.1 million. If, because of budgetary shortfalls or any other reason, the federal government was to significantly reduce or eliminate these credits, it could negatively impact our results of operations and reduce our cash available for distributions.

Non-conventional source fuel tax credits are subject to a pro-rata phase-out or reduction if the annual average wellhead price per barrel for all domestic crude oil (the reference price) as determined by the Secretary of the Treasury exceeds certain levels. The reference price is not subject to regulation by the United States Government. The reference price for a calendar year is typically published in April of the following year. For qualified fuel sold during the 2004 calendar year, the reference price was $36.75. The pro-rata reduction of non-conventional source fuel tax credits for 2004 would have begun if the reference price was approximately $51.00 per barrel, with a complete phase-out or reduction of non-conventional synfuel tax credits if the reference price reached approximately $64.00 per barrel. We could experience a reduction of revenues associated with non-conventional source fuel facilities in the future if non-conventional source fuel tax credits become unavailable to the owners of the non-conventional source fuel facilities we service as a result of the rise in the wellhead price per barrel of crude oil above specified levels. At the present time, we have not been advised of any reductions in coal feedstock supply requirements or related services provided to any of our non-conventional source fuel facility customers. The non-conventional synfuel tax credit is scheduled to expire on December 31, 2007.

A loss of the benefit from state tax credits may adversely affect our ability to pay our quarterly distribution

Several states in which we operate or our utility customers reside have established a statutory framework for tax credits against income, franchise, or severance taxes, which have benefited, directly or indirectly, coal operators or customers purchasing coal mine production from within the applicable state. The state statutes authorizing these tax credits are scheduled to expire in accordance with their term provisions. Furthermore, these state statutes or our ability to benefit, directly or indirectly, from them may be subject to challenge by third parties. One of the states in which we operate has established a statutory framework for tax credits against income or franchise taxes, that have benefited, directly or indirectly, coal operators or customers purchasing coal produced from mines within that state. In 2005, the indirect benefit of this state tax credit to us was approximately $8.3 million. Although this credit is not set to expire by its terms in the near future, we are aware that legislation may be proposed that would eliminate this credit as a potential measure to reduce that state s budget deficit. If these state statutes expire or any challenges are successful, we would lose the benefits of these credits. Therefore, if our operations do not produce increased cash flow sufficient to replace any lost benefits, we may not be able to pay the current quarterly distribution on its outstanding common 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.

We compete with other large coal producers and hundreds of small coal producers in various regions of the United States for domestic sales. The industry has undergone significant consolidation over the last decade. This consolidation

has led to several competitors having significantly larger financial and operating resources than we have. In addition, we compete to some extent with western surface coal mining operations that have a much lower per ton cost of production and produce low-sulfur coal. Over the last 20 years, growth in production from western coal mines has substantially exceeded growth in production from the east. Declining prices would reduce our revenues and would adversely affect our ability to make distributions to our unitholders.

Any change in consumption patterns by utilities away from the use of coal could affect our ability to sell the coal we produce.

Some power plants are fueled by natural gas because of the cheaper construction costs compared to coal-fired plants and because natural gas is a cleaner burning fuel. The domestic electric utility industry accounts for approximately 90% of domestic coal consumption. The amount of coal consumed by the domestic electric utility industry is affected primarily by the overall demand for electricity, the price and availability of competing fuels for power plants such as nuclear, natural gas and fuel oil as well as hydroelectric power, and environmental and other governmental regulations.

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 coal supply agreements. This could affect the stability and profitability of our operations.

A substantial decrease in the amount of coal sold by us pursuant to long-term contracts would reduce the certainty of the price and amounts of coal sold and subject our revenue stream to increased volatility. If that were to happen, changes in spot market coal prices below the long term contract price would have a greater impact on our results, and any decreases in the spot market price for coal could adversely affect our profitability and cash flow. In 2005, we sold approximately 86.0% of our sales tonnage under contracts having a term greater than one year. We refer to these contracts as long-term contracts. Long-term sales contracts have historically provided a relatively secure market for the amount of production committed under the terms of the contracts. From time to time industry conditions, however, may make it more difficult for us to enter into long-term contracts with our electric utility customers in the future. In the future, if supply exceeds demand in the coal industry, electric utilities may become less willing to lock in price or quantity commitments for an extended period of time. Accordingly, we may not be able to continue to obtain long-term sales contracts with reliable customers as existing contracts expire.

Some of our long-term coal supply agreements 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 contain provisions which allow for the purchase price to be renegotiated at periodic intervals. These price reopener provisions may automatically set a new price based on the prevailing market price or, in some instances, require the parties to the contract to agree on a new price. Any adjustment or renegotiation leading to a significantly lower contract price could adversely affect our operating profit margins. Accordingly, long-term contracts may provide only limited protection during adverse market conditions. In some circumstances, failure of the parties to agree on a price under a reopener can also lead to early termination of a contract.

Several of our long-term contracts also contain provisions that allow the customer to suspend or terminate performance under the contract upon the occurrence or continuation of certain specified events. These events are called force majeure events. Some of these events that are specific to the coal industry include:

- our inability to deliver the quantities or qualities of coal specified;

- changes in the Clean Air Act rendering use of our coal inconsistent with the customer s pollution control strategies; and

- the occurrence of events beyond the reasonable control of the affected party, including labor disputes, mechanical malfunctions and changes in government regulations.

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In addition, certain contracts are terminable as a result of events that are beyond our control. For example, we have entered into agreements with several coal synfuel facilities to provide coal feedstock and other services. Each of these agreements provides for early cancellation in the event federal synfuel tax credits become unavailable or upon the termination of associated coal synfuel sales contracts between the facility and our customers. In the event of early termination of any of our long-term contracts, if we are unable to enter into new contracts on similar terms, our business, financial condition and results of operations could be adversely affected.

Extensive environmental laws and regulations affect coal consumers, which have corresponding effects on the demand for our coal as a fuel source.

Federal, state and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from electric power plants, which are the ultimate consumers of our coal. These laws and regulations can require significant emission control expenditures for many coal-fired power plants, and various new and proposed laws and regulations may require further emission reductions and associated emission control expenditures. A substantial portion of our coal has a high sulfur content, which may result in increased sulfur dioxide emissions when combusted. Accordingly, these laws and regulations may affect demand and prices for our low- and high-sulfur coal. There is also continuing pressure on state and federal regulators to impose limits on carbon dioxide emissions from electric power plants, particularly coal-fired power plants. As a result of these current and proposed laws, regulations and trends, electricity generators may elect to switch to other fuels that generate less of these emissions, possibly further reducing demand for our coal. Please read Regulation and Laws Air Emissions.

We depend on a few customers for a significant portion of our revenues, and the loss of one or more significant customers could affect our ability to maintain the sales volume and price of the coal we produce.

During 2005, we derived approximately 36.4% of our total revenues from three customers, which individually accounted for 10% or more of our 2005 total revenues. If we were to lose any of these customers without finding replacement customers willing to purchase an equivalent amount of coal on similar terms, or if these customers were to change the amounts of coal purchased or the terms, including pricing terms, on which they buy coal from us, it could have a material adverse effect on our business, financial condition and results of operations.

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

From time to time we have disputes with our customers over the provisions of long-term coal supply contracts relating to, among other things, coal pricing, quality, quantity and the existence of specified conditions beyond our control that suspend performance obligations under the particular contract. Disputes may occur in the future and we may not be able to resolve those disputes in a satisfactory manner.

Our profitability may decline due to unanticipated mine operating conditions and other factors that are not within our control.

Our mining operations are influenced by changing conditions that can affect production levels and costs at particular mines for varying lengths of time and as a result can diminish our profitability.

These conditions include, among others:

- weather conditions;
- equipment availability, replacement or repair;
- prices for fuel, steel, explosives and other supplies;
- Fires;

variations in thickness of the layer, or seam, of coal;

amounts of overburden, partings, rock and other natural materials;

accidental mine water discharges and other geological conditions;

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shortage of skilled labor; or

fluctuations in transportation costs and the availability or reliability of transportation.

These conditions have had, and can be expected in the future to have, a significant impact on our operating results. For example, during the past two years, three loss incidents have occurred at our mine complexes. For details on these incidents and their negative effect on our results of operations, please read Item 7.Management s Discussion and Analysis of Financial Condition and Results of Operations Pattiki Vertical Belt Incident, MC Mining Fire Incident and Dotiki Fire Incident. Prolonged disruption of production at any of our mines would result in a decrease in our revenues and profitability, which could be material. Decreases in our profitability as a result of the factors described above could materially adversely impact our quarterly or annual results. These risks may not be covered by our insurance policies.

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

Our mines are subject to conditions or events beyond our control that could disrupt operations and affect the cost of mining at particular mines for varying lengths of time. These risks include:

fires and explosions from methane;

natural disasters, such as heavy rains and flooding;

mining and processing equipment failures and unexpected maintenance problems;

mine flooding due to the failure of subsurface water seals or water removal equipment;

changes or variations in geologic conditions, such as the thickness of the coal deposits and the amount of rock and soil overlying the coal deposits;

inability to acquire mining rights or permits;

employee injuries or fatalities; and

labor-related interruptions.

During the past two years, three loss incidents have occurred at our mining complexes. On June 14, 2005, our Pattiki mining complex was temporarily idled for a period of 36 calendar days by the failure of the vertical conveyor belt system used in conveying raw coal out of the mine. Please read Item 7. Management s Discussion and Analysis of Financial Conditions and Results of Operations Pattiki Vertical Belt Incident. On December 26, 2004, our Excel No. 3 mine was temporarily idled for a period of 57 calendar days following the occurrence of a mine fire. Production continues to be adversely impacted by inefficiencies attributable to or associated with this mine fire. Please read Item 7. Management s Discussion and Analysis of Financial Conditions and Results of Operations MC Mining Fire Incident. On February 11, 2004, our Dotiki mining complex was temporarily idled for a period of 27 calendar days following the occurrence of a mine fire that originated with a diesel supply tractor. Please read Item 7. Management s Discussion and Analysis of Financial Conditions and Results of Operations Dotiki Fire Incident. For details on how these incidents adversely affected our financial condition and results of operations, please read Item 7. Management s Discussion and Analysis of Financial Conditions and Results of Operations Analysis of Historical Results of Operations. Loss incidents such as these are likely to increase the cost of mining and delay or halt production at particular mines for varying lengths of time. We do carry commercial (including business interruption and extra expense) property insurance policies; however, these risks may not be fully covered by these insurance policies.

A shortage of skilled labor may make it difficult for us to maintain labor productivity and competitive costs and could adversely affect our profitability.

Efficient coal mining using modern techniques and equipment requires skilled laborers, preferably with at least one year of experience and proficiency in multiple mining tasks. In recent years, a shortage of trained coal miners has caused us to operate certain mining units without full staff, which decreases our productivity and increases our costs. This shortage of trained coal miners is the result of a significant percentage of experienced coal miners reaching the age for retirement, combined with the difficulty of attracting new workers to the coal industry. Thus, this shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on our labor productivity and costs and our ability to expand production in the event there is an increase in the demand for our coal, which could adversely affect our profitability.

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

None of our employees are represented under collective bargaining agreements. However, all of our work force may not remain union-free in the future. If some or all of our currently union-free operations were to become unionized, it could adversely affect our productivity and increase the risk of work stoppages at our mining complexes. In addition, even if we remain union-free, our operations may still be adversely affected by work stoppages at unionized companies, particularly if union workers were to orchestrate boycotts against our operations.

We may be unable to obtain and renew permits necessary for our operations, which could reduce our production, cash flow and profitability.

Mining companies must obtain numerous permits that impose strict conditions and obligations relating to various environmental and safety matters in connection with coal mining. The permitting rules are complex and can change over time. The public has the right to comment on permit applications and otherwise participate in the permitting process, including through court intervention. Accordingly, permits required by us to conduct our operations may not be issued, maintained or renewed, or may not be issued or renewed in a timely fashion, or may involve requirements that restrict our ability to economically conduct our mining operations. Limitations on our ability to conduct our mining operations due to the inability to obtain or renew necessary permits could reduce our production, cash flow and profitability. Please read Regulations and Laws Mining Permits and Approvals.

Recent federal district court decisions in West Virginia, and related litigation filed in federal district court in Kentucky, have created uncertainty regarding the future ability to obtain certain general permits authorizing the construction of valley fills for the disposal of overburden from mining operations. A July 2004 decision by the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Bulen* enjoined the Huntington District of the U.S. Army Corps of Engineers from issuing further permits pursuant to Nationwide Permit 21, which is a general permit issued by the U.S. Army Corps of Engineers to streamline the process for obtaining permits under Section 404 of the Clean Water Act. The Fourth Circuit Court of Appeals issued a decision on November 23, 2005, vacating the district court decision in *Bulen* and remanding the case to the lower court for further argument. A similar lawsuit has been filed in federal district court in Kentucky that seeks to enjoin the issuance of permits pursuant to Nationwide Permit 21 by the Louisville District of the U.S. Army Corps of Engineers. We do not operate any mines located within the Southern District of West Virginia, and currently only utilize Nationwide Permit 21 at one location in Indiana. In the event current or future litigation contesting the use of Nationwide Permit 21 is successful, we may be required to apply for individual discharge permits pursuant to Section 404 of the Clean Water Act in areas where it would have otherwise utilized Nationwide Permit 21. Such a change could result in delays in obtaining required mining permits to conduct operations, which could in turn result in reduced production, cash flow and profitability.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce revenues by causing us to reduce our production or by impairing our ability to supply coal to our customers.

Transportation costs represent a significant portion of the total cost of coal for our customers and, as a result, the cost of transportation is a critical factor in a customer s purchasing decision. Increases in transportation costs could make coal a less competitive source of energy or could make our coal production less competitive than coal produced from other sources.

On the other hand, significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country. For instance, difficulty in coordinating the many eastern coal loading facilities, the large number of small shipments, the steeper average grades of the terrain and a more unionized workforce are all issues that combine to make coal shipments originating in the eastern United States inherently more expensive on a per-mile basis than coal shipments originating in the western United States. Historically, high coal transportation rates from the western coal producing areas into certain eastern markets limited the use of western coal in those markets. Lower or higher rail rates from the western coal producing areas to markets served by eastern U.S. coal producers have created

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major competitive challenges, as well as opportunities for eastern coal producers. In the event of lower transportation costs, the increased competition could have a material adverse effect on our business, financial condition and results of operations.

Some of our mines depend on a single transportation carrier or a single mode of transportation. Disruption of any of these transportation services due to weather-related problems, flooding, drought, accidents, mechanical difficulties, strikes, lockouts, bottlenecks, and other events could temporarily impair our ability to supply coal to our customers. Our transportation providers may face difficulties in the future that may impair our ability to supply coal to our customers, resulting in decreased revenues.

If there are disruptions of the transportation services provided by our primary rail or barge carriers that transport our coal and we are unable to find alternative transportation providers to ship our coal, our business could be adversely affected.

The states of Kentucky and West Virginia have recently increased enforcement of weight limits on coal trucks on their public roads. It is possible that other states in which our coal is transported by truck will modify their laws to limit truck weight limits. Such legislation could result in shipment delays and increased costs. An increase in transportation costs could have an adverse effect on our ability to increase or to maintain production and could adversely affect revenues.

Expansions of existing mines that we have completed since our formation, as well as mine expansions that we may undertake in the future, involve a number of risks, any of which could cause us not to realize the anticipated benefits.

Since our formation and the acquisition of our predecessor in August 1999, we have expanded our operations by adding and developing mines and coal reserves in existing, adjacent and neighboring properties. We continually seek to expand our operations and coal reserves. If we are unable to successfully integrate the companies, businesses or properties we are able to acquire through such expansion, our profitability may decline and we could experience a material adverse effect on our business, financial condition, or results of operations. Expansion transactions involve various inherent risks, including:

- uncertainties in assessing the value, strengths, and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental or mine safety liabilities) of, expansion opportunities;
- the ability to achieve identified operating and financial synergies anticipated to result from an expansion;
- problems that could arise from the integration of the new operations; and
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying our rationale for pursuing the expansion opportunity.

Any one or more of these factors could cause us not to realize the benefits anticipated to result from an expansion. Any expansion opportunities we pursue could materially affect our liquidity and capital resources and may require us to incur indebtedness, seek equity capital or both. In addition, future expansions could result in us assuming more long-term liabilities relative to the value of the acquired assets than we have assumed in our previous expansions.

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

Historically, a portion of our growth and operating results have been from acquisitions. Our future growth could be limited if we are unable to continue to make acquisitions, or if we are unable to successfully integrate the companies, businesses or properties we acquire. We may not be successful in consummating any acquisitions and the consequences of these acquisitions is unknown. Moreover, any acquisition could be dilutive to earnings and distributions to unitholders and any additional debt incurred to finance an acquisition could affect our ability to make distributions to unitholders. Our ability to make acquisitions in the future could be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties or the lack of suitable acquisition candidates.

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The unavailability of an adequate supply of coal reserves that can be mined at competitive costs could cause our profitability to decline.

Our profitability depends substantially on our ability to mine coal reserves that have the geological characteristics that enable them to be mined at competitive costs and to meet the quality needed by our customers. Because our reserves decline as we mine coal, our future success and growth depend, in part, upon our ability to acquire additional coal reserves that are economically recoverable. Replacement reserves may not be available when required or, if available, may not be capable of being mined at costs comparable to those characteristic of the depleting mines. We may not be able to accurately assess the geological characteristics of any reserves that we acquire, which may adversely affect our profitability and financial condition. Exhaustion of reserves at particular mines also may have an adverse effect on our operating results that is disproportionate to the percentage of overall production represented by such mines. Our ability to obtain other reserves in the future could be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties, the lack of suitable acquisition candidates or the inability to acquire coal properties on commercially reasonable terms.

Our business depends, in part, upon our ability to find, develop or acquire additional coal reserves that we can recover economically. Our existing reserves will decline as they are depleted. Our planned development projects and acquisition activities may not increase our reserves significantly and we may not have continued success expanding existing and developing additional mines. We believe that there are substantial reserves on certain adjacent or neighboring properties that are unleased and otherwise available. However, we may not be able to negotiate leases with the landowners on acceptable terms. An inability to expand our operations into adjacent or neighboring reserves under this strategy could have a material adverse effect on our business, financial condition or results of operations.

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

The estimates of our coal reserves may vary substantially from actual amounts of coal we are able to economically recover. The reserve data set forth in Item 2. Properties represent our engineering estimates. All of the reserves presented in this Annual Report on Form 10-K constitute proven and probable reserves. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. Estimates of coal reserves necessarily depend upon a number of variables and assumptions, any one of which may vary considerably from actual results. These factors and assumptions relate to:

- geological and mining conditions, which may not be fully identified by available exploration data and/or differ from our experiences in areas where we currently mine;
- the percentage of coal in the ground ultimately recoverable;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulation by governmental agencies; and
- assumptions concerning future coal prices, operating costs, capital expenditures, severance and excise taxes and development and reclamation costs.

For these reasons, estimates of the recoverable quantities of coal attributable to any particular group of properties, classifications of reserves based on risk of recovery and estimates of future net cash flows expected from these properties as prepared by different engineers or by the same engineers at different times, may vary substantially. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and these variations may be material. As a result, you should not place undue reliance on the coal reserve data included herein.

Mining in certain areas in which we operate is more difficult and involves more regulatory constraints than mining in other areas of the United States, which could affect the mining operations and cost structures of these areas.

The geological characteristics of some of our coal reserves, such as depth of overburden and coal seam thickness, make them difficult and costly to mine. As mines become depleted, replacement reserves may not be available when required or, if available, may not be capable of being mined at costs comparable to those characteristic of the depleting mines. In addition, permitting, licensing and other environmental and regulatory requirements associated with certain of our mining operations are more costly and time-consuming to satisfy. These factors could materially adversely affect the mining operations and cost structures of, and our customers ability to use coal produced by, our mines.

Unexpected increases in raw material costs could significantly impair our operating profitability.

Our coal mining operations use significant amounts of steel, petroleum products and other raw materials in various pieces of mining equipment, supplies and materials, including the roof bolts required by the room and pillar method of mining. Steel prices have risen significantly in recent years, and historically, the prices of scrap steel, natural gas and coking coal consumed in the production of iron and steel have fluctuated. Recently we have experienced cost increases for various commodities and services influenced by the recent steep increases in the price of crude oil and natural gas. Costs of diesel fuel, explosives, and coal trucking have all escalated as a direct result of supply chain problems related to the effect of recent hurricanes along the U.S. Gulf Coast. There may be other acts of nature or terrorist attacks or threats that could also increase the costs of raw materials. If the price of steel, petroleum products or other raw materials increase, our operational expenses will increase, which could have a significant negative impact on our profitability.

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

Because distributions on our common units are dependent on the amount of cash generated through our coal sales, distributions may fluctuate based on the amount of coal we are able to produce and the price at which we are able to sell it. Therefore, the current quarterly distribution or any distribution may not be paid each quarter. The actual amount of cash that is available to be distributed each quarter will depend upon numerous factors, some of which are beyond our control and the control of our managing general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

The partnership agreement gives our managing general partner broad discretion in establishing financial reserves for the proper conduct of our business. These reserves also will affect the amount of cash available for distribution. In addition, the partnership agreement requires the managing general partner to deduct from operating surplus each year estimated maintenance capital expenditures as opposed to actual expenditures in order to reduce wide disparities in operating surplus caused by fluctuating maintenance capital expenditure levels. If estimated maintenance capital expenditures in a year are higher than actual maintenance capital expenditures, then the amount of cash available for distribution to unitholders will be lower than if actual maintenance capital expenditures were deducted from operating surplus.

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

We have long-term indebtedness, consisting of our outstanding 8.31% senior unsecured notes. At December 31, 2005, our total indebtedness outstanding was $162.0 million. Our leverage may:

- adversely affect our ability to finance future operations and capital needs;
- limit our ability to pursue acquisitions and other business opportunities;
- make our results of operations more susceptible to adverse economic or operating conditions; and
- make it more difficult to self-insure for our workers compensation obligations.

In addition, we have unused borrowing capacity under our revolving credit facility. Future borrowings, under our credit facilities or otherwise, could result in a significant increase in our leverage.

Our payments of principal and interest on any indebtedness will reduce the cash available for distribution on our units. We will be prohibited from making cash distributions:

during an event of default under any of our indebtedness; or

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if either before or after such distribution, it fails to meet a coverage test based on the ratio of our consolidated debt to our consolidated cash flow.

Various limitations in our debt agreements may reduce our ability to incur additional indebtedness, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Federal and state laws require bonds to secure our obligations related to the statutory requirement that we return mined property to its approximate original condition and workers compensation and black lung benefits. Our inability to acquire or failure to maintain surety bonds that are required by state and federal law would have a material adverse effect on us.

Federal and state laws require us to place and maintain bonds to secure our obligations to repair and return property to its approximate original state after it has been mined (often referred to as reclaim or reclamation), to pay federal and state workers compensation and pneumoconiosis, or black lung, benefits and to satisfy other miscellaneous obligations. These bonds provide assurance that we will perform our statutorily required obligations and are referred to as surety bonds. These bonds are typically renewable on a yearly basis. The failure to maintain or the inability to acquire sufficient surety bonds, as required by state and federal laws, could subject us to fines and penalties as well as the loss of our mining permits. Such failure could result from a variety of factors, including:

- lack of availability, higher expense or unreasonable terms of new surety bonds;
- the ability of current and future surety bond issuers to increase required collateral, or limitations on availability of collateral for surety bond issuers due to the terms of our credit agreements; and
- the exercise by third-party surety bond holders of their right to refuse to renew the surety.

We have outstanding surety bonds with third parties for reclamation expenses and for federal and state workers compensation obligations and other miscellaneous obligations. We may have difficulty maintaining our surety bonds for mine reclamation as well as workers compensation and black lung benefits. Our inability to acquire or failure to maintain these bonds would have a material adverse effect on us.

Our mining operations are subject to extensive and costly laws and regulations, and such current and future laws and regulations could increase current operating costs or limit our ability to produce coal.

We are subject to numerous and detailed federal, state and local laws and regulations affecting the coal mining industry, including laws and regulations pertaining to employee health and safety, permitting and licensing requirements, air quality standards, water pollution, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Numerous governmental permits and approvals are required for mining operations. We are required to prepare and present to federal, state and local authorities data pertaining to the effect or impact that any proposed exploration for or production of coal may have upon the environment. The costs, liabilities and requirements associated with these regulations may be costly and time consuming and may delay commencement or continuation of exploration or production operations. The possibility exists that new laws or regulations (or judicial interpretations of existing laws and regulations) may be adopted in the future that could materially affect our mining operations, cash flow, and profitability, either through direct impacts such as new requirements impacting our existing mining operations, or indirect impacts such as new laws and regulations that discourage or limit our customers use of coal. Please read Regulation and Laws.

Recent mining accidents involving fatalities in West Virginia and Kentucky have received national attention and prompted responses at the state and national level that have resulted in increased scrutiny of current industry safety practices and procedures at all mining operations. On January 26, 2006, West Virginia Governor Joe Manchin signed into law a bill imposing stringent new mine safety and accident reporting requirements and increased civil and criminal penalties for violations of mine safety laws. Other states, including Illinois, have proposed or passed similar bills and resolutions addressing mine safety practices. In addition, several mine safety bills have been introduced in Congress that would mandate similar improvements in mine safety practices; increase or add civil and criminal penalties for non-compliance with such laws or regulations; and expand the scope of federal oversight, inspection, and enforcement activities. On February 7, 2006, the federal MSHA announced the promulgation of new emergency rules on mine safety.

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These rules address mine safety equipment, training, and emergency reporting requirements. Unlike most MSHA rules, these emergency rules will become effective immediately upon their publication in the *Federal Register*. Implementing and complying with these new laws and regulations could adversely affect our results of operation and financial position.

Some of our operating subsidiaries lease a portion of the surface properties upon which their mining facilities are located.

Our operating subsidiaries do not, in all instances, own all of the surface properties upon which their mining facilities have been constructed. Certain of the operating companies have constructed and now operate all or some portion of their facilities on properties owned by unrelated third parties with whom the applicable company has entered into a long-term lease. We have no reason to believe that there exists any risk of loss of these leasehold rights given the terms and provisions of the subject leases and the nature and identity of the third party lessors; however, in the unlikely event of any loss of these leasehold rights, operations could be disrupted or otherwise adversely impacted as a result of increased costs associated with retaining the necessary land use.

Tax Risks to Our Common Unitholders

If we were to become subject to entity-level taxation for federal or state tax purposes, then our cash available for distribution to you would be substantially reduced.

The anticipated after-tax benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service (IRS) on this matter.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in our anticipated cash flow and after-tax return to you, likely causing a substantial reduction in the value of our units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity level taxation. For example, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us or as an entity, the cash available for distribution to you would be reduced.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any contest will reduce cash available for distribution to our unitholders.

The IRS may adopt positions that differ from the positions that we take, even positions taken with the advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the prices at which they trade. Moreover, the costs of any contest between us and the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

Even if you do not receive any cash distributions from us, you will be required to pay taxes on your share of our taxable income.

You will be required to pay federal income taxes and, in some cases, state and local income taxes on your share of our taxable income, whether or not you receive cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from your share of our taxable income.

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

If you sell your units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in those units. Prior distributions to you in excess of the total net taxable income you were allocated for a unit, which decreased your tax basis in that unit, will, in effect, become taxable income to you if the unit is sold at a price greater than your tax basis in that unit, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to you.

Tax-exempt entities and foreign persons face unique tax issues from owning units that may result in adverse tax consequences to them.

Investment in units by tax-exempt entities, such as individual retirement accounts (known as IRAs) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

We will treat each purchaser of our units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of our units.

Because we cannot match transferors and transferees of units, we will adopt depreciation and amortization positions that may not conform with all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of units and could have a negative impact on the value of our units or result in audit adjustments to your tax returns.

You will likely be subject to state and local taxes and income tax return filing requirements as a result of investing in our units.

In addition to federal income taxes, you will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We may own property or conduct business in other states in the future. It is your responsibility to file all federal, state and local tax returns. Our counsel has not rendered an opinion on the state and local tax consequences of an investment in our units.

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

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. A termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income for the year in which the termination occurs. Thus, if this occurs you will be allocated an increased amount of federal taxable income for the year in which we are considered to be terminated as a percentage of the cash distributed to you with respect to that period. Although the amount of increase cannot be estimated because it depends upon numerous factors including the timing of the termination, the amount could be material. Our termination, currently would not affect our classification, as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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

At December 31, 2005, we had approximately 549.0 million tons of proven and probable coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania, and West Virginia. 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, 2005, about each of our mining complexes:

			Proven and Probable Reserves Pounds $S0_2$ per MMbtu (tons in millions)				Reserve Assignment	
Operations	**Mine Type**	**Heat Content (Btus per pound)**	**<1.2**	**1.2-2.5**	**>2.5**	**Total**	**Assigned**	**Unassigned**
Illinois Basin Operations								
Dotiki	Underground	12,300			89.5	89.5	89.5	
Warrior	Underground	12,500			17.8	17.8	17.8	
Pattiki	Underground	11,700			47.6	47.6	47.6	
Hopkins	Underground	11,300			56.7	56.7	36.5	20.2
	/ Surface				7.6	7.6	7.6	
Gibson (North)	Underground	11,600		27.2	7.9	35.1	35.1	
Gibson (South)	Underground	11,600		18.6	64.1	82.7		82.7
Region Total				45.8	291.2	337.0	234.1	102.9
Central Appalachia Operations								
Pontiki	Underground	12,800	6.5	11.9		18.4	18.4	
MC Mining	Underground	12,800	21.0		1.8	22.8	22.8	
Region Total			27.5	11.9	1.8	41.2	41.2	
Northern Appalachia Operations								
Mettiki	Underground	13,000		8.1	10.5	18.6	18.6	
Mettiki (WV)	Underground	13,000		6.7	18.3	25.0	25.0	
Tunnel Ridge	Underground	12,600			70.5	70.5	70.5	
Penn Ridge	Underground	12,500			56.7	56.7	56.7	

Region Total		14.8	156.0	170.8	170.8	
Total	27.5	72.5	449.0	549.0	446.1	102.9
% of Total	5.0%	13.2%	81.8%	100%	81.3%	18.7%

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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 1/2 mile apart and are projected to extend as a 1/4 mile wide belt around each point of measurement and (b) probable reserves is that points of observation are between 1/2 and 1 1/2 miles apart and are projected to extend as a 1/2 mile wide belt that lies 1/4 mile from the points of measurement.

Reserve estimates will change from time to time to reflect evolving market conditions, mining activities, additional analyses, new engineering and geological data, acquisition or divestment of reserve holdings, modification of mining plans or mining methods, and other factors.

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 27.5 million tons of reserves listed as <1.2 pounds of SO_2 per MMbtu are compliance coal which means coal that meets sulfur emission standards imposed by Phase I and II of the CAA.

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.

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. As of December 31, 2005, these non-reserve coal deposits are as follows: Dotiki 20.2 million tons, Pattiki 3.2 million tons, Hopkins County 1.7 million tons, Gibson (North) 0.9 million tons, Gibson (South) 7.5 million tons, and Warrior 8.2 million tons.

We lease almost all of our reserves and generally have the right to maintain leases in force until the exhaustion of mineable 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.

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

Operations	Tons Produced 2005	2004	2003	Transportation	Equipment
	(tons in millions)				
Illinois Basin Operations					
Dotiki	4.7	4.8	4.9	CSX, PAL; truck; barge	CM
Warrior	4.1	3.1	2.4	CSX, PAL; truck	CM
Pattiki	2.6	2.5	1.8	CSX; barge	CM
Hopkins	0.9	0.2	0.8	CSX, PAL; truck	DL; CM
Gibson (North)	3.4	3.0	2.4	Truck; barge	CM
Region Total	15.7	13.6	12.3		
Central Appalachia Operations					
Pontiki	1.7	1.7	2.0	NS; truck	CM
MC Mining	1.6	1.9	1.6	CSX; truck	CM
Region Total	3.3	3.6	3.6		
Northern Appalachia Operations					
Mettiki	3.3	3.2	3.3	Truck; CSX	LW; CM; CS
Region Total	3.3	3.2	3.3		
TOTAL	22.3	20.4	19.2		

CSX - CSX Railroad
PAL - Paducah & Louisville Railroad
NS - Norfolk & Southern Railroad
CM - Continuous Miner
CS - Contour Strip
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 ICG which was settled in late 2005, as described under Other in Item 8. Financial Statements and Supplementary Data Note 17. 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 and Other under Item 8. Financial Statements and Supplementary Data. Note 18. 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 EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

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 10, 2006, the closing market price for the common units was $36.32 per unit. As of March 10, 2006, there were 36,426,306 common units outstanding, which included 6,422,531 common units that converted from subordinated units in November 2003 and 2004. There were approximately 20,200 record holders and beneficial owners (held in street name) of common units at December 31, 2005.

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

	High	Low	Distributions Per Unit
1st Quarter 2004	$ 20.455	$ 15.255	$0.3125 (paid May 14, 2004)
2nd Quarter 2004	$ 23.690	$ 16.550	$0.3250 (paid August 13, 2004)
3rd Quarter 2004	$ 28.285	$ 22.060	$0.3250 (paid November 12, 2004)
4th Quarter 2004	$ 37.385	$ 27.400	$0.3750 (paid February 14, 2005)
1st Quarter 2005	$ 40.495	$ 30.100	$0.3750 (paid May 13, 2005)
2nd Quarter 2005	$ 38.300	$ 27.750	$0.4125 (paid August 12, 2005)
3rd Quarter 2005	$ 48.410	$ 35.550	$0.4125 (paid November 14, 2005)
4th Quarter 2005	$ 46.600	$ 35.450	$0.4600 (paid February 14, 2006)

We will distribute to our partners, on a quarterly basis, all of our available cash. Available cash , as defined in our partnership agreement, generally means, with respect to any quarter, all cash on hand at the end of each quarter, plus working capital borrowings after the end of the quarter, less cash reserves in the amount necessary or appropriate in the reasonable discretion of our managing general partner to (a) provide for the proper conduct of our business, (b) comply with applicable law of any debt instrument or other agreement of ours or any of its affiliates, and (c) provide funds for distributions to unitholders and the general partners for any one or more of the next four quarters. If quarterly distributions of available cash exceed the minimum quarterly distribution (MQD) and certain target distribution levels as established in our partnership agreement, our managing general partner will receive distributions based on specified increasing percentages of the available cash that exceed the MQD and the target distribution levels. Our partnership agreement defines the MQD as $0.25 for each full fiscal quarter.

Under the quarterly incentive distribution provisions of the partnership agreement, our managing general partner is entitled to receive 15% of the amount we distribute in excess of $0.275 per unit, 25% of the amount we distribute in excess of $0.3125 per unit, and 50% of the amount we distribute in excess of $0.375 per unit.

Equity Compensation Plans

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

ITEM 6. SELECTED FINANCIAL DATA

Our historical financial data below were derived from our audited consolidated financial statements as of and for the years ended December 31, 2005, 2004, 2003, 2002 and 2001. We acquired Warrior from ARH Warrior Holdings, Inc. (ARH Warrior Holdings), a subsidiary of Alliance Resource Holdings, in February 2003. Because the Warrior acquisition was between entities under common control, it is accounted for at historical cost in a manner similar to that used in a pooling of interests. Accordingly, the financial statements as of December 31, 2002, and for each of the two years in the period ended December 31, 2002, have been restated to reflect the combined historical results of operations, financial position, and cash flows of the Partnership and Warrior. ARH Warrior Holdings acquired the assets that comprise Warrior on January 26, 2001.

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(in millions, except per unit and per ton data)	Year Ended December 31,				
	2005	2004	2003	2002	2001
Statements of Income:					
Sales and operating revenues					
Coal sales	$ 768.9	$ 599.4	$ 501.6	$ 479.5	$ 453.1
Transportation revenues	39.1	29.8	19.5	19.0	18.2
Other sales and operating revenues	30.7	24.1	21.6	20.4	6.2
Total revenues	838.7	653.3	542.7	518.9	477.5
Expenses:					
Operating expenses	521.5	436.4	368.8	367.5	337.2
Transportation expenses	39.1	29.8	19.5	19.0	18.2
Outside purchases	15.1	9.9	8.5	10.1	28.9
General and administrative	33.5	45.4	28.3	20.3	18.7
Depreciation, depletion and amortization	55.6	53.7	52.5	52.4	50.7
Interest expense	11.8	15.0	16.0	16.4	16.8
Net gain from insurance settlement (1)		(15.2)			
Total expenses	676.6	575.0	493.6	485.7	470.5
Income from operations	162.1	78.3	49.1	33.2	7.0
Other income	0.6	1.0	1.4	0.5	0.8
Income before income taxes and cumulative effect of accounting change	162.7	79.3	50.5	33.7	7.8
Income tax expense (benefit)	2.7	2.7	2.6	(1.1)	(0.8)
Income before cumulative effect of accounting change	160.0	76.6	47.9	34.8	8.6
Cumulative effect of accounting change (2)					7.9
Net income	$ 160.0	$ 76.6	$ 47.9	$ 34.8	$ 16.5
General Partners interest in net income	$ 12.4	$ 3.3	$ 0.3	$ (0.8)	$ (0.2)
Limited Partners interest in net income	$ 147.6	$ 73.3	$ 47.6	$ 35.6	$ 16.7
Basic net income per limited partner unit	$ 2.89	$ 1.76	$ 1.30	$ 1.14	$ 0.54
Basic net income per limited partner unit before accounting change	$ 2.89	$ 1.76	$ 1.30	$ 1.14	$ 0.29
Diluted net income per limited partner unit	$ 2.84	$ 1.71	$ 1.26	$ 1.11	$ 0.53
Diluted net income per limited partner unit before accounting change	$ 2.84	$ 1.71	$ 1.26	$ 1.11	$ 0.29
Weighted average number of units outstanding-basic	36,288,527	35,881,896	35,161,468	30,810,622	30,810,622
Weighted average number of units outstanding-diluted	36,977,061	36,874,336	36,325,678	31,685,416	31,369,100
Balance Sheet Data:					
Working capital (deficit)	$ 76.1	$ 54.2	$ 16.4	$ (15.8)	$ 0.9

Total assets	532.7	412.8	336.5	316.9	310.3
Long-term debt	144.0	162.0	180.0	195.0	211.3
Total liabilities	376.9	357.6	323.9	355.7	347.8
Partners capital (deficit)	155.8	55.2	12.6	(38.8)	(37.6)
Other Operating Data:					
Tons sold	22.8	20.8	19.5	18.4	18.6
Tons produced	22.3	20.4	19.2	18.0	17.4
Revenues per ton sold (3)	$ 35.07	$ 29.98	$ 26.83	$ 27.17	$ 24.69
Cost per ton sold (4)	$ 25.00	$ 23.64	$ 20.80	$ 21.63	$ 20.69
Other Financial Data:					
Net cash provided by operating activities	$ 193.6	$ 145.1	$ 110.3	$ 101.3	$ 70.5
Net cash used in investing activities	(110.2)	(77.6)	(77.8)	(56.9)	(31.1)
Net cash used in financing activities	(82.6)	(46.4)	(31.3)	(46.4)	(35.2)
EBITDA (5)	230.1	147.9	119.0	102.5	83.2
Maintenance capital expenditures (6)	56.7	31.6	30.0	29.0	24.4

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

(2) Represents the cumulative effect of the change in the method of estimating coal workers pneumoconiosis (black lung) benefits liability effective January 1, 2001.

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

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

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

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the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;

our operating performance and return on investment as compared to those of other companies in the coal energy sector, without regard to financing or capital structures; and

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

The following table presents a reconciliation of (a) GAAP Cash Flows Provided by Operating Activities to a non-GAAP EBITDA and (b) non-GAAP EBITDA to GAAP net income (in thousands):

	Year Ended December 31,				
	2005	2004	2003	2002	2001
Cash flows provided by operating activities	$ 193,618	$ 145,055	$ 110,312	$ 101,306	$ 70,465
Reclamation and mine closing	(1,918)	(1,622)	(1,341)	(1,365)	(1,175)
Coal inventory adjustment to market	(573)	(488)	(687)	(48)	(233)
Other	(759)	(255)	353	1,014	890
Loss on retirement of damaged vertical belt equipment	(1,298)				
Net effect of working capital changes	26,577	(12,405)	(8,240)	(13,714)	(2,706)
Interest expense	11,816	14,963	15,981	16,360	16,772
Income taxes	2,682	2,641	2,577	(1,094)	(836)
EBITDA	230,145	147,889	118,955	102,459	83,177
Depreciation, depletion and amortization	(55,637)	(53,664)	(52,495)	(52,408)	(50,696)
Interest expense	(11,816)	(14,963)	(15,981)	(16,360)	(16,772)
Income taxes	(2,682)	(2,641)	(2,577)	1,094	836
Net income	$ 160,010	$ 76,621	$ 47,902	$ 34,785	$ 16,545

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

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

General

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

Supplementary Data. - Note 1. Organization and Presentation and Note 2. Summary of Significant Accounting Policies.

Business

We are a diversified producer and marketer of coal to major U.S. utilities and industrial users. In 2005, our total production was 22.3 million tons and our total sales were 22.8 million tons. The coal we produced in 2005 was approximately 30.0% low-sulfur coal, 14.8% medium-sulfur coal and 55.2% high-sulfur coal.

At December 31, 2005, we had approximately 549.0 million tons of proven and probable coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. We believe we control adequate reserves to implement our currently contemplated mining plans.

In 2005, approximately 83.7% of our sales tonnage was consumed by electric utilities or coal sunfuel facilities, whose ultimate customers are electric utilities with the balance consumed by cogeneration plants and industrial users. Our largest customers in 2005 were SSO, TVA and Mt. Storm Coal Supply. In 2005, approximately 86.0% of our sales tonnage, including approximately 85.6% 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 2005, approximately 89.8% 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.

In 2002, we entered into long-term agreements with SSO to host and operate its coal synfuel production facility currently located at Warrior, supply the facility with coal feedstock, assist SSO with the marketing of coal synfuel and provide it with other services. These agreements provide us with coal sales and rental and service fees from SSO based on the synfuel facility throughput tonnages. Certain of the operating services provided to SSO are performed by Alliance Service, a wholly-owned subsidiary of Alliance Coal. Alliance Service is subject to federal and state income taxes.

In 2005, Gibson and Mettiki entered into long-term agreements with PCIN and Mt. Storm Coal Supply, respectively, which also own coal synfuel facilities. At Gibson, we host PCIN s coal synfuel facility, supply the facility with coal feedstock, assist PCIN with the marketing of coal synfuel and provide it with other services. At Mettiki, we supply Mt. Storm Coal Supply with coal feedstock.

All of the coal synfuel related agreements expire on December 31, 2007 and are contingent on the ability of the synfuel facilities members to use certain qualifying tax credits applicable to the facilities. The term of each of these agreements is subject to early cancellation provisions customary for transactions of these types, including the unavailability of coal synfuel tax credits, the termination of associated coal synfuel sales contracts, and the occurrence of certain force majeure events. We have maintained back up coal supply agreements with each coal synfuel customer that automatically provide for sale of our coal to these customers in the event they do not purchase coal synfuel from the synfuel facilities.

For 2005, the incremental net income benefit from the combination of the various coal synfuel-related agreements was approximately $24.1 million, assuming that coal pricing would not have increased without the availability of synfuel. The continuation of the incremental net income benefit associated with coal synfuel agreements cannot be assured. Pursuant to our coal synfuel related agreements, we are not obligated to make retroactive adjustments or reimbursements if the synfuel facilities owners tax credits are disallowed.

In June 2003, the IRS suspended the issuance of private letter rulings on the significant chemical change requirement to qualify for synfuel tax credits and announced that it was reviewing the test procedures and results used by taxpayers to establish that a significant chemical change had occurred. In October 2003, the IRS completed its review and concluded that the test procedures and results were scientifically valid if applied in a consistent and unbiased manner. The IRS has resumed issuing private letter rulings under its existing guidelines. SSO has advised us that its private letter ruling could be reviewed by the IRS as part of a tax audit, similar to the IRS reviews of other synfuel procedures.

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 are often the determining factor in a coal consumer s contracting decision. Our mining operations are located near many of the major eastern utility generating plants and on major coal hauling railroads in the eastern U.S.

Summary

In 2005, we reported record net income of $160.0 million, an increase of 108.8% over 2004 net income of $76.6 million. These results were achieved despite lost production, continuing fixed expenses, and other expenses incurred as a result of the MC Mining Fire and Pattiki Vertical Belt Incidents described below. Financial results for 2004 include the impact of lost production, continuing fixed expenses and other expenses incurred as a result of the Dotiki Fire Incident offset by the final settlement of an insurance claim with our insurance underwriters relating to the Dotiki Fire Incident described below. Tons produced increased 9.4% over 2004 to 22.3 million tons in 2005. Tons sold increased 9.7% over 2004 to 22.8 million tons in 2005.

During 2005, we benefited from strong coal markets as revenues rose to record levels and average coal sales prices in 2005 increased 16.9% compared to 2004.

We have commitments for substantially all of our 2006 production. For our estimated 2007 production, approximately 70% is committed under existing coal sales agreements and approximately 42% of the committed tonnage is subject to market price negotiations.

Analysis of Historical Results of Operations

2005 Compared with 2004

	December 31,		December 31,	
	2005	2004	2005	2004
	(in thousands)		(per ton sold)	
Tons sold	22,849	20,823	N/A	N/A
Tons produced	22,290	20,377	N/A	N/A
Coal Sales	$ 768,958	$ 599,399	$ 33.65	$ 28.79
Operating Expenses and Outside Purchases	$ 536,601	$ 446,384	$ 23.48	$ 21.44

Coal sales. Coal sales increased 28.3% to $769.0 million for 2005 from $599.4 million for 2004. The increase of $169.6 million reflects increased sales volumes (contributing $58.3 million of the increase) and higher coal sales prices (contributing $111.3 million of the increase). Tons sold increased 9.7% to 22.8 million tons for 2005 from 20.8 million tons in 2004, primarily reflecting an increase in tons produced. Tons produced increased 9.4% to 22.3 million tons for 2005 from 20.4 million tons in 2004.

Operating expenses. Operating expenses increased 19.5% to $521.5 million in 2005 from $436.5 million in 2004. The increase of $85.0 million primarily resulted from an increase in operating expenses associated with additional coal sales of 2.0 million tons, including the following specific factors:

Labor and benefit costs increased $27.3 million reflecting increased headcount, pay rate increases and escalating health care costs;

Material and supplies, and maintenance costs increased $32.6 million and $7.8 million, respectively, reflecting increased production and increased costs for the products and services used in the mining process;

Third party mining costs increased $7.5 million reflecting the addition of two small third party mining operations at Mettiki;

Production taxes and royalties (which are incurred as a percentage of coal sales or volumes) increased $14.1 million;

Coal supply agreement buy-out expense decreased $2.1 million;

The impact of $2.9 million of expenses related to the Pattiki Vertical Belt Incident along with expenses associated with the MC Mining Fire Incident, both of which incidents are described below; and

Operating expenses were reduced by $4.9 million, reflecting the net of additional operating expenses incurred in the mine development process offset by revenues received for coal produced incidental with the mine development process.

Operating expenses in 2004 include a $3.5 million buy-out expense of several coal contracts that allowed us to take advantage of higher spot coal prices in 2005 and out-of-pocket expenses related to the Dotiki Fire that were not offset by proceeds from the final settlement with our insurance underwriters. Please read Dotiki Fire Incident below.

Other sales and operating revenues. Other sales and operating revenues are principally comprised of rental and service fees to coal synfuel production facilities and Mt. Vernon Transfer Terminal transloading fees. Other sales and operating revenues increased 27.5% to $30.7 million in 2005 from $24.1 million in 2004. The increase of $6.6 million was primarily attributable to $4.5 million of additional rent and service fees associated with a new third-party coal synfuel facility at the Gibson, which began producing synfuel in May 2005, $0.4 million of rent and service fees associated with increased volumes at the third-party coal synfuel facility at Warrior and $1.1 million of additional transloading fees attributable to increased transloading volumes at the Mt. Vernon Transfer Terminal.

Outside purchases. Outside purchases increased $5.2 million to $15.1 million in 2005 from $9.9 million in 2004. The increase was primarily attributable to the previously described coal supply arrangement with a third-party supplier, in the Illinois Basin ($8.3 million) which also contributed to additional coal sales volumes at our Illinois Basin operations offset by lower outside purchases in Central Appalachia ($3.4 million).

General and administrative. General and administrative expenses for 2005 decreased to $33.5 million compared to $45.4 million for 2004. The decrease of $11.9 million resulted from lower incentive compensation expense related to the Long-Term Incentive Plan (LTIP) of $12.1 million. The lower incentive compensation expense for the LTIP is primarily attributable to a reduction in the number of restricted units outstanding due to the vesting in November 2005 and 2004 of the LTIP, units for grant years 2003 and 2000 to 2002, respectively, combined with a lower incremental change in the market value of our common units from 2004 to 2005 than from 2003 to 2004. The reduction in incentive compensation expense was partially offset by increased salaries and related costs and a number of other general and administrative costs, none of which was individually significant.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased to $55.6 million in 2005 compared to $53.7 million in 2004. The increase of $1.9 million was primarily the result of additional depreciation expense associated with operating Hopkins County Coal for the full year 2005 compared to three months in 2004 after resumption of operations following the temporary idling of Hopkins surface mine and increased capital expenditures and infrastructure investments in recent years, which have increased our production capacity.

Interest expense. Interest expense decreased to $11.8 million in 2005 from $15.0 million in 2004. The decrease of $3.2 million was principally attributable to increased interest income earned on increased marketable securities which is netted against interest expense in addition to the capitalization of $0.6 million in 2005 related to the development at the Elk Creek and Mountain View mines. We had no borrowings under the credit facility during 2005 or 2004.

Transportation revenues and expenses. Transportation revenues and expenses increased 31.0% to $39.1 million in 2005 from $29.8 million for 2004. The increase of $9.3 million was primarily attributable to increased shipments to customers that reimburse us for transportation costs rather than arranging and paying for transportation directly with transportation providers. Transportation services are a pass-through to our customers. Consequently, we do not realize any margin on transportation revenues.

Income before income tax expense. Income before income tax expense increased 105.3% to $162.7 million for 2005 compared to $79.3 million for 2004. The increase was primarily attributable to increased sales volumes, higher coal prices and reduced general and administrative expenses, primarily reflecting lower incentive compensation expense, partially offset by higher operating expenses and expenses related to the Pattiki Vertical Belt Incident and MC Mining Fire Incident described below. The 2004 results included a $3.5 million buy-out expense of several coal contracts which allowed us to take advantage of higher spot coal prices in 2005 in addition to the impact of lost production, continuing fixed expenses and other expenses incurred as a result of the Dotiki Fire Incident offset by the final settlement of an insurance claim with our insurance underwriters relating to the Dotiki Fire Incident described below.

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Income tax expense. Income tax expense was comparable for both 2005 and 2004 at $2.7 and $2.6 million, respectively.

Our 2005 Segment Adjusted EBITDA increased $70.3 million, or 36.4% to $263.6 million from 2004 Segment Adjusted EBITDA of $193.3 million. Segment Adjusted EBITDA, tons sold, coal sales, operating revenues and Adjusted Segment EBITDA Expense by segment are as follows (in thousands):

	Year Ended December 31, 2005	2004	Increase (Decrease)	
Segment Adjusted EBITDA				
Illinois Basin	$ 183,075	$ 121,763	$ 61,312	50.4%
Central Appalachia	41,583	28,953	12,630	43.6%
Northern Appalachia	36,047	41,141	(5,094)	(12.4)%
Other and Corporate	2,924	1,432	1,492	
Total Segment Adjusted EBITDA (1)	$ 263,629	$ 193,289	$ 70,340	36.4%
Tons sold				
Illinois Basin	16,264	13,760	2,504	18.2%
Central Appalachia	3,249	3,781	(532)	(14.1)%
Northern Appalachia	3,330	3,282	48	1.5%
Other and Corporate	6		6	
Total tons sold	22,849	20,823	2,026	9.7%
Coal sales				
Illinois Basin	$ 504,916	$ 356,307	$ 148,609	41.7%
Central Appalachia	153,615	143,160	10,455	7.3%
Northern Appalachia	106,997	99,932	7,065	7.1%
Other and Corporate	3,430		3,430	
Total coal sales	$ 768,958	$ 599,399	$ 169,559	28.3%
Other sales and operating revenues				
Illinois Basin	$ 24,493	$ 19,087	$ 5,406	28.3%
Central Appalachia	282	187	95	50.8%
Northern Appalachia	2,163	2,127	36	1.7%
Other and Corporate	3,753	2,672	1,081	
Total other sales and operating revenues	$ 30,691	$ 24,073	$ 6,618	27.5%
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 346,335	$ 268,848	$ 77,487	28.8%
Central Appalachia	112,313	114,394	(2,081)	(1.8)%
Northern Appalachia	73,112	60,917	12,195	20.0%
Other and Corporate	4,260	1,241	3,019	
Total Segment Adjusted EBITDA Expense (2)	$ 536,020	$ 445,400	$ 90,620	20.3%

(1) Segment Adjusted EBITDA is defined as net income before income tax expense (benefit), interest expense and interest income, depreciation, depletion and amortization, and general and administrative expense. Adjusted Segment EBITDA is reconciled to net income below.

(2)

Segment Adjusted EBITDA Expense includes operating expenses, outside purchases and other income. Pass through transportation expenses are excluded.

Illinois Basin Segment Adjusted EBITDA for 2005 increased 50.4%, to $183.1 million from 2004 Segment Adjusted EBITDA of $121.8 million. The increase of $61.3 million was primarily attributable to increased coal sales which rose by $148.6 million, or 41.7%, to $504.9 million during 2005 as compared to $356.3 million in 2004.

Increased coal sales in 2005 reflect higher average coal sales prices per ton which increased $5.15 per ton to $31.05 per ton (contributing $83.8 million of the increase in coal sales) and increased tons sold of 2.5 million tons (contributing $64.8 million of the increase in coal sales). Other sales and operating revenues increased $5.4 million, primarily due to $4.5 million of revenues associated with the coal synfuel facility that began operating at Gibson in 2005. Total Segment Adjusted EBITDA Expense for 2005 increased 28.8% to $346.3 million from 268.8 million in 2004. On a per ton sold basis, 2005 Segment Adjusted EBITDA Expense rose to $21.30 per ton, an increase of 9.0% over the 2004 Segment Adjusted EBITDA Expense per ton of $19.54 per ton. The increase in 2005 Segment Adjusted EBITDA Expense in 2005 compared to 2004 primarily reflects the impact of cost increases described above under consolidated operating expenses and outside purchases, partially offset by the benefit of increased tons produced, which increased 2.2 million tons in 2005 to 15.7 million tons. Segment Adjusted EBITDA for the year 2004 includes $15.2 million reported as the net gain from insurance settlement associated with the Dotiki Fire Incident.

Central Appalachia   Segment Adjusted EBITDA for 2005 increased $12.6 million, or 43.6%, to $41.6 million as compared to 2004 Segment Adjusted EBITDA of $29.0 million. The increase was primarily attributable to increased coal sales of $10.5 million, reflecting a higher average coal sales price per ton of $47.27 in 2005, an increase of $9.41 per ton over the 2004 average coal sales price per ton, (which contributed $30.6 million of the increase in coal sales) partially offset by a reduction in tons sold in 2005 to 3.2 million tons, a decrease of 0.5 million tons sold from 2004 (resulting in a reduction of coal sales of $20.1 million). Segment Adjusted EBITDA Expense for 2005 decreased 1.8% to $112.3 million from $114.4 million in 2004. On a per ton basis, 2005 Segment Adjusted EBITDA Expense rose by $4.31, or 14.3%, to $34.56 per ton reflecting the impact of cost increases described under consolidated operating expenses above. This increase in per ton expense included the continuing impact of the MC Mining Fire Incident, partially offset by lower outside purchases ($3.5 million), and less favorable mining conditions, which contributed to lower production (0.4 million tons) resulting in fewer tons available for sale.

Northern Appalachia   Segment Adjusted EBITDA for 2005 decreased $5.1 million, or 12.4%, to $36.0 million as compared to 2004 Segment Adjusted EBITDA of $41.1 million. The decrease was primarily due to higher costs, reflecting less favorable mining conditions at Mettiki as the D-Mine approaches the depletion of its coal reserves. Segment Adjusted EBITDA Expense for 2005 increased 20.0% to $73.1 million as compared to $60.9 million in 2004. On a per ton basis, 2005 Segment Adjusted EBITDA Expense increased 18.3% to $21.95. The impact of higher costs was partially offset by higher coal sales in 2005, which increased $7.1 million to $107.0 million, primarily reflecting a 5.5% increase in the average coal sales price per ton which rose $1.68 per ton to $32.13 per ton (contributing $5.6 million of the increase in coal sales). The increase in the average sales price per ton primarily reflects coal sales that began in 2005 to a third-party coal synfuel producer.

A reconciliation of Segment Adjusted EBITDA to net income is as follows (in thousands):

	Year Ended December 31, 2005	2004
Segment Adjusted EBITDA	$ 263,629	$ 193,289
General & administrative	(33,484)	(45,400)
Depreciation, depletion and amortization	(55,637)	(53,664)
Interest expense	(11,816)	(14,963)
Income taxes	(2,682)	(2,641)
Net income	$ 160,010	$ 76,621

2004 Compared with 2003

	December 31, 2004	2003	December 31, 2004	2003
	(in thousands)		(per ton sold)	
Tons sold	20,823	19,467	N/A	N/A
Tons produced	20,377	19,238	N/A	N/A
Coal Sales	$ 599,399	$ 501,596	$ 28.79	$ 25.77
Operating Expenses and Outside Purchases	$ 446,384	$ 377,343	$ 21.44	$ 19.38

Coal sales. Coal sales increased 19.5% to $599.4 million for 2004 from $501.6 million for 2003. The increase of $97.8 million reflects higher prices on long-term coal sales agreements and the sale of additional production at significantly higher prices on short-term coal sales agreements into the export and Central Appalachia coal markets. The increased average sales price contributed $62.9 million to the total increase in coal sales and an increase in tons sold contributed $34.9 million to the total increase in coal sales.

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

Operating expenses. Operating expenses increased 18.3% to $436.5 million in 2004 from $368.8 million in 2003. The increase of $67.7 million was associated with additional coal sales of 1.6 million tons, including the following specific factors:

- Labor and benefit costs increased $18.1 million reflecting increased headcount, pay rate increases, higher levels of overtime and escalating health care costs;

- Material and supplies and maintenance costs increased $19.5 million and $9.3 million, respectively, reflecting increased production and increased costs for the products and services used in the mining process;

- Third-party mining costs increased $1.9 million reflecting the addition, late in the year 2004, of two small third party mining operations at Mettiki;

- Production taxes and royalties (which are incurred as a percentage of coal sales or volumes) increased $7.7 million;

- Coal supply agreement buy-out expense of $3.5 million; and

- Expenses of $4.1 million associated with the MC Mining Fire Incident.

Our initial estimate of the minimum non-reimbursable costs attributable to the MC Mining Fire Incident was $4.1 million. The $3.5 million buy-out expense of several coal supply agreements allowed us to take advantage of anticipated higher spot coal prices in 2005. Additionally, operating expense per ton sold was adversely impacted by adverse geologic conditions at our Pontiki mine and increased longwall moves associated with shorter longwall panels at Mettiki.

Outside purchases. Outside purchases increased 16.5% to $9.9 million in 2004 from $8.5 million in 2003. The increase was primarily attributable to an increase in outside purchases associated with our Illinois Basin ($4.6 million) and Central Appalachia ($2.7 million) operations partially offset by a decrease in the domestic brokerage market of $6.1 million.

Other sales and operating revenues. Other sales and operating revenues are primarily comprised of services to the coal synfuel production facility and increased 11.5% to $24.1 million in 2004 from $21.6 million in 2003. The increase of $2.5 million was primarily attributable to $1.5 million of additional rental and service fees associated with increased volumes at SSO s coal synfuel facility that originally operated at Hopkins County Coal and was relocated to Warrior in April 2003 and $1.1 million of additional transloading fees attributable to increased volumes at the Mt. Vernon Transfer Terminal.

General and administrative. General and administrative expenses for 2004 increased to $45.4 million compared to $28.3 million for 2003. The $17.1 million increase was primarily attributable to higher incentive compensation expense, which increased approximately $16.0 million. The last reported sales price of our common units on the NASDAQ was $37.00 on December 31, 2004 compared to a closing price of $17.19 on December 31, 2003 (both closing prices are adjusted for the two-for-one unit split in September 2005).

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased to $53.7 million in 2004 compared to $52.5 million in 2003. The increase of $1.2 million was primarily the result of additional depreciation expense associated with increased capital expenditures and infrastructure investments over the last few years, which have increased our production capacity. The increase was partially offset by a $2.6 million decrease in depreciation attributable to operating Hopkins County Coal six months in 2003 compared to three months in 2004.

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

Transportation revenues and expenses. Transportation revenues and expenses increased 52.5% to $29.8 million in 2004 from $19.6 million for 2003. The increase of $10.2 million was primarily attributable to increased shipments to customers that reimburse us for transportation costs rather than arranging and paying for transportation directly with transportation providers. Transportation services are a pass-through to our customers. Consequently, we do not realize any margin on transportation revenues.

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

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

Our Segment Adjusted EBITDA of $193.3 million for 2004 was $46.0 million, or 31.3% higher than 2003 Segment Adjusted EBITDA of $147.2 million. Segment Adjusted EBITDA, tons sold, coal sales, operating revenues and Adjusted Segment EBITDA Expense by segment are as follows (in thousands):

	Year Ended December 31,		**Increase (Decrease)**	
	2004	**2003**		
Segment Adjusted EBITDA				
Illinois Basin	$ 121,763	$ 95,351	$ 26,412	27.7%
Central Appalachia	28,953	23,962	4,991	20.8%
Northern Appalachia	41,141	27,288	13,853	50.8%
Other and Corporate	1,432	624	808	129.5%
Total Segment Adjusted EBITDA (1)	$ 193,289	$ 147,225	$ 46,064	31.3%
Tons sold				
Illinois Basin	13,760	12,223	1,537	12.6%
Central Appalachia	3,781	3,608	173	4.8%
Northern Appalachia	3,282	3,445	(163)	(4.7)%
Other and Corporate		191	(191)	
Total tons sold	20,823	19,467	1,356	7.0%
Coal sales				
Illinois Basin	$ 356,307	$ 301,976	$ 54,331	18.0%
Central Appalachia	143,160	114,366	28,794	25.2%
Northern Appalachia	99,932	79,076	20,856	26.4%
Other and Corporate		6,178	(6,178)	
Total coal sales	$ 599,399	$ 501,596	$ 97,803	19.5%
Other sales and operating revenues				
Illinois Basin	$ 19,087	$ 17,233	$ 1,854	10.8%
Central Appalachia	187	779	(592)	(76.0)%
Northern Appalachia	2,127	1,980	147	7.4%
Other and Corporate	2,672	1,606	1,066	
Total operating revenues	$ 24,073	$ 21,598	$ 2,475	11.5%

Segment Adjusted EBITDA Expense				
Illinois Basin	$ 268,848	$ 223,858	$ 44,990	20.1%
Central Appalachia	114,394	91,183	23,211	25.5%
Northern Appalachia	60,917	53,768	7,149	13.3%
Other and Corporate	1,241	7,160	(5,919)	
Total Segment Adjusted EBITDA Expense (2)	$ 445,400	$ 375,969	$ 69,431	18.5%

(1) Segment Adjusted EBITDA is defined as net income before income tax expense (benefit), interest expense and interest income, depreciation, depletion and amortization, and general and administrative expense. Adjusted Segment EBITDA is reconciled to income before income taxes below.

(2) Segment Adjusted EBITDA Expense includes operating expenses, outside purchases and other income. Pass through transportation expenses are excluded.

IIllinois Basin Segment Adjusted EBITDA for 2004 increased $26.4 million, or 27.7%, to $121.8 million as compared to 2003 Segment Adjusted EBITDA of $95.4 million. The increase was primarily attributable to increased coal sales which rose $54.3 million in 2004 to $356.3 million, reflecting a 1.5 million ton, or 12.6%, increase in tons sold to 13.8 million tons (which contributed $37.9 million of the increase in coal sales) and a 4.8% increase in the average coal sales price per ton to $25.90 per ton (which contributed $16.4 million of the increase in coal sales). Other sales and operating revenues increased $1.9 million in 2004 to $19.1 million, reflecting additional revenues associated with SSO s coal synfuel facility. Segment Adjusted EBITDA Expense for 2004 increased 20.1% to $268.8 million while Segment Adjusted EBITDA Expense per ton increased 6.7% to $19.54. This increase reflects the impact of increased costs as discussed under consolidated operating expenses and outside purchases above, including the $3.3 million associated with the buy-out of several coal supply agreements that allowed us to take advantage of higher spot coal prices in 2005. The impact of increased costs was partially offset by higher production in 2004, which increased 1.1 million tons, or 8.9%, to 13.5 million tons. Segment Adjusted EBITDA for the year 2004 includes $15.2 million reported as the net gain from insurance settlement associated with the Dotiki Fire Incident.

Central Appalachia Segment Adjusted EBITDA for 2004 increased $5.0 million, or 20.8%, to $29.0 million as compared to 2003 Segment Adjusted EBITDA of $24.0 million. The increase was primarily attributable to increased coal sales, which rose $28.8 million in 2004 to $143.2 million, reflecting a 19.4% increase in the average coal sales price per ton to $37.86 per ton (which contributed $23.3 million of the increase in coal sales) and increased tons sold of 0.2 million tons (which contributed $5.5 million of the increase in coal sales). Segment Adjusted EBITDA Expense for 2004 increased 25.5% to $114.4 million while Segment Adjusted EBITDA Expense per ton increased 19.7% to $30.25, reflecting less favorable mining conditions and the impact of cost increases as discussed under consolidated operating expenses and outside purchases above. Segment Adjusted EBITDA Expense for the year 2004 included $4.1 million reflecting our initial estimate of the minimum non-reimbursable costs attributable to the MC Mining Fire Incident.

Northern Appalachia Segment Adjusted EBITDA for 2004 increased $13.9 million, or 50.8%, to $41.1 million as compared to 2003 Segment Adjusted EBITDA of $27.3 million. The increase was primarily attributable to increased coal sales which rose $20.9 million in 2004 to $99.9 million, reflecting a 32.6% increase in the average coal sales price per ton to $30.45 (which increased coal sales by $24.6 million). The higher average coal sales price per ton was attributable to spot market opportunities for sales into the export market to satisfy demand created by economic expansion in China and India. The increase was partially offset by a 0.2 million ton decrease in tons sold during 2004 to 3.3 million tons (which reduced coal sales by $3.7 million). Segment Adjusted EBITDA Expense for 2004 increased 13.3% to $60.9 million, while Segment Adjusted EBITDA Expense per ton increased 18.9% to $18.56, primarily as a result of less favorable mining conditions and the impact of cost increases and described under consolidated operating expenses above.

Other and Corporate Lower coal sales and Segment Adjusted EBITDA Expense reflects a reduction in coal brokerage volumes. A strengthening coal market resulted in reduced opportunities for coal brokerage transactions.

A reconciliation of Adjusted Segment EBITDA to net income is as follows (in thousands):

	Year Ended December 31, 2004	2003
Segment Adjusted EBITDA	$ 193,289	$ 147,225
General & administrative	(45,400)	(28,270)
Depreciation, depletion and amortization	(53,664)	(52,495)
Interest expense	(14,963)	(15,981)
Income taxes	(2,641)	(2,577)
Net income	$ 76,621	$ 47,902

Long-Term Incentive Plan

On October 25, 2005, the compensation committee of our managing general partner determined that the vesting requirements for the 2003 LTIP grants of 278,710 restricted units (net of 3,700 restricted unit forfeitures) had been satisfied as of September 30, 2005. As a result of this vesting, on November 1, 2005, we issued 165,426 common units to LTIP participants. The remaining units were settled in cash primarily to satisfy individual tax obligations of the LTIP participants.

Unit Split

On September 15, 2005, we completed a two-for-one split of our common units, whereby holders of record at the close of business on September 2, 2005 received one additional common unit for each common unit owned on that date. This unit split resulted in the issuance of 18,130,440 common units.

Pattiki Vertical Belt Incident

On June 14, 2005, our Pattiki mine was temporarily idled following the failure of the vertical conveyor belt system (the Vertical Belt Incident) used in conveying raw coal out of the mine. White County Coal surface personnel detected a failure of the vertical conveyor belt on June 14, 2005 and immediately shut down operation of all underground conveyor belt systems. On July 20, 2005, White County Coal s efforts to repair the vertical belt system had progressed sufficiently to allow it to perform a full test of the vertical belt system. After evaluating the test results, the Pattiki mine resumed initial production operations on July 21, 2005. Production of raw coal has returned to levels that existed prior to the occurrence of the Vertical Belt Incident. The majority of repairs to the vertical belt conveyor system and ancillary equipment have been completed. Operating expenses were increased by $2.9 million in 2005 to reflect the estimated direct expenses and costs attributable to the Vertical Belt Incident, which estimate included a $1.3 million retirement of the damaged vertical belt equipment. We have not identified currently any significant additional costs compared to the original cost estimates. We conducted an analysis of a number of possible alternatives to mitigate the losses arising from the Vertical Belt Incident. This analysis included a review of the Vertical Belt System Design, Supply, and Oversight of Installation Contract (Installation Contract), dated December 7, 2000, between White County Coal and Lake Shore Mining, Inc. As a result of this analysis, we filed suit on January 19, 2006, against Frontier-Kemper Constructors, Inc. to whom Lake Shore Mining, Inc. had assigned all of its rights and obligations under the Installation Contract, for the damages we suffered on account of the Vertical Belt Incident. Until this litigation is resolved, however, we can make no assurances of the amount or timing of recoveries, if any. Concurrent with the renewal of our commercial property (including business interruption) insurance policies concluded on October 31, 2005, White County Coal confirmed with the current underwriters of the commercial property insurance coverage that it would not file a formal insurance claim for losses arising from or in connection with the Vertical Belt Incident.

MC Mining Fire

On December 26, 2004 the MC Mining Excel No. 3 mine was temporarily idled following the occurrence of a mine fire (MC Mining Fire Incident). The fire was discovered by mine personnel near the bottom of the Excel No. 3 mine slope late the evening of December 25, 2004. Under a firefighting plan developed by MC Mining, in cooperation with mine emergency response teams from MSHA and the Kentucky Office of Mine Safety and Licensing, the four portals at the Excel No. 3 mine were capped to deprive the fire of oxygen. A series of boreholes were then drilled into the fire area to further suppress the fire. As a result of these efforts, the mine atmosphere was rendered substantially inert, or without oxygen, and the Excel No. 3 mine fire was effectively suppressed. MC Mining then began construction of temporary and permanent barriers designed to completely isolate the mine fire area. Once construction of the permanent barriers was completed, MC Mining began efforts to repair and rehabilitate the Excel No. 3 mine infrastructure. On February 21, 2005, the repair and rehabilitation efforts had progressed sufficiently to allow initial resumption of production. Coal production has returned to near normal levels, but continues to be adversely impacted by inefficiencies attributable to or associated with the MC Mining Fire Incident.

We maintain commercial property (including business interruption) insurance policies with various underwriters, which are renewed annually in October and provide for self-retention and various applicable deductibles, including certain monetary and/or time element forms of deductibles, (collectively, the 2005 Deductibles) and 10% co-insurance (2005 Co-Insurance), but we cannot give any assurances as to the eventual timing or amount of any recovery of proceeds under these policies. We believe such insurance coverage will cover a substantial portion of the total cost of the disruption to MC Mining s operations. However, concurrent with the renewal of our commercial property (including business interruption) insurance policies concluded on October 31, 2005, MC Mining confirmed with the current underwriters of the commercial property insurance coverage that any negotiated settlement of the losses arising from or in connection with the MC Mining Fire Incident would not exceed $40.0 million (inclusive of the 2005 Co-insurance and 2005 Deductible amounts). Until the claim is resolved ultimately, either through the claim adjustment process, settlement, or litigation, with the applicable underwriters, we can make no assurance of the amount or timing of recovery of insurance proceeds.

We made an initial estimate of certain costs primarily associated with activities relating to the suppression of the fire and the initial resumption of operations. Operating expenses for 2004 were increased by $4.1 million to reflect an initial estimate of certain minimum costs attributable to the MC Mining Fire Incident that are not reimbursable under our insurance policies due to the application of the 2005 Deductibles and 2005 Co-Insurance.

Following the initial two submittals to a representative of the underwriters of our estimate of the expenses and losses (including business interruption losses) incurred by MC Mining and other affiliates arising from and in connection with the MC Mining Fire Incident (MC Mining Insurance Claim), on September 15, 2005, we filed a third partial proof of loss, with an update through July 31, 2005. Partial payments of $12.2 million were received in 2005, which are net of the 2005 Deductibles and 2005 Co-Insurance. The accounting for these partial payments and future payments, if any, made to us by the underwriters will be subject to the accounting methodology described below. We continue to evaluate our potential insurance recoveries under the applicable insurance policies in the following areas:

1. Fire Brigade/Extinguishing/Mine Recovery Expense; Expenses to Reduce Loss; Debris Removal Expenses; Demolition and Increased Cost of Construction; Expediting Expenses; and Extra Expenses incurred as a result of the fire These expenses and other costs (e.g. professional fees) associated with extinguishing the fire, reducing the overall loss, demolition of certain property and removal of debris, expediting the recovery from the loss, and extra expenses that would not have been incurred by us, but for the MC Mining Fire Incident, are being expensed as incurred with related actual and/or estimated insurance recoveries recorded as they are considered to be probable, up to the amount of the actual cost incurred.

2. Damage to MC Mining mine property The net book value of property destroyed of $154,000, was written off in the first quarter of 2005 with a corresponding amount recorded as an estimated insurance recovery, since such recovery is considered probable. Any insurance proceeds from the claims relating to the MC Mining mine property (other than amounts relating to the matters discussed in 1. above) that exceed the net book value of such damaged property would result in a gain. Any gain will be recorded when the MC Mining Insurance Claim is resolved and/or proceeds are received.

3. MC Mining mine business interruption losses We have submitted to a representative of the underwriters a business interruption loss analysis for the period of December 24, 2004 through July 31, 2005. Expenses associated with business interruption losses are expensed as incurred, and estimated insurance recoveries of such losses are recognized to the extent such recoveries are considered to be probable, up to the actual amount incurred. Recoveries in excess of actual costs incurred will be recorded as gains when the MC Mining Insurance Claim is resolved and/or proceeds are received.

In 2005, pursuant to the accounting methodology described above, of the $12.2 million of partial payments received, we recorded, as an offset to operating expenses, $10.7 million, which amount represents the current estimated insurance recovery of actual costs incurred, net of the 2005 Deductibles and 2005 Co-Insurance. We continue to discuss the MC Mining Insurance Claim and the determination of the total claim amount with representatives of the underwriters. The MC Mining Insurance Claim will continue to be developed as additional information becomes available and we have completed our assessment of the losses (including the methodologies associated therewith) arising from or in connection with the MC Mining Fire Incident. At this time, based on the magnitude and complexity of the MC Mining Insurance Claim, we are unable to reasonably estimate the total amount of the MC Mining Insurance Claim as well as its exposure, if any, for amounts not covered by the our insurance program.

Dotiki Mine Fire

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

On September 10, 2004, we filed a third and final proof of loss with the applicable insurance underwriters reflecting a settlement of all expenses, losses and claims incurred by Webster County Coal and other affiliates arising from or in connection with the Dotiki Fire Incident in the aggregate amount of $27.0 million, inclusive of a $1.0 million self-retention of initial loss, a $2.5 million deductible and 10% co-insurance.

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

Ongoing Acquisition Activities

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

Liquidity and Capital Resources

Liquidity

We generally satisfy our working capital requirements and fund our capital expenditures and debt service obligations from cash generated from operations and borrowings under our revolving credit facility. We believe that the cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated capital expenditures (other than major capital improvements or acquisitions), scheduled debt payments and distribution payments. To further develop available financing alternatives, in October 2002, we entered into a master lease agreement. Under the master lease agreement, lease terms and rental payments are negotiated individually when specific pieces of equipment are leased. During 2005, 2004 and 2003, we had rental expense of $0.8 million, $1.3 million and $1.0 million, respectively, under the master lease agreement. Our credit facility limits the amount of total operating lease obligations to $15.0 million payable in any period of 12 consecutive months. Our ability to satisfy our obligations and planned expenditures will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry, some of which are beyond our control.

We earn income by supplying three coal synfuel facilities with coal feedstock and assist the owners of two of these facilities with the marketing of coal synfuel as well as the provision of certain other services. Assuming that coal pricing would not have increased without the availability of coal synfuel, the incremental net income benefit associated with these facilities (i.e., which equals cash generation except for working capital timing differences) was $24.1 million for the year ended December 31, 2005.

The continuation of the incremental net income benefit associated with the coal synfuel related agreements, however, cannot be assured. The terms of the coal synfuel related agreements expire on December 31, 2007, and the agreements are not expected to be extended. Additionally, the term of the synfuel related 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. However, we have maintained back up coal supply agreements with each coal synfuel customer that automatically provides for sale of our coal to these customers in the event they do not purchase coal synfuel.

One of the states in which we operate has established a statutory framework for tax credits against income or franchise taxes, which tax credit has benefited, directly or indirectly, coal operators or customers purchasing coal produced from mines within that state. Our indirect benefit of this state tax credit was $8.3 million for the year ended December 31, 2005. Although this tax credit is not set to expire by its terms in the near future, legislation may be proposed in the future that would eliminate the credit as a potential measure to reduce that state s budget deficit.

Crude oil and natural gas prices have increased significantly since 2003. These increases have not had a material direct impact on our financial results since our direct purchases of crude oil based fuel and natural gas does not represent a significant percentage of our operating expenses. Higher crude oil and natural gas prices have also resulted in increases to the cost of goods, services and equipment provided to us and therefore indirectly impacted our financial results. We can provide no assurance that we will be able to pass the impact of these direct or indirect cost increases through to our customers.

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Cash Flows

Cash provided by operating activities was $193.6 million in 2005, compared to $145.1 million in 2004. The increase in cash provided by operating activities was attributable principally to an increase in net income partially offset by an increase in total working capital. Increased working capital reflects a revenue driven increase in trade receivables, increased inventories, prepaid expenses and advance royalties, partially offset by increased accounts payable due to increased production and a lesser increase in 2005 compared to 2004 in the total accrued liability for the LTIP included in the current and long-term liability due to affiliates resulting from the vesting in 2005 of the 2003 LTIP grants and in 2004 of the 2000 to 2002 LTIP grants.

Net cash used in investing activities was $110.2 million in 2005, compared to $77.6 million in 2004. The increase is primarily attributable to an increase in capital expenditures associated with the addition of continuous mining units at our Pattiki and Warrior mining complexes and costs associated with the initial development of the Elk Creek and Mountain View mines along with construction to transition the Pontiki mine into the Van Lear coal seam. The increase in investing activities was partially offset by purchases, net of proceeds, of marketable securities during 2004 of $25.7 million.

Net cash used in financing activities was $82.6 million for 2005 compared to $46.4 million for 2004. The increase is primarily attributable to a scheduled $18.0 million debt payment in August 2005 in addition to increased distributions to partners in 2005.

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 the sale of marketable securities, and borrowings under our revolving credit facility. The following table provides details regarding our contractual cash obligations as of December 31, 2005 (in thousands):

Contractual Obligations	Total	Less than 1 year	2-3 years	4-5 years	After 5 years
Long-term debt	$ 162,000	$ 18,000	$ 36,000	$ 36,000	$ 72,000
Future interest obligations on long-term debt	62,406	12,917	21,347	15,364	12,778
Operating leases	15,874	3,812	6,643	5,203	216
Other long-term obligations (excluding discount effect of $29.4 million for reclamation liability)	70,652	2,597	7,675	3,223	57,157
Purchase obligations for capital projects	10,830	10,830			
ICG coal purchases	46,526	46,526			
	$ 368,288	$ 94,682	$ 71,665	$ 59,790	$ 142,151

We expect to contribute $7.9 million to the defined benefit pension plan (Pension Plan) during 2006. We estimate our income tax cash requirements to be approximately $2.7 million in 2006.

Capital Expenditures

Capital expenditures increased to $119.9 million in 2005 compared to $54.7 million in 2004. See discussion of Cash Flows above concerning the increase in capital expenditures. Capital expenditures includes items received but not yet paid, which is disclosed as non-cash activity, purchase of property, plant and equipment in Supplemental Cash Flow Information in Item 8, Financial Statements Consolidated Statements of Cash Flows.

We currently project that our average annual maintenance capital expenditures will be approximately $59.4 million. We also currently expect to fund our anticipated total capital expenditures for 2006 of $160.0 million, with cash generated from operations and borrowings under our revolving credit facility described below.

Notes Offering and Credit Facility

Alliance Resource Operating Partners, L.P., our intermediate partnership, has $162.0 million principal amount of 8.31% senior notes due August 20, 2014, payable in nine remaining equal annual installments of $18.0 million beginning in August 2005 with interest payable semi-annually (Senior Notes). On August 22, 2003, our intermediate partnership completed an $85 million revolving credit facility (Credit Facility), which expires September 30, 2006. The Credit Facility replaced a $100 million credit facility that would have expired August 2004. We paid in full all amounts outstanding under the $100 million original credit facility with borrowings of $20 million under the Credit Facility. The interest rate on the Credit Facility is based on either the (i) London Interbank Offered Rate (LIBOR) or (ii) the Base Rate, which is equal to the greater of the JPMorgan Chase Prime Rate or the Federal Funds Rate plus 1/2 of 1%, plus, in either case, an applicable margin. We incurred certain costs aggregating $1.2 million associated with the Credit Facility. These costs have been deferred and are being amortized as a component of interest expense over the term of the Credit Facility. We had no borrowings outstanding under the Credit Facility at December 31, 2005. Letters of credit can be issued under the Credit Facility not to exceed $30.0 million. Outstanding letters of credit reduce amounts available under the Credit Facility. At December 31, 2005, we had letters of credit of $9.0 million outstanding under the Credit Facility.

The Senior Notes and Credit Facility are guaranteed by all of the subsidiaries of our intermediate partnership. The Senior Notes and Credit Facility contain various restrictive and affirmative covenants, including restrictions on the amount of distributions by our intermediate partnership and the incurrence of other debt. We were in compliance with the covenants of both the Credit Facility and Senior Notes at December 31, 2005.

We have previously entered into and have maintained agreements with two banks to provide additional letters of credit in an aggregate amount of $25.0 million to maintain surety bonds to secure our obligations for reclamation liabilities and workers compensation benefits as statutorily required. At December 31, 2005, we had $24.8 million in letters of credit outstanding under these agreements. Our special general partner guarantees the letters of credit.

Critical Accounting Policies

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

Revenue Recognition

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

Long-Lived Assets

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

Mine Development Costs

Mine development costs are capitalized until production, other than production incidental to the mine development process, commences and amortized over the estimated life of the mine. Mine development costs represent costs that establish access to mineral reserves and include costs associated with sinking or driving shafts and underground drifts, permanent excavations, roads and tunnels.

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 $41.3 million and $34.0 million for these costs at December 31, 2005 and 2004, respectively. The liability for mine reclamation and closing procedures is sensitive to changes in cost estimates and estimated mine lives.

Workers Compensation and Pneumoconiosis (Black Lung) Benefits

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. We provide for these claims through self-insurance programs. The liability for traumatic injury claims is the estimated present value of current workers compensation benefits, based on an annual independent actuarial study. The actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including development patterns, mortality, medical costs and interest rates. We had accrued liabilities of $37.0 million and $32.6 million for these costs at December 31, 2005 and 2004, respectively. A one-percentage-point reduction in the discount rate would have increased the liability at December 31, 2005 approximately $2.1 million, which would have a corresponding increase in operating expenses.

Coal mining companies are subject to the Federal Coal Mine Health and Safety Act of 1969, as amended, and various state statutes for the payment of medical and disability benefits to eligible recipients related to coal worker s pneumoconiosis or 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 $23.8 million and $20.3 million for these benefits at December 31, 2005 and 2004, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2005 by approximately $1.2 million. Under the service cost method used to estimate our black lung benefits liability, actuarial gains or losses attributable to changes in actuarial assumptions such as the discount rate are amortized over the remaining service period of active miners.

Universal Shelf

In April 2002, we filed with the Securities and Exchange Commission a universal shelf registration statement allowing us to issue from time-to-time up to an aggregate of $200 million of debt or equity securities. At March 5, 2006, we had approximately $143 million available under this registration statement.

Related Party Transactions

Administrative Services

Our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses they incur or payments they make on our behalf, including, but not limited to, management s salaries and related benefits (including incentive compensation), and accounting, budget, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers compensation management, legal and information technology services. Our managing general partner may determine in its sole discretion the expenses that are allocable to us. Total costs billed by our managing general partner and its affiliates to us were approximately $14,069,000, $28,536,000, and $12,471,000 for the years ended December 31, 2005, 2004, and 2003, respectively. The decrease from 2005 to 2004 was primarily attributable to lower compensation accruals for the

LTIP, Short-Term Incentive Plan (STIP) and Supplemental-Executive Retirement Plan (SERP). The increase from 2003 to 2004 was primarily attributable to higher accruals for the LTIP, STIP and SERP. The expenses associated with LTIP and SERP were impacted by the market value of the our common units, which had a closing market price of $37.20, $37.00, and $17.19 at December 31, 2005, 2004 and 2003, respectively. The amounts billed by the managing general partner include $10,559,000, $24,242,000, and $9,319,000 for the years ended December 31, 2005, 2004 and 2003, respectively, for the LTIP, STIP and SERP.

Tunnel Ridge Acquisition

In January 2005, we acquired 100% of the limited liability company member interests of Tunnel Ridge, LLC (Tunnel Ridge) for approximately $500,000 and the assumption of reclamation liabilities from Alliance Resource Holdings, Inc., a company owned by our management. Tunnel Ridge controls through a coal lease agreement with our special general partner, approximately 9,400 acres of land located in Ohio County, West Virginia and Washington County, Pennsylvania containing an estimated 70 million tons of high-sulfur coal in the Pittsburgh No. 8 coal seam. Under the terms of the coal lease, beginning on January 1, 2005, Tunnel Ridge has paid and will continue to pay our special general partner an advance minimum royalty of $3.0 million per year. The advance royalty payments are fully recoupable against earned royalties.

Tunnel Ridge also has rights to surface land and other tangible assets under a separate lease agreement with our special general partner. Under the terms of the lease agreement, Tunnel Ridge has paid and will continue to pay our special general partner an annual lease payment of $240,000. The lease agreement has an initial term of four years, which may be extended to be consistent with the term of the coal lease. Lease expense was $240,000 for the year ended December 31, 2005.

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

Warrior Acquisition

On February 14, 2003, we acquired Warrior Coal from an affiliate, ARH Warrior Holdings, a subsidiary of Alliance Resource Holdings, a subsidiary of ARH, pursuant to a 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. 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 Coal. 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 Coal in January 2001 for $10.0 million.

The Put/Call Agreement preserved the opportunity for us to acquire Warrior Coal during a specified time period. Under the terms of the Put/Call Agreement, ARH Warrior Holdings exercised its put option requiring 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 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, we developed financial projections for Warrior Coal 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 Coal included, among others, (a) annual production levels ranging from 1.5 million to 1.8 million tons, (b) coal prices at or below the then current coal prices and (c) a discount rate of 12 percent. Based on these financial projections, as of the date of the acquisition and at December 31, 2002 and 2001, we believe that the fair value of Warrior Coal was equal to or greater than the put option exercise price.

The put option price of $12.7 million was paid to ARH Warrior Holdings in accordance with the terms of the Put/Call Agreement. In addition, we repaid Warrior Coal s borrowings of $17.0 million under the revolving credit agreement between our special general partner and Warrior Coal. The primary borrowings under the revolving credit agreement financed new infrastructure capital projects at Warrior Coal that have contributed to improved productivity and significantly increased capacity. We funded the Warrior Coal acquisition through a portion of the proceeds received from the issuance of 4,500,000 common units. Because the Warrior Coal acquisition was between entities under common control, it has been accounted for at historical cost in a manner similar to that used in a pooling of interests.

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

SGP Land

Webster County Coal has a mineral lease and sublease with SGP Land requiring annual minimum royalty payments of $2.7 million, payable in advance through 2013 or until $37.8 million of cumulative annual minimum and/or earned royalty payments have been paid. Webster County Coal paid royalties of $3,449,000, $4,611,000, and $3,460,000 for the years ended December 31, 2005, 2004 and 2003, respectively. As of December 31, 2005, Webster County Coal has recouped, as earned royalties, all advance minimum royalty payments made under these lease terms except for $1,018,000.

Warrior Coal has a mineral lease and sublease with SGP Land. Under the terms of the lease, Warrior Coal has paid and will continue to pay in arrears an annual minimum royalty obligation of $2,270,000 until $15,890,000 of cumulative annual minimum and/or earned royalty payments have been paid. The annual minimum royalty periods are from October 1st through the end of the following September, expiring September 30, 2007. Warrior Coal paid royalties of $3,627,000, $2,561,000, and $2,453,000 for the years ended December 31, 2005, 2004, and 2003, respectively. As of December 31, 2005, Warrior Coal has recouped, as earned royalties, all advance minimum royalty payments made in accordance with these lease terms.

Under the terms of the mineral lease and sublease agreements described above, Webster County Coal and Warrior Coal also reimbursed SGP Land for SGP Land s base lease obligations. We reimbursed SGP Land $6,379,000, $5,428,000, and $4,395,000 for the years ended December 31, 2005, 2004 and 2003 respectively, for the base lease obligations. As of December 31, 2005, Webster County Coal and Warrior Coal have recouped, as earned royalties, all advance minimum royalty payments made in accordance with these terms except for $236,000.

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 $600,000 and $479,000 during the years ended December 31, 2005 and 2003, respectively. The 2004 annual minimum royalty obligation of $300,000 was paid in January, 2005. As of December 31, 2005, MC Mining has recouped, as earned royalties, all advance minimum royalty payments made in accordance with these lease terms except for $600,000.

On October 23, 2005, we exercised our option to lease and/or sublease certain reserves from SGP Land that are associated with Hopkins County Coal s Elk Creek mine. Upon exercise of the option agreement, Hopkins County Coal entered into a Coal Lease and Sublease Agreement as well as a Royalty Agreement (collectively the Coal Lease Agreements). The terms of the Coal Lease Agreements are through December 2015, with the right to extend the term for successive one-year periods for as long as we are mining within the coal field, as such term is defined in the Coal Lease Agreements.

The Coal Lease Agreements provide for five annual minimum royalty payments of $684,000. The combined annual minimum royalty payments, consistent with the option agreement, and cumulative option fees of $3.4 million previously paid by Hopkins County Coal are fully recoupable against future tonnage royalty payments. Under the terms of the Coal Lease Agreements, Hopkins County Coal will also reimburse SGP Land for SGP Land s base lease obligations. Under

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the terms of the option to lease and/or lease and sublease agreements, Hopkins County Coal paid advance minimum royalties and/or option fees of $684,000 and $1,368,000 during the years ended December 31, 2005 and 2004, respectively. The 2003 option fee of $684,000 was paid in January 2004 and is included in the due to affiliates balance sheet as of December 31, 2003. As of December 31, 2005, Hopkins County Coal has available $4,059,000 of advance minimum royalty payments made under the Coal Lease Agreements that management expects will be recouped against future production.

Special General Partner

Effective January 2001, Gibson entered into a noncancelable operating lease arrangement with our special general partner for its coal preparation plant and ancillary facilities. Based on the terms of the lease, Gibson has paid and will continue to make monthly payments of approximately $216,000 through January 2011. Lease expense incurred for each of the three years in the period ended December 31, 2005 was $2,595,000.

We have previously entered into and have maintained agreements with two banks to provide letters of credit in an aggregate amount of $25.0 million. At December 31, 2005, we had $24.8 million in outstanding letters of credit. Our special general partner guarantees these letters of credit. Historically, we have compensated our special general partner a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. Our special general partner agreed to waive the guarantee fee in exchange for a parent guarantee from our intermediate partnership and Alliance Coal, LLC on the mineral lease and sublease with Webster County Coal and Warrior Coal. Since the guarantee is made on behalf of entities within the consolidated partnership, the guarantee has no fair value under Financial Accounting Standards Board (FASB) Interpretation No. 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, including Indirect Guarantees of Indebtedness of Others,* and does not impact the consolidated financial statements. We paid approximately $31,300 in guarantee fees to our special general partner for the year ended December 31, 2003.

Accruals of Other Liabilities

We had accruals for other liabilities, including current obligations, totaling $115.5 million and $101.1 million at December 31, 2005 and 2004. These accruals were chiefly comprised of workers compensation benefits, black lung benefits, and costs associated with reclamation and mine closings. These obligations are self-insured. The accruals of these items were based on estimates of future expenditures based on current legislation, related regulations and other developments. Thus, from time to time, our results of operations may be significantly affected by changes to these liabilities. Please see Item 8. Financial Statements and Supplementary Data. Note 15. Reclamation and Mine Closing Costs and Note 16. Pneumoconiosis (Black Lung) Benefits.

Pension Plan

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

Our pension expense was approximately $3,006,000 and $2,751,000 for the years ended December 31, 2005 and 2004, respectively. The pension expense is based upon a number of actuarial assumptions, including an expected long-term rate of returns on our Pension Plan assets of 8.0% and 8.0% and discount rates of 5.75% and 6.25% for the years ended December 31, 2005 and 2004, respectively. Our actual return on plan assets was 7.2% and 11.9% for the years ended December 31, 2005 and 2004, respectively. Additionally, we base our determination of pension expense on an unsmoothed market-related valuation of assets equal to the fair value of assets, which immediately recognizes all investment gains or losses.

In developing our expected long-term rate of return assumption, we evaluated input from our investment manager, including their review of asset class return expectations by economists, and our actuary. At January 1, 2006, our expected long-term return assumption is at least 8%. Our advisors base the projected returns on broad equity and bond indices. Our expected long-term rate of return on Pension Plan assets is based on an asset allocation assumption of 80.0% with equity managers, with an expected long-term rate of return of 10.4%, and 20.0% with fixed income managers, with an expected long-term rate of return of 5.3%. The pension plan trustee regularly reviews our actual asset allocation in accordance with our investment guidelines and periodically rebalances our investments to our targeted allocation when considered appropriate. The investment committee annually reviews our asset allocation with the compensation committee of our managing general partner.

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 5.75% at December 31, 2004 to 5.6% at December 31, 2005.

We estimate that our Pension Plan expense and cash contributions will be approximately $3,350,000 and $7,900,000, respectively, in 2006. Future actual pension expense and contributions will depend on future investment performance, changes in future discount rates and various other factors related to the employees participating in the Pension Plan.

Lowering the expected long-term rate of return assumption by 1.0% (from 8.0% to 7.0%) at December 31, 2004 would have increased our pension expense for the year ended December 31, 2005 by approximately $240,000. Lowering the discount rate assumption by 0.5% (from 5.75% to 5.25%) at December 31, 2004 would have increased our pension expense for the year ended December 31, 2005 by approximately $482,000.

Inflation

In 2005 an increase in the cost of steel, power and fuel has increased, directly and indirectly, our materials, supplies and maintenance costs. Other elements of inflation in the U.S. have 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, 2005.

New Accounting Standards

In November 2004, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 151, *Inventory Costs*. SFAS No. 151 is an amendment of Accounting Research Bulletin (ARB) No. 43, chapter 4, paragraph 5 that deals with inventory pricing. SFAS No. 151 clarifies the accounting for abnormal amounts of idle facility expenses, freight, handling costs, and spoilage. Under previous guidance, paragraph 5 of ARB No. 43, chapter 4, items such as idle facility expense, excessive spoilage, double freight, and rehandling costs might be considered to be so abnormal, under certain circumstances, as to require treatment as current period charges. This Statement eliminates the criterion of so abnormal and requires that those items be recognized as current period charges. Also, SFAS No. 151 requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. SFAS No. 151 is effective on January 1, 2006. We believe that its adoption will not have any significant impact on our financial position, results of operations or cash flows.

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

In April 2005, the Securities and Exchange Commission issued a rule that amended the implementation date for our adoption of SFAS No. 123R from the third quarter of 2005 to the first quarter of 2006. SFAS No. 123R permits companies to adopt its requirements using either a modified prospective method, or a modified retrospective method. Under the modified prospective method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS No. 123R, of all share-based payments granted after that date, and based on the requirements of SFAS No. 123 for all unvested awards granted prior to the effective date of SFAS No. 123R. Under the modified retrospective method, the requirements are the same as under the modified prospective method, but also permits entities to restate financial statements of previous periods based on pro forma disclosures made in accordance with SFAS No. 123. We adopted SFAS No. 123R on January 1, 2006. We used the modified prospective method of adoption provided under SFAS No. 123R, and therefore, will not restate prior period results. Because we have previously expensed share-based payments using the current market value of our common units at the end of each period, the adoption of SFAS No. 123R will not have a material impact on our consolidated results of operations. The intrinsic value previously recognized at December 31, 2005 essentially equals the fair value at January 1, 2006 and therefore, no incremental compensation cost will be recognized upon adoption of SFAS 123R. As required by SFAS No. 123R, the fair value will be reduced for expected forfeitures, to the extent compensation cost has been previously recognized and this amount will be recognized as a cumulative effect of accounting change. Because the

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share-based compensation will be settled by delivery of common units, except for the minimum statutory withholding requirements, the previously recognized liability reflected in the due to affiliates current and long-term accounts in the consolidated balance sheet will be reclassed to Partners Capital upon adoption of SFAS 123R.

As permitted by SFAS No. 123, prior to January 1, 2006, we accounted for share-based payments to employees using the APB No. 25 intrinsic method and related FASB Interpretation No. 28 based upon the current market value of our common units at the end of each period. We have recorded compensation expense of $8,193,000, $20,320,000 and $7,687,000 for each of the three years ended December 31, 2005, respectively.

In March 2005, the FASB issued Emerging Issues Task Force (EITF) No. 04-6, *Accounting for Stripping Costs in the Mining Industry* and concluded that stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced during the period that the stripping costs are incurred. EITF No. 04-6 does not address the accounting for stripping costs incurred during the pre-production phase of a mine. EITF No. 04-6 is effective for the first reporting period in fiscal years beginning after December 15, 2005 with early adoption permitted. The effect of initially applying this consensus would be accounted for in a manner similar to a cumulative-effect adjustment. Since we have historically adhered to the accounting principles similar to EITF No. 04-6 in accounting for stripping costs incurred at our surface operation, the adoption of EITF No. 04-6, on January 1, 2006, did not have a material impact on our consolidated financial statements.

In April 2005, the FASB adopted Financial Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47). FIN 47 clarifies that the term conditional asset obligation from SFAS No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform an asset retirement activity on which the timing or method of settlement is conditional on a future event and requires the recognition of such conditional obligations even though uncertainty exists. Our adoption of FIN 47 at December 31, 2005 did not affect on our consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We have significant long-term coal supply agreements. Virtually all of the long-term coal supply agreements are subject to price adjustment provisions, which permit an increase or decrease periodically in the contract price to principally reflect changes in specified price indices or items such as taxes, royalties or actual production costs. For additional discussion of coal supply agreements, please see Item 1. Business. Coal Marketing and Sales and Item 8. Financial Statements and Supplementary Data. Note 19. Concentration of Credit Risk and Major Customers.

Almost all of our transactions are, denominated in U.S. dollars, and as a result, we do not have material exposure to currency exchange-rate risks. At the current time, we do not have any interest rate, foreign currency exchange rate or commodity price-hedging transactions outstanding.

Borrowings under our Credit Facility are at variable rates and, as a result, we have interest rate exposure. Our earnings are not materially affected by changes in interest rates. We had no borrowings outstanding under the Credit Facility during 2005 or at December 31, 2005.

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, 2005, and 2004. The carrying amounts and fair values of financial instruments are as follows (in thousands):

Expected Maturity Dates as of December 31, 2005	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Total**	**Fair Value December 31, 2005**
Senior Notes fixed rate	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 72,000	$ 162,000	$ 176,254
Weighted Average interest rate	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%		

Expected Maturity Dates as of December 31, 2004	**2005**	**2006**	**2007**	**2008**	**2009**	**Thereafter**	**Total**	**Fair Value December 31,**

								2004
Senior Notes fixed rate	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 90,000	$ 180,000	$ 197,278
Weighted Average interest rate	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%		

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of the Managing

General Partner and the Partners of

Alliance Resource Partners, L.P.:

We have audited the accompanying consolidated balance sheets of Alliance Resource Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2005 and 2004, and the related consolidated statements of income, cash flows and Partners capital (deficit) and comprehensive income for each of the three years in the period ended December 31, 2005. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 16, 2006 expressed an unqualified opinion on management s assessment of the effectiveness of the Partnership s internal control over financial reporting and an unqualified opinion on the effectiveness of the Partnership s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Tulsa, Oklahoma

March 16, 2006

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 2005 AND 2004

(In thousands, except unit data)

	December 31, 2005	December 31, 2004
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 32,054	$ 31,177
Trade receivables, net	94,495	56,967
Other receivables	2,330	1,637
Marketable securities	49,242	49,397
Inventories	17,270	13,839
Advance royalties	2,952	3,117
Prepaid expenses and other assets	8,934	4,345
Total current assets	207,277	160,479
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment, at cost	635,086	526,468
Less accumulated depreciation, depletion and amortization	(330,672)	(292,900)
Total property, plant and equipment	304,414	233,568
OTHER ASSETS:		
Advance royalties	16,328	11,737
Coal supply agreements, net		2,723
Other long-term assets	4,668	4,277
Total other assets	20,996	18,737
TOTAL ASSETS	$ 532,687	$ 412,784
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 53,473	$ 30,961
Due to affiliates	8,795	10,338
Accrued taxes other than income taxes	13,177	10,742
Accrued payroll and related expenses	12,466	11,730
Accrued pension benefit	7,588	5,798
Accrued interest	4,855	5,402
Workers compensation and pneumoconiosis benefits	7,740	7,081
Other current liabilities	5,120	6,253
Current maturities, long-term debt	18,000	18,000
Total current liabilities	131,214	106,305
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities	144,000	162,000
Pheumoconiosis benefits	23,293	19,833
Workers compensation	30,050	25,994

Reclamation and mine closing	38,716	32,838
Due to affiliates	6,940	7,457
Other liabilities	2,697	3,170
Total long-term liabilities	245,696	251,292
Total liabilities	376,910	357,597
COMMITMENTS AND CONTINGENCIES		
PARTNERS CAPITAL:		
Limited Partners - Common Unitholders 36,426,306 and 36,260,880 units outstanding, respectively	461,068	363,658
General Partners deficit	(298,270)	(303,295)
Unrealized loss on marketable securities	(68)	(54)
Minimum pension liability	(6,953)	(5,122)
Total Partners capital	155,777	55,187
TOTAL LIABILITIES AND PARTNERS CAPITAL	$ 532,687	$ 412,784

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

FOR THE YEARS ENDED DECEMBER 31, 2005, 2004 AND 2003

(In thousands, except unit and per unit data)

	Year Ended December 31, 2005	2004	2003
SALES AND OPERATING REVENUES:			
Coal sales	$ 768,958	$ 599,399	$ 501,596
Transportation revenues	39,069	29,817	19,553
Other sales and operating revenues	30,691	24,073	21,598
Total revenues	838,718	653,289	542,747
EXPENSES:			
Operating expenses	521,488	436,471	368,835
Transportation expenses	39,069	29,817	19,553
Outside purchases	15,113	9,913	8,508
General and administrative	33,484	45,400	28,270
Depreciation, depletion and amortization	55,637	53,664	52,495
Interest expense (net of interest income and interest capitalized of $3,367, $852 and $545, respectively)	11,816	14,963	15,981
Net gain from insurance settlement		(15,217)	
Total operating expenses	676,607	575,011	493,642
INCOME FROM OPERATIONS	162,111	78,278	49,105
OTHER INCOME	581	984	1,374
INCOME BEFORE INCOME TAXES	162,692	79,262	50,479
INCOME TAX EXPENSE	2,682	2,641	2,577
NET INCOME	$ 160,010	$ 76,621	$ 47,902
ALLOCATION OF NET INCOME:			
PORTION APPLICABLE TO WARRIOR COAL LOSS PRIOR TO ITS ACQUISITION ON FEBRUARY 14, 2003	$	$	$ (666)
PORTION APPLICABLE TO PARTNERS INTEREST	160,010	76,621	48,568
NET INCOME	$ 160,010	$ 76,621	$ 47,902
GENERAL PARTNERS INTEREST IN NET INCOME	$ 12,409	$ 3,324	$ 306
LIMITED PARTNERS INTEREST IN NET INCOME	$ 147,601	$ 73,297	$ 47,596
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 2.89	$ 1.76	$ 1.30
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 2.84	$ 1.71	$ 1.26

DISTRIBUTIONS PAID PER COMMON AND SUBORDINATED UNIT	$ 1.58	$ 1.24	$ 1.05
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING BASIC	36,288,527	35,881,896	35,161,468
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING DILUTED	36,977,061	36,874,336	36,325,678

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31, 2005, 2004 AND 2003

(In thousands)

	Year Ended December 31,		
	2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 160,010	$ 76,621	$ 47,902
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	55,637	53,664	52,495
Reclamation and mine closings	1,918	1,622	1,341
Coal inventory adjustment to market	573	488	687
Loss on retirement of damaged vertical belt equipment	1,298		
Other	759	255	(353)
Changes in operating assets and liabilities:			
Trade receivables	(37,528)	(20,593)	(3,459)
Other receivables	(693)	294	(1,828)
Inventories	(4,004)	200	(2,049)
Prepaid expenses and other assets	(4,584)	(913)	(648)
Advance royalties	(4,396)	(1,307)	2,227
Accounts payable	13,115	8,678	(679)
Due to affiliates	4,928	14,194	9,978
Accrued taxes other than income taxes	2,435	367	2,270
Accrued payroll and related benefits	736	635	1,091
Pneumoconiosis benefits	3,460	2,702	1,064
Workers compensation	4,715	3,849	4,002
Other	(4,761)	4,299	(3,729)
Total net adjustments	33,608	68,434	62,410
Net cash provided by operating activities	193,618	145,055	110,312
CASH FLOWS FROM INVESTING ACTIVITIES:			
Purchase of property, plant and equipment	(110,517)	(54,713)	(43,004)
Purchase of Warrior Coal			(12,661)
Proceeds from sale of property, plant and equipment	198	687	913
Purchase of marketable securities	(63,448)	(49,271)	(23,091)
Proceeds from marketable securities	63,589	23,537	
Proceeds from assumption of liability		2,112	
Net cash used in investing activities	(110,178)	(77,648)	(77,843)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from common unit offering to public			53,927
Cash contribution by General Partners	143	3	9
Payments on Warrior Coal revolving credit balance			(17,000)
Borrowings under revolving credit and working capital facilities			31,600
Payments under revolving credit and working capital facilities			(31,600)
Payments on long-term debt	(18,000)		(31,250)
Distributions to Partners	(64,706)	(46,389)	(37,027)

Net cash used in financing activities	(82,563)	(46,386)	(31,341)
NET CHANGE IN CASH AND CASH EQUIVALENTS	877	21,021	1,128
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	31,177	10,156	9,028
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 32,054	$ 31,177	$ 10,156
SUPPLEMENTAL CASH FLOW INFORMATION:			
CASH PAID FOR:			
Cash paid for interest	$ 15,160	$ 15,229	$ 15,960
Cash paid for taxing authorities	$ 3,025	$ 2,150	$ 2,681
NON-CASH ACTIVITY:			
Purchase of property, plant and equipment	$ 9,364	$	$
Market value of common units issued to Long-Term Incentive Plan participants upon vesting	$ 6,988	$ 13,680	$

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL (DEFICIT) AND COMPREHENSIVE INCOME

FOR THE YEARS ENDED DECEMBER 31, 2005, 2004, AND 2003

(In thousands, except unit data)

	Number of Limited Partner Units		Limited Partners Capital		General Partners Capital	Unrealized Gain	Minimum Pension	Total Partners Capital
	Common	Subordinated	Common	Subordinated	(Deficit)	(Loss)	Liability	(Deficit)
Balance at January 1, 2003	17,965,560	12,845,062	$ 144,219	$ 112,916	$ (290,472)	$ (150)	$ (5,275)	$ (38,762)
Comprehensive income:								
Net income			31,346	16,250	306			47,902
Unrealized gain						48		48
Minimum pension liability							1,486	1,486
Total comprehensive income			31,346	16,250	306	48	1,486	49,436
Issuance of units to public	5,076,000		53,927					53,927
General Partners contribution					9			9
Retirement of common units contributed by Managing General Partner	(79,036)		(890)		890			
Subordinated units conversion to common units	6,422,530	(6,422,530)	57,268	(57,268)				
Warrior Coal purchase					(15,026)			(15,026)
Distribution to Partners			(22,799)	(13,487)	(741)			(37,027)
Balance at December 31, 2003	29,385,054	6,422,532	263,071	58,411	(305,034)	(102)	(3,789)	12,557
Comprehensive income:								
Net income			60,685	12,612	3,324			76,621
Unrealized gain						48		48
Minimum pension liability							(1,333)	(1,333)
Total comprehensive income			60,685	12,612	3,324	48	(1,333)	75,336
Issuance of units to Long-Term Incentive Plan participants upon vesting	462,252		13,680					13,680
General Partners contribution					3			3
Retirement of common units contributed by Managing General Partner	(8,958)		(265)		265			
Distribution to Partners			(36,548)	(7,988)	(1,853)			(46,389)
Subordinated units conversion to common units	6,422,532	(6,422,532)	63,035	(63,035)				
Balance at December 31, 2004	36,260,880		363,658		(303,295)	(54)	(5,122)	55,187
Comprehensive income:								
Net income			147,601		12,409			160,010
Unrealized loss						(14)		(14)
Minimum pension liability							(1,831)	(1,831)

Total comprehensive income		147,601		12,409	(14)	(1,831)	158,165
Issuance of units to Long-Term Incentive Plan participants upon vesting	165,426	6,988					6,988
General Partners contribution				143			143
Distribution to Partners		(57,179)		(7,527)			(64,706)
Balance at December 31, 2005	36,426,306	$ 461,068	$	$ (298,270)	$ (68)	$ (6,953)	$ 155,777

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2005, 2004, AND 2003

1. ORGANIZATION AND PRESENTATION

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

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

On September 15, 2005, the Partnership completed a two-for-one split of the Partnership s Common Units, whereby holders of record at the close of business on September 2, 2005 received one additional Common Unit for each Common Unit owned on that date. The unit split resulted in the issuance of 18,130,440 Common Units. For all periods presented, all references to the number of units and per unit net income and distribution amounts included in this report have been adjusted to give effect for the unit split.

The Partnership completed its initial public offering (the IPO) in August 1999, issuing 15,500,000 Common Units (Common Units) at $9.50 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, a 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 2,465,560 Common Units and 12,845,062 Subordinated Units (Subordinated Units), that converted into Common Units during November 2004 and 2003 (Note 10), issued to and 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 4,500,000 and 576,000 additional Common Units at a public offering price of $11.26 per unit and received net proceeds of $48.5 million and $6.2 million, respectively, before expenses of approximately $0.8 million, excluding underwriters fees. In November 2003, 6,422,530 outstanding Subordinated Units were converted to Common Units in accordance with the partnership agreement, and, in November 2004, the remaining 6,422,532 Subordinated Units converted to Common Units. The Partnership issued 165,426 and 462,252 additional Common Units in 2005 and 2004, respectively, pursuant to the Long-Term Incentive Plan (Note 14). If at any time not more than twenty percent of the then-issued and outstanding limited partner interests are held by persons other than the general partners and their affiliates, the managing general partner will have the right to acquire all, but not less than all, of the remaining limited partner interest held by unaffiliated persons.

On February 14, 2003, the Partnership acquired Warrior Coal, LLC (Warrior Coal) (Note 3). Because the Warrior Coal acquisition was between entities under common control, the acquisition was recorded at historical cost in a manner similar to that used in a pooling of interests.

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, 2005 and 2004 and the results of their operations, cash flows and changes in partners capital (deficit) and comprehensive income for each of the three years in the period ended December 31, 2005. 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, 2005 and 2004, the estimated fair value of long-term debt, including current maturities, was approximately $176.3 million and $197.3 million, respectively. The fair value of long-term debt is based on interest rates that management believes are currently available to the Partnership for issuance of debt with similar terms and remaining maturities.

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

Cash Management The Partnership has presented book overdrafts of $10,526,000 and $2,192,000 at December 31, 2005 and 2004, respectively, in accounts payable in the consolidated balance sheets.

Marketable Securities The Partnership currently classifies all marketable securities as available-for-sale securities. At December 31, 2005 and 2004, the cost of marketable securities are reported at fair value with unrealized gains and losses reported as a component of Partners capital until realized. The Partnership has restricted investments of $1,858,000 and $1,816,000 at December 31, 2005 and 2004, respectively, which are included in other assets in the consolidated balance sheets. The restricted marketable securities are held in escrow and secure reclamation bonds (Note 6).

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

Property, Plant and Equipment Additions and replacements constituting improvements, are capitalized. Maintenance, repairs, and minor replacements are expensed as incurred. Depreciation and amortization are computed principally on the straight-line method based upon the estimated useful lives of the assets or the estimated life of each mine, whichever is less ranging from 2 to 13 years. Depreciable lives for mining equipment and processing facilities range from 2 to 13 years. Depreciable lives for land and land improvements and depletable lives for mineral rights range from 5 to 13 years. Depreciable lives for buildings, office equipment and improvements range from 2 to 13 years. Gains or losses arising from retirements are included in current operations. Depletion of mineral rights is provided on the basis of tonnage mined in relation to estimated recoverable tonnage. At December 31, 2005 and 2004, land and mineral rights include $3,147,000 and $2,030,000, respectively, 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.

Mine Development Costs Mine development costs are capitalized until production, other than production incidental to the mine development process, commences and are amortized over the estimated life of the mine. Mine development costs represent costs that establish access to mineral reserves and include costs associated with sinking or driving shafts and underground drifts, permanent excavations, roads and tunnels.

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

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

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

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

Coal Supply Agreements A portion of the acquisition costs from a business combination in 1996 was allocated to coal supply agreements. This allocated cost was amortized on the basis of coal shipped in relation to total coal to be supplied during the respective coal supply agreement terms. The amortization periods ended December 2005. Accumulated amortization for coal supply agreements was $38,463,000 and $35,740,000 at December 31, 2005 and 2004, respectively. The aggregate amortization expense recognized for coal supply agreements was $2,723,000, $2,722,000, and $2,722,000 for the years ended December 31, 2005, 2004 and 2003, respectively.

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 permanently sealing portals at underground mines and to reclaiming the final pits and support acreage at surface mines. Other costs common to both types of mining are related to removing or covering refuse piles and settling ponds, and dismantling preparation plants, other facilities and roadway infrastructure.

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

Income Taxes The Partnership is not a taxable entity for federal or state income tax purposes; the tax effect of its activities accrues to the unitholders. Although publicly traded partnerships as a general rule will be taxed as corporations, the Partnership qualifies for an exemption because at least 90% of its income consists of qualifying income. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the Partnership agreement. The Partnership s subsidiary, Alliance Service, Inc. (Alliance Service), is subject to federal and state income taxes. Prior to the Partnership s acquisition of Warrior Coal, the financial results of Warrior Coal were subject to federal and state income taxes. The federal and state income taxes associated with Warrior Coal s financial results from January 26, 2001, the date of ARH Warrior Holdings, Inc. s (ARH Warrior Holdings) acquisition of Warrior Coal, to February 14, 2003, the date of the Partnership s acquisition of Warrior Coal, are included in income taxes. The Partnership s tax counsel has provided an opinion that the Partnership, the Intermediate Partnership and the holding company will each be treated as a partnership. However, as is customary, no ruling has been or will be requested from the IRS regarding the Partnership s classification as a partnership for federal income tax purposes. The Partnership s tax basis in net assets exceeded the book basis in net assets by $130.0 million and $125.8 million at December 31, 2005 and 2004, respectively.

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

Common Unit-Based Compensation The Partnership accounts for the compensation expense of the non-vested restricted common units granted under the Long-Term Incentive Plan (LTIP) (Note 14) using the intrinsic value method prescribed in Accounting Principles Board Opinion (APB) 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.

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

	Year Ended December 31,		
	2005	**2004**	**2003**
Net income, as reported	$ 160,010	$ 76,621	$ 47,902
Add: compensation expenses related to LTIP units included in reported net income	8,193	20,320	7,687
Deduct: compensation expense related to LTIP units determined under fair value method for all awards	(8,193)	(20,320)	(7,687)
Net income, pro forma	160,010	76,621	47,902
General partners interest in net income, pro forma	12,409	3,324	306
Limited partners interest in net income, pro forma	$ 147,601	$ 73,297	$ 47,596
Earnings per limited partner unit:			
Basic, as reported	$ 2.89	$ 1.76	$ 1.30
Basic, pro forma	$ 2.89	$ 1.76	$ 1.30
Diluted, as reported	$ 2.84	$ 1.71	$ 1.26
Diluted, pro forma	$ 2.84	$ 1.71	$ 1.26

The total accrued liability associated with the LTIP as of December 31, 2005 and 2004 was $6,517,000 and $10,013,000, respectively, and is reported separately in current and long-term due to affiliates liabilities in the consolidated balance sheets. See New Accounting Standards discussion below concerning the impact of SFAS No. 123R, *Share-Based Payment*, on accounting for the LTIP.

Net Income Per Unit Basic net income per limited partner unit is determined by dividing Limited Partners interest in net income (Note 12), by the weighted average number of outstanding Common Units and Subordinated Units. In periods when the Partnership s aggregate net income exceeds the aggregate distributions, EITF Issue No. 03-6, *Participating Securities and the Two-Class Method under FASB Statement No. 128*, requires the Partnership to present earnings per unit as if all of the earnings for the periods were distributed (Note 12). Warrior Coal s earnings (loss) prior to the Partnership s acquisition on February 14, 2003 was allocated entirely to the general partner. Diluted net income per unit is based on the combined weighted average number of Common Units, Subordinated Units and common unit equivalents outstanding, which primarily include restricted units granted under the LTIP (Note 14).

New Accounting Standards In November 2004, the FASB issued SFAS No. 151, *Inventory Costs*. SFAS No. 151 is an amendment of Accounting Research Bulletin (ARB) No. 43, Chapter 4, Paragraph 5 that deals with inventory pricing. SFAS No. 151 clarifies the accounting for abnormal amounts of idle facility expenses, freight, handling costs, and spoilage. Under previous guidance, Chapter 4, Paragraph 5 of ARB No. 43, items such as idle facility expense, excessive spoilage, double freight, and re-handling costs might be considered to be so abnormal, under certain circumstances, as to require treatment as current period charges. This Statement eliminates the criterion of so abnormal and requires that those items be recognized as current period charges. Also, SFAS No. 151 requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. SFAS No. 151 is effective for the Partnership on January 1, 2006. The Partnership believes that its adoption will not have any significant impact on the Partnership s financial position, results of operations or cash flows.

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

In April 2005, the Securities and Exchange Commission issued a rule that amended the implementation date for the Partnership s adoption of SFAS No. 123R from the third quarter of 2005 to the first quarter of 2006. SFAS No. 123R permits companies to adopt its requirements using either a modified prospective method, or a modified retrospective method. Under the modified prospective method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS No. 123R, of all share-based payments granted after that date, and based on the requirements of SFAS No. 123 for all unvested awards granted prior to the effective date of SFAS No. 123R. Under the modified retrospective method, the requirements are the same as under the modified prospective method, but also permits entities to restate financial statements of previous periods based on pro forma disclosures made in accordance with SFAS No. 123. The Partnership adopted SFAS No. 123R effective on January 1, 2006. The Partnership used the modified prospective method of adoption provided under SFAS No. 123R and, therefore, will not restate prior period results. Because the Partnership has previously expensed share-based payments using the current market value of the Partnership s Common Units at the end of each period, the adoption of SFAS No. 123R will not have a material impact on the Partnership s consolidated results of operations.

The intrinsic value previously recognized at December 31, 2005 essentially equals the fair value at January 1, 2006 and, therefore, no incremental compensation cost will be recognized upon adoption of SFAS 123R. As required by SFAS No. 123R, the fair value will be reduced for expected forfeitures, to the extent compensation cost has been previously recognized and this amount will be recognized as a cumulative effect of accounting change. Because the share-based compensation will be settled by delivery of Common Units, except for the minimum statutory income tax withholding requirements, the previously recognized liability reflected in the due to affiliates current and long-term accounts in the consolidated balance sheet will be reclassified as Partners Capital upon adoption of SFAS 123R (Note 14).

As permitted by SFAS No. 123, prior to January 1, 2006 the Partnership accounted for share-based payments to employees using the APB No. 25 intrinsic method and related FASB Interpretation No. 28 based upon the current market value of the Partnership s Common Units at the end of each period. The Partnership has recorded compensation expense of $8,193,000, $20,320,000 and $7,687,000 for each of the three years ended December 31, 2005, 2004 and 2003, respectively.

In March 2005, the FASB issued EITF No. 04-6, *Accounting for Stripping Costs in the Mining Industry* and concluded that stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced during the period that the stripping costs are incurred. EITF No. 04-6 does not address the accounting for stripping costs incurred during the pre-production phase of a mine. EITF No. 04-6 is effective for the first reporting period in fiscal years beginning after December 15, 2005 with early adoption permitted. The effect of initially applying this consensus would be accounted for in a manner similar to a cumulative-effect adjustment. Since the Partnership has historically adhered to the accounting principles similar to EITF No. 04-6 in accounting for stripping costs incurred at the Partnership s surface operation, the Partnership s adoption of EITF No. 04-6, on January 1, 2006, did not have a material impact on its consolidated financial statements.

In April 2005, the FASB adopted Financial Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47). FIN 47 clarifies that the term conditional asset obligation from SFAS No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform an asset retirement activity on which the timing or method of settlement is conditional on a future event and requires the recognition of such conditional obligations even though uncertainty exists. The Partnership s adoption of FIN 47 at December 31, 2005 did not affect the Partnership s consolidated financial statements.

Reclassifications Certain reclassifications have been made to the 2004 balance sheet presentation of the accrued pension benefit and other current liabilities to conform to the 2005 classifications. For 2004 and 2003 cash flow presentation, prepaid expenses and other assets are reported separately to conform to the 2005 presentation.

3. ACQUISITIONS

Tunnel Ridge

In January 2005, the Partnership acquired 100% of the limited liability company member interests of Tunnel Ridge, LLC (Tunnel Ridge) for approximately $500,000 and the assumption of reclamation liabilities from ARH, a company owned by management of the Partnership. Tunnel Ridge controls through a coal lease agreement with the Special GP, approximately 9,400 acres of land located in Ohio County, West Virginia and Washington County, Pennsylvania containing an estimated 70 million tons of high-sulfur coal in the Pittsburgh No. 8 coal seam. Under the terms of the coal lease, beginning on January 1, 2005, Tunnel Ridge has paid and will continue to pay the Special GP an advance minimum royalty of $3.0 million per year. The advance royalty payments are fully recoupable against earned royalties (Note 17).

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

Warrior Coal

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

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

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

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

The put option price of $12.7 million was paid to ARH Warrior Holdings in accordance with the terms of the Put/Call Agreement. In addition, the Partnership repaid Warrior Coal s borrowings of $17.0 million under the revolving credit agreement between the Special GP and Warrior Coal. The primary borrowings under the revolving credit agreement financed new infrastructure capital projects at Warrior Coal that have contributed to improved productivity and significantly increased capacity. The Partnership funded the Warrior Coal acquisition through a portion of the proceeds received from the issuance of 4,500,000 Common Units (Note 1). Because the Warrior Coal acquisition was between entities under common control, it has been accounted for at historical cost in a manner similar to that used in a pooling of interests.

Under the terms of the Put/Call Agreement, the Partnership assumed certain other obligations, including a mineral lease and sublease with SGP Land, LLC (SGP Land), a subsidiary of the Special GP, covering coal reserves that have been and will continue to be mined by Warrior Coal. The terms and conditions of the mineral lease and sub-lease remained unchanged (Note 17).

Lodestar

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

4. MINE FIRE INCIDENTS

MC Mining Mine Fire

On December 26, 2004, MC Mining, LLC s Excel No. 3 mine was temporarily idled following the occurrence of a mine fire (the MC Mining Fire Incident). The fire was discovered by mine personnel near the bottom of the Excel No. 3 mine slope late in the evening of December 25, 2004. Under a firefighting plan developed by MC Mining, in cooperation with mine emergency response teams from the U.S. Department of Labor s Mine Safety and Health Administration (MSHA) and Kentucky Office of Mine Safety and Licensing, the four portals at the Excel No. 3 mine were temporarily capped to deprive the fire of oxygen. A series of boreholes was then drilled into the mine from the surface, and nitrogen gas and foam were injected through the boreholes into the fire area to further suppress the fire. As a result of these efforts, the mine atmosphere was rendered substantially inert, or without oxygen, and the Excel No. 3 mine fire was effectively suppressed. MC Mining then began construction of temporary and permanent barriers designed to completely isolate the mine fire area. Once the construction of the permanent barriers was completed, MC Mining began efforts to repair and rehabilitate the Excel No. 3 mine infrastructure. On February 21, 2005, the repair and rehabilitation efforts had progressed sufficiently to allow initial resumption of production. Coal production has returned to near normal levels, but continues to be adversely impacted by inefficiencies attributable to or associated with the MC Mining Fire Incident.

The Partnership maintains commercial property (including business interruption and extra expense) insurance policies with various underwriters, which policies are renewed annually in October and provide for self-retention and various applicable deductibles, including certain monetary and/or time element forms of deductibles (collectively, the 2005 Deductibles) and 10% co-insurance (2005 Co-Insurance). The Partnership believes such insurance coverage will cover a substantial portion of the total cost of the disruption to MC Mining s operations. However, concurrent with the renewal of the Partnership s commercial property (including business interruption) insurance policies concluded on October 31, 2005, MC Mining confirmed with the current underwriters of the commercial property insurance coverage that any negotiated settlement of the losses arising from or in connection with the MC Mining Fire Incident would not exceed $40.0 million (inclusive of the 2005 Co-insurance and 2005 Deductible amounts). Until the claim is resolved ultimately, either through the claim adjustment process, settlement, or litigation, with the applicable underwriters, the Partnership can make no assurance of the amount or timing of recovery of insurance proceeds.

The Partnership made an initial estimate of certain costs primarily associated with activities relating to the suppression of the fire and the initial resumption of operations. Operating expenses for 2004 were increased by $4.1 million to reflect an initial estimate of certain minimum costs attributable to the MC Mining Fire Incident that are not reimbursable under the Partnership s insurance policies due to the application of the 2005 Deductibles and 2005 Co-Insurance.

Following the initial two submittals by the Partnership to a representative of the underwriters of its estimate of the expenses and losses (including business interruption losses) incurred by MC Mining and other affiliates arising from and in connection with the MC Mining Fire Incident (the MC Mining Insurance Claim), on September 15, 2005, the Partnership filed a third partial proof of loss, with an update through July 31, 2005. Partial payments of $12.2 million were received in 2005, which are net of the 2005 Deductibles and 2005 Co-Insurance. The accounting for these partial payments and future payments, if any, made to the Partnership by the underwriters will be subject to the accounting methodology described below. The Partnership continues to evaluate its potential insurance recoveries under the applicable insurance policies in the following areas:

1. Fire Brigade/Extinguishing/Mine Recovery Expense; Expenses to Reduce Loss; Debris Removal Expenses; Demolition and Increased Cost of Construction; Expediting Expenses; and Extra Expenses incurred as a result of the fire These expenses and other costs (e.g. professional fees) associated with extinguishing the fire, reducing the overall loss, demolition of certain property and removal of debris, expediting the recovery from the loss, and extra expenses that would not have been incurred by the Partnership, but for the MC Mining Fire Incident, are being expensed as incurred with related actual and/or estimated insurance recoveries recorded as they are considered to be probable, up to the amount of the actual cost incurred.

2. Damage to MC Mining mine property The net book value of property destroyed of $154,000, was written off in the first quarter of 2005 with a corresponding amount recorded as an estimated insurance recovery, since such recovery is considered probable. Any insurance proceeds from the claims relating to the MC Mining mine property (other than amounts relating to the matters discussed in 1. above) that exceed the net book value of such damaged property would result in a gain. Any gain will be recorded when the MC Mining Insurance Claim is resolved and/or proceeds are received.

3. MC Mining mine business interruption losses The Partnership has submitted to a representative of the underwriters a business interruption loss analysis for the period of December 24, 2004 through July 31, 2005. Expenses associated with business interruption losses are expensed as incurred, and estimated insurance recoveries of such losses are recognized to the extent such recoveries are considered to be probable, up to the actual amount incurred. Recoveries in excess of actual costs incurred will be recorded as gains when the MC Mining Insurance Claim is resolved and/or proceeds are received.

In 2005, pursuant to the accounting methodology described above, of the $12.2 million of partial payments received, the Partnership recorded, as an offset to operating expenses, $10.7 million, amount represents the current estimated insurance recovery of actual costs incurred, net of the 2005 Deductibles and 2005 Co-Insurance. The Partnership continues to discuss the MC Mining Insurance Claim and the determination of the total claim amount with representatives of the underwriters. The MC Mining Insurance Claim will continue to be developed as additional information becomes available and the Partnership has completed its assessment of the losses (including the methodologies associated therewith) arising from or in connection with the MC Mining Fire Incident. At this time, based on the magnitude and complexity of the MC Mining Insurance Claim, the Partnership is unable to reasonably estimate the total amount of the MC Mining Insurance Claim as well as its exposure, if any, for amounts not covered by the Partnership s insurance program.

Dotiki Mine Fire

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

On September 10, 2004, the Partnership filed a third and final proof of loss with the applicable insurance underwriters reflecting a settlement of all expenses, losses and claims incurred by Webster County Coal and other affiliates arising from or in connection with the Dotiki Fire Incident in the aggregate amount of $27.0 million, inclusive of a $1.0 million self-retention of initial loss, a $2.5 million deductible and 10% co-insurance.

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

5. VERTICAL BELT FAILURE

On June 14, 2005, White County Coal, LLC s (White County Coal) Pattiki mine was temporarily idled following the failure of the vertical conveyor belt system (the Vertical Belt Incident) used in conveying raw coal out of the mine. White County Coal surface personnel detected a failure of the vertical conveyor belt on June 14, 2005 and immediately shut down operation of all underground conveyor belt systems. On July 20, 2005, White County Coal s efforts to repair the vertical belt system had progressed sufficiently to allow it to perform a full test of the vertical belt system. After evaluating the test results, the Pattiki mine resumed initial production operations on July 21, 2005. Production of raw coal has returned to levels that existed prior to the occurrence of the Vertical Belt Incident. The majority of repairs to the vertical belt conveyor system and ancillary equipment have been completed. The Partnership s operating expenses were increased by $2.9 million for the year ended December 31, 2005, to reflect the estimated direct expenses and costs attributable to the Vertical Belt Incident, which estimate included a $1.3 million retirement of the damaged vertical belt equipment. The Partnership has not identified currently any significant additional costs compared to the original cost estimates. The Partnership is conducting an analysis of a number of possible alternatives to mitigate the losses arising from the Vertical Belt Incident. This analysis will include a review of the Vertical Belt System Design, Supply, and Oversight of Installation Contract (Installation Contract), dated December 7, 2000, between White County Coal, LLC and Lake Shore Mining, Inc. Until such analysis is completed, however, the Partnership can make no assurances of the amount or timing of recoveries, if any. Concurrent with the renewal of the Partnership s commercial property (including business interruption) insurance policies concluded on October 31, 2005, White County Coal confirmed with the current underwriters of the commercial property insurance coverage that it would not file a formal insurance claim for losses arising from or in connection with the Vertical Belt Incident.

6. MARKETABLE SECURITIES

Marketable securities include Federal home loan discount notes and bankers acceptances. At December 31, 2004, the cost of the bankers acceptances approximated fair value and no effect of unrealized gains (losses) is reflected in Partners capital. There were no bankers acceptances outstanding at December 31, 2005. The Federal home loan discount notes had a cumulative unrealized loss reflected in Partners capital of $68,000 and $54,000 at December 31, 2005 and 2004, respectively.

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

	2005	2004
Federal home loan discount notes	$ 49,242	$ 39,414
Bankers acceptances		9,983
Total unrestricted marketable securities	$ 49,242	$ 49,397
Restricted cash and cash equivalents	$ 1,858	$ 1,816
Total restricted marketable securities (included in other long-term assets)	$ 1,858	$ 1,816

7. INVENTORIES

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

	2005	2004
Coal	$ 6,538	$ 4,822
Supplies	10,732	9,017
	$ 17,270	$ 13,839

8. PROPERTY, PLANT AND EQUIPMENT

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

	2005	2004
Mining equipment and processing facilities	$ 461,005	$ 405,437
Land and mineral rights	26,694	22,281
Buildings, office equipment and improvements	57,943	46,281
Construction in progress	29,699	9,257
Mine development costs	59,745	43,212
	635,086	526,468
Less accumulated depreciation, depletion and amortization	(330,672)	(292,900)
	$ 304,414	$ 233,568

Mine development costs at December 31, 2004 are separately stated to conform with the December 31, 2005 presentation.

9. LONG-TERM DEBT

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

	2005	2004
Senior notes	$ 162,000	$ 180,000
Less current maturities	(18,000)	(18,000)
	$ 144,000	$ 162,000

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The Intermediate Partnership has $162.0 million principal amount of 8.31% senior notes due August 20, 2014, payable in nine remaining equal annual installments of $18.0 million with interest payable semiannually. On August 22, 2003, the Intermediate Partnership completed a $85.0 million revolving credit facility which expires September 30, 2006. The interest rate on the revolving credit facility is based on either the (i) London Interbank Offered Rate or (ii) the Base Rate, which is equal to the greater of the JPMorgan Chase Prime Rate or the Federal Funds Rate plus $^{1}/2$ of 1%, plus, in either case, an applicable margin. The Partnership incurred certain costs aggregating $1.2 million associated with the revolving credit facility. These costs have been deferred and are being amortized as a component of interest expense over the term of the revolving credit facility. In March 2005, the Intermediate Partnership entered into Amendment No. 1 to the credit facility to increase the maximum capital expenditures from $50.2 and $50.6 million for the years ended December 31, 2006 and 2005, respectively, to $125.0 million for each of the years ended December 31, 2006 and 2005. The Partnership had no borrowings outstanding under the revolving credit facility at December 31, 2005. Letters of credit can be issued under the revolving credit facility not to exceed $30.0 million; outstanding letters of credit reduce amounts available under the revolving credit facility. At December 31, 2005, the Partnership had letters of credit of $9.0 million outstanding under the revolving credit facility to secure the Partnership s obligations for reclamation liabilities and workers compensation benefits.

The senior notes and revolving credit facility are guaranteed by all of the subsidiaries of the Intermediate Partnership. The senior notes and revolving credit facility contain various restrictive and affirmative covenants, including the amount of distributions by the Intermediate Partnership and the incurrence of other debt exceeding $35.0 million. The senior note restrictions on distributions are consistent with the Partnership Agreement and the credit facility limit borrowings to fund distributions to $25.0 million. The senior note limitations on the amount of distributions by the Intermediate Partnership include maintaining defined levels of cash, meeting certain debt ratios and maintaining the absence of default or an event of default as defined in the senior note agreement. The Partnership was in compliance with the covenants of both the revolving credit facility and senior notes at December 31, 2005.

The Partnership previously entered into and has maintained agreements with two banks to provide additional letters of credit in an aggregate amount of $25.0 million to maintain surety bonds to secure its obligations for reclamation liabilities and workers compensation benefits as statutorily required. At December 31, 2005, the Partnership had $24.8 million in letters of credit outstanding under these agreements. The Special GP guarantees the letters of credit (Note 17).

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

Year Ending December 31,	
2006	$ 18,000
2007	18,000
2008	18,000
2009	18,000
2010	18,000
Thereafter	72,000
	$ 162,000

10. DISTRIBUTIONS OF AVAILABLE CASH AND CONVERSION OF SUBORDINATED UNITS

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

As quarterly distributions of available cash exceed the minimum quarterly distribution (MQD) and target distributions levels as established in the Partnership Agreement, the Managing GP receives distributions based on specified increasing percentages of the available cash that exceed the MQD and the target distribution levels. The Partnership Agreement defines the MQD as $0.25 per unit ($1.00 per unit on an annual basis). The target distribution levels are based on the amounts of available cash from the Partnership s operating surplus distributed for a given quarter that exceed the MQD and common unit arrearages, if any.

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Under the quarterly incentive distribution rights provisions of the partnership agreement, the Managing GP is entitled to receive 15% of the amount the Partnership distributes in excess of $0.275 per unit, 25% of the amount the Partnership distributes in excess of $0.3125 per unit, and 50% of the amount the Partnership distributes in excess of $0.375 per unit. During 2005 and 2004, the Partnership allocated to the Managing GP incentive distributions of $9,397,000 and $1,828,000, respectively. There were no incentive distributions allocated to the Managing GP during the year ended December 31, 2003. The following table summaries the quarterly per unit distribution paid during the respective quarter.

	Year		
	2005	**2004**	**2003**
First Quarter	$ 0.3750	$ 0.2813	$ 0.2625
Second Quarter	$ 0.3750	$ 0.3125	$ 0.2625
Third Quarter	$ 0.4125	$ 0.3250	$ 0.2625
Fourth Quarter	$ 0.4125	$ 0.3250	$ 0.2625

The Partnership Agreement provides for the conversion of the Subordinated Units into Common Units after meeting certain financial tests. The Partnership satisfied, in two stages, the financial tests that resulted in the Subordinated Units being converted into Common Units. First, the Partnership satisfied certain financial tests that provided for the early conversion of one-half of the Subordinated Units (i.e. 6,422,530 Subordinated Units) to Common Units in September 2003. Second, the Partnership satisfied the final conversion financial tests for converting the remaining Subordinated Units (i.e. 6,422,532 Subordinated Units) to Common Units in September 2004. The Board of Directors (and its Conflicts Committee) for the Managing GP approved management s determination that both the early conversion financial tests and the final conversion financial tests were met. As a result, one-half of the Subordinated Units converted into Common Units on November 15, 2003 and the remaining one-half of the Subordinated Units converted into Common Units on November 2, 2004.

On January 30, 2006, the Partnership declared a quarterly distribution of $0.46 per unit, totaling approximately $21,057,000 (which includes the Managing GP s portion of incentive distributions), payable on February 14, 2006, to all unitholders of record on February 6, 2006.

11. INCOME TAXES

The Partnership s subsidiary, Alliance Service, is subject to federal and state income taxes. Alliance Service s income primarily consists of rental and service fees provided to an independent coal synfuel producer at Warrior Coal. Alliance Service has no temporary differences between the financial reporting basis and the tax basis of its assets and liabilities. Prior to the Partnership s acquisition of Warrior Coal, the financial results of Warrior Coal were subject to federal and state income taxes. The federal and state income taxes associated with Warrior Coal s financial results prior to the Partnership s acquisition on February 14, 2003, are included in income taxes. Components of income tax expense are as follows (in thousands):

	Year Ended December 31,		
	2005	**2004**	**2003**
Current:			
Federal	$ 2,115	$ 2,089	$ 1,516
State	567	552	431
	2,682	2,641	1,947
Deferred:			
Federal			550
State			80
			630
Income tax expense	$ 2,682	$ 2,641	$ 2,577

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

	Year Ended December 31,		
	2005	**2004**	**2003**
Income taxes at statutory rate	$ 56,942	$ 27,742	$ 17,668
Less: Income taxes at statutory rate on Partnership income not subject to income taxes	(54,527)	(25,409)	(15,855)
Increase/(decrease) resulting from:			
State taxes, net of federal income tax benefit	346	333	313
Deferred tax assets retained by ARH Warrior Holdings			413
Other	(79)	(25)	38
Income tax expense	$ 2,682	$ 2,641	$ 2,577

12. NET INCOME PER LIMITED PARTNER UNIT

In March 2004, the FASB issued EITF No. 03-6 , which addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. Essentially, EITF No. 03-6 provides that in any accounting period where the Partnership s aggregate net income exceeds the aggregate distributions for such period, the Partnership is required to present earnings per unit as if all of the earnings for the periods were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed during a particular period from an economic probability standpoint. EITF No. 03-6 was effective for fiscal periods beginning after March 31, 2004, net income per limited partner unit amounts for 2004 and 2003 are restated for comparative purposes. EITF No. 03-6 does not impact the Partnership s aggregate distributions for any period, but it can have the impact of reducing the earnings per limited partner unit. This result occurs as a larger portion of the Partnership s aggregate earnings, as if distributed, is allocated to the incentive distribution rights held by the Managing GP, even though the Partnership makes cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. In accounting periods where aggregate net income does not exceed our aggregate distributions for such period, EITF No. 03-6 does not have any impact on the Partnership s earnings per unit calculation.

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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, 2005	2004	2003
Net income	$ 160,010	$ 76,621	$ 47,902
Adjustments:			
General partner s priority distributions	(9,397)	(1,828)	
General Partners 2% equity ownership	(3,012)	(1,496)	(972)
Portion applicable to Warrior loss prior to its acquisition on February 14, 2003			666
Limited partners interest in net income	147,601	73,297	47,596
Additional earnings allocation to general partner	(42,740)	(10,211)	(1,723)
Net income available to limited partners under EITF No. 03-6	$ 104,861	$ 63,086	$ 45,873
Weighted average limited partner units basic	36,289	35,882	35,162
Basic net income per limited partner unit	$ 2.89	$ 1.76	$ 1.30
Weighted average limited partner units basic	36,289	35,882	35,162
Units contingently issuable:			
Restricted units for LTIP	550	868	1,054
Directors compensation units	37	32	32
Supplemental Executive Retirement Plan	101	92	78
Weighted average limited partner units, assuming dilutive effect of restricted units	36,977	36,874	36,326
Diluted net income per limited partner unit	$ 2.84	$ 1.71	$ 1.26

The Partnership s net income for partners capital purposes is allocated to the general partners and limited partners in accordance with their respective partnership percentages, after giving effect to any priority income allocations for incentive distributions (Note 10), if any, to the Partnership s Managing GP, the holder of the incentive distribution rights pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. For purposes of computing basic and diluted net income per limited partner unit, in periods when the Partnership s aggregate net income exceeds the aggregate distributions for such periods, an increased amount of net income is allocated to the general partner for the additional pro forma priority income attributable to application of EITF No. 03-6. Warrior Coal s loss prior to its acquisition on February 14, 2003 was allocated entirely to the general partners. For purposes of computing basic and diluted net income per limited partner unit, in periods when the Partnership s aggregate net income exceeds the aggregate distributions for such periods, an increased amount of net income is allocated to the general partner for the additional pro forma priority income attributable to application of EITF No. 03-6.

The Partnership s Managing GP is entitled to receive incentive distributions if the amount the Partnership distributes with respect to any quarter exceeds levels specified in the Partnership Agreement. Under the quarterly incentive distribution provisions of the Partnership Agreement, generally, the Managing GP is entitled to receive 15% of the amount the Partnership distributes in excess of $0.275 per unit, 25% of the amount the Partnership distributes in excess of $0.3125 per unit and 50% of the amount the Partnership distributes in excess of $0.375 per unit.

13. EMPLOYEE BENEFIT PLANS

Defined Contribution Plans The Partnership s employees currently participate in a defined contribution profit sharing and savings plan sponsored by the Partnership. This plan covers substantially all full-time employees. Plan participants may elect to make voluntary contributions to this plan up to a specified amount of their compensation. The Partnership makes matching contributions based on a percent of an employee s eligible compensation and for

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certain subsidiaries makes an additional nonmatching contribution, also based on an employee s eligible compensation. Additionally, the Partnership contributes a defined percentage of eligible earnings for certain employees not covered by the defined benefit plan described below. The Partnership s expense for this plan was approximately $3,810,000, $3,267,000, and $2,975,000 for the years ended December 31, 2005, 2004 and 2003, respectively.

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

The following sets forth changes in benefit obligations and plan assets for the years ended December 31, 2005 and 2004 and the funded status of the Pension Plan reconciled with amounts reported in the Partnership s consolidated financial statements at December 31, 2005 and 2004, respectively (dollars in thousands):

	2005	2004
Change in benefit obligations:		
Benefit obligations at beginning of year	$ 29,106	$ 22,948
Service cost	3,007	2,821
Interest cost	1,660	1,427
Actuarial loss	1,745	2,180
Benefits paid	(411)	(270)
Benefit obligation at end of year	35,107	29,106
Change in plan assets:		
Fair value of plan assets at beginning of year	23,307	21,185
Employer contribution	3,000	
Actual return on plan assets	1,623	2,392
Benefits paid	(411)	(270)
Fair value of plan assets at end of year	27,519	23,307
Funded status	(7,588)	(5,799)
Unrecognized prior service cost	42	90
Unrecognized actuarial loss	6,953	5,122
Net amount recognized	$ (593)	$ (587)
Amounts recognized in balance sheet:		
Accrued benefit liability	$ (7,588)	$ (5,799)
Intangible asset	42	90
Accumulated other comprehensive income	6,953	5,122
Net amount recognized	$ (593)	$ (587)
Weighted-average assumptions as of December 31:		
Discount rate	5.60%	5.75%
Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31:		
Discount rate	5.75%	6.25%
Expected return on plan assets	8.00%	8.00%

(continued)

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Weighted-average asset allocations as of December 31:		
Equity securities	88%	88%
Fixed income securities	11%	11%
Cash and cash equivalents	1%	1%
	100%	100%

	2005	2004	2003
Components of net periodic benefit cost:			
Service cost	$ 3,007	$ 2,821	$ 2,502
Interest cost	1,660	1,427	1,215
Expected return on plan assets	(1,916)	(1,686)	(1,115)
Prior service cost	48	48	48
Net loss	207	141	399
Net periodic benefit cost	$ 3,006	$ 2,751	$ 3,049
Effect on minimum pension liability	$ (1,831)	$ (1,333)	$ (1,486)

Estimated future benefit payments as of December 31, 2005 are as follows (in thousands):

Year Ending December 31,	
2006	$ 636
2007	802
2008	983
2009	1,195
2010	1,418
2011-2015	11,650
	$ 16,684

The actuarial loss component of the change in benefit obligations for 2005 and 2004 was primarily attributable to reductions in the discount rate assumptions. The Partnership expects to contribute $7,900,000 to the Pension Plan in 2006.

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

Percentage of Total Portfolio

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

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The expected long-term rate of return assumption is developed based on input from an independent investment manager, including its review of asset class return, expectations by economists, and an independent actuary. The Partnership s advisors base the projected returns on broad equity and bond indices. The Pension Plan s expected long-term rate of return is based on an asset allocation assumption of 80.0% with equity manager, with an expected long-term rate of return of 10.4%, and 20.0% with fixed income managers, with an expected long-term rate of return of 5.3%. The Pension Plan was established effective January 1, 1997 and the Partnership s initial contribution to the Pension Plan was made in 1998.

14. COMPENSATION PLANS

Effective January 1, 2000, the Managing GP adopted 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. On December 22, 2005, the Compensation Committee executed a unanimous consent resolution that, effective January 1, 2006, (a) all existing grants made under the LTIP prior to January 1, 2006 and subsequent thereto be settled, upon satisfaction of any applicable vesting requirements, in Common Units to the extent of net share settlement for minimum statutory income tax withholding requirements for each individual participant based upon the fair market value of the Common Units as of the date of payment and (b) any existing and prospective LTIP grants of restricted units receive quarterly distributions as provided in the distribution equivalent rights provision of the LTIP. Therefore, each LTIP participant will have a contingent right to receive an amount equal to the cash distributions made by the Partnership during the vesting period.

The aggregate number of units reserved for issuance under the LTIP is 1,200,000. Effective January 1, 2004, the Compensation Committee approved an amendment to the LTIP clarifying that any award that is forfeited, expires for any reason, or is paid or settled in cash, including the satisfaction of minimum statutory withholding requirements, rather than through the delivery of units will be available for future grants under the LTIP. Of the initial 1,200,000 units reserved for issuance under the LTIP, cumulative units of 1,092,780 were granted in years 2000, 2001, 2002 and 2003. Of those grants, 43,650 units were forfeited and 421,452 units were settled in cash rather than delivery of units, resulting in the net issuance of 627,678 Common Units under those grants. During 2004 and 2005, the Compensation Committee approved grants of 205,570 units and 114,390 units, respectively, which will vest December 31, 2006 and January 1, 2008, respectively, subject to the satisfaction of certain financial tests that management currently believes will be satisfied. As of December 31, 2005, 3,690 outstanding LTIP grants have been forfeited. Consequently, as of December 31, 2005, 256,052 units remain available for issuance in the future, assuming that all grants currently issued and outstanding for 2004 and 2005 are settled with Common Units and no forfeitures occur. During 2005, 2004 and 2003, the Managing GP billed the Partnership approximately $8,193,000, $20,320,000, and $7,687,000, respectively, attributable to the LTIP. Effective January 1, 2006, the Compensation Committee approved additional grants of 85,275 restricted units, which will vest January 1, 2009, subject to the satisfaction of certain financial tests. See New Accounting Standards (Note 2) for a discussion concerning the impact of SFAS No. 123R on accounting for the LTIP.

Effective January 1, 1997, the Managing GP adopted a Supplemental Executive Retirement Plan (the SERP) for certain officers and key employees. The purpose of the SERP is to enhance the Partnership s ability to retain specific officers and key employees, by providing them with the deferred compensation benefits contained in the SERP. The intent of the SERP is to provide each participant with retirement benefits that are comparable in value to those of similar retirement programs administered by other companies, as well as to align each participant s supplemental benefits under the SERP with the interests of the Partnership s unitholders. All allocations made to participants under the SERP are made in the form of phantom units. The SERP is administered by the Compensation Committee. The Managing GP is able to amend or terminate the plan at any time. The Managing GP is entitled to reimbursement by the Partnership for its costs incurred under the SERP. During 2005, 2004 and 2003, the Managing GP billed the Partnership approximately $393,000, $2,099,000, and $626,000, respectively, attributable to the SERP. The increase from 2003 to 2004 is attributable to the increased market value of the Partnership s Common Units. The total accrued liability associated with the SERP plan as of December 31, 2005 and 2004 was $4,050,000 and $3,657,000, respectively, and is included in the long-term due to affiliates liability in the consolidated balance sheets.

15. RECLAMATION AND MINE CLOSING COSTS

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

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

Discounting resulted in reducing the accrual for reclamation and mine closing costs by $29,339,000 and $28,760,000 at December 31, 2005 and 2004, respectively. Estimated payments of reclamation and mine closing costs as of December 31, 2005 are as follows (in thousands):

Year Ending December 31,	
2006	$ 2,597
2007	4,197
2008	3,478
2009	585
2010	2,638
Thereafter	57,157
Aggregate undiscounted reclamation and mine closing	70,652
Effect of discounting	(29,339)
Total reclamation and mine closing costs	41,313
Less current portion	(2,597)
Reclamation and mine closing costs	$ 38,716

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

	Year Ended December 31,		
	2005	2004	2003
Beginning balance	$ 34,018	$ 23,466	$ 23,456
Accretion expense	1,918	1,622	1,341
Payments	(189)	(899)	(1,054)
Allocation of liability associated with acquisition, mine development and change in assumptions	5,566	9,829	(277)
Ending balance	$ 41,313	$ 34,018	$ 23,466

During the year ended December 31, 2005, the reclamation and mine closing cost liability increase of $5,566,000 was primarily attributable to an increase in the estimates of the cost to perform certain reclamation activities and, in particular, certain land restoration procedures associated with the Lodestar acquisition. Additionally, $411,000 of the 2005 increase is attributable to the Tunnel Ridge acquisition (Note 3). During the year ended December 31, 2004, the reclamation and mine closing cost liability increase of $9,829,000 was primarily attributable to the Lodestar acquisition of $4,129,000 described in Note 3 and the initial land disturbances associated with mine development at Mettiki Coal, LLC and Mettiki Coal (WV), LLC of a combined $2,329,000. The liability also increased as the permitted refuse disposal areas were expanded at several existing operations and a comprehensive study related to water treatment costs was completed.

16. PNEUMOCONIOSIS (BLACK LUNG) BENEFITS

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

Pneumoconiosis (black lung) benefits liability is calculated using the service cost method. Under the service cost method the calculation of the actuarial present value of the estimated black lung obligation is based on an actuarial study performed by an independent actuary. Actuarial gains or losses are amortized over the remaining service period of active miners. The discount rate used to calculate the estimated present value of future obligations was 4.23% and 4.5% at December 31, 2005 and 2004, respectively.

The reconciliation of changes in benefit obligations at December 31, 2005 and 2004 is as follows (in thousands):

	2005	2004
Benefit obligations at beginning of year	$ 20,335	$ 17,633
Service Cost	1,977	1,217
Interest cost	1,203	1,091
Actuarial loss	470	549
Benefits and expense paid	(190)	(155)
Benefit obligations at end of year	$ 23,795	$ 20,335

The U.S. Department of Labor has issued revised regulations that alter the claims process for federal black lung benefit recipients. Both the coal and insurance industries 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 may result in an increase in the incidence and recovery of black lung claims.

17. RELATED PARTY TRANSACTIONS

Administrative Services The Partnership Agreement provides that the Managing GP and its affiliates be reimbursed for all direct and indirect expenses it incurs or payments it makes on behalf of the Partnership, including, but not limited to, management s salaries and related benefits (including incentive compensation), 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 $14,069,000, $28,536,000, and $12,471,000 for the years ended December 31, 2005, 2004 and 2003, respectively. The decrease from 2004 to 2005 was primarily attributable to lower compensation accruals for the LTIP, Short-Term Incentive Plan (STIP) and SERP. The increase from 2003 to 2004 was primarily attributable to higher accruals for the LTIP, STIP and SERP. The expenses associated with LTIP and SERP were impacted by the market value of the Partnership s Common Units, which had a closing market price of $37.20, $37.00, and $17.19 at December 31, 2005, 2004 and 2003, respectively. The amounts billed by the Managing GP include $10,559,000, $24,242,000, and $9,319,000 for the years ended December 31, 2005, 2004 and 2003, respectively, for the LTIP, STIP and SERP.

SGP Land Webster County Coal has a mineral lease and sublease with SGP Land requiring annual minimum royalty payments of $2.7 million, payable in advance through 2013 or until $37.8 million of cumulative annual minimum and/or earned royalty payments have been paid. Webster County Coal paid royalties of $3,449,000, $4,611,000, and $3,460,000 for the years ended December 31, 2005, 2004 and 2003, respectively. As of December 31, 2005, Webster County Coal has recouped, as earned royalties, all advance minimum royalty payments made in accordance with these lease terms except for $1,018,000.

Warrior Coal has a mineral lease and sublease with SGP Land. Under the terms of the lease, Warrior Coal has paid and will continue to pay in arrears an annual minimum royalty obligation of $2,270,000 until $15,890,000 of cumulative annual minimum and/or earned royalty payments have been paid. The annual minimum royalty periods are from October 1 through the end of the following September 30, expiring September 30, 2007. Warrior Coal paid royalties of $3,627,000 $2,561,000, and $2,453,000 for the years ended December 31, 2005, 2004 and 2003, respectively. As of December 31, 2005, Warrior Coal has recouped, as earned royalties, all advance minimum royalty payments made in accordance with these lease terms.

Under the terms of the mineral lease and sublease agreements described above, Webster County Coal and Warrior Coal also reimburse SGP Land for SGP Land s base lease obligations. The Partnership reimbursed SGP Land $6,379,000, $5,428,000, and $4,395,000 for the years ended December 31, 2005, 2004 and 2003, respectively, for the base lease obligations. Webster County Coal and Warrior Coal have recouped, as earned royalties, all advance minimum royalty payments made in accordance with these terms except for $236,000 as of December 31, 2005.

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 $600,000 and $479,000 during the years ended December 31, 2005 and 2003, respectively. The 2004 annual minimum royalty obligation of $300,000 was paid in January 2005. As of December 31, 2005, MC Mining has recouped, as earned royalties, all advance minimum royalty payments made in accordance with these lease terms except for $600,000.

On October 23, 2005, the Partnership exercised its option to lease and/or sublease certain reserves from SGP Land, which reserves are contiguous to the Partnership s Hopkins County Coal mining complex. Upon exercise of the option agreement, Hopkins County Coal entered into a Coal Lease and Sublease Agreement as well as a Royalty Agreement (collectively, the Coal Lease Agreements). The terms of the Coal Lease Agreements are through December 2015, with the right to extend the term for successive one-year periods for as long as the Partnership is mining within the coal field, as such term is defined in the Coal Lease Agreements.

The Coal Lease Agreements provide for five annual minimum royalty payments of $684,000. The combined annual minimum royalty payments, consistent with the option agreement, and cumulative option fees of $3.4 million previously paid by Hopkins County Coal are fully recoupable against future tonnage royalty payments. Under the terms of the Coal Lease Agreements, Hopkins County Coal will also reimburse SGP Land for SGP Land s base lease obligations. Under the terms of the option to lease and/or lease and sublease agreements, Hopkins County Coal paid advance minimum royalties and/or option fees of $684,000 and $1,368,000 during the years ended December 31, 2005 and 2004, respectively. The 2003 option fee of $684,000 was paid in January 2004 and is included in the due to affiliates balance as of December 31, 2003. As of December 31, 2005, Hopkins County Coal has available $4,059,000 of advance minimum royalty payments made under these agreements that management expects will be recouped against future production.

Special GP In January 2005, the Partnership acquired Tunnel Ride from ARH (Note 3), in connection with this acquisition the Partnership assumed a coal lease with the Special GP. Under the terms of the lease, Tunnel Ridge has paid and will continue to pay an annual minimum royalty obligation of $3.0 million until the earlier of January 1, 2033 or the exhaustion of mineable and merchantable coal. The Partnership paid an advance minimum royalty of $3.0 million during 2005, which management expects will be recouped against future production.

Tunnel Ridge also has rights to surface land and other tangible assets under a separate lease agreement with the Special GP. Under the terms of the lease agreement, Tunnel Ridge has paid and will continue to pay the Special GP an annual lease payment of $240,000. The lease agreement has an initial term of four years, which may be extended to be consistent with the term of the coal lease. Lease expense was $240,000 for the year ended December 31, 2005.

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, 2005 was $2,595,000.

The Partnership previously entered into and has maintained agreements with two banks to provide letters of credit in an aggregate amount of $25.0 million (Note 9). At December 31, 2005, the Partnership had $24.8 million in outstanding letters of credit. The Special GP guarantees these letters of credit. Historically, the Partnership has compensated the Special GP for a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. During 2003 the Special GP agreed to waive the guarantee fee in exchange for a parent guarantee from the Intermediate Partnership and Alliance Coal, LLC on the mineral lease and sublease with Webster County Coal and Warrior Coal described above. Since the guarantee is made on behalf of entities within the consolidated partnership, the guarantee has no fair value under FASB Interpretation (FIN) No. 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, including Indirect Guarantees of Indebtedness of Other*s, and does not impact the consolidated financial statements. The Partnership paid approximately $31,300 in guarantee fees to the Special GP for the year ended December 31, 2003.

18. COMMITMENTS AND CONTINGENCIES

Commitments The Partnership leases buildings and equipment under operating lease agreements that provide for the payment of both minimum and contingent rentals. The Partnership also has a noncancelable lease with the Special GP (Note 17). Future minimum lease payments under operating leases are as follows (in thousands):

Year Ending December 31,	Affiliate	Others	Total
2006	$ 2,835	$ 977	$ 3,812
2007	2,835	709	3,544
2008	2,835	264	3,099
2009	2,595	13	2,608
2010	2,595		2,595
Thereafter	216		216
	$ 13,911	$ 1,963	$ 15,874

Rental expense (including rental expense incurred under operating lease agreements) was $6,390,000, $6,112,000, and $5,490,000 for the years ended December 31, 2005, 2004 and 2003, 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 $10.0 million payable in any period of 12 consecutive months. This master equipment lease is subject to this limitation on lease obligations. The Partnership entered into nine operating leases during 2003 under the master equipment lease with lease terms ranging from three to six years. The Partnership did not enter into any new equipment leases under the master equipment lease during 2004 or 2005. The Partnership has exercised purchase options under the master equipment lease as they come available, which has partially contributed to the decrease in future lease commitments.

Contractual Commitments In connection with planned capital projects, the Partnership had contractual commitments of approximately $10.8 million at December 31, 2005.

General Litigation The Partnership is involved in various lawsuits, claims and regulatory proceedings incidental to its business. Disputes between the Partnership and its 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 recently settled contract dispute with ICG described below, the Partnership is not involved in any litigation relating to any of the Partnership s long-term coal supply contracts. However, we cannot assure you that disputes will not occur or that the Partnership will be able to resolve those disputes in a satisfactory manner. The Partnership is not engaged in any litigation that we believe is material to the Partnership s operations, including under the various environmental protection statutes to which the Partnership is subject. The Partnership provides for costs related to litigation and regulatory proceedings, including civil fines issued as part of the outcome of these proceedings, when a loss is probable and the amount is reasonably determinable. Although the ultimate outcome of these matters cannot be predicted with certainty, in the opinion of management, the outcome of these matters to the extent not previously provided for or covered under insurance, is not expected to have a material adverse effect on the Partnership s business, financial position or results of operations. Nonetheless, these matters or estimates that are based on current facts and circumstances, if resolved in a manner different from the basis on which management has formed its opinion, could have a material adverse effect on the Partnership s financial position or results of operations.

Other During October 2005, the Partnership completed its annual property and casualty insurance renewal with various insurance coverages effective as of October 1, 2005. Available capacity for underwriting property insurance has tightened as a result of recent events including insurance carrier losses associated with U.S. gulf coast hurricanes, poor loss claims history in the underground coal mining industry and our recent loss history (i.e., Vertical Belt Incident, MC Mining Fire Incident, and Dotiki Fire Incident). As a result, the Partnership will retain a participating interest along with our insurance carriers at an average rate of approximately 10% in the $75 million commercial property program. The aggregate maximum limit in the commercial property program is $75 million per occurrence of which we would be responsible for a maximum amount of $7.75 million for each occurrence, excluding a $1.5 million deductible for property damage and a 45-day waiting period for business interruption. As a result of the renewal for comparable levels of commercial property coverage, premiums for the property insurance program increased by approximately 130%. The Partnership can make no assurances that it will not experience significant insurance claims in the future, which as a result of the participation in the commercial property program, could have a material adverse effect on the business, financial conditions, results of operations and ability to purchase property insurance in the future.

The Partnership s subsidiary, Mettiki Coal (WV), LLC, is developing an underground longwall mine in Tucker County, West Virginia (referred to as the Mountain View Mine or E-Mine), which will eventually replace Mettiki Coal s existing longwall mining operation at the D-Mine located in Garrett County, Maryland. The Mountain View Mine is located approximately 10 miles from Mettiki Coal. In order to proceed with development of the Mountain View Mine, Mettiki Coal (WV) submitted various permit applications to the West Virginia Department of Environmental Protection, or WVDEP, including an application for approval to conduct underground mining. WVDEP issued the required permits in the Spring of 2004. Certain complainants appealed WVDEP s decision issuing the underground mining permit to the West Virginia Surface Mine Board, or SMB, which held administrative hearings on the matter in late 2004 and early 2005. On March 8, 2005, the SMB on a divided 3-3 vote issued a final order concluding consideration of the appeal without effectively rendering a decision, which, by operation of West Virginia law, resulted in the affirmation of WVDEP s decision to issue the underground mining permit. The complainants appealed the SMB decision, but subsequently voluntarily agreed to withdraw the appeal, which was dismissed with prejudice by the Tucker County circuit court in West Virginia on April 26, 2005.

On April 19, 2005, these same complainants submitted a letter to the U.S. Department of the Interior s Office of Surface Mining, Reclamation and Enforcement, or OSM, and the OSM s regional field office in Charleston, West Virginia, or CHFO, requesting federal monitoring and inspection of the Mountain View Mine and alleging that operations at the mine would create acid mine drainage with no defined end point. By written notice dated April 21, 2005, the CHFO advised WVDEP that it would review the complainants allegation that the Mountain View Mine would cause material harm to the hydrological balance within and outside of the permit area. Following its initial review, on September 15, 2005, the CHFO notified WVDEP that it intended to initiate a formal investigation into the issuance of the underground mining permit for the Mountain View Mine. WVDEP requested an informal review of the CHFO decision by the OSM. By two letters, both dated October 21, 2005, OSM reversed the decision of the CHFO concluding that the CHFO and OSM lacked statutory authority to review the WVDEP s issuance of the underground mining permit, and the Department of the Interior ordered that this was the Department s final decision on the matter raised in the complainants letter dated April 19, 2005. The Mountain View Mine is not currently subject to any pending or threatened agency or third-party claims. However, on March 8, 2006, these same complainants requested that the Director of OSM evaluate West Virginia s State Program pursuant to 30 C.F.R. §§ 733 et seq., but acknowledged a similar request had been made on April 19, 2005, which request had been previously rejected by the Department of Interior s final decision on October 21, 2005.

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

The complaint alleged that from January 2004 to August 2004, Pontiki failed to deliver a total of 138,111 tons of coal that met the contract delivery and quality specifications resulting in an alleged loss of profits for ICG of $4.1 million. The Partnership is aware that certain deliveries under the Horizon Agreement were not made during 2004 for reasons including, but not limited to, force majeure events at Pontiki and ICG s failure to provide transportation services for the delivery of coal as required under the Horizon Agreement. In November 2005, the Partnership settled this contract dispute with ICG. Under this settlement, effective August 1, 2005, Pontiki will ship coal in approximately ratable monthly quantities until the remaining contract obligation of 1,681,303 tons is shipped, and this contract will terminate on or by December 31, 2006. Under the terms of the settlement, the existing coal supply agreement was amended to change the coal quality specifications and to exclude from the definition of force majeure the events of railroad car shortages and geological and quality issues with respect to coal. As part of this settlement, the Partnership and ICG also executed a new coal sales agreement whereby another subsidiary of the Partnership will purchase 892,000 tons of coal from ICG. Approximately 63,000 tons were purchased and sold at a profit in 2005 and the remaining 829,000 tons are expected to be purchased and sold at a profit in 2006. These agreements will expire on or by December 31, 2006.

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

19. 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, in the infrequent circumstance when the coal is sold other than free on board the mine, changes in transportation rates. Total revenues to major customers, including transportation revenues (Note 2), which exceed ten percent of total revenues (Customer C comprised less than nine percent of total revenues in 2004) are as follows (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Customer A	$ 133,672	$ 124,847	$ 116,750
Customer B	88,525	89,887	78,724
Customer C	83,255	56,658	52,561

Trade accounts receivable from these customers totaled approximately $45.3 million at December 31, 2005. The Partnership s bad debt experience has historically been insignificant; however the Partnership established an allowance of $763,000 during 2001, due to the Partnership s total credit exposure to Enron Corp., which filed for bankruptcy protection during December 2001. The Partnership received $114,000 in 2004 for its claim against Enron, which was recognized as a recovery in 2004. The remaining balance of $649,000 was written-off in 2004. Financial conditions of its customers could result in a material change to this estimate in future periods. The coal supply agreements with Customers A, B and C expire in 2007, 2023 and 2013, respectively.

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20. SEGMENT INFORMATION

The Partnership operates in the eastern United States as a producer and marketer of coal to major United States utilities and industrial users, also located in the eastern United States. The Partnership has the following three reportable segments: the Illinois Basin, Central Appalachia and Northern Appalachia. The segments also represent the three major coal deposits in the eastern United States. Coal quality, coal seam height, transportation methods and regulatory issues are similar within each of these three segments. The Illinois Basin segment is comprised of the Dotiki, Gibson, Hopkins, Pattiki and Warrior mines. Central Appalachia segment is comprised of the Pontiki and MC Mining mines. Northern Appalachia segment is comprised of the Mettiki, Mountain View, Tunnel Ridge and Penn Ridge mines. The Mountain View mine is currently being developed to eventually replace production from the Mettiki mine, which is expected to deplete its coal reserves in late 2006. The Partnership is in the process of permitting the Tunnel Ridge and Penn Ridge properties for future mine development.

Operating segment results for the years ended December 31, 2005, 2004 and 2003 are presented below. Other and Corporate, includes marketing and administrative expenses, the Mt. Vernon Transfer Terminal and coal brokerage activity.

	Illinois Basin	Central Appalachia	Northern Appalachia	Other and Corporate (1)	Consolidated
			(in thousands)		
Operating segment results for the year ended December 31, 2005 were as follows:					
Total revenues	$ 553,908	$ 157,203	$ 120,423	$ 7,184	$ 838,718
Selected production expenses (2)	289,720	94,909	62,425	3,606	450,660
Segment Adjusted EBITDA (3)	183,075	41,583	36,047	2,924	263,629
Total assets	274,437	91,853	73,789	92,608	532,687
Capital expenditures (4)	70,353	23,451	24,435	1,642	119,881
Operating segment results for the year ended December 31, 2004 were as follows:					
Total revenues	$ 391,005	$ 147,361	$ 112,251	$ 2,672	$ 653,289
Selected production expenses (2)	224,540	98,162	51,304	585	374,591
Segment Adjusted EBITDA (3)(5)	121,763	28,953	41,141	1,432	193,289
Total assets	216,739	64,241	46,168	85,636	412,784
Capital expenditures	32,870	14,465	6,605	773	54,713
Operating segment results for the year ended December 31, 2003 were as follows:					
Total revenues	$ 328,586	$ 116,443	$ 89,933	$ 7,785	$ 542,747
Selected production expenses (2)	184,112	77,840	44,521	6,748	313,221
Segment Adjusted EBITDA (3)	95,351	23,962	27,288	624	147,225
Total assets	189,079	65,395	43,127	38,853	336,454
Capital expenditures	26,243	12,134	4,408	219	43,004

(1) Revenues included in the Other and Corporate column are attributable to Mt. Vernon Transfer Terminal transloading revenues and brokerage coal sales.

(2) Selected production expenses is comprised of operating expenses and outside purchases (as reflected in the Consolidated Statements of Income), excluding production taxes and royalties that are incurred as a percentage of coal sales or volumes.

(3) Segment adjusted EBITDA is defined as net income before income tax expense (benefit), interest expense and interest income, depreciation, depletion and amortization, and general and administrative expense.

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(4) Capital expenditures includes items received but not yet paid, which is disclosed as non-cash activity, purchase of property, plant and equipment in the supplemental cash flow information in the Consolidated Statements of Cash Flows.

(5) The Illinois Basin s year 2004 segment adjusted EBITDA includes $15.2 million for the net gain from insurance settlement associated with the Dotiki Fire Incident.

	Year Ended December 31, 2005	2004 (in thousands)	2003
Reconciliation of Segment Adjusted EBITDA to net income:			
Segment Adjusted EBITDA	$ 263,629	$ 193,289	$ 147,225
General & administrative	(33,484)	(45,400)	(28,270)
Depreciation, depletion and amortization	(55,637)	(53,664)	(52,495)
Interest expense	(11,816)	(14,963)	(15,981)
Income taxes	(2,682)	(2,641)	(2,577)
Net income	$ 160,010	$ 76,621	$ 47,902
Reconciliation of Selected Production Expenses to Combined Operating Expenses and Outside Purchases:			
Selected Production Expenses	$ 450,660	$ 374,591	$ 313,221
Production taxes and royalties	85,941	71,793	64,122
Combined operating expenses and outside purchases	$ 536,601	$ 446,384	$ 377,343

21. 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, 2005	June 30, 2005 (1)	September 30, 2005	December 31, 2005
Revenues	$ 195,627	$ 208,716	$ 207,043	$ 227,332
Operating income	43,158	44,872	37,949	47,948
Income before income taxes	39,789	41,621	35,198	46,084
Net income	39,079	40,792	34,481	45,658
Basic net income per limited partner unit	$ 0.71	$ 0.73	$ 0.65	$ 0.80
Diluted net income per limited partner unit	$ 0.70	$ 0.72	$ 0.63	$ 0.79
Weighted average number of units outstanding basic	36,260,880	36,260,880	36,260,880	36,370,565
Weighted average number of units outstanding diluted	36,992,828	36,995,172	36,997,338	36,923,444

	Quarter Ended March 31, 2004(2)	June 30, 2004	September 30, 2004(3)	December 31, 2004(4)
Revenues	$ 157,824	$ 162,546	$ 158,261	$ 174,658
Operating income	22,493	27,180	29,337	14,231
Income before income taxes	18,964	23,589	25,867	10,842
Net income	18,225	22,861	25,321	10,214

Basic net income per limited partner unit (5)	$	0.43	$	0.49	$	0.53	$	0.25
Diluted net income per limited partner unit (5)	$	0.42	$	0.47	$	0.51	$	0.25
Weighted average number of units outstanding basic		35,807,586		35,807,586		35,807,586		35,103,212
Weighted average number of units outstanding diluted		36,878,198		36,877,102		36,877,516		36,874,328

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

(1) The Partnership s June 30, 2005 quarterly results were decreased by $2.8 million due to the estimated direct expenses and costs attributable to the Vertical Belt Failure (Note 5).

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

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

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

(5) The sum of per unit net income per limited partner by quarter for the year 2004 does not equal the annual amount of per unit net income per limited partner reported on the income statement due to the effect of EITF No. 03-6 on quarterly calculations of per unit income per limited partner in the fourth quarter of the year ended December 31, 2004. See Note 12 for further discussion of this calculation.

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SCHEDULE II

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

YEARS ENDED DECEMBER 31, 2005, 2004, AND 2003

	Balance At Beginning Of Year	Additions Charged To Income	Deductions	Balance At End Of Year
		(in thousands)		
2005				
Allowance for doubtful accounts	$	$	$	$
2004				
Allowance for doubtful accounts	$ 763	$	$ 763	$
2003				
Allowance for doubtful accounts	$ 763	$	$	$ 763

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. The Partnership maintains controls and procedures designed to ensure that it is able to collect the information it is required to disclose in the reports it files with the U.S. Securities and Exchange Commission (SEC), and to process, summarize and disclose this information within the time periods specified in the rules of the SEC. An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Securities Exchange Act) was performed as of the end of the period covered by the date of this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based on an evaluation of the Partnership s disclosure controls and procedures as of the end of the period covered by this report conducted by the Partnership s management, with the participation of our Chief Executive and Chief Financial Officers, our Chief Executive and Chief Financial Officers believe that these controls and procedures are effective to ensure that the Partnership is able to collect, process and disclose the information it is required to disclose in the reports it files with the SEC within the required time periods.

In August 2005, the Partnership restated its financial statements for the year ended December 31, 2004 and the three months ended March 31, 2005 (the Restated Statements). The restatements related to (a) the failure to apply the provisions of Emerging Issues Task Force 03-6, *Participating Securities and the Two-Class Method under SFAS No. 128* (EITF 03-6) in the computation of basic and diluted net income per limited partner unit and (b) the incorrect presentation of the pro forma information required under SFAS No. 148, *Accounting for Stock-Based Compensation-Transition and Disclosure, an Amendment of SFAS No. 123*.

As a result of the restatements, our management reevaluated its assessment of the effectiveness of the Partnershp s internal control over financial reporting as of December 31, 2004, in which management had originally concluded that the Partnershp s internal control over financial reporting was effective. In the reevaluation, management concluded that the misstatements described above resulted from a control deficiency that represented a material weakness.

Remediation Steps

During the fourth quarter of 2005, management undertook several steps to remediate the control deficiency over financial reporting. The remediation steps included:

- The addition of a staff professional in the financial reporting department. The additional staff professional has extensive financial reporting experience;

- A comprehensive review of accounting literature, including renewed emphasis on the completion of check lists designed to insure compliance with accounting pronouncement and SEC regulations;

- Networking with other financial reporting personnel, including continuing education for member s of the financial reporting staff;

- Canvassing members of the publicly traded partnership (PTP) industry group concerning the emergence of accounting issues unique to PTPs;

- Subscribing to an accounting research tool provided by one of the major accounting firms, other than its independent registered public accounting firm; and

- Enhanced documentation of certain accounting policies and/or decisions.

Management believes the additional procedures performed during the fourth quarter of 2005 and continuing in 2006 in conjunction with the preparation of the financial statements for the year ended December 31, 2005 have remediated the internal controls weakness associated with the restatements.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls or our internal controls over financial reporting (internal controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Partnership have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that simple errors or mistakes can occur. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based, in part, upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our disclosure controls and internal controls and make modifications as necessary; our intent in this regard is that the disclosure controls and the internal controls will be maintained as systems change and conditions warrant.

Management s Annual Report on Internal Control over Financial Reporting. Management of the Partnership is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Securities Exchange Act of 1934. The Partnership s internal control over financial reporting is designed to provide reasonable assurance to the Partnership s management and Board of Directors of the managing general partner regarding the preparation and fair presentation of published financial statements. Our controls are designed to provide reasonable assurance that the Partnership s assets are protected from unauthorized use and that transactions are executed in accordance with established authorizations and properly recorded. The internal controls are supported by written policies and are complemented by a staff of competent business process owners and an internal auditor supported by competent and qualified external resources used to assist in testing the operating effectiveness of the Partnership s internal control over financial reporting. Management believes the design and operations of our internal controls over financial reporting at December 31, 2005 are effective and provide reasonable assurance the books and records accurately reflect the transactions of the Partnership.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2005. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework*. Based on our assessment, we believe that, as of December 31, 2005, the Partnership s internal control over financial reporting is effective based on those criteria, and we believe that we have no material internal control weaknesses in our financial reporting process.

Management s assessment of the effectiveness of internal control over financial reporting as of December 31, 2005, has been audited by Deloitte & Touche, LLP, the independent registered public accounting firm, which also audited the Partnership s consolidated financial statements. Deloitte & Touche s attestation report on management s assessment of the Partnership s internal control over financial reporting appears below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of the Managing

General Partner and the Partners of

Alliance Resource Partners, L.P.:

We have audited management s assessment, included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting, that Alliance Resource Partners, L.P. and subsidiaries (the Partnership) maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Partnership s internal control over financial reporting based on our audit.

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

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

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

In our opinion, management s assessment that the Partnership maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of December 31, 2005 and 2004 and the related consolidated statements of income, cash flows and Partners capital (deficit) and comprehensive income for each of the three years in the period ended December 31, 2005 and the financial statement schedule listed in the Index at Item 15 of the Partnership, and our report dated March 16, 2006 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP

Tulsa, Oklahoma

March 16, 2006

ITEM 9B. OTHER INFORMATION

None.

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PART III

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

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

Name	Age	Position With our Managing General Partner
Joseph W. Craft III	55	President, Chief Executive Officer and Director
Robert G. Sachse	57	Executive Vice President and Vice Chairman of the Board
Thomas L. Pearson	52	Senior Vice President Law and Administration, General Counsel and Secretary
Charles R. Wesley	51	Senior Vice President Operations
Brian L. Cantrell	46	Senior Vice President and Chief Financial Officer
Gary J. Rathburn	55	Senior Vice President Marketing
Michael J. Hall	61	Director and Member of the Audit* and Conflicts Committees
John J. MacWilliams	50	Director
Preston R. Miller, Jr.	57	Director and Member of the Compensation* Committee
John P. Neafsey	66	Chairman of the Board and Member of Audit, Compensation and Conflicts Committees
John H. Robinson	55	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 1999 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, a Director of the Center for Energy and Economic Development, and a member of the Board of Trustees for the University of Tulsa. 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 September 2005. Mr. Sachse has been Executive Vice President and Vice Chairman of our managing general partner since August 2000. Prior to his current position, Mr. Sachse was Executive Vice President and Chief Operating Officer of MAPCO Inc. from 1996 to 1998 when MAPCO merged with The Williams Companies. Following the merger, Mr. Sachse had a two year non-compete consulting agreement with The Williams Companies. Mr. Sachse held various positions while with MAPCO Coal Inc. from 1982 to 1991, and was promoted to President of MAPCO Natural Gas Liquids in 1992. Mr. Sachse holds a Bachelor of Science degree in Business Administration from Trinity University and a Juris Doctor degree from the University of Tulsa.

Thomas L. Pearson has been Senior Vice President Law and Administration, General Counsel and Secretary since August 1996. Mr. Pearson previously was Assistant General Counsel of MAPCO Inc., and served as General Counsel

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

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

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

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

Michael J. Hall became a Director in March 2003. Mr. Hall was elected President and Chief Executive Officer of Matrix Service Company (Matrix) on March 28, 2005 and continues to serve in that capacity. Mr. Hall was Vice President Finance and Chief Financial Officer, Secretary and Treasurer of Matrix from September, 1998 until he retired in May, 2004. He serves on Matrix s board of directors, a position he assumed when he joined Matrix in 1998. Matrix is a company which provides general industrial construction and repair and maintenance services principally to the petroleum, petrochemical, power, bulk storage terminal, pipeline and industrial gas industries. Prior to working for Matrix, Mr. Hall was Vice President and Chief Financial Officer of Pexco Holdings, Inc., Vice President Finance and Chief Financial Officer for Worldwide Sports & Recreation, Inc. an affiliated company of Pexco, and worked for T.D. Williamson, Inc., as Senior Vice President, Chief Financial and Administrative Officer, and Director of Operations Europe, Africa and Middle East Region. Mr. Hall holds a Bachelor of Science degree in Accounting from Boston College and a Master of Business Administration from Stanford University. Mr. Hall is chairman of the audit committee and a member of the conflicts committee.

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

Preston R. Miller, Jr., is a Partner of The Tremont Group, LLC, a private equity investment firm founded in January 2003, located in Newton, MA., which has a specialized expertise in the energy industry. Mr. Miller is a General Partner of The Beacon Group, LP, which he joined in 1993 and has served as a Director since June 1996. As a part of The

Beacon Group, he co-manages a private equity fund focusing on the energy industry. Mr. Miller s previous positions include serving as a General Partner of JP Morgan Partners from June 2000 through December 2002, and was with Goldman Sachs & Co. s from January 1979 through January 1993, most recently as Vice President in the Structured Finance Group in New York City, where he had global responsibility for coverage of the independent power industry, asset-backed power generation, and oil and gas financing. He also has a background in credit analysis, and was head of a revenue bond rating group at Standard & Poor s Corp. Mr. Miller holds a Bachelor of Arts degree from Yale University and a Master of Public Administration degree from Harvard University. Mr. Miller is the chairman of the compensation committee.

John P. Neafsey has served as Chairman since June 1996. Mr. Neafsey is President of JN Associates, an investment consulting firm formed in 1993. Mr. Neafsey served as President and CEO of Greenwich Capital Markets from 1990 to 1993 and a Director since its founding in 1983. Positions that Mr. Neafsey held during a 23-year career at The Sun Company include Director; 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 Chairman of Constar, Inc. and Lead Director of NES Rentals, 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 Vice Chairman of Olsson Associates, an engineering consultancy. From 2003 to 2004, he was Chairman of EPC Global, Ltd., an engineering staffing company, and President of Metilinix, Inc., a system optimization software company. From 2000 to 2002, he was Executive Director of Amey plc, a British business process outsourcing company. Mr. Robinson served as Vice Chairman of Black & Veatch from 1998 to 2000. He began his career at Black & Veatch in 1973 and was a General Partner and Managing Partner prior to becoming Vice Chairman when the firm incorporated. Mr. Robinson is a Director of Coeur d Alene Mining Corporation. Mr. Robinson holds Bachelor and Master of Science degrees in Engineering from the University of Kansas and is a graduate of the Owner-President-Management Program at the Harvard Business School. He is chairman of the conflicts committee and a member of the audit and compensation committees.

Audit Committee

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

Report of the Audit Committee

The audit committee of Alliance Resource Management GP, LLC, oversees our Partnership s financial reporting process on behalf of the Board of Directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls. The audit committee has the responsibility for the appointment, compensation and oversight of the work of our independent registered public accounting firm and assists the Board of Directors by conducting its own review of our:

- filings with the Securities and Exchange Commission (the SEC) and the Securities Act of 1933 and the Securities Exchange Act of 1934 (the Exchange Act) (i.e., Forms 10-K, 10-Q, and 8-K);

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

- systems of internal controls regarding finance and accounting that management and the Board of Directors have established; and

auditing, accounting and financial reporting processes generally.

In fulfilling its oversight and other responsibilities, the audit committee either met or took action in the form of written consents 9 times during 2005. The audit committee s activities included, but were not limited to, (a) the selection of the independent registered public accounting firm, (b) meeting periodically in executive session with the independent registered public accounting firm, (c) the review of the Quarterly Reports on Form 10-Q for the three months ended March 31, June 30, and September 30, 2005, (d) performing a self-assessment of the committee itself, (e) reviewing the audit committee charter, and (f) reviewing the overall scope, plans and finding of the Partnership s internal auditor. Based on the results of the annual self-assessment, the audit committee believes that it satisfied the requirements of its charter. The audit committee also reviewed and discussed with management and the independent registered public accounting firm this Annual Report on Form 10-K, including the audited financial statements.

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

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

Based on the reviews and discussions referred to above, the audit committee recommended to the Board of Directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2005 for filing with the SEC.

Members of the Audit Committee:

Michael J. Hall, Chairman

John P. Neafsey

John H. Robinson

Code of Ethics

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

Communications with the Board

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

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Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities and Exchange Act of 1934, as amended, requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC initial reports of ownership and reports or changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms they file. Based solely upon a review of the copies of the forms furnished to us, or written representations from certain reporting persons, we believe that during 2005 none of our officers and directors were delinquent with respect to any of the filing requirements under Rule 16(a) other than Mr. Wynne who did not timely file a Form 4 related to his sale of 419 units in June, but has since filed a Form 4 with respect to this transaction.

Reimbursement of Expenses of our Managing General Partner and its Affiliates

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

ITEM 11. EXECUTIVE COMPENSATION

Executive Compensation

The following table sets forth certain compensation information for the chief executive officer and each of the four other most highly compensated executive officers of our managing general partner in excess of $100,000 in 2005, 2004 and 2003. 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				
Name and Principal Position	**Year**	**Salary**	**Bonus (1)**	**Other Annual Compensation (2)**	**Long-Term Compensation Payouts (3)**	**All Other Compensation (4)**
Joseph W. Craft III,	2005	$ 334,828	$ 200,000	$ 4,100	$ 3,801,600	$ 77,463
President, Chief Executive Officer	2004	341,267	375,000	3,521	8,286,600	79,479
and Director	2003	334,828	387,000	3,400		62,694
Thomas L. Pearson,	2005	210,257	200,000	8,060	760,320	45,565
Senior Vice President-Law and	2004	203,520	225,000		1,473,746	39,435
Administration, General Counsel and Secretary	2003	199,680	166,000			31,481
Charles R. Wesley,	2005	235,857	245,000		1,182,720	54,631
Senior Vice President-Operations	2004	229,612	300,000	825	1,657,320	75,320
	2003	215,665	234,500			37,115
Gary J. Rathburn,	2005	184,257	200,000	7,300	781,440	43,816
Senior Vice President-Marketing	2004	177,020	222,000		1,508,939	38,790
	2003	173,680	171,000			30,602
Thomas M. Wynne	2005	169,100	200,000		549,120	28,661
Vice President-Operations	2004	164,631	222,000		1,154,205	45,377
	2003	153,600	150,000			17,448

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

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

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(3) The 2005 amounts represent the market value of the LTIP grants for 2003 that vested in November 2005. The 2004 amounts represent the market value of the LTIP grants for the years 2002, 2001 and 2000 that vested in November 2004.

(4) Amounts represent (a) our managing general partner s matching contributions to its profit sharing and savings plan, (b) our managing general partner s contribution to its Supplemental Executive Retirement Plan (SERP), and (c) the 2004 amounts for Mr. Wesley and Mr. Wynne include a non Short-Term Incentive Plan bonus approved by the compensation committee.

Compensation of Directors

Under our managing general partner s Directors Compensation Program (Directors Plan) each non-employee director was paid an annual retainer of $22,500 during 2005. The annual retainer is payable in common units to be paid on a quarterly basis in advance determined by dividing the pro rata annual retainer payable on such date by the closing sales price per common unit averaged over the immediately preceding ten trading days. Each non-employee director is eligible to participate in a deferred compensation plan that is administered by the compensation committee. Prior to the beginning of each plan year, each non-employee director may elect to defer all or a portion of his compensation until he ceases to be a member of the Board of Directors. A new election must be made for each plan year. For compensation deferred by a director, a notional account is established and credited with phantom units equal to the number of common units deferred. In addition, when distributions are made with respect to common units, the notional account is credited with phantom distributions with respect to phantom units that are equal in amount to the distributions made with respect to common units. The Board of Directors may change or terminate the deferred compensation plan at any time; provided, however, that accrued benefits under the deferred benefit plan cannot be impaired. Effective January 1, 2006, the annual retainer was increased to $23,500.

In addition, each non-employee director is entitled to participate in the Long-Term Incentive Plan. Under the Long-Term Incentive Plan such directors receive annual grants of restricted units, which vest in accordance with the procedures described below. Please see Long-Term Incentive Plan below.

Mr. Sachse has a consulting agreement with our managing general partner with an indefinite term, subject to termination by either party upon receipt of ninety-day advance written notice of termination. The consulting agreement provides that Mr. Sachse will serve as Executive Vice President of our managing general partner and devote his services on a part-time basis. In addition to compensation received under the Directors Plan described above and Long-Term Incentive Plan described below, Mr. Sachse is entitled to receive an annual fee of $150,000, payable monthly in arrears. Mr. Sachse also is entitled to receive quarterly payments of $7,500, payable in common units of the Partnership. Copies of Mr. Sachse s original consulting agreement and the letter agreement extending the term of the original agreement are exhibits hereto.

Employment Agreements

In 2005, the executive officers of our managing general partner and some additional members of senior management executed release and waiver forms terminating their employment agreements.

Long-Term Incentive Plan

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

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

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.

The issuance of the common units pursuant to the vesting of restricted units under the LTIP 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. 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.

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

On December 22, 2005, the compensation committee executed a unanimous consent resolution that, effective January 1, 2006, (a) all existing grants made under the LTIP prior to January 1, 2006 and subsequent thereto be settled, upon satisfaction of any applicable vesting requirements, in common units to be reduced by a cash settlement component equal to the minimum statutory income tax withholding requirement for each individual participant based upon the fair market value of the common units as of the date of payment and (b) any existing and prospective LTIP grants of restricted units receive quarterly distributions as provided in the distribution equivalent rights provision of the LTIP. Therefore, each LTIP participant will have a contingent right to receive an amount equal to the cash distributions made by us during the vesting period.

After adjusting for the two-for-one split of our common units in September 2005, the aggregate number of units reserved for issuance under the LTIP is 1,200,000. Effective January 1, 2004, the compensation committee approved an amendment to the LTIP clarifying that any award that is forfeited, expires for any reason, or is paid or settled in cash, including the satisfaction of minimum statutory withholding requirements, rather than through the delivery of units will be available for future grant under the LTIP. Of the initial 1,200,000 units reserved for issuance under the LTIP, cumulative units of 1,092,780 were granted in years 2000, 2001, 2002 and 2003. Of those grants, 43,650 units were forfeited and 421,452 units were settled in cash rather than delivery of units, resulting in the net issuance of 627,678 common units under those grants.

During 2004 and 2005 the compensation committee approved grants of 205,570 units and 114,390 units, respectively, which will vest December 31, 2006 and January 1, 2008, respectively, subject to the satisfaction of certain financial tests. As of December 31, 2005, 3,690 outstanding LTIP grants have been forfeited. Consequently, as of December 31, 2005, 256,052 units remain available for issuance in the future, assuming that all grants currently issued and outstanding for 2004 and 2005 are settled with common units and no forfeitures occur. Effective January 1, 2006 the compensation committee approved additional grants of 85,275 restricted units which vest January 1, 2009, subject to the satisfaction of certain financial tests that management expects we will satisfy.

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	30,000	36 Months
Thomas L. Pearson	6,800	36 Months
Charles R. Wesley	11,150	36 Months
Gary J. Rathburn	6,800	36 Months
Thomas M. Wynne	6,000	36 Months

(1) Units granted under the LTIP will vest January 1, 2008, subject to certain financial tests.

(2) The number of units granted is not subject to minimum thresholds, targets or maximum payout conditions. However, the vesting of these grants is subject to meeting certain financial tests.

Short-Term Incentive Plan

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

Supplemental Executive Retirement Plan

Our managing general partner maintains a 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 our unitholders. All allocations made to participants under the SERP are made in the form of phantom units. The SERP is administered by the compensation committee. Our managing general partner is able to amend or terminate the plan at any time. Our managing general partner is entitled to reimbursement by us for its costs incurred under the SERP.

Compensation Committee s Report on Executive Compensation

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

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

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

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

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

For the fiscal year ended December 31, 2005, the compensation committee met or took action in the form of written consents 6 times and primarily focused its activities on the primary elements of the total direct compensation program for executive officers; and the annual guidelines for the LTIP and STIP pertaining to eligibility, minimum thresholds, target objectives, target results, target payout groups, the respective percentage targets and the payout formula.

Overall Executive Compensation Program

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

- base salary;

- annual incentive bonus awards; and

- equity participation in the form of restricted units.

Executive officers are also entitled to customary benefits available to all of our managing general partner s employees, including group medical, dental, and life insurance and participation in our managing general partner s profit sharing and savings plan.

Base Salary

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

Annual Incentive Bonus Awards

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

Each executive officer of our managing general partner participating in the STIP was eligible to earn a cash bonus expressed as a percentage of such officer s base salary. The incentive bonus opportunities varied by each executive officer s level of responsibility. In order to calculate the annual aggregate cash bonus amount available for discretionary awards under the STIP for employees eligible to receive such cash bonuses, the STIP provides a formula dependent on our actual Adjusted EBITDA results for the year, based on a percentage of each eligible employee s base salary. For fiscal year 2005, we exceeded our annual Adjusted EBITDA target so that all of the 2005 STIP participants were eligible to receive a percentage of their salary as bonus awards at the discretion of the compensation committee and/or our CEO. Bonuses are payable in the first quarter of the following calendar year.

Equity Participation

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

CEO Executive Compensation

In determining Mr. Craft s compensation, the compensation committee considered our financial performance and peer group compensation data as well as Mr. Craft s leadership, decision-making skills, experience, knowledge, communication with the Board of Directors and strategic recommendations. The compensation committee did not place any particular relative weight on any one of these factors, but our financial performance is generally given the most weight. The committee s decisions regarding Mr. Craft s compensation are reported to and discussed with the Board of Directors meeting in executive session without Mr. Craft s participation. For fiscal year 2005, Mr. Craft served as CEO of our managing general partner. Effective June 1, 2002, Mr. Craft s annual salary was increased to $334,828 from $321,950, in which the adjustment was determined in the manner described above. The compensation committee honored Mr. Craft s request that his salary not be increased in 2003, 2004 and 2005 even though a salary increase would have been warranted under the compensation adjustment procedure described above. Any differences in Mr. Craft s annual salary as reported in the summary compensation table above are attributable to the effective date of the salary adjustment in the year 2002 and the number of weekly pay periods in a calendar year. Based on our record performance for 2005, Mr. Craft received a cash bonus (paid in fiscal year 2006) equal to approximately 59.7% of his base salary.

Conclusion

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

Members of the Compensation Committee:

Preston R. (Jeff) Miller, Chairman

John H. Robinson

John P. Neafsey

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth certain information as of March 1, 2006, regarding the beneficial ownership of common units held by (a) each person known by our managing general partner to be the beneficial owner of 5% or more of the common units, (b) each director and executive officer of our managing general partner and (c) all directors and executive officers of our managing general partner as a group. Our managing general partner is owned by members of management. Our special general partner is a wholly-owned subsidiary of Alliance Resource Holdings. The address of Alliance Resource Holdings, our managing general partner and our special general partner is 1717 South Boulder Avenue, Tulsa, Oklahoma 74119.

Name of Beneficial Owner	Common Units Beneficially Owned (5)	Percentage of Common Units Beneficially Owned
Alliance Resource GP, LLC (1)	15,310,622	42.03%
Joseph W. Craft III (1)(4)	15,951,362	43.79%
Robert G. Sachse (1)	29,382	*
Thomas L. Pearson (1)	50,198	*
Charles R. Wesley (1)	106,046	*
Brian L. Cantrell (1)	4,505	*
Gary J. Rathburn (1)	39,054	*
Michael J. Hall (1)	24,850	*
John J. MacWilliams (2)	1,984	*
Preston R. Miller, Jr. (2)	1,984	*
John P. Neafsey (1)	42,635	*
John H. Robinson (3)	17,491	*
All directors and executive officers as a group (11 persons)	16,269,491	44.66%

* Less than one percent

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

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

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

(4) Mr. Craft may be deemed to share beneficial ownership of 15,310,622 common 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 220,484 common units held by AMH II, LLC, of which he is the sole director and majority member. Mr. Craft also may be deemed to share beneficial ownership of 19,522 common units held by Alliance Management Holdings, LLC, of which he is the sole director. Mr. Craft also may be deemed to share beneficial ownership of an additional 27,000 common units held by a private foundation for which he serves as a Trustee. Mr. Craft disclaims beneficial ownership of the common units held by the private foundation.

(5) The amounts set forth do not include any restricted units granted under the LTIP, which units vest at various dates ranging from December 31, 2006 through January 1, 2009, subject to certain financial tests.

Equity Compensation Plan Information

Plan Category	Number of units to be issued upon exercise/vesting of outstanding options, warrants and rights as of March 1, 2006	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, 2006

Equity compensation plans approved by unitholders:			
Long-Term Incentive Plan	401,545	N/A	170,777
Equity compensation plans not approved by unitholders:			
Supplemental Executive Retirement Plan	110,051	N/A	49,949
Deferred Compensation Plan for Directors	40,568	N/A	59,432

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

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Certain Relationships and Related Transactions

Our special general partner owns 15,310,622 common units representing 42.0% of our common units. In addition, our general partners own, on a combined basis, an aggregate 2% general partner interest in us, the intermediate partnership and the subsidiaries. Our managing general partner s ability, as managing general partner, to control us together with our special general partner s ownership of 15,310,622 common units, effectively gives our general partners the ability to veto some of our actions and to control our management.

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

Related Party Transactions

Administrative Services

Our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses they incur or payments they make on our behalf, including, but not limited to, management s salaries and related benefits (including incentive compensation), and accounting, budget, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers compensation management, legal and information technology services. Our managing general partner may determine in its sole discretion the expenses that are allocable to us. Total costs billed by our managing general partner and its affiliates to us were approximately $14,069,000, $28,536,000, and $12,471,000 for the years ended December 31, 2005, 2004, and 2003, respectively.

The decrease in 2005 compared to 2004 was primarily attributable to lower compensation accruals for the LTIP, STIP and SERP. The increase from 2003 to 2004 was primarily attributable to higher accruals for the LTIP, STIP and SERP. The expenses associated with LTIP and SERP were impacted by the market value of the Partnership s Common Units, which had a closing market price of $37.20, $37.00, and $17.19 at December 31, 2005, 2004 and 2003, respectively. The amounts billed by the managing general partner include $10,559,000, $24,242,000, and $9,319,000 for the years ended December 31, 2005, 2004 and 2003, respectively, for the LTIP, STIP and SERP.

Tunnel Ridge Acquisition

In January 2005, we acquired 100% of the limited liability company member interests of Tunnel Ridge, LLC for approximately $500,000 and the assumption of reclamation liabilities from Alliance Resource Holdings, Inc., a company owned by our management. Tunnel Ridge, LLC controls through a coal lease agreement with the special general partner an estimated 70 million tons of high-sulfur coal in the Pittsburgh No. 8 coal seam. The Tunnel Ridge reserve area encompasses approximately 50,571 acres of land located in Ohio County, West Virginia and Washington County, Pennsylvania. Under the terms of the coal lease, beginning on January 1, 2005, Tunnel Ridge, LLC has paid and will continue to pay our special general partner an advance minimum royalty of $3.0 million per year. The advance royalty payments are fully recoupable against earned royalties.

Tunnel Ridge, LLC also has rights to land and other tangible assets under a separate lease agreement with our special general partner. Under the terms of the lease agreement, Tunnel Ridge, LLC has paid and will continue to pay our special general partner an annual lease payment of $240,000. The lease agreement has an initial term of four years, which may be extended to be consistent with the term of the coal lease. Lease expense was $240,000 for the year ended December 31, 2005.

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

Warrior Coal Acquisition

On February 14, 2003, we acquired Warrior Coal from an affiliate, ARH Warrior Holdings, a subsidiary of Alliance Resource Holdings, a subsidiary of ARH, pursuant to a 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. 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 Coal. 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 Coal in January 2001 for $10.0 million.

The Put/Call Agreement preserved the opportunity for us to acquire Warrior Coal during a specified time period. Under the terms of the Put/Call Agreement, ARH Warrior Holdings exercised its put option requiring 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 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, we developed financial projections for Warrior Coal 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 Coal included, among others, (a) annual production levels ranging from 1.5 million to 1.8 million tons, (b) coal prices at or below the then current coal prices and (c) a discount rate of 12 percent. Based on these financial projections, as of the date of the acquisition and at December 31, 2002 and 2001, we believe that the fair value of Warrior Coal was equal to or greater than the put option exercise price.

The put option price of $12.7 million was paid to ARH Warrior Holdings in accordance with the terms of the Put/Call Agreement. In addition, we repaid Warrior Coal s borrowings of $17.0 million under the revolving credit agreement between our special general partner and Warrior Coal. The primary borrowings under the revolving credit agreement financed new infrastructure capital projects at Warrior Coal that have contributed to improved productivity and significantly increased capacity. We funded the Warrior Coal acquisition through a portion of the proceeds received from the issuance of 4,500,000 common units. Because the Warrior Coal acquisition was between entities under common control, it has been accounted for at historical cost in a manner similar to that used in a pooling of interests.

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

SGP Land

Webster County Coal has a mineral lease and sublease with SGP Land requiring annual minimum royalty payments of $2.7 million, payable in advance through 2013 or until $37.8 million of cumulative annual minimum and/or earned royalty payments have been paid. Webster County Coal paid royalties of $3,449,000, $4,611,000, and $3,460,000 for the years ended December 31, 2005, 2004 and 2003, respectively. Webster County Coal has recouped, as earned royalties, all advance minimum royalty payments made under these lease terms except for $1,018,000 as of December 31, 2005.

Warrior Coal has a mineral lease and sublease with SGP Land. Under the terms of the lease, Warrior Coal has paid and will continue to pay in arrears an annual minimum royalty obligation of $2,270,000 until $15,890,000 of cumulative annual minimum and/or earned royalty payments have been paid. The annual minimum royalty periods are from October 1st through the end of the following September, expiring September 30, 2007. Warrior Coal paid royalties of

$3,627,000, $2,561,000, and $2,453,000 for the years ended December 31, 2005, 2004, and 2003, respectively. Warrior Coal has recouped, as earned royalties, all advance minimum royalty payments made in accordance with these lease terms as of December 31, 2005.

Under the terms of the mineral lease and sublease agreements described above, Webster County Coal and Warrior Coal also reimburse SGP Land for SGP Land s base lease obligations. We reimbursed SGP Land $6,379,000, $5,428,000, and $4,395,000 for the years ended December 31, 2005, 2004 and 2003 respectively, for the base lease obligations. Webster County Coal and Warrior Coal have recouped, as earned royalties, all advance minimum royalty payments made in accordance with these terms except for $236,000 as of December 31, 2005.

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 $600,000 and $479,000 during the years ended December 31, 2005 and 2003, respectively. The 2004 annual minimum royalty obligation of $300,000 was paid in January, 2005. As of December 31, 2005, MC Mining has recouped, as earned royalties, all advance minimum royalty payments made in accordance with these lease terms except for $600,000.

On October 23, 2005, we exercised our option to lease and/or sublease certain reserves from SGP Land that are associated with Hopkins County Coal s Elk Creek mine. Upon exercise of the option agreement, Hopkins County Coal entered into a Coal Lease and Sublease Agreement as well as a Royalty Agreement (collectively, the Coal Lease Agreements). The terms of the Coal Lease Agreements are through December 2015, with the right to extend the term for successive one-year periods for as long as we are mining the coal field, as such term is defined in the Coal Lease Agreements.

The Coal Lease Agreements provide for five annual minimum royalty payments of $684,000. The combined annual minimum royalty payments, consistent with the option agreement, and cumulative option fees of $3.4 million previously paid by Hopkins County Coal are fully recoupable against future tonnage royalty payments. Under the terms of the lease and/or option to lease and sublease, Hopkins County Coal paid advance minimum royalties and/or option fees of $684,000 and $1,368,000 during the years ended December 31, 2005 and 2004, respectively. The 2003 option fee of $684,000 was paid in January 2004 and is included in the due to affiliates balance as of December 31, 2003. As of December 31, 2005, Hopkins County Coal has outstanding $4,059,000 of advance minimum royalty payments made under the Coal Lease Agreements that management expects will be recouped from future production.

Special General Partner

Effective January 2001, Gibson entered into a noncancelable operating lease arrangement with our special general partner for its coal preparation plant and ancillary facilities. Based on the terms of the lease, Gibson has paid and will continue to make monthly payments of approximately $216,000 through January 2011. Lease expense incurred for each of the three years in the period ended December 31, 2005 was $2,595,000.

We have previously entered into and have maintained agreements with two banks to provide letters of credit in an aggregate amount of $25.0 million. At December 31, 2005, we had $24.8 million in outstanding letters of credit. Our special general partner guarantees these letters of credit. Historically, we have compensated our special general partner a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. Our special general partner agreed to waive the guarantee fee in exchange for a parent guarantee from our intermediate partnership and Alliance Coal, LLC on the mineral lease and sublease with Webster County and Warrior Coal. Since the guarantee is made on behalf of entities within the consolidated partnership, the guarantee has no fair value under FIN No. 45 and does not impact the consolidated financial statements. We paid approximately $31,300 in guarantee fees to our special general partner for the year ended December 31, 2003.

Other Related Party Transactions

None.

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Omnibus Agreement

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

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

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

Audit Services. Fees for audit services provided during the years ended December 31, 2005 and 2004, were $784,000 and $745,000, respectively. Audit services consist primarily of the audit and quarterly reviews of the consolidated financial statements, but can also be related to statutory audits of subsidiaries required by governmental or regulatory bodies, attestation services required by statute or regulation, comfort letters, consents, assistance with and review of documents filed with the SEC, work performed by tax professionals in connection with the audit and quarterly reviews, and accounting and financial reporting consultations and research work necessary to comply with generally accepted accounting principles.

Audit-Related Services. Fees for audit-related services provided during the years ended December 31, 2005 and 2004, were $44,000 and $18,500, respectively. Audit-related services consist primarily of audits of employee benefit plans, consultations concerning financial accounting and reporting standards, and attestation services associated with third-party compliance.

Tax Services. Fees for tax services provided during the years ended December 31, 2005 and 2004, were $134,000 and $180,000, respectively. Tax services relate primarily to the preparation of federal and state tax returns but can also be related to tax advice, exclusive of tax services rendered in conjunction with the audit.

All Other Fees. There were no other fees for the year ended December 31, 2005. In 2004, other fees for due diligence services provided in conjunction with a proposed investment were $72,000.

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

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) Financial Statements.

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

(a)(2) Financial Statement Schedules.

Schedule II Valuation and Qualifying Accounts Years ended December 31, 2005, 2004 and 2003, 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	Second 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 8-K filed with the Commission on October 27, 2005, File No. 000-26823).
3.2	Amended and Restated Agreement of Limited Partnership of Alliance Resource Operating Partners, L.P. (Incorporated by reference to Exhibit 3.2 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
3.3	Certificate of Limited Partnership of Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 3.6 of the Registrant s Registration Statement on Form S-1 filed with the Commission on May 20, 1999 (Reg. No. 333-78845)).
3.4	Certificate of Limited Partnership of Alliance Resource Operating Partners, L.P. (Incorporated by reference to Exhibit 3.8 of the Registrant s Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).
3.5	Certificate of Formation of Alliance Resource Management GP, LLC (Incorporated by reference to Exhibit 3.7 of the Registrant s Registration Statement on Form S-1/A filed with the Commission on July 23, 1999 (Reg. No. 333-78845)).
3.6	Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC (Incorporated by reference to Exhibit 3.4 of the Registrant s Registration Statement on Form S-3 filed with the Commission on April 1, 2002 (Reg. No. 333-85282)).
3.7	Amendment No. 1 to Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC (Incorporated by reference to Exhibit 3.5 of the Registrant s Registration Statement on Form S-3 filed with the Commission on April 1, 2002 (Reg. No. 333-85282)).
3.8	Amendment No. 2 to Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC (Incorporated by reference to Exhibit 3.6 of the Registrant s Registration Statement on Form S-3 filed with the Commission on April 1, 2002 (Reg. No. 333-85282)).
4.1	Form of Common Unit Certificate (Included as Exhibit A to the Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.)
10.1	Credit Agreement, dated as of August 22, 2003, among Alliance Resource Operating Partners, L.P., JPMorgan Chase Bank (as paying agent), Citicorp USA, Inc. and JPMorgan Chase Bank (as co-administrative agents) and lenders named therein. (Incorporated by reference to Exhibit 10.41 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, File No. 000-26823).

10.2	Note Purchase Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC and the purchasers named therein. (Incorporated by reference to Exhibit 10.20 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
10.3	Letter of Credit Facility Agreement dated as of June 29, 2001, between Alliance Resource Partners, L.P. and Bank of Oklahoma, National Association. (Incorporated by reference to Exhibit 10.20 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
10.4	Amendment One to Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of Oklahoma, National Association. (Incorporated by reference to Exhibit 10.33 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 000-26823).
10.5	Promissory Note Agreement dated as of July 31, 2001, between Alliance Resource Partners, L.P. and Bank of Oklahoma, N. A. (Incorporated by reference to Exhibit 10.21 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
10.6	Guarantee Agreement, dated as of July 31, 2001, between Alliance Resource GP, LLC and Bank of Oklahoma, N.A. (Incorporated by reference to Exhibit 10.22 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
10.7	Letter of Credit Facility Agreement dated as of August 30, 2001, between Alliance Resource Partners, L.P. and Fifth Third Bank. (Incorporated by reference to Exhibit 10.23 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
10.8	Amendment No. 1 to Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Fifth Third Bank. (Incorporated by reference to Exhibit 10.9 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002, File No. 000-26823).
10.9	Guarantee Agreement, dated as of August 30, 2001, between Alliance Resource GP, LLC and Fifth Third Bank. (Incorporated by reference to Exhibit 10.24 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
10.10	Letter of Credit Facility Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association. (Incorporated by reference to Exhibit 10.25 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
10.11	First Amendment to the Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association. (Incorporated by reference to Exhibit 10.32 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 000-26823).
10.12	Promissory Note Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, N.A. (Incorporated by reference to Exhibit 10.26 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).

10.13	Guarantee Agreement, dated as of October 2, 2001, between Alliance Resource GP, LLC and Bank of the Lakes, N.A. (Incorporated by reference to Exhibit 10.27 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
10.14	Guaranty Fee Agreement dated as of July 31, 2001, between Alliance Resource Partners, L.P. and Alliance Resource GP, LLC. (Incorporated by reference to Exhibit 10.28 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File No. 000-26823).
10.15	Contribution and Assumption Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC, Alliance Resource Partners, L.P., Alliance Resource Operating Partners, L.P. and the other parties named therein. (Incorporated by reference to Exhibit 10.3 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
10.16	Omnibus Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC and Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 10.4 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
10.17	Amended and Restated Alliance Resource Management GP, LLC 2000 Long-Term Incentive Plan. (Incorporated by reference to Exhibit 10.17 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, File No. 000-26823).
10.18	First Amendment to the Alliance Resource Management GP, LLC 2000 Long-Term Incentive Plan. (Incorporated by reference to Exhibit 10.18 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, File No. 000-26823).
10.19	Alliance Resource Management GP, LLC Short-Term Incentive Plan. (Incorporated by reference to Exhibit 10.12 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
10.20	Alliance Resource Management GP, LLC Supplemental Executive Retirement Plan. (Incorporated by reference to Exhibit 99.2 of the Registrant s Registration Statement on Form S-8 filed with the Commission on April 1, 2002 (Reg. No. 333-85258)).
10.21	Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors. (Incorporated by reference to Exhibit 99.3 of the Registrant s Registration Statement on Form S-8 filed with the Commission on April 1, 2002 (Reg. No. 333-85258)).
10.22	Restated and Amended Coal Supply Agreement, dated February 1, 1986, among Seminole Electric Cooperative, Inc., Webster County Coal Corporation and White County Coal Corporation. (Incorporated by reference to Exhibit 10.9 of the Registrant s Registration Statement on Form S-1/A filed with the Commission on July 20, 1999 (Reg. No. 333-78845)).
10.23	Amendment No. 1 to the Restated and Amended Coal Supply Agreement effective April 1, 1996, between MAPCO Coal Inc., Webster County Coal Corporation, White County Coal Corporation, and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.14 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2000, File No. 000-26823).
10.24	Amendment No. 2 to the Restated and Amended Coal Supply Agreement effective February 28, 2002 between Webster County Coal, LLC, White County Coal, LLC, and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.32 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002, File No. 000-26823).

10.25	Amendment No. 3 to the Restated and Amended Coal Supply Agreement effective January 1, 2003 between Webster County Coal, LLC, White County Coal, LLC, Alliance Coal, LLC, and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.39 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2003, File No. 000-26823).
10.26	Amendment No. 4 dated October 25, 2005, 2005, between Seminole Electric Cooperative, Inc. and Webster County Coal, LLC (successor-in-interest to Webster County Coal Corporation), White County Coal, LLC (successor-in-interest to White County Coal Corporation), and Alliance Coal, LLC, as successor-in-interest to Mapco Coal, Inc. and agent for Webster County Coal, LLC and White County Coal, LLC, to the Coal Supply Agreement. (Incorporated by reference to Exhibit 10.3 of the Registrant s Form 8-K filed with the Commission on October 26, 2005, File No. 000-26823).
10.27	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).
*10.28	Guaranty by Alliance Coal, LLC dated October 25, 2005
*10.29	Financial Covenants Agreement dated October 25, 2005 by and between Seminole Electric Corporation, Inc. and Alliance Coal, LLC. (Portions of this agreement have been omitted based upon a request for confidential treatment. Those omitted portions have been filed with the SEC).
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	Agreement for the Supply of Coal to the Mount Storm Power Station, dated June 22, 2005, between Virginia Electric and Power Company and Alliance Coal, LLC. (Incorporated by reference to Exhibit 10.1 of A the Registrant s Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823).
10.32	Ancillary Services Agreement, dated June 22, 2005, between Virginia Electric and Power Company and Alliance Coal, LLC. (Incorporated by reference to Exhibit 10.2 of the Registrant s Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823).
10.33	Amended and Restated Lease Agreement, dated June 22, 2005, between Virginia Electric and Power Company and Mettiki Coal, LLC. (Incorporated by reference to Exhibit 10.3 of the Registrant s Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823).
10.34	Amended and Restated Equipment Lease Agreement (Existing Truck Unloading Facility), dated June 22, 2005, between Virginia Electric and Power Company and Mettiki Coal, LLC. (Incorporated by reference to Exhibit 10.4 of the Registrant s Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823).
10.35	Amended and Restated Memorandum of Understanding dated as of June 22, 2005, among Virginia Electric and Power Company, Alliance Coal, LLC and Mettiki Coal, LLC. (Incorporated by reference to Exhibit 10.5 of the Registrant s Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823).
10.36	Feedstock Agreement No. 2, dated as of July 1, 2005, between Alliance Coal, LLC and Mount Storm Coal Supply, LLC. (Incorporated by reference to Exhibit 10.1 of the Registrant s Form 8-K filed with the Commission on August 5, 2005, File No. 000-26823).

10.37	Memorandum of Understanding dated January 17, 2005 between VEPCO and Mettiki. (Incorporated by reference to Exhibit 10.2 of the Registrants Form 8-K filed with the Commission on January 19, 2005, File No. 000-26823).
10.38	Amendment No. 1 dated January 17, 2005 between VEPCO and Mettiki to the Coal Supply Agreement. (Incorporated by reference to Exhibit 10.2 of the Registrants Form 8-K filed with the Commission on January 19, 2005, File No. 000-26823).
10.39	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).
10.40	First Amendment to Coal Feedstock Supply Agreement dated February 28, 2002, between Synfuel Solutions Operating LLC and Hopkins County Coal, LLC (Incorporated by reference to Exhibit 10.28 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2001, File No. 000-26823).
10.41	Second Amendment to Coal Feedstock Supply Agreement dated April 1, 2003, between Synfuel Solutions Operating LLC and Warrior Coal, LLC. (Incorporated by reference to Exhibit 10.40 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File No. 000-26823).
10.42	Assignment and Assumption Agreement dated April 1, 2003 between Synfuel Solutions Operating LLC, Hopkins County Coal, LLC, and Warrior Coal, LLC. (Incorporated by reference to Exhibit 10.31 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003, File No. 000-26823).
10.43	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).
10.44	Letter Agreement dated January 31, 2003 between ARH Warrior Holdings, Inc. and Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 10.34 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002 File No. 000-26823).
10.45	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).
10.46	Extension of Consulting Agreement with Mr. Sachse, dated September 30, 2003. (Incorporated by reference to Exhibit 10.42 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, File No. 000-26823).
10.47	Amended and Restated Charter for the Audit Committee of the Board of Directors dated March 10, 2005. (Incorporated by reference to Exhibit 10.41 of the Registrant s Form 10-K filed with the Commission on March 15, 2005).
18.1	Preferability Letter on Accounting Change. (Incorporated by reference to Exhibit 18.1 of the Registrant s Amended Quarterly Report on Form 10-Q/A for the quarter ended March 31, 2001, File No. 000-26823).
*21.1	List of Subsidiaries
*23.1	Consent of Deloitte & Touche LLP regarding Form S-3 and Form S-8, Registration No. 333-85282 and No. 333-85258, respectively.

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* 31.1	Certification of Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated March 16, 2006, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 furnished herewith.
*31.2	Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated March 16, 2006, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 furnished herewith.
*32.1	Certification of Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated March 16, 2006, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 furnished herewith.
*32.2	Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated March 16, 2006, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 furnished herewith.

* Filed herewith.

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Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, in Tulsa, Oklahoma, on March 16, 2006.

ALLIANCE RESOURCE PARTNERS, L.P.

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

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

/s/ Brian L. Cantrell
Brian L. Cantrell
Senior Vice President and Chief Financial Officer

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

Signature	Title	Date
/s/ Joseph W. Craft III	President, Chief Executive Officer,	March 16, 2006
	and Director (Principal Executive Officer)	
Joseph W. Craft III		
/s/ Brian L. Cantrell	Senior Vice President and	March 16, 2006
	Chief Financial Officer	
Brian L. Cantrell		
/s/ Michael J. Hall	Director	March 16, 2006
Michael J. Hall		
/s/ John J. MacWilliams	Director	March 16, 2006
John J. MacWilliams		
/s/ Preston R. Miller, Jr.	Director	March 16, 2006

Preston R. Miller, Jr.

/s/ John P. Neafsey	Director	March 16, 2006
John P. Neafsey		
/s/ John H. Robinson	Director	March 16, 2006
John H. Robinson		
/s/ Robert G. Sachse	Executive Vice President and Director	March 16, 2006
Robert G. Sachse		