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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, 2008

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 IDENTIFICATION NO.)**
INCORPORATION OR ORGANIZATION)	

1717 SOUTH BOULDER AVENUE, SUITE 400, 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: Common Units representing limited partner interests

Title of Each Class	Name of Each Exchange On Which Registered
Common Units	**The NASDAQ Stock Market LLC**

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ¨ Yes x 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. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer, and smaller reporting company in Rule 12b-2 of the Exchange Act. (check one)

Large Accelerated Filer x	Accelerated Filer ¨
Non-Accelerated Filer ¨ (Do not check if a smaller reporting company)	Smaller Reporting Company ¨

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 $1,138,079,935 as of June 30, 2008, 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 Stock Market, LLC on such date.

As of February 23, 2009, 36,661,029 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 within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 that are intended to come within the safe harbor protection provided by those sections. These statements are based on our beliefs as well as assumptions made by, and information currently available to, us. When used in this document, the words anticipate, believe, continue, estimate, expect, forecast, may, project, will, and similar expressions identify statements. Without limiting the foregoing, all statements relating to our future outlook, anticipated capital expenditures, future cash flows and borrowings and sources of funding are forward-looking statements. These statements reflect our current views with respect to future events and are subject to numerous assumptions that we believe are reasonable, but are open to a wide range of uncertainties and business risks, and actual results may differ materially from those discussed in these statements. Among the factors that could cause actual results to differ from those in the forward-looking statements are:

- increased competition in coal markets and our ability to respond to the competition;
- sustained decreases 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 coal industry, electric utility industry, or general economic conditions;
- dependence on significant customer contracts, including renewing customer contracts upon expiration of existing contracts;
- liquidity constraints, including those resulting from the cost or unavailability of financing due to current credit market conditions;
- customer bankruptcies 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, including those related to carbon emissions, and other factors;
- legislation, regulatory and court decisions and interpretations thereof, including but not limited to issues related to climate change and miner health and safety;
- 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, including claims not yet asserted;
- difficulty maintaining our surety bonds for mine reclamation as well as workers compensation and black lung benefits;
- coal market s share of electricity generation;
- prices of fuel that compete with or impact coal usage, such as oil or natural gas;
- replacement of coal reserves;
- a loss or reduction of direct or indirect benefits from certain state and federal tax credits;
- difficulty obtaining commercial property insurance, and risks associated with our participation (excluding any applicable deductible) in the commercial insurance property program; and
- other factors, including those discussed in Item 1A. Risk Factors and Item 3. Legal Proceedings.

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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Significant Relationships Referenced in this Annual Report

References to we, us, our or ARLP Partnership mean the business and operations of Alliance Resource Partners, L.P., the parent company, as well as its consolidated subsidiaries.

References to ARLP mean Alliance Resource Partners, L.P., individually as the parent company, and not on a consolidated basis.

References to MGP mean Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., also referred to as our managing general partner.

References to SGP mean Alliance Resource GP, LLC, the special general partner of Alliance Resource Partners, L.P., also referred to as our special general partner.

References to Intermediate Partnership mean Alliance Resource Operating Partners, L.P., the intermediate partnership of Alliance Resource Partners, L.P., also referred to as our intermediate partnership.

References to Alliance Coal mean Alliance Coal, LLC, the holding company for the operations of Alliance Resource Operating Partners, L.P., also referred to as our operating subsidiary.

References to AHGP mean Alliance Holdings GP, L.P., individually as the parent company, and not on a consolidated basis.

References to AGP mean Alliance GP, LLC, the general partner of Alliance Holdings GP, L.P.

PART I

ITEM 1. BUSINESS

General

We are a diversified producer and marketer of coal primarily to major U.S. 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 U.S.. At December 31, 2008, we had approximately 686.3 million tons of coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. In 2008, we produced 26.4 million tons of coal and sold 27.2 million tons of coal, of which 26.5% was low-sulfur coal, 11.0% was medium-sulfur coal and 62.5% was high-sulfur coal. In 2008, we sold 90.0% of our total tons to utility plants. 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%.

We operate eight mining complexes in Illinois, Indiana, Kentucky, Maryland, and West Virginia. We are constructing two new mining complexes, one in Kentucky and one in West Virginia, and also operate a coal loading terminal on the Ohio River at Mt. Vernon, Indiana. Our mining activities are conducted in three geographic regions commonly referred to in the coal industry as the Illinois Basin, Central Appalachian and Northern Appalachian 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 these regions.

ARLP is a Delaware limited partnership listed on the NASDAQ Global Select Market under the ticker symbol ARLP. ARLP was formed in May 1999 to acquire, upon completion of ARLP s initial public offering on August 19, 1999, certain coal production and marketing assets of Alliance Resource Holdings, Inc., a Delaware corporation (ARH), consisting of substantially all of ARH s operating subsidiaries, but excluding ARH. ARH was previously owned by current and former management of the ARLP Partnership. In June 2006, our special general partner, SGP, and its parent, ARH, became wholly-owned, directly and indirectly, by Joseph W. Craft, III, the President and Chief Executive Officer and a Director of our managing general partner. SGP, a Delaware limited liability company, holds a 0.01% general partner interest in each of ARLP and the Intermediate Partnership.

We are managed by our managing general partner, MGP, a Delaware limited liability company, which holds a 0.99% and 1.0001% managing general partner interest in ARLP and the Intermediate Partnership, respectively. AHGP is a Delaware limited partnership that was formed to become the owner and controlling member of MGP. AHGP completed its initial public offering (AHGP IPO) on May 15, 2006 and is listed on the NASDAQ Global Select Market under the ticker symbol AHGP. AHGP owns, directly and indirectly, 100% of the members interest of MGP, a 0.001% managing interest in Alliance Coal, the incentive distribution rights (IDR) in ARLP and 15,544,169 common units of ARLP. The following diagram depicts our organization and ownership as of December 31, 2008:

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(1) The Management Group is comprised of current and former members of our management, who are the former indirect owners of MGP, and their affiliates.

(2) The units held by SGP and most of the units held by the Management Group are subject to a transfer restriction agreement that, subject to a number of exceptions (including certain transfers by Mr. Craft in which the other parties to the agreement are entitled or required to participate), prohibits the transfer of such units unless approved by a majority of the disinterested members of the board of directors of AGP pursuant to certain procedures set forth in the agreement.

Our internet address is www.arlp.com, and we make available free of charge on our website our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and Forms 3, 4 and 5 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. Information on our website or any other website is not incorporated by reference into this report and does not constitute a part of this report.

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the U.S. Securities and Exchange Commission (SEC) under the Securities Exchange Act of 1934 (Exchange Act). The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any documents that we file with the SEC at *http://www.sec.gov*.

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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.

Regions and Complexes	Year Ended December 31, 2008	2007	2006	2005	2004
	(tons in millions)				
Illinois Basin:					
Dotiki, Warrior, Pattiki, Hopkins and Gibson complexes	20.3	17.9	16.9	15.7	13.6
Central Appalachian:					
Pontiki and MC Mining complexes	3.2	3.2	3.5	3.3	3.6
Northern Appalachian:					
Mettiki complex	2.9	3.2	3.3	3.3	3.2
Total	26.4	24.3	23.7	22.3	20.4

The following map shows the location of our mining complexes:

Illinois Basin Operations

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. We have approximately 2,025 employees in the Illinois Basin and currently operate five mining complexes and have one mining complex under construction.

Dotiki Complex. Our subsidiary, 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. The Dotiki complex utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. Dotiki s preparation plant has throughput capacity of 1,300 tons of raw coal an hour. Coal from the Dotiki complex is shipped via the CSX Transportation, Inc. (CSX) and Paducah & Louisville Railway, Inc. (PAL) railroads and by truck on U.S. and state highways directly to customers or to various transloading facilities, including our Mt. Vernon Transfer Terminal, LLC (Mt. Vernon) transloading facility, for sale to customers capable of receiving barge deliveries.

Warrior Complex. Our subsidiary, Warrior Coal, LLC (Warrior), operates an underground mining complex located near the city of Madisonville in Hopkins County, Kentucky. 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 to produce high-sulfur coal. Warrior s preparation plant has throughput capacity of 600 tons of raw coal an hour. We are currently constructing a new preparation plant, which is expected to be operational in the first quarter of 2009 and will have throughput capacity of 1,200 tons of raw coal an hour. Warrior s production can be shipped via the CSX and PAL railroads and by truck on U.S. and state highways directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for sale to customers capable of receiving barge deliveries.

Pattiki Complex. Our subsidiary, White County Coal, LLC (White County Coal), operates Pattiki, 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. The Pattiki complex utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. The preparation plant has throughput capacity of 1,000 tons of raw coal an hour. Coal from the Pattiki complex is shipped via the Evansville Western Railway, Inc. (EVW) railroad directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for sale to customers capable of receiving barge deliveries.

Hopkins Complex. The Hopkins complex, which we acquired in January 1998, is located near the city of Madisonville in Hopkins County, Kentucky. It is operated by our subsidiary, Hopkins County Coal, LLC (Hopkins County Coal). During 2006, Hopkins County Coal ceased production from its Newcoal surface mine, which is being reclaimed, and began operations at its Elk Creek underground mine using continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. Coal produced from the Elk Creek mine is processed and shipped through Hopkins County Coal s preparation plant, which has throughput capacity of 1,200 tons of raw coal an hour. Elk Creek s production can be shipped via the CSX and PAL railroads and by truck on U.S. and state highways directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for sale to customers capable of receiving barge deliveries.

Gibson Complex. Our subsidiary, Gibson County Coal, LLC (Gibson County Coal), operates the Gibson mine, an underground mining complex located near the city of Princeton in Gibson County, Indiana. The mine began production in November 2000 and utilizes continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal. The preparation plant has 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 that are not contiguous to the reserves currently being mined, which we refer to as the Gibson South reserves. See Gibson South Reserves discussed below.

Production from Gibson is low-sulfur coal that is either shipped by truck on U.S. and state highways or transported by rail on CSX and Norfolk Southern Railway Company (NS) railroads directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for sale to customers capable of receiving barge deliveries.

River View Complex. In April 2006, we acquired River View Coal, LLC (River View) from ARH. River View currently controls, through coal leases or direct ownership, approximately 105.4 million tons of proven and probable high-sulfur coal in the Kentucky No. 7, No. 9 and No. 11 coal seams underlying properties located primarily in Union County, Kentucky, as well as certain surface properties, facilities and permits. In July 2007, we began construction of the slope and shaft at River View and, in April 2008, the board of directors of our managing general partner (Board of Directors) gave final approval for development of the mining complex. We are developing River View as an underground mining complex with the capacity for up to eight continuous mining units employing room-and-pillar mining techniques. Capital expenditures required to develop the River View mine are estimated to range from approximately $250 to $275 million for an eight unit operation, excluding capitalized interest and capitalized mine development costs. (For more information about mine development costs, please read Mine Development Costs under Item 8. Financial Statements and Supplementary Data Note 2. Summary of Significant Accounting Policies.) River View s preparation plant will have throughput capacity of 1,800 tons of raw coal per hour. Coal produced from the River View mine will be transported by overland belt to a barge loading facility on the Ohio River (mile marker 843). Initial production is expected to commence in the second half of 2009. We expect that annual production capacity of the River View mine will be approximately 6.4 million tons.

Gibson South Reserves. We have partially completed the permitting process for the Gibson South reserves and we continue to evaluate development of the project. (For more information on the permitting process, and matters that could hinder or delay the process, please read Regulation and Laws *Mining Permits and Approvals*.) Development of the project continues to be market dependent, and its timing is open-ended pending sufficient coal sales commitments to support the project. We expect the mine to be operated by our subsidiary, Gibson County Coal (South), LLC (Gibson South). We expect the mine to be developed as an underground mining complex using continuous mining units employing room-and-pillar techniques, and to have an annual production capacity of approximately 3.0 million to 3.5 million tons. Definitive development commitment for Gibson South is dependent upon final approval by the Board of Directors.

Central Appalachian Operations

Our Central Appalachian mining operations are located in eastern Kentucky. We have approximately 530 employees in Central Appalachia and operate two mining complexes.

Pontiki Complex. The Pontiki complex is located near the city of Inez in Martin County, Kentucky. We constructed the mine in 1977. Our subsidiary, Pontiki Coal, LLC (Pontiki), owns the mining complex and controls the reserves, and our subsidiary, Excel Mining, LLC (Excel), conducts all mining operations. The underground operation utilizes continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal. The preparation plant has throughput capacity of 900 tons of raw coal an hour. Coal produced in 2008 remained low sulfur, but does not meet the compliance requirements of Phase II of the Federal Clean Air Act (CAA) (see Regulation and Laws Air Emissions below). Coal produced from the mine is shipped via the NS railroad directly to customers or to various transloading facilities on the Ohio River for sale to customers capable of receiving barge deliveries, or by truck via U.S. and state highways directly to customers or various docks on the Big Sandy River for shipment to customers capable of receiving barge deliveries.

MC Mining Complex. The MC Mining complex is located near the city of Pikeville in Pike County, Kentucky. We acquired the mine in 1989. Our subsidiary, MC Mining, LLC (MC Mining), owns the mining complex and leases the reserves, and Excel conducts all mining operations. The underground operation utilizes continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal. The preparation plant has throughput capacity of 1,000 tons of raw coal an hour. Substantially all of the coal produced at MC Mining in 2008 met or exceeded the compliance requirements of Phase II of the CAA. Coal produced from the mine is shipped via the CSX railroad directly to customers or to various transloading facilities on the Ohio River for sale to customers capable of receiving barge deliveries, or by truck via U.S. and state highways directly to customers or various docks on the Big Sandy River for shipment to customers capable of receiving barge deliveries.

Northern Appalachian Operations

Our Northern Appalachian mining operations employ approximately 240 employees and are located in Maryland and West Virginia. We operate one mining complex and have one mining complex under construction in Northern Appalachia. We also control undeveloped reserves in West Virginia and Pennsylvania.

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Mettiki (MD) Operation. Our subsidiary, Mettiki Coal, LLC (Mettiki (MD)), previously operated an underground longwall mine located near the city of Oakland in Garrett County, Maryland. Underground longwall mining operations ceased at this mine in October 2006 upon the exhaustion of the economically mineable reserves, and the longwall mining equipment was moved from the Mettiki (MD) operation to the operation of our subsidiary, Mettiki Coal (WV), LLC (Mettiki (WV)) (discussed below). Medium-sulfur coal produced from two small-scale third-party mining operations (a surface strip mine and an underground mine) on properties controlled by Mettiki (MD) and another of our subsidiaries, Backbone Mountain, LLC, supplements the Mettiki (WV) production, providing blending optimization and allowing the operation to take advantage of market opportunities as they arise.

Our Mettiki (MD) preparation plant has throughput capacity of 1,350 tons of raw coal an hour. A portion of the Mettiki (WV) production is transported to this preparation plant for processing and then trucked to a blending facility at the Virginia Electric and Power Company (VEPCO) Mt. Storm Power Station. The preparation plant also is served by the CSX railroad, providing the opportunity to capitalize on the metallurgical coal market.

Mettiki (WV) Operation. In July 2005, Mettiki (WV) began continuous miner development of the Mountain View mine located in Tucker County, West Virginia. Upon completion of mining at the Mettiki (MD) longwall operation, the longwall mining equipment was moved to the Mountain View mine and put into operation in November 2006. The Mountain View mine produces medium-sulfur coal which is transported by truck either to the Mettiki (MD) preparation plant (which is served by CSX) or to the coal blending facility at the VEPCO Mt. Storm Power Station.

Tunnel Ridge Complex. Our subsidiary, Tunnel Ridge, LLC (Tunnel Ridge), controls, through a coal lease agreement with our special general partner, approximately 70.5 million tons of proven and probable high-sulfur coal in the Pittsburgh No. 8 coal seam in West Virginia and Pennsylvania. An underground mining permit was issued to us by the West Virginia Department of Environmental Protection on February 12, 2007, and we either have received or have applications pending for all permits necessary to conduct operations. (For more information on the permitting process, and matters that could hinder or delay the process, please read Regulation and Laws *Mining Permits and Approvals*.) In September of 2008, the Board of Directors gave final approval for development of the reserves, and we have begun construction of the mining complex, which will be an underground, longwall mine. Capital expenditures required for development are estimated to be in the range of approximately $265 million to $285 million, excluding capitalized interest and capitalized mine development costs. (For more information about mine development costs, please read Mine Development Costs under Item 8. Financial Statements and Supplementary Data Note 2. Summary of Significant Accounting Policies.) We expect to begin longwall mining operations at Tunnel Ridge in the second half of 2010 or in 2011, and we expect annual production capacity of the mine to ultimately reach approximately 5.5 to 6.0 million tons.

Penn Ridge. Our subsidiary, Penn Ridge Coal, LLC (Penn Ridge), is party to a coal lease agreement effective December 31, 2005 with Allegheny Pittsburgh Coal Company (Allegheny), pursuant to which Penn Ridge leases Allegheny s Buffalo coal reserve in Washington County, Pennsylvania, which is estimated to include approximately 56.7 million tons of proven and probable high-sulfur coal in the Pittsburgh No. 8 seam. We have initiated the permitting process for the Buffalo coal reserves and continue to evaluate development. (For more information on the permitting process, and matters that could hinder or delay the process, please read Regulation and Laws *Mining Permits and Approvals*.) Development of the project continues to be market dependent, and its timing is open-ended pending sufficient coal sales commitments to support the project. It is expected that these reserves will be developed as an underground mining complex using either continuous mining units employing room-and-pillar techniques, longwall mining, or both. We expect the annual production capacity of the Penn Ridge mine to be approximately 2.5 to 3.0 million tons utilizing continuous mining units or up to 5.0 million tons with longwall mining. Definitive development commitment for Penn Ridge is dependent upon final approval by the Board of Directors.

Other Operations

Mt. Vernon Transfer Terminal, LLC

Our subsidiary, Mt. Vernon, leases land and operates a coal loading terminal on the Ohio River (mile marker 827.5) at Mt. Vernon, Indiana. Coal is delivered to Mt. Vernon by both rail and truck. The terminal has a capacity of 8.0 million tons per year with existing ground storage of approximately 60,000 to 70,000 tons. During 2008, the terminal loaded approximately 2.2 million tons for customers of Pattiki, Gibson, and Elk Creek and for third parties.

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Coal Brokerage

As markets allow, we buy coal from non-affiliated producers principally throughout the eastern U.S., which we then resell. We have a policy of matching our outside coal purchases and sales to minimize market risks associated with buying and reselling coal. We did not have any transactions in 2008 classified as brokerage coal in our financial results.

Matrix Design Group, LLC

Our subsidiaries, Matrix Design Group, LLC and Alliance Design Group, LLC (collectively, MDG), provide a variety of mine products and services for our mining operations and to unrelated parties. We acquired this business in September 2006. MDG s products and services include design and installation of underground mine hoists for transporting employees and materials in and out of mines; design of systems for automating and controlling various aspects of industrial and mining environments; and design and sale of mine safety equipment, including its miner and equipment tracking system. In 2008, our financial results were not significantly impacted by MDG s activities.

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. In addition, our affiliate, Mid-America Carbonates, LLC (MAC), which is a joint venture in which White County Coal participates, manufactures and sells rock dust to us and to unrelated parties. In 2008, our financial results were not significantly impacted by MAC s business. Please read Item 8. Financial Statements and Supplementary Data Note 18. Minority Interest.

Reportable Segments

Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, and Segment Information under Item 8. Financial Statements and Supplementary Data Note 22. Segment Information for information concerning our reportable segments.

Synfuel Facilities

For several years, three of our mining complexes the Warrior Complex and the Gibson Complex in the Illinois Basin Region and the Mettiki Complex in the Northern Appalachian Region supplied coal feedstock and provided services to third-party coal synfuel facilities located at or near these complexes. Our agreements with those third-parties terminated on December 31, 2007 coincident with the expiration of the federal non-conventional source fuel tax credit and, as a result, we no longer supply feedstock or provide services to those facilities. In 2007, the incremental net income benefit to us from these synfuel-related agreements was approximately $28.5 million.

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 in that they provide greater predictability of sales volumes and sales prices. In 2008, approximately 94.8% and 98.9% 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 2009 to 2023. Our total nominal commitment under significant long-term contracts for existing operations was approximately 106.3 million tons at December 31, 2008, and is expected to be delivered as follows: 26.0 million tons in 2009, 25.3 million tons in 2010, 22.9 million tons in 2011, and 32.1 million tons thereafter during the remaining terms of the relevant coal supply agreements. The total commitment of coal under contract is an approximate number because, in some instances, our contracts contain provisions that could cause the nominal total commitment to increase or decrease by as much as 20%. The contractual time commitments for customers to nominate future purchase volumes under these contracts are typically sufficient to allow us to balance our sales commitments with prospective production capacity. In addition, the nominal total commitment can otherwise change because of reopener provisions contained in certain of these long-term contracts.

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The provisions of long-term contracts are the results of both bidding procedures and extensive negotiations with each customer. As a result, the provisions 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 for renegotiation of 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 transportation of coal, 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 four largest customers in 2008 were VEPCO, Louisville Gas and Electric Company, Tennessee Valley Authority and Seminole Electric Cooperative, Inc. During 2008, we derived approximately 46.8% of our total revenues from these four customers and at least 10.0% of our total revenues from each of the four. For more information about these customers, please read Item 8. Financial Statements and Supplementary Data Note 21. Concentration of Credit Risk and Major Customers.

Competition

The coal industry is intensely competitive. The most important factors on which we compete are coal quality (including sulfur and heat content), transportation costs from the mine to the customer and the reliability of supply. Our principal competitors include Alpha Natural Resources, Inc., Arch Coal, Inc., CONSOL Energy, Inc., Foundation Coal Holdings, Inc., International Coal Group, Inc., James River Coal Company, Massey Energy Company, Murray Energy, Inc., Patriot Coal Corporation and Peabody Energy Corp. Some of these coal producers are larger and have greater financial resources and larger reserve bases than we do. We also compete directly with a number of smaller producers in the Illinois Basin, Central Appalachian and Northern Appalachian regions. As the price of domestic coal increases, we may also begin to compete with companies that produce coal from one or more foreign countries.

Additionally, coal competes with other fuels such as petroleum, natural gas, nuclear energy and renewable energy sources for electrical power generation. Over time, costs and other factors, such as safety and environmental considerations, may affect the overall demand for coal as a fuel.

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 6.0% to 65.0% of the total 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, and in many cases we are able to accommodate transportation options. Typically, our customers pay the transportation costs from the mining complex to the destination, which is the standard practice in the industry. Approximately 71.1% of our 2008 sales volume was initially shipped from the mines by rail with the remainder leaving the mines by truck. In 2008, the largest volume transporter of our coal shipments was the CSX, which moved approximately 37.1% of our tonnage over its rail system. The practices of, and rates set by, the transportation company serving a particular mine or customer may affect, either adversely or favorably, our marketing efforts with respect to coal produced from the relevant mine.

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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. It is possible that new legislation or regulations may be adopted, or that existing laws or regulations may be differently interpreted or more stringently enforced, any of which could 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 the extensive and detailed nature of these regulatory requirements, it is extremely difficult for us and other underground coal mining companies in particular, as well as the coal industry in general, to comply with all requirements at all times. None of our violations to date has had a material impact on our operations or financial condition. While it is not possible to quantify all of the costs of compliance with applicable federal and state laws and associated regulations, those costs have been and are expected to continue to be significant. Compliance with these laws and regulations has substantially increased the cost of coal mining for domestic coal producers.

Capital expenditures for environmental matters have not been material in recent years. We have accrued for the present value of the estimated cost of asset retirement obligations and mine closings, including the cost of treating mine water discharge, when necessary. The accruals for asset retirement obligations and mine closing costs are based upon permit requirements and the costs and timing of asset retirement obligations 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.

Mining Permits and Approvals

Numerous governmental permits or approvals are required for mining operations. 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. Meeting 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.

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. 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 to 18 months after a completed application is submitted, although regulatory authorities exercise considerable discretion in the timing and scope of permit issuance and the public has rights to engage in the permitting process, including intervention in the courts, which can cause delay. Generally, we have not experienced material difficulties in obtaining mining permits in the areas where our reserves are 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 or delays in obtaining mining permits in the future.

We are required to post bonds to secure performance under our permits. Under some circumstances, substantial fines and penalties, including revocation of mining permits, may be imposed under the laws and regulations described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws and regulations. 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 that 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.

Two townships in Pennsylvania, Donegal and Blaine, enacted ordinances that purport to prohibit all coal mining activities within the townships, invalidate mining permits issued by any state or federal government entity, and, in some instances, require divestiture of all currently held coal property interests. Some of the coal reserves of our Tunnel Ridge and Penn Ridge subsidiaries are located within these townships. We believe these ordinances violate several provisions of the U.S. Constitution and the Pennsylvania Constitution as well as federal and state mining laws. We, along with other affected parties, initiated legal action in April 2008 seeking to have the Donegal ordinances invalidated. The Donegal Township subsequently rescinded its ordinances. In October 2008, we, along with other affected parties, initiated legal action seeking to have the Blaine ordinances invalidated. We believe this litigation also will be successful. However, in the event it is not and Blaine s ordinances are not repealed, these ordinances would prevent mining our properties within the Blaine Township which could adversely affect our results of operation and financial condition.

Mine Health and Safety Laws

Stringent safety and health standards have been imposed by federal legislation since 1969 when the Federal Coal Mine Health and Safety Act of 1969 (CMHSA) was adopted. The Federal Mine Safety and Health Act of 1977 (FMSHA), and regulations adopted pursuant thereto, significantly expanded the enforcement of health and safety standards of the CMHSA, and imposed extensive and detailed 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 numerous other matters. The Mine Safety and Health Administration (MSHA) monitors and rigorously enforces compliance with these federal laws and regulations. In addition, as part of the FMSHA, the Federal Black Lung Benefits Act (BLBA) requires payments of benefits by all businesses that conduct current mining operations to coal miners with black lung disease and to some survivors of miners who die 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. Although many of the requirements primarily impact underground mining, our competitors in all of the areas in which we operate are subject to the same laws and regulations.

In 2006, the Federal Mine Improvement and New Emergency Response Act of 2006 (MINER Act) was enacted. The MINER Act significantly amended the FMSHA, imposing more extensive and stringent compliance standards, increasing criminal penalties and establishing a maximum civil penalty for non-compliance, and expanding the scope of federal oversight, inspection, and enforcement activities. Following the passage of the MINER Act, MSHA has issued new or more stringent rules and policies on a variety of topics, including:

- sealing off abandoned areas of underground coal mines;
- mine safety equipment, training and emergency reporting requirements;
- substantially increased civil penalties for regulatory violations;
- training and availability of mine rescue teams;
- underground refuge alternatives capable of sustaining trapped miners in the event of an emergency;

flame-resistant conveyor belt, fire prevention and detection, and use of air from the belt entry; and

post-accident two-way communications and electronic tracking systems.

Subsequent to passage of the MINER Act, Illinois, Kentucky, Pennsylvania and West Virginia have enacted legislation addressing issues such as mine safety and accident reporting, increased civil and criminal penalties, and increased inspections and oversight. Other states may pass similar legislation in the future. Also, there is pending federal legislation that would impose additional safety and health requirements on coal mining. Although we are unable to quantify the full impact, implementing and complying with these new laws and regulations have and are expected to continue to have an adverse impact on our results of operation and financial position.

Black Lung Benefits Act

The 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 of compensating such miners using our actuary estimates of the cost of present and future claims. We are also liable under state statutes for black lung claims.

Revised BLBA regulations took effect in January 2001, relaxing the stringent award criteria established under previous regulations and thus potentially allowing more new federal claims to be awarded and allowing previously denied claimants to re-file under the revised criteria. These 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. Moreover, Congress and state legislatures regularly consider various items of black lung legislation that, if enacted, could adversely affect our business, financial condition, and results of operation.

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 generally self-insure this potential expense using our actuary estimates of the cost of present and future claims. For more information 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 fund health benefits for some United Mine Workers of America retirees. CIRHBA 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. CIRHBA 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 ARH 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. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of mining activities.

SMCRA and similar state statutes require, among other things, that mined property be restored in accordance with specified standards and approved reclamation plans. SMCRA requires us to restore the surface to approximate the original contours as contemporaneously as practicable with the completion of surface mining operations. 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. We believe we are in compliance in all material respects with applicable regulations relating to reclamation.

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 Abandoned Mine Lands Tax was set to expire June 30, 2006; however, on December 20, 2006, then President Bush signed into law the Tax Relief and Health Care Act of 2006, which, among other things, extended the Abandoned Mine Reclamation Fund provisions until September 30, 2021. This new law also reduced the tax for surface-mined and underground-mined coal to $0.315 per ton and $0.135 per ton, respectively, beginning in the fourth quarter 2007 through 2012. In fiscal years 2013 through 2021, the tax for surface-mined and underground-mined coal will be reduced to $0.28 per ton and $0.12 per ton, respectively. 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 acid mine drainage (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 that 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 having any permits that have been issued since the time of the violations revoked or, in the case of civil penalties and reclamation fees, since the time those 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 be asserted 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 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. In addition, bonding requirements in some states have become more onerous. For example, West Virginia s bonding system requires coal companies to post site-specific bonds in an amount up to $5,000.00 per acre and imposes a per-ton tax on mined coal, currently set at $0.07/ton, which is paid to the West Virginia Special Reclamation Fund (SRF). The taxes were increased by $0.074 per ton in 2008 for a one-year period. An environmental group has claimed the SRF is underfunded and that the one-year increase does not solve the underfunding, and that the Federal Office of Surface Mining (OSM) has an obligation under SMCRA to ensure the SRF funds are increased to cover the supposed shortfall. *See The West Virginia Highlands Conservancy, Plaintiff, v. Dirk Kempthorne, Secretary of the Department of the Interior, et al., Defendants, and the West Virginia Coal Association, Intervenor/Defendant*, Civil Action No. 2:00-cv-1062 (U.S. District Court for the Southern District of West Virginia). If the challenge is successful, we could be forced to bear an additional or continuing increase in the tax on coal mined in West Virginia.

Air Emissions

The CAA and similar state and local laws and regulations that 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, achieve certain emissions standards, or implement certain work practices on sources that emit various 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 federal rulemakings focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technology and any 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 the implementation plan of the state in which each plant is located, 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 the 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.

The EPA has promulgated rules, referred to as the Nitrogen Oxide SIP Call, that, among other things, 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, the EPA issued the final Clean Air Interstate Rule (CAIR) which permanently capped nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. beginning in 2009 and 2010, respectively. CAIR required these states to achieve the mandated nitrogen oxide and sulfur dioxide emission reductions by requiring power plants to either participate in an EPA-administered cap-and-trade program that capped these emissions in two phases, or by meeting an individual state emissions budget through measures established by the state. Similarly, in March 2005, the EPA finalized the Clean Air Mercury Rule (CAMR), which established a two-part, nationwide cap on mercury emissions from coal-fired power plants beginning in 2010. If it had been fully implemented, the CAMR would have permitted states to develop and manage their own mercury control regulations or participate in an interstate cap-and-trade program for mercury emission allowances. The CAIR and CAMR rules were both the subject of successful legal challenges, however, which have rendered the future of these rules uncertain. On February 8, 2008, the D.C. Circuit Court of Appeals vacated the CAMR rule for further consideration by the EPA. EPA is evaluating how to proceed in light of the court s vacatur, but a likely result is to regulate mercury emissions from power plants under the CAA s hazardous air pollutant programs, which would probably require greater mercury emission reductions than would have been required under the CAMR. In addition, on July 8, 2008, the D.C. Circuit Court of Appeals vacated the CAIR, but on petition for rehearing, the court retracted its vacatur and remanded the rule to EPA for further consideration. This remand has the effect of leaving the rule in place while EPA evaluates possible changes to the rule to correct the defects identified in the court s original opinion. While the future of the CAIR and CAMR is uncertain, some significant amount of emissions reductions at coal-fired power generation facilities is likely to be required by whatever rules are adopted to replace them, and the additional costs that could be associated with the implementation of such rules could render coal a less attractive fuel source.

The EPA is required by the CAA to periodically re-evaluate the available health effects information to determine whether the national ambient air quality standards should be revised. Pursuant to this process, in 2006, the EPA adopted a new, more stringent national air quality standard for fine particulate matter, and in 2008, the EPA adopted a new, more stringent national ambient air quality standard for ozone. 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 and other states will be required to develop new state implementation plans for areas that were previously in attainment but do not attain the new standards. States are expected to submit their implementation plans for meeting the new fine particulate matter standard to the EPA over the next three years, and their implementation plans for meeting the new ozone standard over the next five years. Because coal mining operations and coal-fired electric generating facilities emit particulate matter and nitrogen oxides, which are precursors to ozone formation, our mining operations and our customers could be affected when the new standards are implemented by the applicable states.

In June 2005, the 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 were required to develop implementation plans by December 2007 that, among other things, identify facilities that will have to reduce emissions and comply with stricter emission limitations. Most states missed the December 2007 deadline, and on January 9, 2009, EPA issued a Finding of Failure to Submit Plans, which may trigger Federal enforcement plans in some states. 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 the 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. The 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

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide, may be contributing to warming of the earth s atmosphere. Combustion of fossil fuels, such as the coal we produce, results in the emission of carbon dioxide into the atmosphere. The U.S. Congress is considering legislation to reduce emissions of greenhouse gases. President Obama has expressed support for legislation to restrict or regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular program, our customers could be required to purchase and surrender allowances for greenhouse gas emissions resulting from their operations or install emission control equipment to reduce emissions of greenhouse gases. These requirements could increase our customers operational and compliance costs and result in reduced demand for our coal products and have an adverse effect on our operations.

Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may regulate greenhouse gas emissions from mobile sources such as cars and trucks even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court s holding in *Massachusetts, et al. v. EPA* that greenhouse gases including carbon dioxide fall under the federal CAA definition of air pollutant may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources. In July 2008, EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the CAA, in response to the Supreme Court s decision in Massachusetts. In the notice, EPA evaluated the potential regulation of greenhouse gases under the CAA and other potential methods of regulating greenhouse gases. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such new federal, regional or state restrictions on emissions of carbon dioxide or other greenhouse gases that may be imposed in areas in which we conduct business could adversely affect our operations and demand for our products.

In addition, there have been an increasing number of protests of and challenges to the permitting of new coal-fired power plants in several states by environmental organizations for concerns related to greenhouse gas emissions from new plants. Environmental permitting agencies in several states have denied permits for construction of new coal-fired power plants based on concerns over emissions of greenhouse gases. In November 2008, the federal Environmental Appeals Board remanded a CAA permitting decision in the *In re Deseret Power Electric Cooperative* case for reconsideration of whether carbon dioxide is a pollutant subject to regulation under the CAA with instructions to consider its nationwide implications. In response to this decision, in December 2008, the EPA Administrator issued an interpretive rule determining that carbon dioxide is not subject to regulation under the CAA. Environmental groups filed a Petition for Reconsideration of the interpretive rule. On February 17, 2008, the EPA granted the Petition for Reconsideration and sought public comment on the interpretive memorandum as well as the *Deseret* decision. In granting the petition, the EPA emphasized that the memorandum does not bind states issuing air permits under their own State Implementation Plans. The increased difficulty or inability of our customers to obtain permits for construction of new or expansion of existing coal-fired power plants could adversely affect our operations and demand for our products.

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 and the discharge of dredged or fill material into the waters of the U.S. Regular monitoring, as well as compliance with reporting requirements and performance standards, is a precondition 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 permits required under CWA Section 404 as it has traditionally been interpreted by the responsible agencies. However, mitigation requirements under existing and possible future fill permits may vary considerably. For that reason, the setting of post-mine asset retirement obligation accruals for such mitigation projects is difficult to ascertain with certainty and may increase in the future. Although more stringent permitting requirements may be imposed in the future, we are not able to accurately predict the impact, if any, of such permitting requirements.

The U.S. Army Corps of Engineers (Corps of Engineers) maintains two permitting programs under CWA Section 404: one for individual permits and a more streamlined program for general permits.

Decisions from the federal district court for the Southern District of West Virginia, and related litigation filed in federal district court in Kentucky, have created uncertainty regarding the future ability to obtain general permits, including Nationwide Permit 21, authorizing the construction of valley fills for the disposal of overburden from mining operations. We do not operate any mines located within the Southern District of West Virginia and currently utilize Nationwide Permit 21 at limited locations. Although the decision from the Southern District of West Virginia was recently overturned on appeal, if challenges to the use of Nationwide Permit 21 ultimately are successful or Nationwide Permit 21 is invalidated, we may be required to apply for individual discharge permits pursuant to Section 404 of the CWA in areas that 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.

In addition, litigation has been filed in West Virginia and Kentucky challenging the issuance of individual Section 404 permits for mining activities by other coal producers. Although our mining operations are not implicated in any of these particular cases, it is possible that litigation affecting the Corps of Engineers ability to issue CWA permits could adversely affect our ability to obtain permits in a timely manner and could therefore adversely affect our results of operation and financial position.

Each state is required to submit to the 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 various states and the 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 us or our customers to modify existing operations, the extent of which cannot be accurately or reasonably predicted.

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 slurry, 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 such materials 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.

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Hazardous Substances and Wastes

The Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), otherwise known as the Superfund law, and analogous state laws, impose liability, without regard to fault or the legality of the original conduct on certain classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for the release of hazardous substances may be subject to joint and several liability under CERCLA for the costs of cleaning up the hazardous substances released into the environment and for damages to natural resources. Some products used in coal mining 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 Conservation 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 the 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, the EPA declined to impose hazardous waste regulatory controls on the disposal of some coal combustion by-products (CCB), including the practice of using CCB as mine fill. However, under pressure from environmental groups, the EPA has continued evaluating the possibility of placing additional solid waste burdens on the disposal of such 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. As a result of this report, OSM on March 14, 2007 issued an Advanced Notice of Rule Making proposing federal regulations on CCB mine filling practices. On August 29, 2007, EPA published a Notice of Data Availability concerning information regarding the disposal of CCB in landfills and surface impoundments that has been generated since the decision in 2000. No rules on the land disposal of CCB have yet been released. Accordingly, although we believe the beneficial uses of CCB that we employ do not constitute poor environmental practices, it is not currently possible to assess how any such regulations would impact our operations or those of our customers.

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 in which 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 properties are subject to federal, state, and local regulation.

The Federal Safe Explosives Act (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, we employ approximately 2,955 full-time employees, including approximately 160 corporate employees and approximately 2,795 employees involved in active mining operations. Our workforce is entirely union-free. We believe that relations with our employees are generally good.

Administrative Services

In connection with the AHGP IPO, ARLP entered into an administrative services agreement (Administrative Services Agreement) with our managing general partner, our Intermediate Partnership, AGP, AHGP and Alliance Resource Holdings, II (ARH II). Under the Administrative Services Agreement, certain employees, including some executive officers, provide administrative services for AHGP, AGP and ARH II and their respective affiliates. We are reimbursed for services rendered by our employees on behalf of these entities as provided under the Administrative Services Agreement. We billed and recognized administrative service revenue under this agreement for the year ended December 31, 2008 of $0.4 million from AHGP and $0.5 million from ARH II. Please read Item 13 Certain Relationships and Related Transactions, and Director Independence *Administrative Services*.

Managing General Partner Contribution

During 2008 our managing general partner contributed 25,898 common units of AHGP, valued at approximately $0.6 million at the time of contribution, and $0.8 million of cash to us for the purpose of funding certain expenses associated with our employee compensation programs. As provided under our partnership agreement, we made a special allocation to our managing general partner of certain general and administrative expenses equal to the amount of the contribution. Please read Item 13 Certain Relationships and Related Transactions, and Director Independence *Managing General Partner Contribution*.

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ITEM 1A. RISK FACTORS
Risks Inherent in an Investment in Us

Cash distributions are not guaranteed and may fluctuate with our performance and other external factors.

The amount of cash we can distribute to holders of our common units or other partnership securities each quarter principally depends on the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of coal we are able to produce from our properties;
- the price at which we are able to sell coal, which is affected by the supply of and demand for domestic and foreign coal;
- the level of our operating costs;
- weather conditions;
- the proximity to and capacity of transportation facilities;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- the effect of worldwide energy consumption; and
- prevailing economic conditions.

In addition, the actual amount of cash available for distribution will depend on other factors, including:

- the level of our capital expenditures;
- the cost of acquisitions, if any;
- our debt service requirements and restrictions on distributions contained in our current or future debt agreements;
- fluctuations in our working capital needs;

- unavailability of financing resulting in unanticipated liquidity restraints;
- our ability to borrow under our credit agreement to make distributions to our unitholders; and
- the amount, if any, of cash reserves established by our managing general partner, in its discretion, for the proper conduct of our business.

Because of these and other factors, we may not have sufficient available cash to pay a specific level of cash distributions to our unitholders. Furthermore, the amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from financial reserves and working capital borrowing, and is not solely a function of profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record net losses and may be unable to make cash distributions during periods when we record net income. Please read Risks Related to our Business for a discussion of further risks affecting our ability to generate distributable cash flow.

We may issue an unlimited number of limited partner interests, on terms and conditions established by our managing general partner, without the consent of our unitholders, which will dilute your ownership interest in us and may increase the risk that we will not have sufficient available cash to maintain or increase our per unit distribution level.

The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished;
- the ratio of taxable income to distributions may increase; and
- the market price of our common units may decline.

The market price of our common units could be adversely affected by sales of substantial amounts of our common units in the public markets, including sales by our existing unitholders.

As of December 31, 2008, AHGP owned 15,544,169 of our common units. AHGP also owns our managing general partner. In the future, AHGP may sell some or all of these units or it may distribute our common units to the holders of its equity interests and those holders may dispose of some or all of these units. The sale or disposition of a substantial number of our common units in the public markets could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. We do not know whether any such sales would be made in the public market or in private placements, nor do we know what impact such potential or actual sales would have on our unit price in the future.

An increase in interest rates may cause the market price of our common units to decline.

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded limited partnership interests. Reduced demand for our common units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common units to decline.

The credit and risk profile of our managing general partner and its owners could adversely affect our credit ratings and profile.

The credit and risk profile of our managing general partner or its owners may be factors in credit evaluations of us as a master limited partnership. This is because our managing general partner can exercise significant influence over our business activities, including our cash distribution policy, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of AHGP, including the degree of its financial leverage and its dependence on cash flow from us to service its indebtedness. As of December 31, 2008, AHGP had no outstanding debt.

AHGP is principally dependent on the cash distributions from its general and limited partner equity interests in us to service its indebtedness. Any distribution by us to AHGP will be made only after satisfying our then-current obligations to our creditors. Our credit ratings and risk profile could be adversely affected if the ratings and risk profiles of AHGP and the entities that control it were viewed as substantially lower or more risky than ours.

Our unitholders do not elect our managing general partner or vote on our managing general partner s officers or directors. As of December 31, 2008, AHGP owned approximately 42.5% of our outstanding units, a sufficient number to block any attempt to remove our general partner.

Unlike the holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Unitholders did not elect our managing general partner and will have no right to elect our managing general partner on an annual or other continuing basis.

In addition, if our unitholders are dissatisfied with the performance of our managing general partner, they will have little ability to remove our general partner. Our managing general partner may not be removed except upon the vote of the holders of at least 66.7% of our outstanding units. As of December 31, 2008, AHGP held approximately 42.5% of our outstanding units. Consequently, it will be particularly difficult for our managing general partner to be removed without the consent of AHGP. As a result, the price at which our units trade may be lower because of the absence or reduction of a takeover premium in the trading price.

Furthermore, unitholders voting rights are also restricted by a provision in our partnership agreement that provides that any units held by a person that owns 20.0% or more of any class of units then outstanding, other than our managing general partner and its affiliates, cannot be voted on any matter.

The control of our managing general partner may be transferred to a third-party without unitholder consent.

Our managing general partner may transfer its general partner interest in us to a third-party in a merger or in a sale of its equity securities without the consent of our unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of the members of our managing general partner to sell or transfer all or part of their ownership interest in our managing general partner to a third-party. The new owner or owners of our managing general partner would then be in a position to replace the directors and officers of our managing general partner and control the decisions made and actions taken by the Board of Directors and officers.

Unitholders may be required to sell their units to our managing general partner at an undesirable time or price.

If at any time less than 20.0% of our outstanding common units are held by persons other than our general partners and their affiliates, our managing general partner will have the right to acquire all, but not less than all, of those units at a price no less than their then-current market price. As a consequence, a unitholder may be required to sell his common units at an undesirable time or price. Our managing general partner may assign this purchase right to any of its affiliates or to us.

Cost reimbursements due to our general partners may be substantial and may reduce our ability to pay the distributions to unitholders.

Prior to making any distributions to our unitholders, we will reimburse our general partners and their affiliates for all expenses they have incurred on our behalf. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to make distributions to the unitholders. Our managing general partner has sole discretion to determine the amount of these expenses and fees. For additional information, please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Related-Party Transactions, Administrative Services, and Item 8. Financial Statements and Supplementary Data Note 19. Related-Party Transactions.

Your liability as a limited partner may not be limited, and our unitholders may have to repay distributions or make additional contributions to us under certain circumstances.

As a limited partner in a partnership organized under Delaware law, you could be held liable for our obligations to the same extent as a general partner if you participate in the control of our business. Our general partners generally have unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to our general partners. Additionally, the limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in many jurisdictions.

Under certain circumstances, our unitholders may have to repay amounts wrongfully distributed to them. Under Delaware law, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the partnership for the distribution amount. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Our partnership agreement limits our managing general partner s fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partners that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that waive or consent to conduct by our managing general partner and its affiliates and which reduce the obligations to which our managing general partner would otherwise be held by state-law fiduciary duty standards. The following is a summary of the material restrictions contained in our partnership agreement on the fiduciary duties owed by our general partners to the limited partners. Our partnership agreement:

- permits our managing general partner to make a number of decisions in its sole discretion. This entitles our managing general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;

- provides that our managing general partner is entitled to make other decisions in its reasonable discretion ;

- generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be fair and reasonable to us and that, in determining whether a transaction or resolution is fair and reasonable, our managing general partner may consider the interests of all parties involved, including its own. Unless our managing general partner has acted in bad faith, the action taken by our managing general partner shall not constitute a breach of its fiduciary duty; and provides that our general partners and our officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our general partners and those other persons acted in good faith.

In order to become a limited partner of our partnership, a common unitholder is required to agree to be bound by the provisions in the partnership agreement, including the provisions discussed above.

Some of our executive officers and directors face potential conflicts of interest in managing our business.

Certain of our executive officers and directors are also officers and/or directors of AHGP. These relationships may create conflicts of interest regarding corporate opportunities and other matters. The resolution of any such conflicts may not always be in our or our unitholders best interests. In addition, these overlapping executive officers and directors allocate their time among us and AHGP. These officers and directors face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

Our managing general partner s discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our managing general partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to unitholders.

Our general partners have conflicts of interest and limited fiduciary responsibilities, which may permit our general partners to favor their own interests to the detriment of our unitholders.

As of December 31, 2008, AHGP owned approximately 42.5% of our outstanding limited partner interests. Conflicts of interest could arise in the future as a result of relationships between our general partners and their affiliates, on the one hand, and us, on the other hand. As a result of these conflicts our general partners may favor their own interests and those of their affiliates over the interests of our unitholders. The nature of these conflicts includes the following considerations:

- Remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty are limited. Unitholders are deemed to have consented to some actions and conflicts of interest that might otherwise be deemed a breach of fiduciary or other duties under applicable state law.

- Our managing general partner is allowed to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its fiduciary duties to our unitholders.

- Our general partners affiliates are not prohibited from engaging in other businesses or activities, including those in direct competition with us, except as provided in the omnibus agreement (please see Item 13. Certain Relationships and Related Transactions, and Director Independence Omnibus Agreement).

- Our managing general partner determines the amount and timing of our asset purchases and sales, capital expenditures, borrowings and reserves, each of which can affect the amount of cash that is distributed to unitholders.

- Our managing general partner determines whether to issue additional units or other equity securities in us.

- Our managing general partner determines which costs are reimbursable by us.

Our managing general partner controls the enforcement of obligations owed to us by it.

Our managing general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our managing general partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or from entering into additional contractual arrangements with any of these entities on our behalf.

In some instances our managing general partner may borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions.

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Risks Related to our Business

The current global recession and turmoil in financial markets could have a material adverse effect on our financial condition and results of operations.

The current economic downturn has caused a decrease in demand for electricity. Because we sell most of our coal to electric utilities, any decrease in demand for electricity may lead to a decline in demand for our coal. In addition, the instability of domestic and international financial markets could cause a lack of capital availability for our customers, also reducing demand. Although we cannot predict the impact of current economic conditions, any resulting reduction in coal demand could adversely affect our business.

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;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- the effect of worldwide energy consumption; and
- prevailing economic conditions.

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

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 many small coal producers in various regions of the U.S. for domestic coal 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 us. 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 from an oversupply of coal in the market could reduce our revenues and our cash available for distribution.

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 relatively cheaper construction costs of such plants 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, environmental and other governmental regulations, and the price and availability of competing fuels for power plants such as nuclear, natural gas and fuel oil as well as alternative sources of energy. For example, the recent decline in the price of natural gas has resulted, in some instances, in utilities increasing natural gas consumption while decreasing coal consumption. A decrease in coal consumption by the domestic electric utility industry could adversely affect the price of coal, which could negatively impact our results of operations and reduce our cash available for distribution.

The stability and profitability of our operations could be adversely affected if our customers do not honor existing contracts or do not extend existing or enter into new long-term contracts for coal .

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 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 2008, we sold approximately 94.8% 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 may make it more difficult for us to enter into long-term contracts with our electric utility customers, and 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 that 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 provision 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 events that are beyond the customer s reasonable control. Such events may include labor disputes, mechanical malfunctions and changes in government regulations, including changes in the CAA rendering use of our coal inconsistent with the customer s pollution control strategies. 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, and 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 coal-fired 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 regulatory initiatives, electricity generators may elect to switch to other fuels that generate less of these emissions, possibly further reducing demand for our coal. Please read Item 1. Business Regulation and Laws *Air Emissions* and *Carbon Dioxide Emissions*.

Increased regulation of greenhouse gas emissions could result in reduced demand for coal as a fuel source, which would reduce demand for our products and decrease our revenues.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide, may be contributing to warming of the Earth s atmosphere. Combustion of fossil fuels, such as the coal we produce, results in the emission of carbon dioxide into the atmosphere. The U.S. Congress is considering legislation to reduce emissions of greenhouse gases. President Obama has expressed support for legislation to restrict or regulate emissions of greenhouse gases. More than one-third of the states already have begun implementing legal measures to reduce emissions of greenhouse gases. In addition, the Supreme Court s holding in 2007 in *Massachusetts, et al. v. EPA* that greenhouse gases including carbon dioxide fall under the CAA s definition of air pollutant may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources such as power plants. In July 2008, EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the CAA, in response to the Court s decision in *Massachusetts, et al. v. EPA*. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. In addition, there have been an increasing number of challenges and objections to permits for the construction of new coal-fired power plants based on concerns over greenhouse gas emissions, and permits for several proposed new coal-fired power plants have been denied or delayed.

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 reduced demand for coal and some customers switching to alternative sources of fuel, which could have a material adverse effect on our business, financial condition, and results of operations. In addition, increased difficulty or inability of our customers to obtain permits for construction of new or expansion of existing coal-fired power plants could adversely affect demand for our coal and have an adverse effect on our business and results of operation.

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 2008, we derived approximately 46.8% of our total revenues from four customers and at least 10.0% of our 2008 total revenues from each of the four. 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 decrease 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 resulting from 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 ability to collect payments from our customers could be impaired if their creditworthiness declines or if they fail to honor their contracts with us.

Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. If the creditworthiness of our customers declines significantly, our business could be adversely affected. In addition, if a customer refuses to accept shipments of our coal for which they have an existing contractual obligation, our revenues will decrease and we may have to reduce production at our mines until our customer s contractual obligations are honored.

Our profitability may decline due to unanticipated mine operating conditions and other events that are not within our control and that may not be fully covered under our insurance policies.

Our mining operations are influenced by changing conditions or events 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 and events include, among others:

- fires;
- mining and processing equipment failures and unexpected maintenance problems;
- prices for fuel, steel, explosives and other supplies;
- fines and penalties incurred as a result of alleged violations of environmental and safety laws and regulations;
- variations in thickness of the layer, or seam, of coal;

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

weather conditions, such as heavy rains, flooding, ice and other storms;

accidental mine water discharges and other geological conditions;

employee injuries or fatalities;

labor-related interruptions;

inability to acquire mining rights or permits; and

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. Prolonged disruption of production at any of our mines would result in a decrease in our revenues and profitability, which could materially adversely impact our quarterly or annual results.

During September 2008, we completed our annual property and casualty insurance renewal with various insurance coverages effective as of October 1, 2008. Available capacity for underwriting property insurance continues to be limited as a result of insurance carrier losses in the mining industry worldwide. As a result, we have elected to retain a participating interest in our commercial property insurance program at an average rate of approximately 14.7% in the overall $75.0 million of coverage, representing 22% of the primary $50.0 million layer. We do not participate in the second layer of $25.0 million in excess of $50.0 million.

The 14.7% participation rate for this year s renewal is consistent with our prior year participation. The aggregate maximum limit in the commercial property program is $75.0 million per occurrence of which, as a result of our participation, we are responsible for a maximum amount of $11.0 million for each occurrence, excluding a $1.5 million deductible for property damage, a $5.0 million aggregate deductible for extra expense and a 60-day waiting period for business interruption. We can make no assurances that we will not experience significant insurance claims in the future, which as a result of our level of participation in the commercial property program, could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future.

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 experienced coal miners has caused us to include some inexperienced staff in the operation of certain mining units, which decreases our productivity and increases our costs. This shortage of experienced coal miners is the result of a significant percentage of experienced coal miners reaching retirement age, combined with the difficulty of retaining existing workers in and 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 is represented under collective bargaining agreements. However, all of our work force may not remain union-free in the future, and proposed legislation such as the Employee Free Choice Act, could, if enacted, make staying union-free more difficult. 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.

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 comprehensive 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 or release of materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Certain of these laws and regulations may impose joint and several strict liability without regard to fault or legality of the original conduct. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial liabilities, and the issuance of injunctions limiting or prohibiting the performance of operations. Complying with these laws and 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 may be adopted, or that judicial interpretations or more stringent enforcement of existing laws and regulations may occur, 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 Item 1. Business Regulations and Laws.

Congress and several state legislatures (including those in Illinois, Kentucky, West Virginia and Pennsylvania) have passed new laws addressing mine safety practices and imposing stringent new mine safety and accident reporting requirements and increased civil and criminal penalties for violations of mine safety laws. Implementing and complying with these new laws and regulations has increased and will continue to increase our operational expense and to have an adverse effect on our results of operation and financial position. For more information, please read Item 1. Business Regulation and Laws *Mine Health and Safety Laws*.

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 governmental permits or approvals 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. Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. 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 or similar approvals could reduce our production, cash flow and profitability. Please read Item 1. Business Regulations and Laws *Mining Permits and Approvals*.

Lawsuits filed in the federal Southern District of Western Virginia and in the federal Eastern District of Kentucky have sought to enjoin the issuance of permits pursuant to Nationwide Permit 21, which is a general permit issued by the Corps of Engineers to streamline the process for obtaining permits under Section 404 of the CWA. 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 that would have otherwise utilized Nationwide Permit 21. In addition, lawsuits filed in the federal Southern District of West Virginia and in the federal Western District of Kentucky have challenged the Corps of Engineers issuance of certain individual Section 404 permits. Although our mining operations are not implicated in any of these particular cases, it is possible that the outcome of these lawsuits may have long-term effects on the Corps of Engineers ability to issue CWA permits and could thereby adversely affect our results of operation and financial position. 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. Please read Item 1. Business Regulations and Laws *Water Discharge*.

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. Conversely, 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 U.S. inherently more expensive on a per-mile basis than coal shipments originating in the western U.S. 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 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.

Disruption of transportation services due to weather-related problems, flooding, drought, accidents, mechanical difficulties, strikes, lockouts, bottlenecks or 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.

In recent years, the states of Kentucky and West Virginia have increased enforcement of weight limits on coal trucks on their public roads. It is possible that all states in which our coal is transported by truck may modify their laws to limit truck weight limits. Such legislation and enforcement efforts 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.

We may not be able to successfully grow through future acquisitions.

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. 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 undertaking these acquisitions are 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.

Mine expansions and acquisitions involve a number of risks, any of which could cause us not to realize the anticipated benefits.

If we are unable to successfully integrate the companies, businesses or properties we acquire, our profitability may decline and we could experience a material adverse effect on our business, financial condition, or results of operations. Expansion and acquisition 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 and acquisition opportunities;
- the ability to achieve identified operating and financial synergies anticipated to result from an expansion or an acquisition;
- 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 or acquisition opportunity.

Any one or more of these factors could cause us not to realize the benefits anticipated to result from an expansion or acquisition. Any expansion or acquisition 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 or acquisitions 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 and/or acquisitions.

Completion of growth projects and future expansion could require significant amounts of financing which may not be available to us on acceptable terms, or at all.

We plan to fund capital expenditures for our current growth projects with existing cash balances, future cash flow from operations and borrowings under our revolving credit facility. Our funding plans may, however, be negatively impacted by numerous factors, including higher than anticipated capital expenditures or lower than expected cash flow from operations. In addition, we may be unable to refinance our current revolving credit facility when it expires or obtain adequate funding prior to expiry because our lending counterparties may be unwilling or unable to meet their funding obligations. Furthermore, additional growth projects and expansion opportunities may develop in the future which could also require significant amounts of financing. Consequently, completion of growth projects and future expansion could require significant amounts of financing which may not be available to us on acceptable terms or in the proportions that we expect, or at all.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. The debt and equity capital markets have been exceedingly distressed as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions have made, and will likely continue to make, it difficult to obtain funding.

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The cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. The cost of obtaining money from the credit markets generally has also increased as many lenders and institutional investors have raised interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to expiring terms and, in some cases, reduced or ceased to provide funding to borrowers under existing facilities. For a discussion of how these tighter lending standards may impact our 2009 capital expenditure plans, please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources *Capital Expenditures*.

The credit market and debt and equity capital market conditions discussed above could negatively impact our credit ratings or our ability to remain in compliance with the financial covenants under our revolving credit agreement which could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance our growth and future expansions as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our plans.

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 we deplete our reserves 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 mineable at costs comparable to those 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.

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 U.S., 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 mineable 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.

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 our subsidiary 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.

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

Our coal mining operations are affected by commodity prices. We 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 and the prices of scrap steel, natural gas and coking coal consumed in the production of iron and steel fluctuate significantly and may change unexpectedly. There may be acts of nature or terrorist attacks or threats that could also impact the future costs of raw materials. Future volatility in the price of steel, petroleum products or other raw materials will impact our operational expenses and could result in significant fluctuations to our profitability.

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 senior unsecured notes and our revolving credit facility. At December 31, 2008, our total long-term indebtedness outstanding was $440.0 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
- if either before or after such distribution, we fail 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 statutory reclamation requirements 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.

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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 and result in 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 rights to refuse to renew the surety.

We have outstanding surety bonds with third-parties for reclamation expenses, 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.

Tax Risks to Our Common Unitholders

If we were to become subject to entity-level taxation for federal or state tax purposes, 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.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe, based upon our current operations, that we are so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

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% and would likely pay state income tax at varying rates. 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 taxes 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. At the federal level, legislation has recently been considered that would have eliminated partnership tax treatment for certain publicly traded partnerships. Although such legislation would not have appeared to apply to us as considered, it could be reintroduced in a manner that does apply to us. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. At the state level, because of widespread state budget deficits and other reasons, 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.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. 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 result 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. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis therein, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income to you due to potential recapture items, including depreciation and depletion recapture. In addition, because the amount realized includes a unitholder s share of our non-recourse liabilities, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

Tax-exempt entities and non-U.S. persons owning our units face unique tax issues that may result in adverse tax consequences to them.

Investment in our 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 U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

We 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 adopt depreciation and amortization positions that may not conform to 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.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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A unitholder whose units are loaned to a short seller to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a short seller to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our intangible assets and a lesser portion allocated to our tangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests within a twelve-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 twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. A termination does not affect our classification as a partnership for federal income tax purposes.

You will likely be subject to state and local taxes and income tax return filing requirements in jurisdictions where you do not live 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.

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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. For more information on this permitting process, and matters that could hinder or delay the process, please read Item 1. Business Regulation and Laws *Mining Permits and Approvals*.

Our reported coal reserves are those we believe can be economically and legally extracted or produced at the time of the filing of this Annual Report on Form 10-K. In determining whether our reserves meet this economical and legal standard, we take into account, among other things, our potential ability or inability to obtain a mining permit, the possible necessity of revising a mining plan, changes in estimated future costs, changes in future cash flows caused by changes in mining permits, variations in quantity and quality of coal, and varying levels of demand and their effects on selling prices.

At December 31, 2008, we had approximately 686.3 million tons of coal reserves. All of the estimates of reserves which are presented in this Annual Report on Form 10-K are of proven and probable reserves (as defined below) and adhere to the standards described in United States Geological Survey (USGS) Circular 831 and USGS Bulletin 1450-B. For information on the locations of our mines, please read Mining Operations under Item 1. Business.

The following table sets forth reserve information, at December 31, 2008, about our mining operations:

			Proven and Probable Reserves Pounds $S0_2$ per MMbtu				Reserve Assignment	
Operations	**Mine Type**	**Heat Content (Btus per pound)**	**<1.2**	**1.2-2.5**	**>2.5**	**Total**	**Assigned**	**Unassigned**
				(tons in millions)				
Illinois Basin Operations								
Dotiki (KY)	Underground	12,300			109.8	109.8	109.8	
Warrior (KY)	Underground	12,350			69.3	69.3	53.0	16.3
Hopkins (KY)	Underground	12,300			44.2	44.2	29.2	15.0
	/ Surface	11,500			7.8	7.8	7.8	
River View (KY)	Underground	11,700			105.4	105.4	105.4	
Pattiki (IL)	Underground	11,800			57.4	57.4	57.4	
Gibson (North) (IN)	Underground	11,600		24.0	4.0	28.0	28.0	
Gibson (South) (IN)	Underground	11,600		18.6	64.1	82.7		82.7
Region Total				42.6	462.0	504.6	390.6	114.0
Central Appalachian Operations								
Pontiki (KY)	Underground	12,800		7.9		7.9	7.9	
MC Mining (KY)	Underground	12,800	18.0		1.8	19.8	19.8	
Region Total			18.0	7.9	1.8	27.7	27.7	
Northern Appalachian Operations								
Mettiki (MD)	Underground	13,000		2.6	7.3	9.9	9.9	
Mountain View (WV)	Underground	13,000		5.2	11.7	16.9	16.9	
Tunnel Ridge (PA/WV)	Underground	12,600			70.5	70.5	70.5	
Penn Ridge (PA)	Underground	12,500			56.7	56.7	56.7	
Region Total				7.8	146.2	154.0	154.0	
Total			18.0	58.3	610.0	686.3	572.3	114.0

% of Total	2.6%	8.5%	88.9%	100.0%	83.4%	16.6%

Our reserve estimates are prepared from geological data assembled and analyzed by our staff of geologists and engineers. This data is obtained through our extensive, ongoing exploration drilling and in-mine channel sampling programs. Our drill spacing criteria adhere to standards as defined by the USGS. 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.

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Reserve estimates will change from time to time to reflect mining activities, additional analysis, new engineering and geological data, acquisition or divestment of reserve holdings, modification of mining plans or mining methods, and other factors. Weir International Mining Consultants performed an overview audit of our reserves and calculation methods in October 2005.

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, except for the coal being produced at the small contour strip operation at our Mettiki (MD) complex, which has metallurgical qualities. The 18.0 million tons of reserves listed as <1.2 pounds of SO_2 per MMbtu are compliance coal under Phase II of 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. These non-reserve coal deposits are as follows: Dotiki 12.7 million tons, Pattiki 9.9 million tons, Hopkins County Coal 1.8 million tons, River View 23.9 million tons, Gibson (North) 1.2 million tons, Gibson (South) 11.1 million tons, Warrior 5.7 million tons, Tunnel Ridge 7.0 million tons, Penn Ridge 3.4 million tons and Pontiki 9.3 million tons. In addition, in 2008 we acquired approximately 66.0 million tons of coal located near our River View complex that are currently classified as non-reserve coal deposits.

We lease most of our reserves and generally have the right to maintain leases in force until the exhaustion of the mineable and merchantable coal within the leased premises or for so long as we are conducting mining operations in a larger defined 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.

Mining Operations

The following table sets forth production and other data about our mining operations:

Operations	Location	Tons Produced 2008	2007	2006	Transportation	Equipment
Illinois Basin Operations						
Dotiki	Kentucky	4.7	4.6	4.7	CSX, PAL, truck	CM
Warrior	Kentucky	5.1	4.6	4.5	CSX, PAL, truck	CM
Hopkins	Kentucky	4.0	2.6	1.6	CSX, PAL, truck	DL, CM
Pattiki	Illinois	2.7	2.9	2.5	EVW, barge	CM
Gibson (North)	Indiana	3.8	3.2	3.6	CSX, NS, truck, barge	CM
Region Total		20.3	17.9	16.9		
Central Appalachian Operations						
Pontiki	Kentucky	1.5	1.4	1.6	NS, truck, barge	CM
MC Mining	Kentucky	1.7	1.8	1.9	CSX, truck, barge	CM
Region Total		3.2	3.2	3.5		
Northern Appalachian Operations						
Mettiki	Maryland	0.4	0.4	2.8	Truck, CSX	CM, CS

Mountain View	West Virginia	2.5	2.8	0.5	Truck, CSX	LW, CM
Region Total		2.9	3.2	3.3		
TOTAL		26.4	24.3	23.7		

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CSX - CSX Railroad

NS - Norfolk Southern Railroad

PAL - Paducah & Louisville Railroad

CM - Continuous Miner

CS - Contour Strip

DL - Dragline with Stripping Shovel, Front End Loaders and Dozers

LW - Longwall

EVW - Evansville Western Railroad

ITEM 3. LEGAL PROCEEDINGS

We are subject to various types of litigation in the ordinary course of our business. We are not engaged in any litigation that we believe is material to our operations, including without limitation, any litigation relating to our long-term coal supply contracts or under the various environmental protection statutes to which we are subject. However, we cannot assure you that disputes or litigation will not arise or that we will be able to resolve any such future disputes or litigation in a satisfactory manner. The information under General Litigation and Other in Item 8. Financial Statements and Supplementary Data. Note 20. Commitments and Contingencies is incorporated herein by this reference.

On April 24, 2006, we were served with a complaint from Mr. Ned Comer, et al., who we refer to as the plaintiffs, alleging that approximately 40 oil and coal companies, including us, which we refer to as the defendants, are liable to the plaintiffs for tortiously causing damage to plaintiffs property in Mississippi. The plaintiffs allege that the defendants greenhouse gas emissions caused global warming and resulted in the increase in the destructive capacity of Hurricane Katrina. On August 30, 2007, the court dismissed the plaintiffs complaint. On September 17, 2007, plaintiffs filed a notice of appeal of that dismissal to the U.S. Court of Appeals for the Fifth Circuit and their appeal is pending. We believe this complaint is without merit and we do not believe that an adverse decision in this litigation matter, if any, will have a material adverse effect on our business, financial position or results of operations.

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

None.

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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 Global Select Market under the symbol ARLP . The common units began trading on August 20, 1999. On February 23, 2009, the closing market price for the common units was $24.48 per unit. As of February 23, 2009, there were 36,661,029 common units outstanding. There were approximately 25,770 record holders and beneficial owners (held in street name) of common units at December 31, 2008.

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 2007	$ 38.00	$ 33.40	$0.540 (paid May 15, 2007)
2nd Quarter 2007	$ 45.50	$ 37.50	$0.560 (paid August 14, 2007)
3rd Quarter 2007	$ 44.40	$ 30.12	$0.560 (paid November 14, 2007)
4th Quarter 2007	$ 41.08	$ 33.00	$0.585 (paid February 14, 2008)
1st Quarter 2008	$ 40.10	$ 32.54	$0.585 (paid May 15, 2008)
2nd Quarter 2008	$ 58.00	$ 34.34	$0.660 (paid August 14, 2008)
3rd Quarter 2008	$ 56.25	$ 28.74	$0.700 (paid November 14, 2008)
4th Quarter 2008	$ 34.85	$ 17.39	$0.715 (paid February 13, 2009)

We 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 or any debt instrument or other agreement of ours or any of our 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 and Related Unitholder Matters contained herein.

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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, 2008, 2007, 2006, 2005 and 2004.

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

	Year Ended December 31,				
	2008	2007	2006	2005	2004
Statements of Income					
Sales and operating revenues:					
Coal sales	$ 1,093.1	$ 960.3	$ 895.8	$ 768.9	$ 599.4
Transportation revenues	44.7	37.7	39.9	39.1	29.8
Other sales and operating revenues	18.7	35.3	31.9	30.7	24.1
Total revenues	1,156.5	1,033.3	967.6	838.7	653.3
Expenses:					
Operating expenses (excluding depreciation, depletion and amortization)	801.9	685.1	627.8	521.5	436.4
Transportation expenses	44.7	37.7	39.9	39.1	29.8
Outside coal purchases	23.8	22.0	19.2	15.1	9.9
General and administrative	37.2	34.4	30.9	33.5	45.4
Depreciation, depletion and amortization	105.3	85.3	66.5	55.6	53.7
Gain on sale of coal reserves	(5.2)				
Net gain from insurance settlement and other (1)	(2.8)	(11.5)			(15.2)
Total operating expenses	1,004.9	853.0	784.3	664.8	560.0
Income from operations	151.6	180.3	183.3	173.9	93.3
Interest expense (net of interest capitalized)	(22.1)	(11.7)	(12.2)	(14.6)	(15.8)
Interest income	3.7	1.7	3.0	2.8	0.8
Other income	0.9	1.4	0.9	0.6	1.0
Income before income taxes, cumulative effect of accounting change and minority interest	134.1	171.7	175.0	162.7	79.3
Income tax expense (benefit)	(0.5)	1.6	2.4	2.7	2.7
Income before cumulative effect of accounting change and minority interest	134.6	170.1	172.6	160.0	76.6
Cumulative effect of accounting change (2)			0.1		
Minority interest (expense)	(0.4)	0.3	0.2		
Net income	$ 134.2	$ 170.4	$ 172.9	$ 160.0	$ 76.6
General Partners interest in net income	$ 45.7	$ 31.3	$ 24.6	$ 12.4	$ 3.3
Limited Partners interest in net income	$ 88.5	$ 139.1	$ 148.3	$ 147.6	$ 73.3
Basic net income per limited partner unit	$ 2.42	$ 3.07	$ 3.06	$ 2.89	$ 1.76
Diluted net income per limited partner unit	$ 2.41	$ 3.05	$ 3.03	$ 2.84	$ 1.71

Weighted average number of units outstanding-basic	36,604,707	36,548,150	36,425,350	36,288,527	35,881,896
Weighted average number of units outstanding-diluted	36,769,883	36,800,212	36,810,383	36,977,061	36,874,336
Balance Sheet Data:					
Working capital	$ 239.8	$ 25.9	$ 37.4	$ 76.1	$ 54.2
Total assets	1,030.6	701.7	635.0	532.7	412.8
Long-term obligations (3)	440.8	137.1	127.5	144.0	162.0
Total liabilities	741.4	384.5	386.5	376.9	357.6
Partners capital	289 3	317.2	248.5	155.8	55.2
Other Operating Data:					
Tons sold	27.2	24.7	24.4	22.8	20.8
Tons produced	26.4	24.3	23.7	22.3	20.4
Revenues per ton sold (4)	$ 40.88	$ 40.31	$ 38.02	$ 35.07	$ 29.98
Cost per ton sold (5)	$ 31.72	$ 30.02	$ 27.78	$ 25.00	$ 23.64
Other Financial Data:					
Net cash provided by operating activities	$ 261.0	$ 244.0	$ 250.9	$ 193.6	$ 145.1
Net cash used in investing activities	(184.1)	(178.7)	(137.7)	(110.2)	(77.6)
Net cash provided by (used in) financing activities	166.8	(101.0)	(108.5)	(82.6)	(46.4)
EBITDA (6)	257.8	267.0	250.8	230.1	147.9
Maintenance capital expenditures (7)	77.7	76.3	67.8	56.7	31.6

(1) Represents the net gain from the final settlement in 2004 and 2007 with our insurance underwriters for claims relating to a fire at the Dotiki mine and the MC Mining Mine Fire, respectively, and a realized gain in 2008 of $2.8 million on settlement of our claim against the third-party that provided security services at the time of the MC Mining Mine Fire. (Please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations MC Mining Mine Fire).

(2) Represents the cumulative effect of the accounting change attributable to the adoption of Statement of Financial Accounting Standards (SFAS) No. 123R, *Share-Based Payments*, on January 1, 2006.

(3) Long-term obligations include long-term portions of debt and capital lease obligations.

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

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

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

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

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

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The following table presents a reconciliation of (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,				
	2008	2007	2006	2005	2004
Cash flows provided by operating activities	$ 261,041	$ 244,012	$ 250,923	$ 193,618	$ 145,055
Non-cash compensation expense	(3,931)	(3,925)	(4,112)	(8,193)	(20,320)
Asset retirement obligations	(2,827)	(2,419)	(2,101)	(1,918)	(1,622)
Coal inventory adjustment to market	(452)	(21)	(319)	(573)	(488)
Net gain (loss) on sale of property, plant and equipment	911	3,189	1,188	(179)	332
Gain on sale of coal reserves	5,159				
Gain from insurance recoveries for property damage		2,357			
Gain from insurance settlement proceeds received in a prior period		5,088			
Loss on retirement of damaged vertical belt equipment				(1,298)	
Other	(366)	(811)	(1,119)	(580)	(587)
Net effect of working capital changes	(19,661)	7,898	(5,317)	34,770	7,915
Interest expense, net	18,418	9,952	9,175	11,816	14,963
Income tax expense (benefit)	(480)	1,669	2,443	2,682	2,641
EBITDA	257,812	266,989	250,761	230,145	147,889
Depreciation, depletion and amortization	(105,278)	(85,310)	(66,489)	(55,637)	(53,664)
Interest expense, net	(18,418)	(9,952)	(9,175)	(11,816)	(14,963)
Income tax (expense) benefit	480	(1,669)	(2,443)	(2,682)	(2,641)
Cumulative effect of accounting change			112		
Minority interest (expense)	(420)	332	161		
Net income	$ 134,176	$ 170,390	$ 172,927	$ 160,010	$ 76,621

(7) Our maintenance capital expenditures, as defined under the terms of our partnership agreement, are those capital expenditures required to maintain, over the long-term, the operating capacity of our capital assets.

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

General

The following discussion of our financial condition and results of operations should be read in conjunction with the historical financial statements and notes thereto included elsewhere in this Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, please see Item 8. Financial Statements and Supplementary Data. Note 1. Organization and Presentation and Note 2. Summary of Significant Accounting Policies.

Executive Overview

We are a diversified producer and marketer of coal primarily to major U.S. utilities and industrial users. In 2008, our total production was 26.4 million tons and our total sales were 27.2 million tons. The coal we produced in 2008 was approximately 26.5% low-sulfur coal, 11.0% medium-sulfur coal and 62.5% high-sulfur coal. 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%.

We operate eight underground mining complexes, and at December 31, 2008, had approximately 686.3 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. We are constructing two new mining complexes, one in Kentucky and one in West Virginia, and also operate a coal loading terminal on the Ohio River at Mt. Vernon, Indiana. Please see Item 1. Business Mining Operations for further discussion of our mines.

As discussed in more detail in Item 1A. Risk Factors, our results of operations could be impacted by prices for fuel, steel, explosives and other supplies, unforeseen geologic conditions or mining and processing equipment failures and unexpected maintenance problems, and by the availability or reliability of transportation for coal shipments. Additionally, our results of operations could be impacted by our ability to obtain and renew permits necessary for our operations, secure or acquire coal reserves, find replacement buyers for coal under contracts with comparable terms to existing contracts, or the passage of new or expanded regulations that could limit our ability to mine, increase our mining costs or limit our customers ability to utilize coal as fuel for electricity generation.

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Our principal expenses related to the production of coal are labor and benefits, equipment, materials and supplies, maintenance, royalties and excise taxes. Unlike many 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.

Our primary business strategy is to create sustainable, capital-efficient growth in distributable cash flow to maximize our distributions to our unitholders by:

- expanding our operations by adding and developing mines and coal reserves in existing, adjacent or neighboring properties;
- extending the lives of our current mining operations through acquisition and development of coal reserves using our existing infrastructure;
- continuing to make productivity improvements to remain a low-cost producer in each region in which we operate;
- strengthening our position with existing and future customers by offering a broad range of coal qualities, transportation alternatives and customized services; and
- developing strategic relationships to take advantage of opportunities created within the coal industry.

We have four reportable segments: the Illinois Basin, Central Appalachia, Northern Appalachia and Other and Corporate. The first three segments correspond to the three major coal producing regions in the eastern U.S. Coal quality, coal seam height, mining and transportation methods and regulatory issues are similar within each of these three segments.

- *Illinois Basin* segment is comprised of Webster County Coal s Dotiki mining complex, Gibson County Coal s Gibson North mining complex, Hopkins County Coal s Elk Creek mining complex, White County Coal s Pattiki mining complex and Warrior s mining complex, the Gibson South reserves, certain properties of Alliance Resource Properties, LLC (Alliance Resource Properties) and a mining complex currently under construction at River View. We are in the process of permitting the Gibson South property for future mine development. For more information on the permitting process, and matters that could hinder or delay the process, please read Item 1. Business Regulation and Laws *Mining Permits and Approvals*.
- *Central Appalachian* segment is comprised of Pontiki s and MC Mining s mining complexes.
- *Northern Appalachian* segment is comprised of Mettiki (MD) s mining complex, Mettiki (WV) s Mountain View mining complex, two small third-party mining operations, a mining complex currently under construction at Tunnel Ridge, and the Penn Ridge property. We are in the process of permitting the Penn Ridge property for future mine development. For more information on the permitting process, and matters that could hinder or delay the process, please read Item 1. Business Regulation and Laws *Mining Permits and Approvals*.
- *Other and Corporate* segment includes marketing and administrative expenses, the Mt. Vernon dock activities, coal brokerage activity, MAC and Matrix Design Group, LLC (Matrix Design) and certain properties of Alliance Resource Properties.

How We Evaluate Our Performance

Our management uses a variety of financial and operational measurements to analyze our performance. Primary measurements include the following: (1) salable tons produced per unit shift; (2) coal sales price per ton; (3) Segment Adjusted EBITDA Expense per ton; and (4) EBITDA.

Salable Tons Produced Per Unit Shift. We review salable tons produced per unit shift as part of our operational analysis to measure the productivity of our operating segments which is significantly influenced by mining conditions and the efficiency of our preparation plants.

Coal Sales Price per Ton. We define coal sales price per ton as total coal sales divided by tons sold. We review coal sales price per ton for our marketing efforts, market demand and trend analysis.

Segment Adjusted EBITDA Expense per Ton. We define Segment Adjusted EBITDA Expense per ton as the sum of operating expenses, outside coal purchases and other income divided by total tons sold. We review segment adjusted EBITDA expense per ton for cost trends.

EBITDA. We define EBITDA as net income before net interest expense, income taxes, depreciation, depletion and amortization, cumulative effect of accounting change and minority interest. EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

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

Sources of Our Revenue

In 2008, approximately 90% of our sales tonnage was consumed by electric utilities with the balance shipped to third-party resellers, industrial consumers and cogeneration plants. In 2008, approximately 94.8% of our sales tonnage, including approximately 98.9% of our medium- and high-sulfur coal sales tonnage, was sold under long-term contracts. The balance of our sales was made in the spot market. Our long-term contracts contribute to our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2008, approximately 89.3% 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.

Expiration of Federal Non-Conventional Source Fuel Tax Credit

Historically, we received material revenues from coal sales, rental, marketing and other services provided under synfuel-related agreements at three of our mining operations. As anticipated, operations at these third-party synfuel facilities ended in December 2007 as the federal non-conventional source fuel tax credits expired. As a result, we no longer sell coal to the synfuel operators, but instead sell that coal directly to our customers, including (but not exclusively) Louisville Gas and Electric Company, Seminole Electric Cooperative, Inc., the Tennessee Valley Authority and VEPCO, each of which individually accounted for 10% or more of our total revenues in 2008. For 2007, the incremental net income benefit from the combination of the various coal synfuel-related agreements was approximately $28.5 million, assuming that coal pricing would not have increased without the availability of synfuel.

Analysis of Historical Results of Operations

A comparison of our operating results for the years ended December 31, 2008 and 2007 is primarily affected by the following significant items:

- A gain on sale of non-core coal reserves of $5.2 million in 2008;

A gain of $1.9 million on settlement of claims relating to the 2005 failure of the vertical belt system (the Vertical Belt Incident) at our Pattiki mine in 2008 recorded as a reduction to operating expenses. The Vertical Belt Incident temporarily idled our Pattiki mine in June and July of 2005 following the failure of the vertical conveyor belt system used in conveying raw coal out of the mine. The 2008 gain resulted from a settlement reached with the third-party installer of the vertical belt system and represents a partial recovery of expenses incurred in 2005;

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A gain of $2.8 million on settlement of claims against the third-party that provided security services at the time of the December 2004 MC Mining mine fire (MC Mining Fire Incident) was recognized in 2008. Additionally, in 2007 we recognized a net gain of $11.5 million from an insurance settlement of claims relating to the MC Mining Fire Incident as well as a reduction in operating expenses of approximately $0.8 million. Please read MC Mining Mine Fire below;

2007 included realized net income of approximately $28.5 million from various coal synfuel-related agreements. The expiration of the federal non-conventional source fuel tax credit and its impact on our results of operations are discussed in more detail above; and

2007 benefited from a net gain of $3.2 million realized from sales of surplus equipment as compared to a net gain of $0.9 million in 2008.

2008 Compared with 2007

In 2008, we reported net income of $134.2 million, a decrease of 21.3% compared to 2007 net income of $170.4 million. This decrease of $36.2 million was principally due to the significant items discussed above at the beginning of Analysis of Historical Results of Operations, in addition to higher depreciation, depletion and amortization resulting from capital expenditures associated with our growth initiatives and increased interest expense, net of interest income resulting from our 2008 financing activities, partially offset by improved coal sales. Our 2008 financing activities are discussed in more detail below under Debt Obligations. We had record tons sold and tons produced of 27.2 million and 26.4 million, respectively, for 2008 compared to 24.7 million tons sold and 24.3 million tons produced for 2007. Operating expenses in 2008 increased primarily as a result of higher coal production and sales volumes as well as increased labor and labor related expenses, materials and supply costs, maintenance costs, higher regulatory compliance costs and other factors described below.

	December 31,		December 31,	
	2008	2007	2008	2007
	(in thousands)		(per ton sold)	
Tons sold	27,170	24,725	N/A	N/A
Tons produced	26,429	24,269	N/A	N/A
Coal sales	$ 1,093,059	$ 960,354	$ 40.23	$ 38.84
Operating expenses and outside coal purchases	$ 825,630	$ 707,054	$ 30.39	$ 28.60

Coal sales. Coal sales increased 13.8% to $1.1 billion for 2008 from $960.4 million for 2007. The increase of $132.7 million reflected increased sales volumes (contributing $94.9 million of the increase) and higher average coal sales prices (contributing $37.8 million of the increase). Record tons sold increased 9.9% to 27.2 million tons for 2008 from 24.7 million tons in 2007. Record tons produced increased 8.9% to 26.4 million tons for 2008 from 24.3 million tons in 2007. Record average coal sales prices increased $1.39 per ton sold to $40.23 per ton in 2008 as compared to 2007, primarily as a result of improved contract pricing across all operations, as well as from certain higher priced sales in the spot and export markets, particularly in the Central and Northern Appalachian segments.

Operating expenses. Operating expenses increased 17.0% to $801.9 million in 2008 from $685.1 million in 2007 primarily as a result of increased production and tons sold, as well as the following factors:

Labor and benefit expenses per ton produced, excluding workers compensation costs, increased to $9.51 per ton in 2008 from $8.84 per ton in 2007. This increase of $0.67 per ton represents pay rate and benefit increases and increased health care costs, as well as increased headcount due to capacity expansion and increased regulatory compliance;

Material and supplies and maintenance expenses per ton produced increased 10.6% and 8.5%, respectively, to $9.84 and $3.31 per ton, respectively, in 2008 from $8.90 and $3.05 per ton, respectively, in 2007. The respective increases of $0.94 and $0.26 per ton resulted from increased costs for certain products and services (particularly roof support, power, fuel and other consumables) used in the mining process, as well as higher compliance costs associated with more stringent regulatory enforcement which has also contributed to increased mine administrative expenses;

Expenses incurred during 2008 relating to our River View and Tunnel Ridge organic growth projects increased $2.6 million over 2007;

Production taxes and royalties (which were incurred as a percentage of coal sales and coal volumes) increased $3.3 million as a result of increased tons sold and increased average coal sales prices;

Reduced expenses of $6.0 million in 2008 as compared to 2007 were associated with the purchase and sale of coal during 2007 under a settlement agreement we entered into with ICG in November 2005. Consistent with the guidance in EITF No. 04-13, Pontiki s sale of coal to ICG and Alliance Coal s purchase of coal from ICG pursuant to that settlement agreement were combined. Therefore, the excess of Alliance Coal s purchase price from ICG over Pontiki s sales price to ICG was reported as an operating expense. We fully satisfied our coal sales agreement with ICG in April 2007. For more information, please read, Other under Item 8. Financial Statements and Supplementary Data Note 20. Commitments and Contingencies ;

2008 benefited from a $1.9 million gain on settlement of claims relating to the Vertical Belt Incident at our Pattiki mine;

2007 included a $0.8 million reduction in operating expenses as a result of the final insurance settlement of the MC Mining Fire Incident. Please read MC Mining Mine Fire below; and

The 2007 operating expenses benefited from net gains of $3.2 million realized from the sale of surplus equipment as compared to net gains of $0.9 million realized in 2008.

Other sales and operating revenues. Other sales and operating revenues are principally comprised of Mt. Vernon transloading revenues, products and services provided by MAC and Matrix Design, and other outside services and administrative services revenue from affiliates. The 2007 other sales and operating revenues include rental and service fees from third-party coal synfuel facilities. Other sales and operating revenues decreased to $18.7 million for 2008 from $35.3 million for 2007. The decrease of $16.6 million was primarily attributable to the loss of synfuel-related benefits due to the expiration of the non-conventional synfuel tax credits on December 31, 2007, partially offset by increased revenues from transloading services and MAC and Matrix Design product sales. Our synfuel-related arrangements are discussed in more detail above under Executive Overview.

Outside coal purchases. Outside coal purchases increased $1.8 million to $23.8 million in 2008 from $22.0 million in 2007. The increase was primarily attributable to an increase in outside coal purchases in our Northern Appalachian region to supply attractive spot and export market opportunities partially offset by lower purchases in the Illinois Basin and Central Appalachian regions.

General and administrative. General and administrative expenses for 2008 increased to $37.2 million compared to $34.5 million for 2007. The increase of $2.7 million was primarily attributable to higher salary and benefit costs related to increased staffing levels and higher incentive compensation expense.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased to $105.3 million in 2008 compared to $85.3 million in 2007. The increase of $20.0 million was primarily attributable to additional depreciation expense associated with continuing capital expenditures related to infrastructure improvements, efficiency projects, reserve acquisitions and expansion of production capacity.

Interest expense. Interest expense, net of capitalized interest, increased to $22.1 million in 2008 from $11.7 million in 2007. The increase of $10.4 million was principally attributable to interest expense resulting from our 2008 financing activities, partially offset by reduced interest expense resulting from our August 2008 principal repayment of $18.0 million on our original senior notes issued in 1999. The 2008 financing activities are discussed in more detail below under Debt Obligations.

Interest income. Interest income increased to $3.7 million for 2008 from $1.7 million in 2007. The increase of $2.0 million resulted from increased interest income earned on short-term investments purchased with funds received from our 2008 financing activities, which is discussed in more detail below under Debt Obligations.

Transportation revenues and expenses. Transportation revenues and expenses each increased 18.8% to $44.8 million in 2008 compared to $37.7 million for 2007. The increase of $7.1 million in 2008 was primarily attributable to higher transported coal volumes and higher average per ton transportation rates compared to 2007, primarily reflecting higher fuel costs and the location of our customers for which we arranged transportation. The cost of transportation services are passed through to our customers. Consequently, we do not realize any gain or loss on transportation revenues.

Income before income taxes and minority interest. Income before income taxes and minority interest decreased 21.9% to $134.1 million for 2008 compared to $171.7 million for 2007. The decrease of $37.6 million reflects the impact of the changes in revenues and expenses described above.

Income tax expense (benefit). Income tax benefit for 2008 was $0.5 million compared to income tax expense of $1.7 million for 2007. The income tax benefit for 2008 was primarily due to operating losses associated with Matrix Design, a business owned by our subsidiary, Alliance Service, Inc. (Alliance Service). The 2007 income tax expense was impacted by Alliance Service s receipt of a material amount of income from services we provided to a third-party coal synfuel facility, which ceased operations on December 31, 2007 as a result of the expiration of the synfuel tax credits. Our synfuel-related arrangements are discussed in more detail above under Executive Overview.

Minority interest. In March 2006, White County Coal and Alexander J. House (House) entered into a limited liability company agreement to form MAC. MAC was formed to engage in the development and operation of a rock dust mill and to manufacture and sell rock dust. We consolidate MAC s financial results in accordance with FASB Interpretation (FIN) No. 46R, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*. Based on the guidance in FIN No. 46R, we concluded that MAC is a variable interest entity and that we are the primary beneficiary. House s portion of MAC s net income and net loss was $0.4 million and $0.3 million for 2008 and 2007, respectively, and is recorded as minority interest on our consolidated income statement.

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Segment Information. Please read Item 8. Financial Statements and Supplementary Data Note 22. Segment Information for more information concerning our reportable segments. Our 2008 Segment Adjusted EBITDA decreased $6.5 million, or 2.1%, to $295.0 million from 2007 Segment Adjusted EBITDA of $301.5 million. Segment Adjusted EBITDA, tons sold, coal sales, other sales and operating revenues and Segment Adjusted EBITDA Expense by segment are as follows (in thousands):

	Year Ended December 31,			
	2008	2007	Increase (Decrease)	
Segment Adjusted EBITDA				
Illinois Basin	$ 194,410	$ 208,658	$ (14,248)	(6.8)%
Central Appalachia	52,812	58,937	(6,125)	(10.4)%
Northern Appalachia	39,480	35,478	4,002	11.3%
Other and Corporate	8,264	(1,605)	9,869	(1)
Elimination	22		22	
Total Segment Adjusted EBITDA (2)	$ 294,988	$ 301,468	$ (6,480)	(2.1)%
Tons sold				
Illinois Basin	20,496	17,970	2,526	14.1%
Central Appalachia	3,428	3,455	(27)	(0.8)%
Northern Appalachia	3,246	3,300	(54)	(1.6)%
Other and Corporate				
Elimination				
Total tons sold	27,170	24,725	2,445	9.9%
Coal sales				
Illinois Basin	$ 715,862	$ 612,850	$ 103,012	16.8%
Central Appalachia	207,339	193,104	14,235	7.4%
Northern Appalachia	169,858	147,315	22,543	15.3%
Other and Corporate		7,085	(7,085)	(1)
Elimination				
Total coal sales	$ 1,093,059	$ 960,354	$ 132,705	13.8%
Other sales and operating revenues				
Illinois Basin	$ 1,123	$ 25,371	$ (24,248)	(95.6)%
Central Appalachia	258	99	159	(1)
Northern Appalachia	4,422	4,201	221	5.3%
Other and Corporate	23,546	10,423	13,123	(1)
Elimination	(10,614)	(4,802)	(5,812)	(1)
Total other sales and operating revenues	$ 18,735	$ 35,292	$ (16,557)	(46.9)%
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 522,575	$ 429,563	$ 93,012	21.7%
Central Appalachia	157,575	145,759	11,816	8.1%
Northern Appalachia	134,800	116,037	18,763	16.2%
Other and Corporate	20,441	19,112	1,329	7.0%
Elimination	(10,636)	(4,802)	(5,834)	(1)
Total Segment Adjusted EBITDA Expense (3)	$ 824,755	$ 705,669	$ 119,086	16.9%

(1) Percentage increase or decrease was greater than or equal to 100%.

(2) Segment Adjusted EBITDA is defined as net income before net interest expense, income taxes, depreciation, depletion and amortization, minority interest and general and administrative expense. Consolidated EBITDA is used as a supplemental financial measure by 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.

Segment Adjusted EBITDA is also used as a supplemental financial measure by our management for reasons similar to those stated in the above explanation of EBITDA. In addition, the exclusion of corporate general and administrative expenses from Segment Adjusted EBITDA allows management to focus solely on the evaluation of segment operating profitability as it relates to our revenues and operating expenses which are primarily controlled by our segments.

The following is a reconciliation of consolidated Segment Adjusted EBITDA to net income (in thousands):

	Year Ended December 31, 2008	2007
Segment Adjusted EBITDA	$ 294,988	$ 301,468
General and administrative	(37,176)	(34,479)
Depreciation, depletion and amortization	(105,278)	(85,310)
Interest expense, net	(18,418)	(9,952)
Income tax (expense) benefit	480	(1,669)
Minority interest (expense)	(420)	332
Net income	$ 134,176	$ 170,390

(3) Segment Adjusted EBITDA Expense includes operating expenses, outside coal purchases and other income. Transportation expenses are excluded as these expenses are passed through to our customers, and consequently we do not realize any gain or loss on transportation revenues. Segment Adjusted EBITDA Expense is used as a supplemental financial measure by our management to assess the operating performance of our segments. In our evaluation of EBITDA, which is discussed above under *How We Evaluate Our Performance*, Segment Adjusted EBITDA Expense is a key component of EBITDA in addition to coal sales and other sales and operating revenues. The exclusion of corporate general and administrative expenses from Segment Adjusted EBITDA Expense allows management to focus solely on the evaluation of segment operating performance as it primarily relates to our operating expenses. Outside coal purchases are included in Segment Adjusted EBITDA Expense because tons sold and coal sales include sales from outside coal purchases.

The following is a reconciliation of consolidated Segment Adjusted EBITDA Expense to Operating expense (in thousands):

	Year Ended December 31, 2008	2007
Segment Adjusted EBITDA Expense	$ 824,755	$ 705,669
Outside coal purchases	(23,776)	(21,969)
Other income	875	1,385
Operating expense (excluding depreciation, depletion and amortization)	$ 801,854	$ 685,085

Illinois Basin Segment Adjusted EBITDA for 2008, as defined in reference (2) to the table above, decreased 6.8% to $194.4 million, as compared to 2007 Segment Adjusted EBITDA of $208.7 million. The decrease of $14.3 million is primarily attributable to the loss of synfuel-related benefits and higher operating expenses partially offset by increased coal sales and a $1.9 million gain on settlement of claims relating to the Pattiki Vertical Belt Incident. Other sales and operating revenues decreased by $24.2 million due to the expiration of the non-conventional synfuel-related tax credits on December 31, 2007 and the resulting loss of benefits derived from supplying third-party coal synfuel facilities with coal feedstock and related services. Our synfuel-related arrangements are discussed in more detail above under Executive Overview . Illinois Basin coal sales in 2008 increased by $103.0 million to $715.9 million as compared to $612.9 million in 2007, primarily as a result of increased tons sold of 2.5 million tons (contributing $86.0 million of the increase in coal sales) reflecting increased production capacity at the Elk Creek and Warrior mines and increased production at the Dotiki and Gibson mines. Additionally, increased coal sales in 2008 resulted from a higher average coal sales price per ton, which increased 2.4% to $34.93 per ton for 2008 as compared to $34.10 per ton for 2007 (contributing $17.0 million of the total increase in coal sales). The 2008 average coal sales prices benefited from improved long-term contract realizations. Total Segment Adjusted EBITDA Expense, as defined in reference (3) to the above table, for 2008 increased 21.7% to $522.6 million from $429.6 million in 2007, primarily as a result of production costs and sales related expenses associated with increased tons sold, as well as the impact of the cost increases described above under consolidated operating expenses. The 2007 Segment Adjusted EBITDA Expense also benefited from certain favorable operating tax adjustments. On a per ton sold basis, 2008 Segment Adjusted EBITDA Expense increased $1.60 to $25.50 per ton as compared to the 2007 Segment Adjusted EBITDA Expense of $23.90 per ton.

Central Appalachia Segment Adjusted EBITDA for 2008, as defined in reference (2) to the table above, decreased 10.4% to $52.8 million as compared to 2007 Segment Adjusted EBITDA of $58.9 million. The $6.1 million decrease was primarily the result of the net gain from insurance settlement of approximately $11.5 million and a reduction in operating expenses of approximately $0.8 million in 2007 related to the MC Mining Fire Incident, as compared to a $2.8 million gain recognized in 2008 on settlement of claims from the third-party that provided security services at the time of the fire. Please read MC Mining Mine Fire below. Central Appalachia coal sales for 2008 and 2007 were $207.3 million and $193.1 million, respectively, an increase of $14.2 million primarily resulting from a higher average coal sales price per ton, which increased $4.60 to $60.49 per ton for 2008 as compared to $55.89 per ton for 2007 (contributing $15.7 million of the total increase in coal sales). Higher 2008 average coal sales prices reflect both improved contract sales prices, as well as certain higher priced sales in the spot and export markets. Segment Adjusted EBITDA Expense, as defined in reference (3) to the above table, for 2008, increased 8.1% to $157.6 million, as compared to $145.8 million for 2007. Segment Adjusted EBITDA Expense per ton increased $3.78 to $45.97 per ton in 2008, as compared to $42.19 per ton in 2007 resulting from a lower percentage of saleable tons recovered from raw production, increased labor and benefits expense, as well as other cost increases described above under consolidated operating expenses.

Northern Appalachia Segment Adjusted EBITDA for 2008, as defined in reference (2) to the table above, increased 11.3% to $39.5 million as compared to 2007 Segment Adjusted EBITDA of $35.5 million. The increase of $4.0 million in Segment Adjusted EBITDA was primarily attributable to a higher average sales price of $52.33 per ton during 2008 as compared to $44.64 per ton during 2008, resulting from improved pricing on long-term sales contracts and certain higher priced sales in the spot and export markets. Segment Adjusted EBITDA Expense per ton sold during 2008 of $41.53 per ton was an increase of $6.37 per ton as compared to $35.16 per ton in 2007 (for a definition of Segment Adjusted EBITDA Expense, see reference (3) to the above table). The increase in Segment Adjusted EBITDA Expense per ton sold was primarily a result of higher purchased coal expense, lower production in 2008 and increased power costs, coal transportation costs, water treatment costs and contract mining expenses. The decreased production in 2008 reflects adverse mining conditions and reduced saleable coal recoveries as compared to 2007.

Other and Corporate Segment Adjusted EBITDA, as defined in reference (2) to the above table, increased to $8.3 million in 2008 from a loss of $1.6 million in 2007, primarily due to the $5.2 million gain on sale of non-core coal reserves and increased outside services revenue and product sales in 2008. The increase in Segment Adjusted EBITDA Expense, as defined in reference (3) to the above table, primarily reflects increased expenses associated with higher outside services revenue and product sales.

Elimination The increase is primarily comprised of the elimination of sales and operating expenses between MAC and Matrix Design and our operating mines.

2007 Compared with 2006

In 2007, we reported net income of $170.4 million, a decrease of 1.5% compared to 2006 net income of $172.9 million. The 2007 results were negatively impacted by higher materials and supplies and maintenance expenses per ton, higher incentive compensation expenses and increased depreciation and amortization, partially offset by higher average coal sales prices per ton and a $12.3 million benefit representing the net gain and reduced operating expenses associated with the final settlement of claims related to the MC Mining Mine Fire described below.

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	December 31, 2007	December 31, 2006	December 31, 2007	December 31, 2006
	(in thousands)		(per ton sold)	
Tons sold	24,725	24,351	N/A	N/A
Tons produced	24,269	23,738	N/A	N/A
Coal sales	$ 960,354	$ 895,823	$ 38.84	$ 36.79
Operating expenses and outside coal purchases	$ 707,054	$ 646,969	$ 28.60	$ 26.57

Coal sales. Coal sales increased 7.2% to $960.3 million for 2007 from $895.8 million for 2006. The increase of $64.5 million reflected increased sales volumes (contributing $13.8 million of the increase) and higher average coal sales prices (contributing $50.7 million of the increase). Tons sold increased 1.5% to 24.7 million tons for 2007 from 24.4 million tons in 2006. Tons produced increased 2.2% to 24.3 million tons for 2007 from 23.7 million tons in 2006. Average coal sales prices increased $2.05 per ton sold in 2007 to $38.84 per ton as compared to 2006, primarily attributable to higher pricing on long-term sales contracts particularly in the Northern Appalachian segment described below.

Operating expenses. Operating expenses increased 9.1% to $685.1 million in 2007 from $627.8 million in 2006. The increase of $57.3 million primarily resulted from an increase in operating expenses associated with additional 407,000 produced tons sold as well as the following specific factors:

Labor and benefit expenses per ton produced increased 1.3% to $9.69 per ton in 2007 from $9.57 per ton in 2006. The increase of $0.12 per ton resulted from pay rate increases, higher health care costs, productivity reductions due to recently enacted federal and state regulations partly offset by lower workers compensation expense due to changes in estimates associated with year end valuations and improved productivity at certain mines that transitioned out of the development stage in 2006;

Material and supplies and maintenance expenses per ton produced increased 8.4% and 8.2%, respectively, to $8.75 and $3.05 per ton, respectively, in 2007 from $8.07 and $2.82 per ton, respectively, in 2006. The respective increases of $0.68 and $0.23 per ton resulted from increased costs for certain products and services (particularly roof support costs and transportation costs) used in the mining process, as well as higher regulatory compliance costs. Those regulations also contributed to increased mine administrative expenses;

Production taxes and royalties (which were incurred as a percentage of coal sales or based on coal volumes) increased $10.2 million and included the impact of West Virginia severance tax on coal sold from Mountain View mine as compared to Maryland. We completed the transition of longwall operations to the Mountain View mine in West Virginia from the depleted Mettiki D-Mine in Maryland in the fourth quarter of 2006;

Reduced expenses of $9.0 million in 2007 as compared to 2006 were associated with the purchase and sale of more coal during 2006 under a settlement agreement we entered into with ICG in November 2005. Consistent with the guidance in the Financial Accounting Standards Board s (FASB) Emerging Issues Task Force (EITF) Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, Pontiki s sale of coal to ICG and Alliance Coal s purchase of coal from ICG are combined. Therefore, the excess of Alliance Coal s purchase price from ICG over Pontiki s sales price to ICG is reported as an operating expense. We fully satisfied our coal sales agreement with ICG in April 2007. For more information about the ICG settlement agreement, please read Other under Item 8. Financial Statements and Supplementary Data Note 20. Commitments and Contingencies ;

The 2006 operating expenses were reduced by $13.9 million reflecting capitalized costs net of revenues received for incidental coal production during mine development. In 2007, there was no incidental coal production associated with mine development. See Item 8. Financial Statements and Supplementary Data Note 2. Summary of Significant Accounting Policies Mine Development Costs ;

Reduced tax credit benefits of $6.6 million in 2007 were due to reduced coal production in Maryland. (See comments above concerning production taxes and royalties and depletion of the Mettiki D-Mine in Maryland); and

2007 benefited from net gains of $3.2 million realized from sale of surplus equipment.

Other sales and operating revenues. Other sales and operating revenues are principally comprised of rental and service fees from third-party coal synfuel production facilities, Mt. Vernon transloading revenues, and outside services and administrative services revenue from affiliates. Other sales and operating revenues increased 10.7% to $35.3 million in 2007 from $31.9 million in 2006. The increase of $3.4 million was primarily attributable to an increase in rental and service fees associated with increased volumes at third-party coal synfuel facilities, increased revenues from hoist and control system services, mine safety services and products, and revenues from outside services, partially offset by lower transloading revenues due to decreased volumes. Synfuel operations ended on December 31, 2007. A more detailed discussion of our synfuel-related arrangements is discussed above under Executive Overview.

Outside coal purchases. Outside coal purchases increased $2.8 million to $22.0 million in 2007 from $19.2 million in 2006. The increase was primarily attributable to an increase in outside coal purchases in our Central Appalachia region to supply new market opportunities partially offset by lower purchases in the Illinois Basin and Northern Appalachian regions.

General and administrative. General and administrative expenses for 2007 increased to $34.5 million compared to $30.9 million for 2006. The increase of $3.6 million was primarily attributable to increased headcount and related salary and benefit costs and higher incentive compensation expense.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased to $85.3 million in 2007 compared to $66.5 million in 2006. The increase of $18.8 million was primarily attributable to additional depreciation expense associated with an increase in capital expenditures, particularly at our Elk Creek, Mountain View and Van Lear mines, and other infrastructure investments in recent years that have increased our production capacity.

Interest expense. Interest expense, net of capitalized interest, decreased to $11.7 million in 2007 from $12.2 million in 2006. The decrease of $0.5 million was principally attributable to reduced interest expense resulting from the August 2007 and 2006 scheduled principal payments of $18.0 million, respectively, on our senior notes, partially offset by increased interest expense under our revolving credit facility.

Interest income. Interest income decreased to $1.7 million for 2007 from $3.0 million in 2006. The decrease of $1.3 million resulted from decreased interest income earned on marketable securities, which were substantially liquidated to fund increased capital expenditures during 2006.

Transportation revenues and expenses. Transportation revenues and expenses decreased 5.5% to $37.7 million in 2007 from $39.9 million for 2006. The decrease of $2.2 million was primarily attributable to lower average per ton transportation charges in 2007 as compared to 2006, primarily driven by the location of our customers for which we arranged transportation. The decrease was partially offset by higher transported coal volumes in 2007. The cost of transportation services are a pass-through to our customers. Consequently, we do not realize any margin on transportation revenues.

Income before income taxes, cumulative effect of accounting change and minority interest. Income before income taxes, cumulative effect of accounting change and minority interest decreased 1.9% to $171.7 million for 2007 compared to $175.1 million for 2006. The decrease of $3.4 million reflects the impact of the changes in revenues and expenses described above.

Income tax expense. Income tax expense decreased to $1.7 million for 2007 from $2.4 million for 2006, primarily due to operating losses associated with Matrix Design Group, LLC, a business Alliance Service, Inc. acquired in September 2006, partially offset by increased tax expense due to increased volumes at the third-party coal synfuel facilities.

Cumulative effect of accounting change. The cumulative effect of accounting change of $0.1 million was attributable to the adoption of SFAS No. 123R, *Share-Based Payment*, on January 1, 2006.

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Minority interest. In March 2006, White County Coal and House entered into a limited liability company agreement to form MAC. MAC was formed to engage in the development and operation of a rock dust mill and to manufacture and sell rock dust. We consolidate MAC s financial results in accordance with FIN No. 46R, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*. Based on the guidance in FIN No. 46R, we concluded that MAC is a variable interest entity and that we are the primary beneficiary. House s portion of MAC s net loss was $0.3 million for 2007 and $0.2 million for 2006, and is recorded as minority interest on our consolidated income statement.

Segment Information. Please read Item 8. Financial Statements and Supplementary Data Note 22. Segment Information for more information concerning our reportable segments. Our 2007 Segment Adjusted EBITDA increased 7.0% to $301.4 million from 2006 Segment Adjusted EBITDA of $281.6 million. Segment Adjusted EBITDA, tons sold, coal sales, other sales and operating revenues and Segment Adjusted EBITDA Expense by segment are as follows (in thousands):

	Year Ended December 31,			
	2007	**2006**	**Increase (Decrease)**	
Segment Adjusted EBITDA				
Illinois Basin	$ 208,658	$ 206,209	$ 2,449	1.2%
Central Appalachia	58,937	40,050	18,887	47.2%
Northern Appalachia	35,478	29,911	5,567	18.6%
Other and Corporate	(1,605)	5,475	(7,080)	(1)
Elimination				
Total Segment Adjusted EBITDA (2)	$ 301,468	$ 281,645	$ 19,823	7.0%
Tons sold				
Illinois Basin	17,970	17,354	616	3.5%
Central Appalachia	3,455	3,552	(97)	(2.7)%
Northern Appalachia	3,300	3,423	(123)	(3.6)%
Other and Corporate		22	(22)	(1)
Elimination				
Total tons sold	24,725	24,351	374	1.5%
Coal sales				
Illinois Basin	$ 612,850	$ 587,087	$ 25,763	4.4%
Central Appalachia	193,104	182,922	10,182	5.6%
Northern Appalachia	147,315	106,628	40,687	38.2%
Other and Corporate	7,085	19,186	(12,101)	(63.1)%
Elimination				
Total coal sales	$ 960,354	$ 895,823	$ 64,531	7.2%
Other sales and operating revenues				
Illinois Basin	$ 25,371	$ 24,168	$ 1,203	5.0%
Central Appalachia	99	304	(205)	(67.4)%
Northern Appalachia	4,201	2,010	2,191	(1)
Other and Corporate	10,423	7,639	2,784	36.44%
Elimination	(4,802)	(2,266)	(2,536)	(1)
Total other sales and operating revenues	$ 35,292	$ 31,855	$ 3,437	10.8%
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 429,563	$ 405,045	$ 24,518	6.1%
Central Appalachia	145,759	143,176	2,583	1.8%

Northern Appalachia	116,037	78,727	37,310	47.4%
Other and Corporate	19,112	21,351	(2,239)	(10.5)%
Elimination	(4,802)	(2,266)	(2,536)	(1)
Total Segment Adjusted EBITDA Expense (3)	$ 705,669	$ 646,033	$ 59,636	9.2%

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(1) Percentage increase or decrease was greater than or equal to 100%.

(2) Segment Adjusted EBITDA is defined as net income before net interest expense, income taxes, depreciation, depletion and amortization, minority interest, cumulative effect of accounting change and general and administration expense. Consolidated EBITDA is used as a supplemental financial measure by management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

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

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

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

- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Segment Adjusted EBITDA is also used as a supplemental financial measure by our management for reasons similar to those stated in the above explanation of EBITDA. In addition, the exclusion of corporate general and administrative expenses from Segment Adjusted EBITDA allows management to focus solely on the evaluation of segment operating profitability as it relates to our revenues and operating expenses which are primarily controlled by our segments.

The following is a reconciliation of consolidated Segment Adjusted EBITDA to net income (in thousands):

	Year Ended December 31, 2007	2006
Segment Adjusted EBITDA	$ 301,468	$ 281,645
General and administrative	(34,479)	(30,884)
Depreciation, depletion and amortization	(85,310)	(66,489)
Interest expense, net	(9,952)	(9,175)
Income tax expense	(1,669)	(2,443)
Cumulative effect of accounting change		112
Minority interest	332	161
Net income	$ 170,390	$ 172,927

(3) Segment Adjusted EBITDA Expense includes operating expenses, outside coal purchases and other income. Transportation expenses are excluded as these expenses are passed through to our customers, and consequently we do not realize any gain or loss on transportation revenues. Segment Adjusted EBITDA Expense is used as a supplemental financial measure by our management to assess the operating performance of our segments. In our evaluation of EBITDA, which is discussed above under *How We Evaluate Our Performance*, Segment Adjusted EBITDA Expense is a key component of EBITDA in addition to coal sales and other sales and operating revenues. The exclusion of corporate general and administrative expenses from Segment Adjusted EBITDA Expense allows management to focus solely on the evaluation of segment operating performance as it primarily relates to our operating expenses. Outside coal purchases are included in Segment Adjusted EBITDA Expense because tons sold and coal sales include sales from outside coal purchases.

The following is a reconciliation of consolidated Segment Adjusted EBITDA Expense to Operating expense (in thousands):

	Year Ended December 31, 2007	2006
Segment Adjusted EBITDA Expense	$ 705,669	$ 646,033
Outside coal purchases	(21,969)	(19,213)
Other income	1,385	936
Operating expense (excluding depreciation, depletion and amortization)	$ 685,085	$ 627,756

Illinois Basin Segment Adjusted EBITDA for 2007, as defined in reference (2) to the table above, increased 1.2% to $208.7 million from 2006 Segment Adjusted EBITDA of $206.2 million. The increase of $2.5 million was primarily attributable to increased coal sales which rose by $25.8 million to $612.9 million during 2007 as compared to $587.1 million in 2006. Coal sales benefited from increased tons sold of 0.6 million tons (contributing $20.9 million of the increase in coal sales) reflecting expanded production capacity at the Hopkins mine and improved productivity at the Pattiki and Warrior mines. Additionally, increased coal sales in 2007 reflected higher average coal sales price per ton, which increased $0.27 per ton to $34.10 per ton (contributing $4.9 million of the increase in coal sales). The price increase was primarily the result of higher pricing on long-term sales contracts. Other sales and operating revenues increased $1.2 million, primarily due to an increase in rent and service fees associated with increased synfuel volumes at our third-party coal synfuel facilities. Please read Executive Overview above for a discussion regarding the status of third-party coal synfuel facilities. Total Segment Adjusted EBITDA Expense, as defined in reference (3) to the above table, for 2007, increased 6.1% to $429.6 million from $405.0 million in 2006. On a per ton sold basis, 2007 Segment Adjusted EBITDA Expense rose to $23.90 per ton over the 2006 Segment Adjusted EBITDA Expense of $23.34 per ton. In addition to the increased tons sold, increased Segment Adjusted EBITDA Expense in 2007 compared to 2006 reflects the impact of cost increases described above under consolidated operating expenses.

Central Appalachia Segment Adjusted EBITDA for 2007, as defined in reference (2) to the table above, increased $18.9 million to $58.9 million as compared to 2006 Segment Adjusted EBITDA of $40.0 million. The increase was primarily the result of the final settlement of the MC Mining Mine Fire, which resulted in a net gain from insurance settlement of approximately $11.5 million and a reduction in operating expenses of approximately $0.8 million (please read MC Mining Mine Fire below) and higher average coal sales price per ton discussed above of $55.89 in 2007, an increase of 8.5% over the 2006 average coal sales price per ton of $51.50 (contributing a $15.2 million increase in coal sales). Coal sales increased 5.6% to $193.1 million for 2007 as compared to $182.9 million for 2006, reflecting higher average coal sales price per ton partially offset by a decrease of 2.7% in tons sold, or 97,000 tons (contributing a $5.0 million decrease in coal sales). Segment Adjusted EBITDA Expense, as defined in reference (3) to the above table, for 2007 increased 1.8% to $145.8 million. The increase in Segment Adjusted EBITDA Expense per ton of $1.89 to $42.19 in 2007, as compared to 2006, was primarily a result of higher operating expenses associated with recently enacted federal and state regulations and increased purchased coal volumes, among other cost increases described above under consolidated operating expenses.

Northern Appalachia Segment Adjusted EBITDA for 2007, as defined in reference (2) to the table above, increased $5.6 million to $35.5 million as compared to 2006 Segment Adjusted EBITDA of $29.9 million. The net increase in Segment Adjusted EBITDA reflects both an increase in the average sales price of $13.49 per ton to $44.64 per ton during 2007 as compared to $31.15 per ton during 2006 due to new coal sales contracts, as well as increased other sales and operating revenues of $2.2 million, partially offset by an increase in Segment Adjusted EBITDA Expense, as defined in reference (3) to the above table, of $12.16 per ton to $35.16 per ton during 2007 as compared to $23.00 per ton during 2006. These variances reflect the impact of higher coal sales contract prices, as well as higher operating costs resulting from the transition of the Mettiki D-Mine longwall operation in Maryland to the new Mountain View longwall operation in West Virginia. Other impacts on Segment Adjusted EBITDA for 2007 as compared to 2006 include a 3.6% decrease in sold tonnage volume, increased other sales and operating revenues of $2.2 million, and the cost increases described above under consolidated operating expenses.

Other and Corporate The decrease in Segment Adjusted EBITDA Expense, as defined in reference (3) to the above table, primarily reflects lower operating expenses in 2007 attributable to lower brokerage coal purchases associated with the ICG agreement referred to above under consolidated operating expenses, partially offset by increased expenses associated with higher outside services revenue, which includes MAC and Matrix Design.

Elimination The increase is primarily comprised of the elimination of sales and operating expenses between MAC and Matrix Design and our operating mines.

MC Mining Mine Fire

On June 18, 2007, we agreed to a full and final resolution of our insurance claims relating to a mine fire that occurred on or about December 25, 2004 at our MC Mining s Excel No. 3 mine. This resolution included settlement of all expenses, losses and claims we incurred for the aggregate amount of $31.6 million, inclusive of $8.2 million of various deductibles and co-insurance, netting to $23.4 million of insurance proceeds paid to us. In 2006 and 2005, we received partial advance payments on the claims totaling $16.2 million, part of which we recognized as an offset to operating expenses ($0.4 million and $10.7 million in the three months ended March 31, 2006 and the year ended December 31, 2005, respectively), with the remaining $5.1 million of partial payments previously included in other current liabilities pending final claim resolution. In June 2007, as a result of this final resolution, we received additional cash payments of $7.2 million and recognized a net gain from insurance settlement of approximately $11.5 million, as well as a reduction in operating expenses of approximately $0.8 million. In May 2008, we realized a $2.8 million gain on settlement of our claim against the third-party that provided security services at the time of the fire.

Ongoing Acquisition Activities

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

Liquidity and Capital Resources

Liquidity

We have satisfied our working capital requirements and funded our capital expenditures and debt service obligations from cash generated from operations, cash provided by the issuance of debt or equity and borrowings under revolving credit facilities. We believe that the current cash on hand along with 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. Our ability to satisfy our obligations and planned expenditures will depend upon our future operating performance and access to financing sources, which will be affected by prevailing economic conditions generally and in the coal industry specifically, some of which are beyond our control. Based on our recent operating results, current cash position, anticipated future cash flows and sources of financing that we expect to have available, we do not anticipate any significant liquidity constraints in the foreseeable future. However, to the extent operating cash flow is materially lower than expected, including the impact of increases in interest rates, future liquidity may be adversely affected. Please see Item 1A. Risk Factors above.

Cash Flows

Cash provided by operating activities was $261.0 million in 2008, compared to $244.0 million in 2007. The increase in cash provided by operating activities was principally attributable to favorable change in cash flows for certain operating assets and liabilities such as accounts payable, inventories, accrued payroll and related benefits and other assets and liabilities partially offset by decreased net income.

Net cash used in investing activities was $184.1 million in 2008, compared to $178.7 million in 2007. The increased use of cash in 2008 was primarily attributable to an increase in capital expenditures partially offset by a $23.5 million decrease in acquisitions of coal reserves and other assets for 2008 compared to 2007. Additionally, timing differences related to payment of accounts payable and accrued liabilities for 2008 capital expenditures and advances made on the Gibson County Coal rail project in 2007 partially offset the increases in capital expenditures for 2008.

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Net cash provided by financing activities was $166.8 million for 2008 compared to net cash used in financing activities of $101.0 million for 2007. The increase in cash provided by financing activities was primarily attributable to the proceeds from our issuance of the 2008 financing activities (see Debt Obligations) partially offset by repayments under our revolving credit facility outstanding in 2008 as compared to 2007 and increased distributions paid to partners in 2008.

We have various commitments primarily related to long-term debt, including capital leases, operating lease commitments related to buildings and equipment, obligations for estimated asset retirement obligations costs, workers compensation and pneumoconiosis, capital project commitments and pension funding. We expect to fund these commitments with cash on hand, cash generated from operations and borrowings under our revolving credit facility. The following table provides details regarding our contractual cash obligations as of December 31, 2008 (in thousands):

Contractual Obligations	Total	Less than 1 year	2-3 years	4-5 years	After 5 years
Long-term debt	$ 458,000	$ 18,000	$ 36,000	$ 36,000	$ 368,000
Future interest obligations on senior notes	207,409	31,593	58,698	52,715	64,403
Operating leases	13,242	4,583	5,702	1,155	1,802
Capital leases(1)	1,985	485	969	531	
Reclamation obligations(2)	123,773	2,385	5,012	3,631	112,745
Purchase obligations for capital projects	116,128	116,128			
Coal purchase commitments	21,000	13,600	7,400		
Workers compensation and pneumoconiosis benefit(2)	232,755	13,222	18,061	15,025	186,447
	$ 1,174,292	$ 199,996	$ 131,842	$ 109,057	$ 733,397

(1) Includes amounts classified as interest and maintenance cost.
(2) Future commitments for reclamation obligations, workers compensation and pneumoconiosis are shown at undiscounted amounts.

We expect to contribute $10.6 million to the defined benefit pension plan (Pension Plan) during 2009. We estimate our income tax cash requirements to be approximately $2.1 million in 2009.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements. These arrangements include guarantees and financial instruments with off-balance sheet risk, such as bank letters of credit and surety bonds. Liabilities related to these arrangements are not reflected in our consolidated balance sheets, and we do not expect any material adverse effects on our financial condition, results of operations or cash flows to result from these off-balance sheet arrangements.

We use a combination of surety bonds and letters of credit to secure our financial obligations for reclamation, workers compensation and other obligations as follows as of December 31, 2008 (dollars in thousands):

	Reclamation Obligation	Workers Compensation Obligation	Other	Total
Surety bonds	$ 58,979	$ 22,024	$ 2,127	$ 83,130
Letters of credit		32,772	10,198	42,970

Capital Expenditures

Capital expenditures increased to $176.5 million in 2008 compared to $119.6 million in 2007. See discussion of Cash Flows above concerning this increase in capital expenditures.

We currently project average estimated annual maintenance capital expenditures of approximately $3.90 per ton produced. Our anticipated total capital expenditures for 2009 are estimated in a range of $430 to $480 million. Management anticipates funding 2009 capital requirements with our December 31, 2008 cash and cash equivalents of $244.9 million, cash flows provided by operations and borrowing available under our revolving credit facility as discussed below. The terms of our credit facility require us to seek a waiver from our lenders to incur capital expenditures, excluding acquisitions, in excess of $328.9 million in 2009. We have not yet sought to obtain a waiver or to amend our credit facility but may seek such a waiver for our 2009 capital expenditures. We will continue to have significant capital requirements over the long-term, which may require us to incur debt or seek additional equity capital. The availability of additional capital will depend upon prevailing market conditions, the market price of our common units and several other factors over which we have limited control, as well as our financial condition and results of operations.

Insurance

During September 2008, we completed our annual property and casualty insurance renewal with various insurance coverages effective as of October 1, 2008. Available capacity for underwriting property insurance continues to be limited as a result of insurance carrier losses in the mining industry worldwide. As a result, we have elected to retain a participating interest in our commercial property insurance program at an average rate of approximately 14.7% in the overall $75.0 million of coverage, representing 22% of the primary $50.0 million layer. We do not participate in the second layer of $25.0 million in excess of $50.0 million.

The 14.7% participation rate for this year s renewal is consistent with our prior year participation. The aggregate maximum limit in the commercial property program is $75.0 million per occurrence of which, as a result of our participation, we are responsible for a maximum amount of $11.0 million for each occurrence, excluding a $1.5 million deductible for property damage, a $5.0 million aggregate deductible for extra expense and a 60-day waiting period for business interruption. We can make no assurances that we will not experience significant insurance claims in the future, which as a result of our level of participation in the commercial property program, could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future.

Debt Obligations

Notes Offering and Credit Facility

Credit Facility. On September 25, 2007, our Intermediate Partnership entered into a $150.0 million revolving credit facility (ARLP Credit Facility), which matures in 2012. Borrowings under the ARLP Credit Facility bear interest based on a floating base rate plus an applicable margin. The applicable margin is based on a leverage ratio of our Intermediate Partnership, as computed from time to time. For London Interbank Offered Rate (LIBOR) borrowings, the applicable margin under the ARLP Credit Facility ranges from 0.625% to 1.150% over LIBOR. Outstanding letters of credit reduce amounts available under the ARLP Credit Facility. At December 31, 2008, we had $13.9 million of letters of credit outstanding with $136.1 million available for borrowing under the ARLP Credit Facility. We had no borrowings outstanding under the ARLP Credit Facility at December 31, 2008. We incur an annual commitment fee of 0.175% on the undrawn portion of the ARLP Credit Facility.

Lehman Commercial Paper, Inc. (Lehman), a subsidiary of Lehman Brothers Holding, Inc., holds a 5%, or $7.5 million, commitment in our $150 million ARLP Credit Facility. The ARLP Credit Facility is underwritten by a syndicate of twelve financial institutions including Lehman with no individual institution representing more than 11.3% of the $150 million revolving credit facility. Lehman filed for protection under Chapter 11 of the Federal Bankruptcy Code in early October 2008. Although we have not made any borrowing requests since the bankruptcy filing by Lehman, we do not know if Lehman could, or would, fund its share of the commitment if requested. In the event Lehman, or any other financial institution in our syndicate, does not fund our future borrowing requests, our borrowing availability under the ARLP Credit Facility could be reduced. The obligations of the lenders under our credit facility are individual obligations and the failure of one or more lenders does not relieve the remaining lenders of their funding obligations.

Senior Notes. Our Intermediate Partnership has $108.0 million principal amount of 8.31% senior notes due August 20, 2014, payable in six remaining equal annual installments of $18.0 million with interest payable semi-annually (Senior Notes).

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Series A Senior Notes. On June 26, 2008, our Intermediate Partnership entered into a Note Purchase Agreement (the 2008 Note Purchase Agreement) with a group of institutional investors in a private placement offering. We issued $205.0 million of Series A Senior Notes, which bear interest at 6.28% and mature on June 26, 2015 with interest payable semi-annually.

Series B Senior Notes. On June 26, 2008, we issued under the 2008 Note Purchase Agreement $145.0 million of Series B Senior Notes, which bear interest at 6.72% and mature on June 26, 2018 with interest payable semi-annually.

The proceeds from the Series A and Series B Senior Notes (collectively, the 2008 Senior Notes) were used to repay $21.5 million outstanding under the ARLP Credit Facility and pay expenses associated with the offering of the 2008 Senior Notes. The remaining proceeds will be used to fund the development of the River View and Tunnel Ridge mining complexes and for other general working capital requirements. We incurred debt issuance costs of approximately $1.7 million associated with the 2008 Senior Notes, which have been deferred and are being amortized as a component of interest expense over the term of the respective notes.

The ARLP Credit Facility, Senior Notes and 2008 Senior Notes (collectively, the ARLP Debt Arrangements) are guaranteed by all of the direct and indirect subsidiaries of our Intermediate Partnership. The ARLP Debt Arrangements contain various covenants affecting our Intermediate Partnership and its subsidiaries restricting, among other things, the amount of distributions by our Intermediate Partnership, the incurrence of additional indebtedness and liens, the sale of assets, the making of investments, the entry into mergers and consolidations and the entry into transactions with affiliates, in each case subject to various exceptions. The ARLP Debt Arrangements also require the Intermediate Partnership to remain in control of a certain amount of mineable coal reserves relative to its annual production. In addition, the ARLP Debt Arrangements require our Intermediate Partnership to maintain (i) a minimum debt to cash flow ratio of not more than 3.0 to 1.0, (ii) a ratio of cash flow to interest expense during the four most recently ended fiscal quarters of not less than 4.0 to 1.0 and (iii) maximum annual capital expenditures, excluding acquisitions, of $330.4 million for 2008. The debt to cash flow ratio, cash flow to interest expense ratio and actual capital expenditures were 1.7 to 1.0, 11.6 to 1.0 and $176.5 million for the year ended December 31, 2008, respectively. We were in compliance with the covenants of the ARLP Debt Arrangements as of December 31, 2008.

Other. We have agreements with two banks to provide additional letters of credit in an aggregate amount of $31.0 million to maintain surety bonds to secure certain asset retirement obligations and our obligations for workers compensation benefits. At December 31, 2008, we had $29.0 million in letters of credit outstanding under these agreements. Our special general partner guarantees $5.0 million of these outstanding letters of credit.

On March 19, 2007, MAC entered into a secured line of credit (LOC) with a third-party, which was scheduled to expire on March 19, 2008. In September 2007, MAC entered into a $1.5 million Revolving Credit Agreement (Revolver) with ARLP. Concurrent with the execution of the Revolver, MAC repaid all amounts outstanding under the LOC. By amendment effective April 1, 2008, the term of the Revolver was extended to June 30, 2009. Due to the consolidation of MAC in accordance with FIN No. 46R, the intercompany transactions associated with the Revolver are eliminated.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the U.S. From our summary of significant accounting policies included in Item 8. Financial Statements and Supplementary Data, we have identified the following accounting policies that require us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingencies. On an on-going basis, we evaluate our estimates. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these 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 adjust 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 transloading fees, administrative service revenues from our affiliates, mine safety services and products, rock dust sales and other handling and service fees. For 2007 and 2006, non-coal sales revenues included rental and service fees from third-party coal synfuel facilities, agreements related to these services expired on December 31, 2007 in conjunction with the expiration of non-conventional synfuel tax credits. These non-coal sales revenues are recognized as the services are performed. Transportation revenues are recognized in connection with us incurring the corresponding costs of transporting coal to customers through third-party carriers for which we are directly reimbursed through customer billings. We had no allowance for doubtful accounts for trade receivables at December 31, 2008 and 2007.

Long-Lived Assets

We review 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 impairment is measured by the difference between the carrying value and the fair value of the asset. We have not recorded an impairment loss for any of the periods presented.

Mine Development Costs

Mine development costs are capitalized until production, other than production incidental to the mine development process, commences and are amortized on a units of production method based on the estimated proven and probable reserves. Mine development costs represent costs incurred in establishing access to mineral reserves and include costs associated with sinking or driving shafts and underground drifts, permanent excavations, roads and tunnels. The end of the development phase and the beginning of the production phase takes place when construction of the mine for economic extraction is substantially complete. Coal extracted during the development phase is incidental to the mine s production capacity and is not considered to shift the mine into the production phase. Amortization of capitalized mine development is computed based on the estimated life of the mine and commences when production, other than production incidental to the mine development process, begins.

Asset Retirement Obligations

SMCRA and similar state statutes require that mined property be restored in accordance with specified standards and an approved reclamation plan. A liability is recorded for the estimated cost of future mine asset retirement and closing procedures on a present value basis when incurred and a corresponding amount 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. Examples of these types of costs, common to both types of mining, include, but are not limited to, removing or covering refuse piles and settling ponds, water treatment obligations, and dismantling preparation plants, other facilities and roadway infrastructure. Accrued liabilities of $58.6 million and $56.9 million for these costs are recorded at December 31, 2008 and 2007, respectively. The liability for asset retirement and closing procedures is sensitive to changes in cost estimates and estimated mine lives. For additional information on our asset retirement obligations, please read Item 8. Financial Statements and Supplementary Data. Note 16. Asset Retirement Obligations.

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 generally provide for these claims through self-insurance programs. Workers compensation laws also compensate survivors or workers who suffer employment related deaths. The liability for traumatic injury claims is our estimate of the present value of current workers compensation benefits, based on our actuary estimates. Our 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 $56.7 million and $51.6 million for these costs at December 31, 2008 and 2007, respectively. A one-percentage-point reduction in the discount rate would have increased the liability at December 31, 2008 approximately $3.7 million, which would have a corresponding increase in operating expenses.

Coal mining companies are subject to CMHSA, 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 black lung benefits liability is calculated using the service cost method based on the actuarial present value of the estimated black lung obligation. Our actuarial calculations are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and interest rates. We had accrued liabilities of $32.0 million and $30.0 million for these benefits at December 31, 2008 and 2007, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2008 by approximately $0.5 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.

Related Party Transactions

The Board of Directors of our managing general partner and its conflicts committee (Conflicts Committee) review each of our related-party transactions to determine that each such transaction reflects market-clearing terms and conditions customary in the coal industry. As a result of these reviews, the Board of Directors and the Conflicts Committee approved each of the transactions described below as fair and reasonable to us and our limited partners.

River View Coal, LLC Acquisition

In April 2006, we acquired River View for approximately $1.65 million from ARH, which at the time of our acquisition was owned by our current and former management, including majority shareholder Joseph W. Craft, III, President and Chief Executive Officer of our managing general partner. At the time of this acquisition, our managing general partner was owned jointly by Alliance Management Holdings, LLC (AMH) and AMH II, LLC (AMH II), and Mr. Craft was the majority owner and sole director of each of AMH and AMH II. Prior to our acquisition of River View, it had the right to purchase certain assets, including additional coal reserves, surface properties, facilities and permits from an unrelated party, for $4.15 million plus an overriding royalty on all coal mined and sold by River View from certain of the leased properties included in the assets. In a separate transaction in April 2006, immediately subsequent to our acquisition of River View, River View purchased these assets from the unrelated party and assumed initial asset retirement obligations of $2.9 million. After the completion of this purchase, River View controlled, through coal leases or direct ownership, approximately 105.4 million tons of high-sulfur coal reserves in the No. 7, No. 9 and No. 11 coal seams, located in Union County, Kentucky. As a result of these acquisitions, we recorded assets of $8.7 million, offset by the fair value of the initial asset retirement obligation of approximately $2.9 million. Because the River View acquisition was between entities under common control, it was accounted for at historical cost.

Administrative Services

In connection with the AHGP IPO in 2006, ARLP entered into an Administrative Services Agreement between our managing general partner, our Intermediate Partnership, AHGP and its general partner AGP, and ARH II, the indirect parent of SGP. Under the Administrative Services Agreement, certain employees, including some executive officers, provide administrative services to our managing general partner, AHGP, AGP, ARH II and their respective affiliates. We are reimbursed for services rendered by our employees on behalf of these affiliates as provided under the Administrative Services Agreement. We billed and recognized administrative service revenue under this agreement of $0.4 million, $0.3 million and $0.3 million for the years ended December 31, 2008 and 2007, respectively, and the period May 15, 2006 to December 31, 2006, from AHGP and $0.5 million, $0.4 million and $0.4 million from ARH II for the years ended December 31, 2008 and 2007 and the period from May 15, 2006 to December 31, 2006, respectively. Concurrently in 2006, AHGP and AGP joined as parties to our Omnibus Agreement which addresses areas of non-competition between us and ARH, ARH II, SGP and our managing general partner.

Our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses incurred or payments made on behalf of us, including, but not limited to, management s salaries and related benefits (including incentive compensation), and accounting, budgeting, 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 $0.3 million, $0.9 million and $4.2 million for the years ended December 31, 2008, 2007 and 2006, respectively. The decrease from 2007 to 2008 was primarily attributable to lower unit based directors compensation accruals due to a decrease in market value of our common units from the beginning of the year compared to the end of the year. The decrease from 2006 to 2007 was attributable to certain employees and the sponsorship of the Long-Term Incentive Plan

(LTIP), Short-Term Incentive Plan (STIP) and Supplemental Executive Retirement Plan (SERP) being transferred from our managing general partner to Alliance Coal effective May 15, 2006 in connection with the closing of AHGP s IPO. On May 15, 2006, our executive officers became employees of record of Alliance Coal, and we no longer reimburse our managing general partner for compensation expenses associated with them. The impact of the change in plan sponsorship resulted in a reduction in the billing to us from our managing general partner directly offset by a corresponding increase in LTIP, STIP and SERP expense of our Alliance Coal subsidiary.

Managing General Partner Contribution

During 2008 and 2007, an affiliated entity controlled by Joseph W. Craft III, contributed 25,898 and 50,980 AHGP common units, respectively, valued at approximately $0.6 million and $1.1 million, respectively, at the time of contribution and $0.8 million of cash for each of the years 2008 and 2007 to AHGP for the purpose of funding certain expenses associated with our employee compensation programs. Upon AHGP s receipt of this contribution it immediately contributed the same to its subsidiary MGP, our managing general partner, which in turn contributed the same to our subsidiary Alliance Coal. Concurrent with this contribution, Alliance Coal distributed the 25,898 and 50,980 AHGP common units to certain employees and recognized compensation expense of $1.4 million and $1.9 million in 2008 and 2007, respectively. As provided under our partnership agreement we made a special allocation to our managing general partner of certain general and administrative expenses equal to the amount of its contribution.

SGP Land, LLC

On May 2, 2007, SGP Land, a subsidiary of our special general partner that is controlled by Mr. Craft, entered into a time sharing agreement with Alliance Coal, our operating subsidiary, concerning the use of aircraft owned by SGP Land. In accordance with the provisions of the time sharing agreement as amended, we reimbursed SGP Land $0.7 million and $0.3 million for the years ended December 31, 2008 and 2007, respectively, for use of the aircraft.

On January 28, 2008, effective January 1, 2008, we acquired, through our subsidiary Alliance Resource Properties, additional rights to approximately 48.2 million tons of coal reserves located in western Kentucky from SGP Land. The purchase price was $13.3 million. At the time of our acquisition, these reserves were leased by SGP Land to our subsidiaries, Webster County Coal, Warrior and Hopkins County Coal through the mineral leases and sublease agreements described below. Those mineral leases and sublease agreements between SGP Land and our subsidiaries were assigned to Alliance Resource Properties by SGP Land in this transaction. The recoupable balances of advance minimum royalties and other payments at the time of this acquisition, other than $0.4 million to the base lessors, are eliminated in our consolidated financial statements as of December 31, 2008.

In 2000, Webster County Coal entered into 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 $2.7 million and $3.0 million for the years ended December 31, 2007 and 2006, respectively. As of December 31, 2007, Webster County Coal had recouped, against earned royalties otherwise due, all but $3.2 million of the advance minimum royalty payments made under the lease. As described above, this mineral lease and sublease is now with Alliance Resource Properties.

In 2001, Warrior entered into a mineral lease and sublease with SGP Land. Under the terms of the lease, Warrior paid in arrears an annual minimum royalty of $2.3 million until $15.9 million of cumulative annual minimum and/or earned royalty payments were paid. The annual minimum royalty periods expired on September 30, 2007. In 2006, Warrior s cumulative total of annual minimum royalties and/or earned royalty payments exceeded $15.9 million, and therefore the annual minimum royalty payment of $2.3 million was no longer required. Warrior paid royalties of $1.3 million, and $5.1 million for the years ended December 31, 2007 and 2006, respectively. As of December 31, 2007, Warrior had recouped, against earned royalties otherwise due, all advance minimum royalty payments made in accordance with these lease terms. As described above, this mineral lease and sublease is now with Alliance Resource Properties.

In 2005, Hopkins County Coal entered into a mineral lease and sublease with SGP Land encompassing the Elk Creek reserves, and the parties also entered into a Royalty Agreement (collectively, the Coal Lease Agreements) in connection therewith. The Coal Lease Agreements extend through December 2015, with the right to renew for successive one-year periods for as long as Hopkins County Coal 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 $0.7 million beginning in December 2005. The annual minimum royalty payments, together with cumulative option fees of

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g$3.4 million previously paid prior to December 2005 by Hopkins County Coal to SGP Land, are fully recoupable against future earned royalty payments. Hopkins County Coal paid to SGP Land advance minimum royalties and/or option fees of $0.7 million during each of the years ended December 31, 2007 and 2006, respectively. As of December 31, 2007, Hopkins County Coal had recouped against advance minimum royalties and/or option fees otherwise due all but $4.4 million paid under the Coal Lease Agreements As described above, this mineral lease and sublease is now with Alliance Resource Properties.

Under the terms of the mineral lease and sublease agreements described above, Webster County Coal, Warrior, and Hopkins County Coal also reimburse SGP Land for its base lease obligations. We reimbursed SGP Land $6.1 million and $5.0 million for the years ended December 31, 2007 and 2006, respectively, for the base lease obligations. As of December 31, 2007, Webster County Coal, Warrior, and Hopkins County Coal had recouped, against earned royalties otherwise due base lessors by SGP Land, all advance minimum royalty payments paid by SGP Land to the base lessors in accordance with the terms of the base leases (and reimbursed by Webster County Coal, Warrior, and Hopkins County Coal), except for $0.4 million.

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 of $0.3 million until $6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. MC Mining paid royalties of $0.3 million during each of the years ended December 31, 2008, 2007 and 2006, respectively. As of December 31, 2008, $1.5 million of advance minimum royalties paid under the lease is available for recoupment, and management expects that it will be recouped against future production.

SGP

In January 2005, we acquired Tunnel Ridge from ARH. In connection with this acquisition, we assumed a coal lease with the SGP. Under the terms of the lease, Tunnel Ridge has paid and will continue to pay an annual minimum royalty of $3.0 million until the earlier of January 1, 2033 or the exhaustion of the mineable and merchantable leased coal. Tunnel Ridge paid advance minimum royalties of $3.0 million during each of the years ended December 31, 2008, 2007 and 2006. As of December 31, 2008, $12.0 million of advance minimum royalties paid under the lease is available for recoupment and management expects that it will be recouped against future production.

Tunnel Ridge also controls surface land and other tangible assets under a separate lease agreement with the SGP. Under the terms of the lease agreement, Tunnel Ridge has paid and will continue to pay the SGP an annual lease payment of $0.2 million. The lease agreement has an initial term of four years, which may be extended to match the term of the coal lease. Lease expense was $0.2 million for each of the years ended December 31, 2008, 2007 and 2006, respectively.

We have a noncancelable operating lease arrangement with the SGP for the coal preparation plant and ancillary facilities at the Gibson County Coal mining complex. Based on the terms of the lease, we will make monthly payments of approximately $0.2 million through January 2011. Lease expense incurred for each of the years ended December 31, 2008, 2007 and 2006 was $2.6 million, respectively.

We have agreements with two banks to provide letters of credit in an aggregate amount of $31.0 million. At December 31, 2008, we had $29.0 million in outstanding letters of credit under these agreements. The SGP guarantees $5.0 million of these outstanding letters of credit. The SGP does not charge us for this guarantee. Since the guarantee is made on behalf of entities within the consolidated partnership, the guarantee has no fair value under FIN No. 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, including Indirect Guarantees of Indebtedness of Other*s, and does not impact our consolidated financial statements.

Accruals of Other Liabilities

We had accruals for other liabilities, including current obligations, totaling $162.0 million and $149.6 million at December 31, 2008 and 2007. These accruals were chiefly comprised of workers compensation benefits, black lung benefits, and costs associated with asset retirement obligations. 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 16. Asset Retirement Obligations and Note 17. Accrued Workers Compensation and Pneumoconiosis (Black Lung) Benefits.

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Pension Plan

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

Our pension expense was $1.9 million and $3.3 million for the years ended December 31, 2008 and 2007. Our pension expense is based upon a number of actuarial assumptions, including an expected long-term rate of return on our Pension Plan assets of 8.35% and 7.75% and discount rates of 6.70% and 5.55% for the years ended December 31, 2008 and 2007, respectively. Our actual return gain/(loss) on plan assets was (27.2)% and 8.6% for the years ended December 31, 2008 and 2007, 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.

The expected long-term rate of return assumption is based on broad equity and bond indices. At December 31, 2008, our expected long-term rate of return assumption was 8.35% determined by the above factors and based on an asset allocation assumption of 60.0% with domestic equity securities, with an expected long-term rate of return of 10.6%, 10.0% invested in international equities with an expected long-term rate of return of 6.9% and 30.0% with fixed income securities, with an expected long-term rate of return of 5.8%. We, along with our Pension Plan trustee, regularly review 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 (Compensation Committee).

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 A-rated utility bond index as the primary benchmark for establishing the discount rate. At December 31, 2008, the discount rate was determined using high quality bond yield curves adjusted to reflect the plan s estimated payout. The discount rate determined on this basis decreased from 6.65% at December 31, 2007 to 6.15% at December 31, 2008.

As of December 31, 2008, our Pension Plan was underfunded by approximately $20.0 million. We estimate that our Pension Plan expense and cash contributions will be approximately $4.7 million and $10.6 million, respectively, in 2009. 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 8.35% to 7.35%) at December 31, 2007 would have increased our pension expense for the year ended December 31, 2008 by approximately $0.4 million. Lowering the discount rate assumption by 0.5% (from 6.65% to 6.15%) at December 31, 2007 would have increased our pension expense for the year ended December 31, 2008 by approximately $0.4 million.

Inflation

Over the course of the last three years, our results have been significantly impacted by price increases affecting many of the components of our operating expenses such as fuel, steel, maintenance expense and labor. The impact of recent governmental initiatives to stimulate economies worldwide remains unclear. Any resulting inflationary or deflationary pressures could adversely affect the results of our operations. Please see Item 1A. Risk Factors.

New Accounting Standards

New Accounting Standards Issued and Adopted

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This standard defines fair value, establishes a framework for measuring fair value in accounting principles generally accepted in the U.S., and expands disclosure about fair value measurements. SFAS No. 157 applies under other accounting standards that require or permit fair value measurements. Accordingly, this statement does not require any new fair value measurement. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 with the exception of nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value on a nonrecurring basis for which the requirements of SFAS No. 157 have been deferred by the FASB for one year. The adoption of SFAS No. 157 on January 1, 2008 did not have a material impact on our consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. SFAS No. 159 allows entities to choose to measure at fair value financial instruments and certain other eligible items which are not otherwise currently required to be measured at fair value. Under SFAS No. 159, the decision to measure items at fair value is made at specified election dates on an irrevocable instrument-by-instrument basis. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We have not elected to present any of our financial assets or liabilities currently recorded on our consolidated balance sheet at fair value under SFAS No. 159; therefore, the adoption of SFAS No. 159 on January 1, 2008 did not have a material impact on our consolidated financial statements.

New Accounting Standards Issued and Not Yet Adopted

In December 2007, the FASB issued SFAS No. 141R, *Business Combinations.* SFAS No. 141R applies to all business combinations and establishes guidance for recognizing and measuring identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree and goodwill. Most of these items are recognized at their full fair value on the acquisition date, including acquisitions where the acquirer obtains control but less than 100% ownership in the acquiree. SFAS No. 141R also requires expensing restructuring and acquisition-related costs as incurred and establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. SFAS No. 141R is effective for business combinations with an acquisition date in fiscal years beginning after December 15, 2008. We are currently evaluating the changes provided in this statement; however, we do not expect the adoption of SFAS No. 141R on January 1, 2009 to impact our historical consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements*, which establishes accounting and reporting standards for noncontrolling ownership interests in subsidiaries. Noncontrolling ownership interests in consolidated subsidiaries will be presented in the consolidated balance sheet within partners capital as a separate component from the parent s equity. Consolidated net income will now include earnings attributable to both the parent and the noncontrolling interests. Earnings per share will continue to be based on earnings attributable to only the parent company and does not change upon adoption of SFAS No. 160. SFAS No. 160 provides guidance on accounting for changes in the parent s ownership interest in a subsidiary, including transactions where control is retained and where control is relinquished. SFAS No. 160 also requires additional disclosure of information related to amounts attributable to the parent for income from continuing operations, discontinued operations and extraordinary items and reconciliations of the parent and noncontrolling interests equity of a subsidiary. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008. The Statement will be applied prospectively to transactions involving noncontrolling interests, including noncontrolling interests that arose prior to the effective date, as of the beginning of the fiscal year it is initially adopted. However, the presentation of noncontrolling interests within partners capital and the inclusion of earnings attributable to the noncontrolling interests in consolidated net income requires retrospective application to all periods presented. We do not anticipate the adoption of SFAS No. 160 on January 1, 2009 to have a material impact on our consolidated financial statements.

In March 2008, the FASB issued EITF No. 07-4 *Application of the Two-Class Method under FASB Statement No. 128, Earnings Per Share, to Master Limited Partnerships*, which considers whether the IDR of a master limited partnership represents a participating security when considered in the calculation of earnings per unit under the two-class method. The EITF considers whether the partnership agreement contains any contractual limitations concerning distributions to IDR holders that would impact the amount of earnings to allocate to the IDR holders for each reporting period. If distributions are contractually limited to the IDR holders share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the IDR holders. In addition, the EITF presents alternative methods for inclusion of IDR in the earnings per unit computation. When cash distributions exceed net income for the period, net income should be reduced by the distributions made to the holders of the general partner interest, the holder of the limited partner interest and IDR holders for the period. The provisions of EITF No. 07-4 are effective for fiscal years beginning after December 15, 2008. We expect the adoption of EITF No. 07-4 will impact our presentation of earnings per unit. We currently present earnings per unit as though all earnings were distributed each quarter. For more information, please read Part II. Item 8. Financial Statements and Supplementary Data Note 12. Net Income Per Limited Partner Unit of this Annual Report on Form 10-K. Under the new guidance of EITF No. 07-4, we believe our partnership agreement contractually limits our distributions to available cash and therefore undistributed earnings will no longer be allocated to the IDR holder upon adoption of EITF No. 07-4 effective January 1, 2009.

In June 2008, the FASB issued Staff Position (FSP) No. EITF No. 03-6-1 *Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities*. This FSP affects entities that accrue cash

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dividends on share-based payment awards during the awards service period when the dividends do not need to be returned if the employees forfeit the award. The FSP requires that all outstanding unvested share-based payment awards that contain rights to nonforfeitable dividends participate in undistributed earnings with common shareholders and are considered participating securities. Because the awards are considered participating securities, the issuing entity is required to apply the two-class method of computing basic and diluted earnings per share. The provisions of FSP No. EITF No. 03-6-1 are effective for fiscal years beginning after December 15, 2008. We do not anticipate the adoption of FSP No. EITF 03-6-1 on January 1, 2009, to have a material impact on our basic and diluted earnings per unit.

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 21. 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 the ARLP Credit Facility are at variable rates and, as a result, we have interest rate exposure. Historically, our earnings have not been materially affected by changes in interest rates. We had no borrowings outstanding under the ARLP Credit Facility at December 31, 2008.

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, 2008 and 2007. The carrying amounts and fair values of financial instruments are as follows (in thousands):

Expected Maturity Dates as of December 31, 2008	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Total**	**Fair Value December 31, 2008**
Fixed rate debt	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 368,000	$ 458,000	$ 362,824
Weighted Average interest rate	6.88%	6.82%	6.75%	6.68%	6.61%	6.60%		

Expected Maturity Dates as of December 31, 2007	**2008**	**2009**	**2010**	**2011**	**2012**	**Thereafter**	**Total**	**Fair Value December 31, 2007**
Senior Notes fixed rate	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 36,000	$ 126,000	$ 136,559
Weighted Average interest rate	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%		

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, 2008 and 2007, and the related consolidated statements of income, cash flows and Partners capital for each of the three years in the period ended December 31, 2008. 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 the 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 Alliance Resource Partners, L.P. and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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, present 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 Partnership s internal control over financial reporting as of December 31, 2008, 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 2, 2009 expressed an unqualified opinion on the Partnership s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Tulsa, Oklahoma
March 2, 2009

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 2008 AND 2007

(In thousands, except unit data)

	December 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 244,875	$ 1,118
Trade receivables	87,922	92,667
Other receivables	6,018	3,399
Due from affiliates		139
Inventories	26,510	26,100
Advance royalties	3,200	4,452
Prepaid expenses and other assets	10,070	9,099
Total current assets	378,595	136,974
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment, at cost	1,085,214	948,210
Less accumulated depreciation, depletion and amortization	(468,784)	(427,572)
Total property, plant and equipment, net	616,430	520,638
OTHER ASSETS:		
Advance royalties	23,828	25,974
Other long-term assets	11,787	18,137
Total other assets	35,615	44,111
TOTAL ASSETS	$ 1,030,640	$ 701,723
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 63,236	$ 46,392
Due to affiliates	706	1,343
Accrued taxes other than income taxes	11,195	11,091
Accrued payroll and related expenses	20,555	15,180
Accrued interest	3,454	3,826
Workers compensation and pneumoconiosis benefits	9,377	8,124
Current capital lease obligation	351	377
Other current liabilities	11,911	6,754
Current maturities, long-term debt	18,000	18,000
Total current liabilities	138,785	111,087
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities	440,000	136,000
Pneumoconiosis benefits	31,436	29,392

Accrued pension benefit	19,952	
Workers compensation	47,828	44,150
Asset retirement obligations	56,204	54,903
Due to affiliates	420	1,295
Long-term capital lease obligation	784	1,135
Minority interest	927	507
Other liabilities	5,039	6,037
Total long-term liabilities	602,590	273,419
Total liabilities	741,375	384,506
COMMITMENTS AND CONTINGENCIES		
PARTNERS CAPITAL:		
Limited Partners - Common Unitholders 36,613,458 and 36,550,659 units outstanding, respectively	604,998	607,777
General Partners deficit	(295,834)	(290,669)
Accumulated other comprehensive income (loss)	(19,899)	109
Total Partners capital	289,265	317,217
TOTAL LIABILITIES AND PARTNERS CAPITAL	$ 1,030,640	$ 701,723

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, 2008, 2007 AND 2006

(In thousands, except unit and per unit data)

	Year Ended December 31,		
	2008	**2007**	**2006**
SALES AND OPERATING REVENUES:			
Coal sales	$ 1,093,059	$ 960,354	$ 895,823
Transportation revenues	44,755	37,688	39,879
Other sales and operating revenues	18,735	35,292	31,855
Total revenues	1,156,549	1,033,334	967,557
EXPENSES:			
Operating expenses (excluding depreciation, depletion and amortization)	801,854	685,085	627,756
Transportation expenses	44,755	37,688	39,879
Outside coal purchases	23,776	21,969	19,213
General and administrative	37,176	34,479	30,884
Depreciation, depletion and amortization	105,278	85,310	66,489
Gain from sale of coal reserves	(5,159)		
Net gain from insurance settlement and other	(2,790)	(11,491)	
Total operating expenses	1,004,890	853,040	784,221
INCOME FROM OPERATIONS	151,659	180,294	183,336
Interest expense (net of interest capitalized of $808, $1,237 and $1,558, respectively)	(22,145)	(11,656)	(12,177)
Interest income	3,727	1,704	3,002
Other income	875	1,385	936
INCOME BEFORE INCOME TAXES, CUMULATIVE EFFECT OF ACCOUNTING CHANGE AND MINORITY INTEREST	134,116	171,727	175,097
INCOME TAX EXPENSE (BENEFIT)	(480)	1,669	2,443
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE AND MINORITY INTEREST	134,596	170,058	172,654
CUMULATIVE EFFECT OF ACCOUNTING CHANGE			112
MINORITY INTEREST (EXPENSE)	(420)	332	161
NET INCOME	$ 134,176	$ 170,390	$ 172,927
GENERAL PARTNERS INTEREST IN NET INCOME	$ 45,697	$ 31,310	$ 24,594
LIMITED PARTNERS INTEREST IN NET INCOME	$ 88,479	$ 139,080	$ 148,333
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 2.42	$ 3.07	$ 3.06

DILUTED NET INCOME PER LIMITED PARTNER UNIT		$	2.41	$	3.05	$	3.03
DISTRIBUTIONS PAID PER COMMON UNIT		$	2.53	$	2.20	$	1.92
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING	BASIC		36,604,707		36,548,150		36,425,350
WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING	DILUTED		36,769,883		36,800,212		36,810,383

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, 2008, 2007 AND 2006

(In thousands)

	Year Ended December 31,		
	2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 134,176	$ 170,390	$ 172,927
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	105,278	85,310	66,489
Non-cash compensation expense	3,931	3,925	4,112
Asset retirement obligations	2,827	2,419	2,101
Coal inventory adjustment to market	452	21	319
Net gain on sale of property, plant and equipment	(911)	(3,189)	(1,188)
Gain from sale of coal reserves	(5,159)		
Gain from insurance recoveries for property damage		(2,357)	
Gain from insurance settlement proceeds received in a prior period		(5,088)	
Minority interest expense (income)	420	(332)	(161)
Cumulative effect of accounting change			(112)
Other	366	811	1,119
Changes in operating assets and liabilities:			
Trade receivables	4,745	3,891	(2,051)
Other receivables	(1,711)	1,236	(1,048)
Inventories	(960)	(6,484)	(3,851)
Prepaid expenses and other assets	(971)	(874)	757
Advance royalties	(4,244)	(2,724)	(6,484)
Accounts payable	5,617	(6,623)	1,677
Due to affiliates	(1,373)	116	(1,762)
Accrued taxes other than income taxes	104	(3,527)	1,441
Accrued payroll and related benefits	5,375	482	1,659
Pneumoconiosis benefits	2,044	3,230	3,022
Workers compensation	4,931	5,929	8,402
Other	6,104	(2,550)	3,555
Total net adjustments	126,865	73,622	77,996
Net cash provided by operating activities	261,041	244,012	250,923
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(176,482)	(119,590)	(188,630)
Changes in accounts payable and accrued liabilities	10,046	(7,094)	2,776
Proceeds from sale of property, plant and equipment	2,708	6,770	1,401
Proceeds from sale of coal reserves	7,159		
Proceeds from insurance settlement for replacement assets		2,511	
Purchase of marketable securities			(19,447)
Proceeds from marketable securities		260	68,497
Payment for acquisition of coal reserves and other assets	(29,800)	(53,309)	
Payments for acquisition of businesses			(2,289)
Advances on Gibson rail project		(8,212)	

Receipts on prior advances on Gibson rail project	2,244		
Net cash used in investing activities	(184,125)	(178,664)	(137,692)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of long-term debt	350,000		
Payments on long-term debt	(18,000)	(18,000)	(18,000)
Borrowings under revolving credit facilities	88,850	195,650	
Payments under revolving credit facilities	(116,850)	(167,650)	
Payments on capital lease obligation	(377)	(339)	
Payment of debt issuance costs	(1,721)	(264)	(690)
Equity contribution received by Mid-America Carbonates, LLC			1,000
Cash contributions by General Partners	866	904	2
Distributions paid to Partners	(135,927)	(111,320)	(90,808)
Net cash provided by (used in) financing activities	166,841	(101,019)	(108,496)
NET CHANGE IN CASH AND CASH EQUIVALENTS	243,757	(35,671)	4,735
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	1,118	36,789	32,054
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 244,875	$ 1,118	$ 36,789

See notes to consolidated financial statements, including Note 15 for supplemental cash flow information.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006

(In thousands, except unit data)

	Number of Limited Partner Units	Limited Partners Capital	General Partners Capital (Deficit)	Unrealized Gain (Loss)	Accumulated Other Comprehensive Income (Loss)	Total Partners Capital
Balance at January 1, 2006	36,426,306	$ 461,068	$ (298,270)	$ (68)	$ (6,953)	$ 155,777
Comprehensive income:						
Net income		148,333	24,594			172,927
Unrealized loss				68		68
Other comprehensive income (loss)					(3)	(3)
Total comprehensive income						172,992
Common unit based compensation under Long-Term Incentive Plan		10,517				10,517
General Partner contributions			2			2
Retirement of common units contributed by our Managing General Partner	(6,459)	(222)	222			
Distributions on common unit based compensation		(753)				(753)
Distribution to Partners		(69,938)	(20,117)			(90,055)
Balance at December 31, 2006	36,419,847	549,005	(293,569)		(6,956)	248,480
Comprehensive income:						
Net income		139,080	31,310			170,390
Other comprehensive income					7,065	7,065
Total comprehensive income						177,455
Issuance of units to Long-Term Incentive Plan participants upon vesting	130,812	(2,227)				(2,227)
Common unit based compensation under Long-Term Incentive Plan		2,820				2,820
General Partners contribution			2,009			2,009
Distributions on common unit based compensation		(489)				(489)
Distribution to Partners		(80,412)	(30,419)			(110,831)
Balance at December 31, 2007	36,550,659	607,777	(290,669)		109	317,217
Comprehensive income:						
Net income		88,479	45,697			134,176
Other comprehensive income (loss)					(20,008)	(20,008)
Total comprehensive income (loss)						114,168
Issuance of units to Long-Term Incentive Plan participants upon vesting	62,799	(1,181)				(1,181)
Common unit based compensation under Long-Term Incentive Plan		3,311				3,311
Common control acquisition (Note 3)			(9,809)			(9,809)
General Partners contribution			1,486			1,486
Distributions on common unit based compensation		(793)				(793)

Distribution to Partners		(92,595)	(42,539)				(135,134)
Balance at December 31, 2008	36,613,458	$ 604,998	$ (295,834)	$	$	(19,899)	$ 289,265

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006

1. ORGANIZATION AND PRESENTATION

Significant Relationships Referenced in Notes to Consolidated Financial Statements

References to we, us, our or ARLP Partnership mean the business and operations of Alliance Resource Partners, L.P., the parent company, as well as its consolidated subsidiaries.

References to ARLP mean Alliance Resource Partners, L.P., individually as the parent company, and not on a consolidated basis.

References to MGP mean Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., also referred to as our managing general partner.

References to SGP mean Alliance Resource GP, LLC, the special general partner of Alliance Resource Partners, L.P., also referred to as our special general partner.

References to Intermediate Partnership mean Alliance Resource Operating Partners, L.P., the intermediate partnership of Alliance Resource Partners, L.P., also referred to as our intermediate partnership.

References to Alliance Coal mean Alliance Coal, LLC, the holding company for the operations of Alliance Resource Operating Partners, L.P., also referred to as our operating subsidiary.

References to AHGP mean Alliance Holdings GP, L.P., individually as the parent company, and not on a consolidated basis.

References to AGP mean Alliance GP, LLC, the general partner of Alliance Holdings GP, L.P.

Organization

ARLP is a Delaware limited partnership listed on the NASDAQ Global Select Market under the ticker symbol ARLP. ARLP was formed in May 1999 to acquire, upon completion of ARLP s initial public offering on August 19, 1999, certain coal production and marketing assets of Alliance Resource Holdings, Inc., a Delaware corporation (ARH), consisting of substantially all of ARH s operating subsidiaries, but excluding ARH. ARH was previously owned by our current and former management. In June 2006, our special general partner, SGP, and its parent, ARH, became wholly-owned, directly and indirectly, by Joseph W. Craft, III, a director and the President and Chief Executive Officer of our managing general partner. SGP, a Delaware limited liability company, holds a 0.01% general partner interest in each of ARLP and the Intermediate Partnership. We have a time sharing agreement for the use of aircraft and we lease certain assets, including coal reserves and certain surface facilities, owned by SGP (Note 19).

We are managed by our managing general partner, MGP, a Delaware limited liability company, which holds a 0.99% and a 1.0001% managing general partner interest in ARLP and the Intermediate Partnership, respectively, and a 0.001% managing member interest in Alliance Coal.

AHGP is a Delaware limited partnership that was formed to become the owner and controlling member of MGP. AHGP completed its initial public offering (AHGP IPO) on May 15, 2006. AHGP owns directly and indirectly 100% of the members interest of MGP, the incentive distribution rights (IDR) in ARLP and 15,544,169 common units of ARLP.

The Delaware limited partnership, limited liability companies and corporation that comprise our subsidiaries are as follows: Intermediate Partnership, Alliance Coal, Alliance Design Group, LLC, Alliance Land, LLC, Alliance Properties, LLC, Alliance Resource Properties, LLC, (Alliance Resource Properties), Alliance Service, Inc. (Alliance Service), Backbone Mountain, LLC, Excel Mining, LLC (Excel), Gibson County Coal, LLC (Gibson County Coal), Gibson County Coal (South), LLC (Gibson South), Hopkins County Coal, LLC (Hopkins County Coal), Matrix Design Group, LLC (Matrix Design), MC Mining, LLC (MC Mining), Mettiki Coal, LLC (Mettiki (MD)), Mettiki Coal (WV), LLC (Mettiki (WV)), Mt. Vernon Transfer Terminal, LLC (Mt. Vernon), Penn Ridge Coal, LLC (Penn Ridge), Pontiki Coal, LLC (Pontiki), River View Coal, LLC (River View), Tunnel Ridge, LLC (Tunnel Ridge), Warrior Coal, LLC (Warrior), Webster County Coal, LLC (Webster County Coal), and White County Coal, LLC (White County Coal).

The accompanying consolidated financial statements include the accounts and operations of the ARLP Partnership and present our financial position as of December 31, 2008 and 2007, and results of our operations, cash flows and changes in partners capital for each of the three years in the period ended December 31, 2008. All of our intercompany transactions and accounts 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, 2008 and 2007, the estimated fair value of long-term debt, including current maturities, was approximately $362.8 million and $136.6 million, respectively (Note 9).

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. We had no restricted cash and cash equivalents at December 31, 2008 and had $2.0 million in restricted cash and cash equivalents at December 31, 2007, which were included in other assets in our consolidated balance sheets. The restricted cash and cash equivalents at December 31, 2007 were held in escrow and secured reclamation bonds.

Cash Management We presented book overdrafts of $10.0 million and $6.7 million at December 31, 2008 and 2007, respectively, in accounts payable in the consolidated balance sheets.

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, less a reserve for obsolete and surplus items.

Property, Plant and Equipment Expenditures which extend the useful lives of existing plant and equipment assets are capitalized. Maintenance and repairs that do not extend the useful life or increase productivity of the asset are charged to operating expense as incurred. Exploration expenditures are charged to operating expense as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves. 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 depletable lives for mineral rights range from 2 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 which equals estimated proven and probable reserves. Therefore, our mineral rights are depleted based on only proven and probable reserves derived in accordance with Industry Guide 7. At December 31, 2008 and 2007, land and mineral rights include $27.1 million and $12.2 million, respectively, representing the carrying value of coal reserves attributable to properties where we are not currently engaged in mining operations or leasing to third-parties, and therefore, the coal reserves are not currently being depleted. We believe 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 on a units of production method based on the estimated proven and probable reserves. Mine development costs represent costs incurred in establishing access to mineral reserves and include costs associated with sinking or driving shafts and underground drifts, permanent excavations, roads and tunnels. The end of the development phase and the beginning of the production phase takes place when construction of the mine for economic extraction is substantially complete. Coal extracted during the development phase is incidental to the mine s production capacity and is not considered to shift the mine into the production phase. Amortization of capitalized mine development is computed based on the estimated life of the mine and commences when production, other than production incidental to the mine development process, begins.

Long-Lived Assets We review 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 impairment is measured by the difference between the carrying value and the fair value of the asset. We have not recorded an impairment loss for any of the periods presented.

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Intangible Assets Costs allocated to contracts with covenants not to compete (Non-Compete Agreements) are amortized on a straight-line basis over the life of the Non-Compete Agreement. Amortization expense associated with Non-Compete Agreements was $0.5 million, $0.3 million and $38,000 for the years ending December 31, 2008, 2007 and 2006, respectively. Our Non-Compete Agreements are included in other assets on our consolidated balance sheets at December 31, 2008 and 2007. Our Non-Compete Agreements at December 31, are summarized as follows (in thousands):

	2008	2007
Non-Compete Agreements, original cost	$ 4,153	$ 4,153
Accumulated amortization	(851)	(372)
Non-Compete Agreements, net	$ 3,302	$ 3,781

Amortization expense related to Non-Compete Agreements is estimated to be $0.5 million per year in 2009-2010 and $0.4 million per year in 2011-2013.

Advance Royalties Rights to coal mineral leases are often acquired and/or maintained through advance royalty payments. Where royalty payments represent prepayments recoupable against future production, they are recorded as an asset, with amounts expected to be recouped within one year classified as a current asset. As mining occurs on these leases, the royalty prepayments are charged to operating expenses. We assess the recoverability of royalty prepayments based on estimated future production. Royalty prepayments estimated to be nonrecoverable are expensed.

Asset Retirement Obligations We record a liability for the estimated cost of future mine asset retirement and closing procedures on a present value basis when incurred and a corresponding amount 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. Examples of these types of costs, common to both types of mining, include, but are not limited to, removing or covering refuse piles and settling ponds, water treatment obligations, and dismantling preparation plants, other facilities and roadway infrastructure. Amortization of the related asset is recorded on a units of production method generally based upon the estimated life of the mine (Note 16).

Workers Compensation and Pneumoconiosis (Black Lung) Benefits We are generally self-insured for workers compensation benefits, including black lung benefits. We accrue a workers compensation liability for the estimated present value of workers compensation and black lung benefits based on our actuarial determined calculations (Note 17).

Income Taxes We are not a taxable entity for federal or state income tax purposes; the tax effect of our activities accrues to the unitholders. Although publicly traded partnerships as a general rule will be taxed as corporations, we qualify for an exemption because at least 90% of our 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 basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. Individual unitholders have different investment bases depending upon the timing and price of acquisition of their partnership units. Furthermore, each unitholder s tax accounting, which is partially dependent upon the unitholder s tax position, differs from the accounting followed in our consolidated financial statements. Accordingly, the aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder s tax attributes in our partnership is not available to us. Our subsidiary, Alliance Service, is subject to federal and state income taxes. Our tax counsel has provided an opinion that ARLP, the Intermediate Partnership and Alliance Coal will each be treated as a partnership. However, as is customary, no ruling has been or will be requested from the Internal Revenue Service (IRS) regarding our classification as a partnership for federal income tax purposes.

Revenue Recognition Revenues from coal sales are recognized when title passes to the customer as the coal is shipped. Some coal supply agreements provide for price adjustments based on variations in quality characteristics of the coal shipped. In certain cases, a customer s analysis of the coal quality is binding and the results of the analysis are received on a delayed basis. In these cases, we estimate the amount of the quality adjustment and adjust 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 transloading fees, administrative service revenues from our affiliates, mine safety

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services and products, rock dust sales and other handling and service fees. For 2007 and 2006, non-coal sales revenues included rental and service fees from third-party coal synfuel facilities, agreements related to these services expired on December 31, 2007 in conjunction with the expiration of non-conventional synfuel tax credits. These non-coal sales revenues are recognized as the services are performed. Transportation revenues are recognized in connection with us incurring the corresponding costs of transporting coal to customers through third-party carriers for which we are directly reimbursed through customer billings. We had no allowance for doubtful accounts for trade receivables at December 31, 2008 and 2007, respectively.

Pension Benefits Our defined benefit pension obligation and the related benefit cost are accounted for in accordance with Statement of Financial Accounting Standards (SFAS) No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)* and SFAS No. 87, *Employers Accounting for Pensions*. Pension cost and obligations are actuarially determined and are affected by assumptions including expected return on plan assets, discount rates, compensation increases, employee turnover rates and health care cost trend rates. We evaluate our assumptions periodically and make adjustments to these assumptions and the recorded liability as necessary (Note 13).

Common Unit-Based Compensation We account for compensation expense attributable to non-vested restricted common units granted under the Long-Term Incentive Plan (LTIP) based on requirements of SFAS No. 123R, *Share-Based Payment*. Accordingly, the fair value of award grants are determined on the grant date of the award and this value is recognized as compensation expense on a pro-rata basis, as appropriate over the requisite service period, and the corresponding liability is classified as equity and included in Limited Partners Capital in the consolidated financial statements (Note 14).

Net Income Per Unit Basic net income per limited partner unit is determined by dividing Limited Partners interest in net income by the weighted average number of outstanding common units and subordinated units. In periods when our aggregate net income exceeds the aggregate distributions to our limited and general partners, Emerging Issues Task Force Issue (EITF) No. 03-6, *Participating Securities and the Two-Class Method under FASB Statement No. 128*, requires us to present earnings per unit as if all of the earnings for the periods were distributed (Note 12). Diluted net income per unit is based on the combined weighted average number of common units and common unit equivalents outstanding, which primarily include restricted units granted under the LTIP (Note 14). On January 1, 2009, we will adopt the provisions of EITF No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships.* The adoption of EITF No. 07-4 will impact our presentation of earnings per unit in periods when our aggregate net income exceeds the aggregate distributions because undistributed earnings will no longer be allocated to the IDR holder since our partnership agreement contractually limits our distributions to available cash.

New Accounting Standards Issued and Adopted In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, *Fair Value Measurements*. This standard defines fair value, establishes a framework for measuring fair value in accounting principles generally accepted in the U.S., and expands disclosure about fair value measurements. SFAS No. 157 applies under other accounting standards that require or permit fair value measurements. Accordingly, this statement does not require any new fair value measurement. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 with the exception of nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value on a nonrecurring basis for which the requirements of SFAS No. 157 have been deferred by the FASB for one year. The adoption of SFAS No. 157 on January 1, 2008 did not have a material impact on our consolidated financial statements (Note 9).

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. SFAS No. 159 allows entities to choose to measure at fair value financial instruments and certain other eligible items which are not otherwise currently required to be measured at fair value. Under SFAS No. 159, the decision to measure items at fair value is made at specified election dates on an irrevocable instrument-by-instrument basis. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We have not elected to present any of our financial assets or liabilities currently recorded on our consolidated balance sheet at fair value under SFAS No. 159; therefore, the adoption of SFAS No. 159 on January 1, 2008 did not have a material impact on our consolidated financial statements.

New Accounting Standards Issued and Not Yet Adopted In December 2007, the FASB issued SFAS No. 141R, *Business Combinations*. SFAS No. 141R applies to all business combinations and establishes guidance for recognizing and measuring identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree and goodwill. Most of these items are recognized at their full fair value on the acquisition date, including acquisitions where the acquirer obtains control but less than 100% ownership in the acquiree. SFAS No. 141R also requires expensing restructuring and acquisition-related costs as incurred and establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. SFAS No. 141R is effective for business combinations with an acquisition date in fiscal years beginning after December 15, 2008. We are currently evaluating the changes provided in this statement; however, we do not expect the adoption of SFAS No. 141R on January 1, 2009 to impact our historical consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements*, which establishes accounting and reporting standards for noncontrolling ownership interests in subsidiaries. Noncontrolling ownership interests in consolidated subsidiaries will be presented in the consolidated balance sheet within partners capital as a separate component from the parent s equity. Consolidated net income will now include earnings attributable to both the parent and the noncontrolling interests. Earnings per share will continue to be based on earnings attributable to only the parent company and does not change upon adoption of SFAS No. 160. SFAS No.160 provides guidance on accounting for changes in the parent s ownership interest in a subsidiary, including transactions where control is retained and where control is relinquished. SFAS No. 160 also requires additional disclosure of information related to amounts attributable to the parent for income from continuing operations, discontinued operations and extraordinary items and reconciliations of the parent and noncontrolling interests equity of a subsidiary. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008. The Statement will be applied prospectively to transactions involving noncontrolling interests, including noncontrolling interests that arose prior to the effective date, as of the beginning of the fiscal year it is initially adopted. However, the presentation of noncontrolling interests within partners capital and the inclusion of earnings attributable to the noncontrolling interests in consolidated net income requires retrospective application to all periods presented. We do not anticipate the adoption of SFAS No. 160 on January 1, 2009 to have a material impact on our consolidated financial statements.

In March 2008, the FASB issued EITF No. 07-4, which considers whether the IDR of a master limited partnership represents a participating security when considered in the calculation of earnings per unit under the two-class method. The EITF considers whether the partnership agreement contains any contractual limitations concerning distributions to IDR holders that would impact the amount of earnings to allocate to the IDR holders for each reporting period. If distributions are contractually limited to the IDR holders share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the IDR holders. In addition, the EITF presents alternative methods for inclusion of IDR in the earnings per unit computation. When cash distributions exceed net income for the period, net income should be reduced by the distributions made to the holders of the general partner interest, the holder of the limited partner interest and IDR holders for the period. The provisions of EITF No. 07-4 are effective for fiscal years beginning after December 15, 2008. We expect the adoption of EITF No. 07-4 will impact our presentation of earnings per unit. We currently present earnings per unit as though all earnings were distributed each quarter (Note 12). Under the new guidance of EITF No. 07-4, we believe our partnership agreement contractually limits our distributions to available cash and therefore undistributed earnings will no longer be allocated to the IDR holder upon adoption of EITF No. 07-4 effective January 1, 2009.

In June 2008, the FASB issued Staff Position (FSP) No. EITF No. 03-6-1 *Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities*. This FSP affects entities that accrue cash dividends on share-based payment awards during the awards service period when the dividends do not need to be returned if the employees forfeit the award. The FSP requires that all outstanding unvested share-based payment awards that contain rights to nonforfeitable dividends participate in undistributed earnings with common shareholders and are considered participating securities. Because the awards are considered participating securities, the issuing entity is required to apply the two-class method of computing basic and diluted earnings per share. The provisions of FSP No. EITF No. 03-6-1 are effective for fiscal years beginning after December 15, 2008. We do not anticipate the adoption of FSP No. EITF 03-6-1, on January 1, 2009, to have a material impact on our basic and diluted earnings per unit.

3. ACQUISITIONS

SGP Land Acquisition

On January 28, 2008, effective January 1, 2008, we acquired, through our subsidiary Alliance Resource Properties, additional rights to approximately 48.2 million tons of coal reserves located in western Kentucky from SGP Land, LLC (SGP Land). SGP Land is a subsidiary of our special general partner and is indirectly owned by Mr. Craft. Because the acquisition was between entities under common control, it was accounted for at historical cost. At the time of our acquisition, these reserves were leased by SGP Land to our subsidiaries, Webster County Coal, Warrior and Hopkins County Coal through mineral leases and sublease agreements, pursuant to which we had paid advance royalties of approximately $8.0 million that had not yet been recouped against production royalties. Those mineral leases and sublease agreements between SGP Land and our subsidiaries were assigned to Alliance Resource Properties by SGP Land in this transaction. The recoupable balances of advance minimum royalties and other payments at the time of this acquisition, other than $0.4 million paid to the base lessors, were eliminated upon consolidation of the Partnership s financial statements. The purchase price of $13.3 million cash paid at closing was primarily attributable to the historical cost basis of the mineral rights included in property, plant and equipment. We financed this acquisition using a combination of existing cash on hand and borrowings under our revolving credit facility.

Illinois Basin Reserve Acquisition

In June 2007, we acquired through our subsidiary, Alliance Resource Properties, the rights to approximately 78.4 million tons of high-sulfur coal reserves in Webster and Hopkins County, Kentucky from Island Creek Coal Company, a subsidiary of Consol Energy, Inc. The purchase price of $53.3 million cash paid at closing was primarily allocated to owned and leased coal rights. We financed the purchase using a combination of existing cash on hand and borrowings under our revolving credit facility. We are mining these reserves from our adjacent Dotiki and Warrior mining complexes. As a result of the purchase, we reclassified 8.4 million tons of high-sulfur, non-reserve coal deposits as reserves. This acquisition represented an approximate 14% increase in our reserves at the acquisition date. During 2008, we received a return of purchase price of $1.1 million due to title failures on a portion of these coal reserves and consequently, we reduced the cost basis in these coal reserves.

River View Coal, LLC

In April 2006, we acquired River View for approximately $1.65 million from ARH, which at the time of our acquisition was owned by our current and former management, including majority shareholder Mr. Craft, President and Chief Executive Officer of our managing general partner. At the time of this acquisition, our managing general partner was owned jointly by Alliance Management Holdings, LLC (AMH) and AMH II, LLC (AMH II), and Mr. Craft was the majority owner and sole director of each of AMH and AMH II. Prior to our acquisition of River View, it had the right to purchase certain assets, including additional coal reserves, surface properties, facilities and permits from an unrelated party, for $4.15 million plus an overriding royalty on all coal mined and sold by River View from certain of the leased properties included in the assets. In a separate transaction in April 2006, immediately subsequent to our acquisition of River View, River View purchased these assets from the unrelated party and assumed initial asset retirement obligations of $2.9 million. After the completion of this purchase, River View controlled, through coal leases or direct ownership, approximately 105.4 million tons of high-sulfur coal reserves in the No. 7, No. 9 and No. 11 coal seams, located in Union County, Kentucky. As a result of these acquisitions, we recorded assets of $8.7 million, offset by the fair value of the initial asset retirement obligation of approximately $2.9 million.

The SGP Land and River View transactions described above were related-party transactions and, as such, were reviewed by the board of directors of our managing general partner (Board of Directors) and its conflicts committee (Conflicts Committee). Based upon these reviews, the Conflicts Committee determined that the transactions reflected market-clearing terms and conditions customary in the coal industry. As a result, the Board of Directors and its Conflicts Committee approved the SGP Land and River View transactions as fair and reasonable to us and our limited partners. Because the SGP Land and River View acquisitions were between entities under common control, they were accounted for at historical cost.

4. MC MINING MINE FIRE

On June 18, 2007, we agreed to a full and final resolution of our insurance claims relating to a mine fire that occurred on or about December 25, 2004 at our MC Mining s Excel No. 3 mine. This resolution included settlement of all expenses, losses and claims we incurred for the aggregate amount of $31.6 million, inclusive of $8.2 million of various deductibles and co-insurance, netting to $23.4 million of insurance proceeds paid to us. In 2006 and 2005, we received partial advance payments on the claims totaling $16.2 million, part of which we recognized as an offset to operating expenses ($0.4 million and $10.7 million in the three months ended March 31, 2006 and the year ended December 31, 2005, respectively), with the remaining $5.1 million of partial payments previously included in other current liabilities pending final claim resolution. In June 2007, as a result of this final resolution, we received additional cash payments of $7.2 million and recognized a net gain from insurance settlement of approximately $11.5 million, as well as a reduction in operating expenses of approximately $0.8 million. In May 2008, we realized a $2.8 million gain on settlement of our claim against the third-party that provided security services at the time of the fire.

5. INVENTORIES

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

	2008	2007
Coal	$ 9,186	$ 12,660
Supplies (net of reserve for obsolescence of $1,332 and $1,233, respectively)	17,324	13,440
Total inventory	$ 26,510	$ 26,100

6. PROPERTY, PLANT AND EQUIPMENT

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

	2008	2007
Mining equipment and processing facilities	$ 660,636	$ 627,712
Land and mineral rights	116,881	91,240
Buildings, office equipment and improvements	120,296	109,624
Construction in progress	73,479	13,341
Mine development costs	113,922	106,293
Property, plant and equipment, at cost	1,085,214	948,210
Less accumulated depreciation, depletion and amortization	(468,784)	(427,572)
Total property, plant and equipment, net	$ 616,430	$ 520,638

Equipment leased by us under lease agreements which are determined to be capital leases are stated at an amount equal to the present value of the minimum lease payments during the lease term, less accumulated amortization. Equipment under capital leases totaling $1.9 million included in mining equipment and processing facilities is amortized on the straight-line method over the shorter of its useful life or the related lease term. The provision for amortization of leased properties is included in depreciation, depletion and amortization expense. Accumulated amortization related to our capital lease was $0.6 million and $0.3 million as of December 31, 2008 and 2007, respectively, and amortization expense was $0.3 million, $0.2 million and $0.1 million for the years ended December 31, 2008, 2007, and 2006 respectively.

7. GIBSON RAIL ADVANCES

In 2007, our subsidiary, Gibson County Coal entered into contracts with CSX Transportation, Inc. (CSX) and Norfolk Southern Railway Company (NS), pursuant to which Gibson County Coal constructed a rail loop and the railroads constructed connections and siding facilities, in order to provide Gibson County Coal access to CSX and NS railways. Although these connections and siding facilities are assets of the respective rail companies, Gibson County Coal advanced $8.2 million on a combined basis to CSX and NS during 2007 toward the cost of construction of their infrastructure. In 2008, advances of $2.2 million were repaid to Gibson County Coal by rebates from CSX and NS as coal was shipped on their respective railways. The $6.0 million and $8.2 million of advances not yet repaid as of December 31, 2008 and 2007, respectively, are recorded in other receivables and other long-term assets in our consolidated balance sheet. Gibson County Coal also received additional rebates from both CSX and NS that were not recoupment of advances.

8. LONG-TERM DEBT

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

	2008	2007
Credit facility	$	$ 28,000
Senior notes	108,000	126,000
Series A senior notes	205,000	
Series B senior notes	145,000	
	458,000	154,000
Less current maturities	(18,000)	(18,000)
Total long-term debt	$ 440,000	$ 136,000

Credit Facility. On September 25, 2007, our Intermediate Partnership entered into a $150.0 million revolving credit facility (ARLP Credit Facility), which matures in 2012. Borrowings under the ARLP Credit Facility bear interest based on a floating base rate plus an applicable margin. The applicable margin is based on a leverage ratio of our Intermediate Partnership, as computed from time to time. For London Interbank Offered Rate (LIBOR) borrowings, the applicable margin under the ARLP Credit Facility ranges from 0.625% to 1.150% over LIBOR. Outstanding letters of credit reduce amounts available under the ARLP Credit Facility. At December 31, 2008, we had $13.9 million of letters of credit outstanding with $136.1 million available for borrowing under the ARLP Credit Facility. We had no borrowings outstanding under the ARLP Credit Facility at December 31, 2008. We incur an annual commitment fee of 0.175% on the undrawn portion of the ARLP Credit Facility.

Lehman Commercial Paper, Inc. (Lehman), a subsidiary of Lehman Brothers Holding, Inc., holds a 5%, or $7.5 million, commitment in our $150 million ARLP Credit Facility. The ARLP Credit Facility is underwritten by a syndicate of twelve financial institutions including Lehman, with no individual institution representing more than 11.3% of the $150 million revolving credit facility. Lehman filed for protection under Chapter 11 of the Federal Bankruptcy Code in early October 2008. Although we have not made any borrowing requests since the bankruptcy filing by Lehman, we do not know if Lehman could, or would, fund its share of the commitment if requested. In the event Lehman, or any other financial institution in our syndicate, does not fund our future borrowing requests, our borrowing available under the ARLP Credit Facility could be reduced. The obligations of the lenders under our credit facility are individual obligations, and the failure of one or more lenders does not relieve the remaining lenders of their funding obligations.

Senior Notes. Our Intermediate Partnership has $108.0 million principal amount of 8.31% senior notes due August 20, 2014, payable in six remaining equal annual installments of $18.0 million with interest payable semi-annually (Senior Notes).

Series A Senior Notes. On June 26, 2008, our Intermediate Partnership entered into a Note Purchase Agreement (the 2008 Note Purchase Agreement) with a group of institutional investors in a private placement offering. We issued $205.0 million of Series A Senior Notes, which bear interest at 6.28% and mature on June 26, 2015 with interest payable semi-annually.

Series B Senior Notes. On June 26, 2008, we issued under the 2008 Note Purchase Agreement $145.0 million of Series B Senior Notes, which bear interest at 6.72% and mature on June 26, 2018 with interest payable semi-annually.

The proceeds from the Series A and Series B Senior Notes (collectively, the 2008 Senior Notes) were used to repay $21.5 million outstanding under the ARLP Credit Facility and pay expenses associated with the offering of the 2008 Senior Notes. The remaining proceeds will be used to fund the development of the River View and Tunnel Ridge mining complexes and for other general working capital requirements. We incurred debt issuance costs of approximately $1.7 million associated with the 2008 Senior Notes, which have been deferred and are being amortized as a component of interest expense over the term of the respective notes.

The ARLP Credit Facility, Senior Notes and 2008 Senior Notes (collectively, the ARLP Debt Arrangements) are guaranteed by all of the direct and indirect subsidiaries of our Intermediate Partnership. The ARLP Debt Arrangements

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contain various covenants affecting our Intermediate Partnership and its subsidiaries restricting, among other things, the amount of distributions by our Intermediate Partnership, the incurrence of additional indebtedness and liens, the sale of assets, the making of investments, the entry into mergers and consolidations and the entry into transactions with affiliates, in each case subject to various exceptions. The ARLP Debt Arrangements also require the Intermediate Partnership to remain in control of a certain amount of mineable coal reserves relative to its annual production. In addition, the ARLP Debt Arrangements require our Intermediate Partnership to comply with certain financial ratios, including a maximum leverage ratio and a minimum interest coverage ratio. We were in compliance with the covenants of the ARLP Debt Arrangements as of December 31, 2008.

Other. We maintain agreements with two banks to provide additional letters of credit in an aggregate amount of $31.0 million to maintain surety bonds to secure certain asset retirement obligations and our obligations for workers compensation benefits. At December 31, 2008, we had $29.0 million in letters of credit outstanding under these agreements. Our special general partner guarantees $5.0 million of these outstanding letters of credit (Note 19).

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

Year Ending December 31,	
2009	$ 18,000
2010	18,000
2011	18,000
2012	18,000
2013	18,000
Thereafter	368,000
	$ 458,000

9. FAIR VALUE MEASUREMENTS

Effective January 1, 2008, we adopted SFAS No. 157, *Fair Value Measurements,* which, among other things, defines fair value, requires enhanced disclosures about assets and liabilities carried at fair value and establishes a hierarchal disclosure framework based upon the quality of inputs used to measure fair value. We have elected to defer the application of SFAS No. 157 to nonfinancial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis until our fiscal year beginning January 1, 2009, as permitted by FASB Staff Position No. Financial Accounting Standard 157-2. As a result of this deferral, we have not applied the provisions of SFAS No. 157 to asset retirement obligations initially measured at fair value.

Valuation techniques are based upon observable and unobservable inputs. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect our own market assumptions. These two types of inputs create the following fair value hierarchy:

Level 1 Quoted prices for identical instruments in active markets.

Level 2 Quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model derived valuations whose inputs are observable or whose significant value drivers are observable.

Level 3 Instruments whose significant value drivers are unobservable.

We account for our workers compensation and long-term disability liabilities at fair value based on the estimated present value of current workers compensation and long-term disability benefits using our actuarial estimates. Our actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including development patterns, mortality, medical costs and interest rates and, therefore, are considered Level 3 inputs.

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The following table provides a summary of changes in fair value of our Level 3 workers compensation and long-term disability liabilities (included in other current and long-term liabilities) for the year ended December 31, 2008 (in thousands):

	Balance December 31, 2007	Accruals Increase/ (Decrease)	Payments	Interest Accretion	Valuation Changes (Gain)/ Loss	Balance December 31, 2008
Workers compensation liability	$ 51,619	16,864	(11,653)	3,059	(3,218)	$ 56,671
Long-term disability liability	2,791	(406)	(163)	184	79	2,485

Valuation changes gain/loss related to the workers compensation and the long-term disability liabilities primarily represent valuation changes attributable to changes in the estimated liability for benefits associated with prior years or due to changes in interest rates and are recorded in operating expenses in our condensed consolidated statement of income.

At December 31, 2008 and 2007, respectively, the estimated fair value of our fixed rate term debt was $362.8 million and $136.6 million, respectively, based on interest rates that we believe are currently available to us for issuance of debt with similar terms and remaining maturities. The increase in fair value of total debt during the year ended December 31, 2008 primarily reflects the issuance by our Intermediate Partnership of the 2008 Senior Notes aggregating $350 million in principal amount on June 26, 2008 (Note 8).

SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities,* provides a fair value option election that allows companies to irrevocably elect fair value as the initial and subsequent measurement attribute for certain financial assets and liabilities not currently accounted for at fair value under other applicable accounting guidance. As of January 1, 2008, we have not elected to present any of our financial assets or liabilities currently recorded on our condensed consolidated balance sheet at fair value under SFAS No. 159.

10. DISTRIBUTIONS OF AVAILABLE CASH

We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partners. Available cash is generally defined in the partnership agreement as all cash and cash equivalents on hand at the end of each quarter less reserves established by our managing general partner in its reasonable discretion for future cash requirements. These reserves are retained to provide for the conduct of our 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 distribution levels as established in our partnership agreement, our managing general partner receives 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 per unit ($1.00 per unit on an annual basis). The target distribution levels are based on the amounts of available cash from our operating surplus distributed for a given quarter that exceed the MQD and common unit arrearages, if any.

Under the quarterly IDR provisions of our 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. For the years ended December 31, 2008, 2007 and 2006, we allocated to our managing general partner incentive distributions of $45.3 million, $30.4 million and $21.6 million, respectively. The following table summarizes the quarterly per unit distribution paid during the respective quarter.

		Year	
	2008	2007	2006
First Quarter	$ 0.585	$ 0.54	$ 0.46
Second Quarter	$ 0.585	$ 0.54	$ 0.46
Third Quarter	$ 0.660	$ 0.56	$ 0.50
Fourth Quarter	$ 0.700	$ 0.56	$ 0.50

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On January 28, 2009, we declared a quarterly distribution of $0.715 per unit, totaling approximately $39.8 million (which includes our managing general partner s incentive distributions), on all our common units outstanding, which was paid on February 13, 2009, to all unitholders of record on February 6, 2009.

11. INCOME TAXES

Our subsidiary, Alliance Service, is subject to federal and state income taxes. Alliance Service s income in 2007 and 2006 consists primarily of rental and service fees provided to an independent coal synfuel producer at Warrior. In September 2006, Alliance Service purchased assets from Matrix Design Group, Inc. through Matrix Design, a newly formed wholly-owned subsidiary. Alliance Service has minor temporary differences between Matrix Design s financial reporting basis and the tax basis of its assets and liabilities. Our adoption of FASB Interpretation (FIN) No. 48 on January 1, 2007 did not have a material impact on the consolidated financial statements and does not impact our financial position at December 31, 2008. Components of income tax expense (benefit) are as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Current:			
Federal	$ (312)	$ 1,467	$ 2,070
State	(30)	276	399
	(342)	1,743	2,469
Deferred:			
Federal	(109)	(61)	(21)
State	(29)	(13)	(5)
	(138)	(74)	(26)
Income tax expense (benefit)	$ (480)	$ 1,669	$ 2,443

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

	Year Ended December 31,		
	2008	2007	2006
Income taxes at statutory rate	$ 46,940	$ 59,921	$ 61,101
Less: Income taxes at statutory rate on Partnership income not subject to income taxes	(47,402)	(58,420)	(58,923)
Increase/(decrease) resulting from:			
State taxes, net of federal income tax	(6)	183	318
Other	(12)	(15)	(53)
Income tax expense (benefit)	$ (480)	$ 1,669	$ 2,443

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 our aggregate net income exceeds the aggregate distributions to unitholders for such period, we are required to present earnings per unit as if all of the earnings for the period 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 does not impact our aggregate distributions to unitholders for any period, but it can have the impact of reducing our earnings per limited partner unit. This result

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occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the IDR held by our managing general partner, even though we make cash distributions on the basis of cash available for distributions to unitholders, not earnings, in any given accounting period. In accounting periods where aggregate net income does not exceed our aggregate distributions for such periods, EITF No. 03-6 does not have any impact on our earnings per unit calculation.

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

	Year Ended December 31,		
	2008	2007	2006
Net income	$ 134,176	$ 170,390	$ 172,927
Adjustments:			
General partner s priority distributions	(45,326)	(30,390)	(21,567)
General partners 2% equity ownership	(1,806)	(2,838)	(3,027)
General partners special allocation of certain general and administrative expenses	1,435	1,918	
Limited partners interest in net income	88,479	139,080	148,333
Additional earnings allocation to general partners		(27,009)	(36,937)
Net income available to limited partners under EITF No. 03-6	$ 88,479	$ 112,071	$ 111,396
Weighted average limited partner units basic	36,605	36,548	36,425
Basic net income per limited partner unit	$ 2.42	$ 3.07	$ 3.06
Weighted average limited partner units basic	36,605	36,548	36,425
Units contingently issuable:			
Restricted units for Long-Term Incentive Plan	155	135	231
Directors compensation units	3	33	42
Supplemental Executive Retirement Plan	7	84	112
Weighted average limited partner units, assuming dilutive effect of restricted units	36,770	36,800	36,810
Diluted net income per limited partner unit	$ 2.41	$ 3.05	$ 3.03

Our 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 special income or expense allocations, including incentive distributions to our managing general partner, the holder of the IDR pursuant to our partnership agreement, which are declared and paid following the close of each quarter (Note 10). During 2008 and 2007 our managing general partner made capital contributions of $1.4 million and $1.9 million, respectively, to us to fund certain expenses associated with our employee compensation programs. A special allocation of certain general and administrative expenses equal to the amount of our managing general partner s contribution was made to our managing general partner. Net income allocated to the limited partners was not burdened by this expense (Note 19). For purposes of computing basic and diluted net income per limited partner unit, in periods when our aggregate net income exceeds the aggregate distributions to unitholders for such periods, an increased amount of net income is allocated to the general partners for the additional pro forma priority income attributable to the application of EITF No. 03-6.

Effective January 1, 2009, we will adopt the provisions of EITF No. 07-4. The EITF considers whether the partnership agreement contains any contractual limitations concerning distributions to IDR holders that would impact the amount of earnings to allocate to the IDR holders for each reporting period. If distributions are contractually limited to the IDR holders share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the IDR holders. We believe our partnership agreement contractually limits our distribution to available cash and therefore, undistributed earnings will no longer be allocated to the IDR holder upon adoption of EITF No. 07-4. Accordingly, the adoption of EITF No. 07-4 will impact our presentation of earnings per unit in periods when our aggregate net income exceeds the aggregate distributions because undistributed earnings will no longer be allocated to the IDR holder.

On January 29, 2008 the compensation committee of the Board of Directors (Compensation Committee) approved amendments to the Deferred Compensation Plan for Directors and Supplemental Executive Retirement Plan (SERP) to require that vested benefits be paid to participants in cash only, rather than a combination of cash and/or common units of ARLP. As a result, the dilutive effect of phantom units associated with these plans is no longer considered in the calculation of diluted units effective January 29, 2008.

13. EMPLOYEE BENEFIT PLANS

Defined Contribution Plans Our employees currently participate in a defined contribution profit sharing and savings plan (PSSP) that we sponsor. 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. We make matching contributions based on a percent of an employee s eligible compensation and for certain subsidiaries, make an additional nonmatching contribution, based on an employee s eligible compensation. Additionally, we contribute a defined percentage of eligible compensation for certain employees not covered by the defined benefit plan described below. Our expense for this plan was approximately $8.0 million, $5.6 million and $4.6 million for the years ended December 31, 2008, 2007 and 2006, respectively. The increase from 2007 to 2008 was primarily attributable to a greater number of PSSP participants principally due to changes in the defined benefit plan (the Pension Plan) described below and higher salaries and wages included in the matching calculation.

Defined Benefit Plans Employees at certain of our mining operations participate in a Pension Plan that we sponsor. The benefit formula for the Pension Plan is a fixed dollar unit based on years of service. Effective during 2008, new employees of some of these participating operations are no longer eligible to participate in the Pension Plan, but are eligible to participate in the PSSP that we sponsor. Additionally, certain employees participating in the Pension Plan, for some of those participating operations, had the one-time option during 2008 to remain in the Pension Plan or participate in enhanced benefit provisions under the PSSP. The impact of the amended Pension Plan was not material to the 2008 consolidated financial statements.

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The following sets forth changes in benefit obligations and plan assets for the years ended December 31, 2008 and 2007 and the funded status of the Pension Plan reconciled with the amounts reported in our consolidated financial statements at December 31, 2008 and 2007, respectively (dollars in thousands):

	2008	2007
Change in benefit obligations:		
Benefit obligations at beginning of year	$ 39,648	$ 41,229
Service cost	2,555	3,435
Interest cost	2,726	2,267
Actuarial (gain)/loss	5,467	(6,616)
Benefits paid	(763)	(667)
Benefit obligation at end of year	49,633	39,648
Change in plan assets:		
Fair value of plan assets at beginning of year	41,647	35,038
Employer contribution		4,400
Actual return on plan assets	(11,203)	2,876
Benefits paid	(763)	(667)
Fair value of plan assets at end of year	29,681	41,647
Funded status at the end of year	$ (19,952)	$ 1,999
Amounts recognized in balance sheet:		
Non-current asset	$	$ 1,999
Non-current liability	(19,952)	
	$ (19,952)	$ 1,999
Amounts recognized in accumulated other comprehensive income consists of:		
Net actuarial gain (loss)	$ (19,899)	$ 109
Weighted-average assumptions as of December 31,		
Discount rate	6.15%	6.65%
Expected rate of return on plan assets	8.35%	8.35%
Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31,		
Discount rate	6.70%	5.55%
Expected return on plan assets	8.35%	7.75%
Weighted-average asset allocations as of December 31,		
Equity securities	58%	71%
Fixed income securities	35%	24%
Cash and cash equivalents	7%	5%
	100%	100%

2008	2007	2006

Components of net periodic benefit cost:			
Service cost	$ 2,555	$ 3,435	$ 3,224
Interest cost	2,726	2,268	1,949
Expected return on plan assets	(3,368)	(2,687)	(2,285)
Prior service cost			42
Net loss	30	258	313
Net periodic benefit cost	$ 1,943	$ 3,274	$ 3,243

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	2008	2007
Other changes in plan assets and benefit obligation recognized in accumulated other comprehensive income		
Net actuarial (gain) loss	$ 20,038	$ (6,807)
Reversal of amortization item:		
Net actuarial (gain) loss	(30)	(258)
Total recognized in accumulated other comprehensive income	20,008	(7,065)
Net periodic benefit cost	1,943	3,274
Total recognized in net periodic benefit cost and accumulated other comprehensive income	$ 21,951	$ (3,791)

Estimated future benefit payments as of December 31, 2008 are as follows (in thousands):

Year Ending December 31,	
2009	$ 1,132
2010	1,353
2011	1,589
2012	1,837
2013	2,094
2014-2017	14,374
	$ 22,379

The actuarial loss component of the change in benefit obligations for 2008 was primarily attributable to negative returns in asset values during 2008. The actuarial gain component of the change in benefit obligation for 2007 was primarily attributable to changes in the discount rate assumptions. We expect to contribute $10.6 million to the Pension Plan in 2009. The estimated net actuarial loss for the Pension Plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost during the 2009 fiscal year is $1.4 million.

As permitted under FASB No. 87, *Employer s Accounting for Pensions*, the amortization of any prior service cost is determined using a straight-line amortization of the cost over the average remaining service period of employees expected to receive benefits under the Pension Plan.

The Compensation Committee 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 prudent manner based on the stated purpose of the Pension Plan and diversified among a broad range of investments including domestic equity securities and international equity securities, domestic fixed income securities and cash equivalents. The Policy Statement provides that the Pension Plan shall be funded by employer contributions in amounts determined in accordance with generally accepted actuarial standards.

The investment objectives as established by the Policy Statement are, first, to increase the value of the assets under the Pension Plan and, second, to control the level of risk or volatility of investment returns associated with Pension Plan investments. The investments shall be managed with the goal of ensuring that Pension Plan assets provide sufficient resources to meet or exceed benefit obligations as determined under the terms and conditions of the Pension Plan.

The Compensation Committee has selected an investment manager to implement the selection and on-going evaluation of Pension Plan investments. The investments shall be selected from the following assets classes including mutual funds, collective funds, or the direct investment in individual stocks, bonds or cash equivalent investments, including: (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 provides guidelines and limitations, subject to exceptions authorized by the Compensation Committee under unusual market conditions: (i) the maximum investment in any one stock should not exceed 10.0% of the total stock portfolio, (ii) the maximum investment in any one industry should not exceed 30.0% of the total stock portfolio, and (iii) the average credit quality of the bond portfolio should be at least AA with a maximum amount of non-investment grade debt of 10.0%.

The Policy Statement s current asset allocation guidelines are as follows:

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

The expected long-term rate of return assumption is based on broad equity and bond indices. The Pension Plan s expected long-term rate of return of 8.35% is determined by the above factors and an asset allocation assumption of 60.0% invested in domestic equity securities with an expected long-term rate of return of 10.6%, 10.0% invested in international equities with an expected long-term rate of return of 6.9% and 30.0% invested in fixed income securities with an expected long-term rate of return of 5.8%. The Pension Plan was established effective January 1, 1997 and our initial contribution to the Pension Plan was made in 1998.

14. COMPENSATION PLANS

We have the LTIP for certain of our employees and directors of our managing general partner and its affiliates who perform services for us. The LTIP awards are of non-vested restricted units, which upon satisfaction of vesting requirements entitle the LTIP participant to receive ARLP common units. Annual grant levels and vesting provisions for designated participants are recommended by our President and Chief Executive Officer, subject to the review and approval of the Compensation Committee. The aggregate number of units reserved for issuance under the LTIP was 1,200,000. Sponsorship of the LTIP was transferred to Alliance Coal effective May 15, 2006.

On January 29, 2008, the Compensation Committee determined that the vesting requirements for the 2005 grants of 92,730 restricted units (which is net of 21,660 forfeitures) had been satisfied as of January 1, 2008. As a result of this vesting, on February 21, 2008, we issued 62,799 unrestricted common units to LTIP participants. The remaining units were settled in cash to satisfy the tax withholding obligations for the LTIP participants. On January 29, 2008 and October 28, 2008, the Compensation Committee authorized additional grants of up to 100,000 and 152,445 restricted units, respectively.

During the three months ended December 31, 2008, the nine months ended September 30, 2008 and years ended December 31, 2007 and 2006, we issued grants of 141,145 units, 93,600 units, 93,475 units and 90,700 units, respectively, which vest on January 1, 2012, January 1, 2011, January 1, 2010 and January 1, 2009, respectively, subject to the satisfaction of certain financial tests that management currently believes will be satisfied. As of December 31, 2008, 23,225 of these outstanding LTIP grants have been forfeited. On January 27, 2009, the Compensation Committee determined that the vesting requirements for the 2006 grants of 71,975 restricted units (which is net of 18,725 forfeitures) had been satisfied as of January 1, 2009. As a result of this vesting, on February 12, 2009, we issued 47,571 unrestricted common units to the LTIP participants. The remaining units were settled in cash to satisfy the individual tax obligations of the LTIP participants. After consideration of the January 1, 2009 vesting and subsequent issuance of 47,571 common units, 7,420 units remain available for issuance in the future, assuming that all grants currently issued and outstanding for 2007 and 2008 are settled with common units and no future forfeitures occur.

For the years ended December 31, 2008, 2007 and 2006, our LTIP expense was $3.3 million, $2.9 million and $4.1 million, respectively. The total obligation associated with the LTIP as of December 31, 2008 and 2007 was $5.9 million and $6.0 million, respectively, and is included in partners capital-limited partners line item in our consolidated balance sheets.

The fair value of the 2008, 2007 and 2006 grants is based upon the intrinsic value at the date of grant, which were $31.27, $35.84 and $37.79 per restricted unit, respectively, on a weighted average basis. As required by SFAS No. 123R, the fair value was reduced for expected forfeitures, to the extent compensation expense had been previously recognized and we recorded a benefit of $112,000 upon adoption of SFAS No. 123R on January 1, 2006 as a cumulative effect of accounting change. We expect to settle the non-vested LTIP grants by delivery of ARLP common units, except for the portion of the grants that will satisfy the minimum statutory tax withholding requirements. As provided under the distribution equivalent rights provision of the LTIP, all non-vested grants include contingent rights to receive quarterly cash distributions in an amount equal to the cash distribution we make to unitholders during the vesting period.

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A summary of non-vested LTIP grants as of and for the year ended December 31, 2008 is as follows:

Non-vested grants at January 1, 2008	255,180
Granted	234,745
Vested	(92,730)
Forfeited	(1,500)
Non-vested grants at December 31, 2008	395,695

As of December 31, 2008, there was $6.8 million in total unrecognized compensation expense related to the non-vested LTIP grants that are expected to vest. That expense is expected to be recognized over a weighted-average period of 2.1 years. As of December 31, 2008, the intrinsic value of the non-vested LTIP grants was $10.6 million.

We have the SERP to provide deferred compensation benefits for certain officers and key employees. All allocations made to participants under the SERP are made in the form of phantom ARLP units. The SERP is administered by the Compensation Committee. Sponsorship of the SERP was transferred to Alliance Coal effective May 15, 2006.

For the years ended December 31, 2008, 2007 and 2006, our SERP expense (income) was $(0.5) million, $0.4 million and $0.1 million, respectively. The SERP income for the year ended December 31, 2008 resulted from lower unit based compensation accruals due to a decrease in market value of our common units from the beginning of the year to the end of the year. During 2007 we made cash distributions from the SERP totaling $1.5 million to three former executive officers that retired. The total accrued liability associated with the SERP plan was $2.6 million and $3.1 million as of December 31, 2008 and 2007, respectively, and is included in other long-term liabilities in the consolidated balance sheets.

15. SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2008	**2007**	**2006**
		(in thousands)	
Cash Paid For:			
Interest	$ 22,920	$ 13,034	$ 13,760
Income taxes	$	$ 2,175	$ 2,400
Non-Cash Activity:			
Accounts payable for purchase of property, plant and equipment	$ 15,092	$ 5,046	$ 12,140
Non-cash contribution by General Partner	$ 620	$ 1,105	$
Market value of common units vested in Long-Term Incentive Plan before minimum statutory tax withholding requirements	$ 3,658	$ 6,674	$
Asset acquired by capital lease	$	$	$ 1,862

16. ASSET RETIREMENT OBLIGATIONS

The majority of our 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. We account for our asset retirement obligations in accordance with 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. We have estimated the costs and timing of future asset retirement obligations escalated for inflation, then discounted at a risk free rate ranging from 1.72% to 6.0% and recorded the present value of those estimates.

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Discounting resulted in reducing the accrual for asset retirement obligations by $65.2 million and $65.1 million at December 31, 2008 and 2007, respectively. Estimated payments of asset retirement obligations as of December 31, 2008 are as follows (in thousands):

Year Ending December 31,	
2009	$ 2,385
2010	4,512
2011	500
2012	284
2013	3,347
Thereafter	112,745
Aggregate undiscounted asset retirement obligations	123,773
Effect of discounting	(65,184)
Total asset retirement obligations	58,589
Less: current portion	(2,385)
Asset retirement obligations	$ 56,204

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

	Year ended December 31,	
	2008	**2007**
Beginning balance	$ 56,903	$ 50,895
Accretion expense	2,827	2,419
Payments	(1,414)	(617)
Allocation of liability associated with acquisition, mine development and change in assumptions	273	4,206
Ending balance	$ 58,589	$ 56,903

For the year ended December 31, 2008, the allocation of liability associated with acquisition, mine development and change in assumptions is a net increase of $0.3 million, and was primarily attributable to increased surface disturbances as a result of the new mine development work at River View and increased refuse site capacity at the Gibson County Coal and White County Coal operations, offset by reduced remaining liability estimates at Pontiki operations and a refuse site owned by Hopkins County Coal, as well as overall general changes in current estimates of the costs and scope of remaining reclamation work and fluctuations in projected mine life estimates for coal reserve increases and decreases. For the year ended December 31, 2007, the allocation of liability associated with acquisition, mine development and change in assumptions of $4.2 million was primarily attributable to revisions in the cost estimates for existing water treatment obligations associated with Mettiki (MD) of $2.4 million and to the expansion of permitted refuse disposal areas at Gibson County Coal and Pontiki of $1.4 million and $1.7 million, respectively, as well as general increases in estimated costs of reclamation work, offset by liability decreases at certain other operations resulting from mine life extensions due to coal reserve acquisitions. Accretion expense was $2.1 million for the year ended December 31, 2006.

17. ACCRUED WORKERS COMPENSATION AND PNEUMOCONIOSIS (BLACK LUNG) BENEFITS

Certain of our mine operating entities 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. In addition, we are liable for workers compensation benefits for traumatic injuries. Both black lung and traumatic claims are covered through our self-insured programs.

Our black lung benefits liability is calculated using the service cost method that considers the calculation of the actuarial present value of the estimated black lung obligation. Our actuarial calculations are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and interest rates. Actuarial gains or losses are amortized over the remaining service period of active miners.

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We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. Workers compensation laws also compensate survivors or workers who suffer employment related deaths. Our liability for traumatic injury claims is the estimated present value of current workers compensation benefits, based on our actuarial estimates. Our actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including development patterns, mortality, medical costs and interest rates. The discount rate used to calculate the estimated present value of future obligations for black lung was 5.89% and 6.38% at December 31, 2008 and 2007, respectively, and for workers compensation was 6.11% and 5.95% at December 31, 2008 and 2007, respectively.

The black lung and workers compensation expense consists of the following components for the year ended December 31, 2008, 2007 and 2006 (in thousands):

	2008	2007	2006
Black lung benefits:			
Service cost	$ 1,415	$ 2,027	$ 1,497
Interest cost	1,641	1,504	1,241
Net amortization	(745)	70	584
Total black lung	2,311	3,601	3,322
Workers compensation expense	18,395	17,192	21,242
Total expense	$ 20,706	$ 20,793	$ 24,564

The following is a reconciliation of the changes in black lung benefit obligations at December 31, 2008 and 2007 (in thousands):

	2008	2007
Benefit obligations at beginning of year	$ 30,047	$ 26,816
Service cost	1,415	2,027
Interest cost	1,641	1,504
Actuarial loss	(745)	70
Benefits and expense paid	(388)	(370)
Benefit obligations at end of year	$ 31,970	$ 30,047

Summarized below is information about the amounts recognized in the accompanying consolidated balance sheets for black lung and workers compensation benefits at December 31, 2008 and 2007 (in thousands):

	2008	2007
Black lung claims	$ 31,970	$ 30,047
Workers compensation claims	56,671	51,619
Total obligations	88,641	81,666
Less current portion	(9,377)	(8,124)
Non-current obligations	$ 79,264	$ 73,542

Both the black lung and workers compensation obligations were unfunded at December 31, 2008 and 2007.

As of December 31, 2008 and 2007, we had $54.8 million and $47.9 million, respectively, in surety bonds and letters of credit outstanding to secure workers compensation obligations.

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.

18. MINORITY INTEREST

In March 2006, White County Coal, and Alexander J. House (House) entered into a limited liability company agreement to form Mid-America Carbonates, LLC (MAC). MAC was formed to engage in the development and operation of a rock dust mill and to manufacture and sell rock dust. White County Coal initially invested $1.0 million in exchange for a 50% equity interest in MAC. We consolidate MAC s financial results in accordance with FIN No. 46R, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*. Based on the guidance in FIN No. 46R, we concluded that MAC is a variable interest entity and that we are the primary beneficiary. House s equity ownership in the net assets of MAC was $0.9 million and $0.5 million as of December 31, 2008 and 2007, respectively, which is recorded as minority interest on our consolidated balance sheet.

On March 19, 2007, MAC entered into a secured line of credit (LOC) which was scheduled to expire on March 19, 2008. In September 2007, MAC entered into a $1.5 million Revolving Credit Agreement (Revolver) with ARLP. Concurrent with the execution of the Revolver, MAC repaid all amounts outstanding under the LOC. By amendment effective April 1, 2008 the term of the Revolver was extended to June 30, 2009. Due to the consolidation of MAC in accordance with FIN 46R, the intercompany transactions associated with the Revolver are eliminated.

19. RELATED-PARTY TRANSACTIONS

The Board of Directors of our managing general partner and its Conflicts Committee review each of our related-party transactions to determine that each such transaction reflects market-clearing terms and conditions customary in the coal industry. As a result of these reviews, the Board of Directors and the Conflicts Committee approved each of the transactions described below as fair and reasonable to us and our limited partners.

Administrative Services In connection with the AHGP IPO in 2006, ARLP entered into an administrative services agreement, (Administrative Services Agreement), between our managing general partner, our Intermediate Partnership, AHGP and its general partner AGP, and Alliance Resource Holdings II, Inc. (ARH II), the indirect parent of SGP. Under the Administrative Services Agreement, certain employees, including some executive officers, provide administrative services to our managing general partner, AHGP, AGP, ARH II and their respective affiliates. We are reimbursed for services rendered by our employees on behalf of these affiliates as provided under the Administrative Services Agreement. We billed and recognized administrative service revenue under this agreement of $0.4 million, $0.3 million and $0.3 million for the years ended December 31, 2008 and 2007 and the period from May 15, 2006 to December 31, 2006, respectively, from AHGP and $0.5 million, $0.4 million and $0.6 million from ARH II for the years ended December 31, 2008 and 2007 and the period from May 15, 2006 to December 31, 2006, respectively. Concurrently in 2006, AHGP and AGP joined as parties to our Omnibus Agreement which addresses areas of non-competition between us and ARH, ARH II, SGP and our managing general partner.

Our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses incurred or payments made on behalf of us, including, but not limited to, management s salaries and related benefits (including incentive compensation), and accounting, budgeting, 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 $0.3 million, $0.9 million and $4.2 million for the years ended December 31, 2008, 2007 and 2006, respectively. The decrease from 2007 to 2008 was primarily attributable to lower unit based directors compensation accruals due to a decrease in market value of our common units from the beginning of the year compared to the end of the year. The decrease from 2006 to 2007 was attributable to certain employees and the sponsorship of the LTIP, Short-Term Incentive Plan (STIP) and SERP being transferred from our managing general partner to Alliance Coal effective May 15, 2006 in connection with the closing of AHGP s IPO. On May 15, 2006, our executive officers became employees of record of Alliance Coal, and we no longer reimburse our managing general partner for compensation expenses associated with them. The impact of the change in plan sponsorship resulted in a reduction in the billing to us from our managing general partner directly offset by a corresponding increase in LTIP, STIP and SERP expense of our Alliance Coal subsidiary.

Managing General Partner Contribution During 2008 and 2007, an affiliated entity controlled by Mr. Craft, contributed 25,898 and 50,980 AHGP common units, respectively, valued at approximately $0.6 million and $1.1 million, respectively, at the time of contribution and $0.8 million of cash for each of the years 2008 and 2007 to AHGP for the purpose of funding certain expenses associated with our employee compensation programs. Upon AHGP s receipt of this contribution, it immediately contributed the same to its subsidiary MGP, our managing general partner, which in turn contributed the same to our subsidiary Alliance Coal. Concurrent with this contribution, Alliance Coal distributed the 25,898 and 50,980 AHGP common units to certain employees and recognized compensation expense of $1.4 million and $1.9 million in 2008 and 2007, respectively. As provided under our partnership agreement, we made a special allocation to our managing general partner of certain general and administrative expenses equal to the amount of its contribution (Note 12).

SGP Land, LLC On May 2, 2007, SGP Land, a subsidiary of our special general partner controlled by Mr. Craft, entered into a time sharing agreement with Alliance Coal, our operating subsidiary, concerning the use of aircraft owned by SGP Land. In accordance with the provisions of the time sharing agreement as amended, we reimbursed SGP Land $0.7 million and $0.3 million for the years ended December 31, 2008 and 2007, respectively, for use of the aircraft.

On January 28, 2008, effective January 1, 2008, we acquired, through our subsidiary Alliance Resource Properties, additional rights to approximately 48.2 million tons of coal reserves located in western Kentucky from SGP Land. The purchase price was $13.3 million. At the time of our acquisition, these reserves were leased by SGP Land to our subsidiaries, Webster County Coal, Warrior and Hopkins County Coal through the mineral leases and sublease agreements described below. Those mineral leases and sublease agreements between SGP Land and our subsidiaries were assigned to Alliance Resource Properties by SGP Land in this transaction. The recoupable balances of advance minimum royalties and other payments at the time of this acquisition, other than $0.4 million to the base lessors, are eliminated in our consolidated financial statements as of December 31, 2008.

In 2000, Webster County Coal entered into 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 $2.7 million and $3.0 million for the years ended December 31, 2007 and 2006, respectively. As of December 31, 2007, Webster County Coal had recouped, against earned royalties otherwise due, all but $3.2 million of the advance minimum royalty payments made under the lease. As described above, this mineral lease and sublease is now with Alliance Resource Properties.

In 2001, Warrior entered into a mineral lease and sublease with SGP Land. Under the terms of the lease, Warrior paid in arrears an annual minimum royalty of $2.3 million until $15.9 million of cumulative annual minimum and/or earned royalty payments were paid. The annual minimum royalty periods expired on September 30, 2007. In 2006, Warrior s cumulative total of annual minimum royalties and/or earned royalty payments exceeded $15.9 million, and therefore the annual minimum royalty payment of $2.3 million was no longer required. Warrior paid royalties of $1.3 million and $5.1 million for the years ended December 31, 2007 and 2006, respectively. As of December 31, 2007, Warrior had recouped, against earned royalties otherwise due, all advance minimum royalty payments made in accordance with these lease terms. As described above, this mineral lease and sublease is now with Alliance Resource Properties.

In 2005, Hopkins County Coal entered into a mineral lease and sublease with SGP Land encompassing the Elk Creek reserves, and the parties also entered into a Royalty Agreement (collectively, the Coal Lease Agreements) in connection therewith. The Coal Lease Agreements extend through December 2015, with the right to renew for successive one-year periods for as long as Hopkins County Coal 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 $0.7 million beginning in December 2005. The annual minimum royalty payments, together with cumulative option fees of $3.4 million previously paid prior to December 2005 by Hopkins County Coal to SGP Land, are fully recoupable against future earned royalty payments. Hopkins County Coal paid to SGP Land advance minimum royalties and/or option fees of $0.7 million during each of the years ended December 31, 2007 and 2006, respectively. As of December 31, 2007, Hopkins County Coal had recouped against advance minimum royalties and/or option fees otherwise due all but $4.4 million paid under the Coal Lease Agreements. As described above, this mineral lease and sublease is now with Alliance Resource Properties.

Under the terms of the mineral lease and sublease agreements described above, Webster County Coal, Warrior, and Hopkins County Coal also reimburse SGP Land for its base lease obligations. We reimbursed SGP Land $6.1 million and $5.0 million for the years ended December 31, 2007 and 2006, respectively, for the base lease obligations. As of December 31, 2007, Webster County Coal, Warrior, and Hopkins County Coal had recouped, against earned royalties otherwise due base lessors by SGP Land, all advance minimum royalty payments paid by SGP Land to the base lessors in accordance with the terms of the base leases (and reimbursed by Webster County Coal, Warrior, and Hopkins County Coal), except for $0.4 million.

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 of $0.3 million until $6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. MC Mining paid royalties of $0.3 million during each of the years ended December 31, 2008, 2007 and 2006, respectively. As of December 31, 2008, $1.5 million of advance minimum royalties paid under the lease is available for recoupment, and management expects that it will be recouped against future production.

SGP In January 2005, we acquired Tunnel Ridge from ARH. In connection with this acquisition, we assumed a coal lease with the SGP. Under the terms of the lease, Tunnel Ridge has paid and will continue to pay an annual minimum royalty of $3.0 million until the earlier of January 1, 2033 or the exhaustion of the mineable and merchantable leased coal. Tunnel Ridge paid advance minimum royalties of $3.0 million during each of the years ended December 31, 2008, 2007 and 2006. As of December 31, 2008, $12.0 million of advance minimum royalties paid under the lease is available for recoupment and management expects that it will be recouped against future production.

Tunnel Ridge also controls surface land and other tangible assets under a separate lease agreement with the SGP. Under the terms of the lease agreement, Tunnel Ridge has paid and will continue to pay the SGP an annual lease payment of $0.2 million. The lease agreement has an initial term of four years, which may be extended to match the term of the coal lease. Lease expense was $0.2 million for each of the years ended December 31, 2008, 2007 and 2006, respectively.

We have a noncancelable operating lease arrangement with the SGP for the coal preparation plant and ancillary facilities at the Gibson County Coal mining complex. Based on the terms of the lease, we will make monthly payments of approximately $0.2 million through January 2011. Lease expense incurred for each of the years ended December 31, 2008, 2007 and 2006 was $2.6 million, respectively.

We have agreements with two banks to provide letters of credit in an aggregate amount of $31.0 million (Note 8). At December 31, 2008, we had $29.0 million in outstanding letters of credit under these agreements. The SGP guarantees $5.0 million of these outstanding letters of credit. The SGP does not charge us for this guarantee. Since the guarantee is made on behalf of entities within the consolidated partnership, the guarantee has no fair value under FIN No. 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, including Indirect Guarantees of Indebtedness of Other*s, and does not impact our consolidated financial statements.

ARH In April 2006, we acquired River View from ARH (Note 3).

20. COMMITMENTS AND CONTINGENCIES

Commitments We lease buildings and equipment under operating lease agreements that provide for the payment of both minimum and contingent rentals. We also have a noncancelable lease with SGP (Note 19) and a noncancelable lease for equipment under a capital lease obligation. Future minimum lease payments are as follows (in thousands):

	Capital	Other Operating Leases		
Year Ending December 31,	**Lease**	**Affiliate**	**Others**	**Total**
2009	$ 412	$ 2,835	$ 1,748	$ 4,583
2010	364	2,595	1,697	4,292
2011	315	216	1,194	1,410
2012	111		775	775
2013	53		380	380
Thereafter	10		1,802	1,802
Total future minimum lease payments	$ 1,265	$ 5,646	$ 7,596	$ 13,242
Less: amount representing interest	(130)			
Present value of future minimum lease payments	1,135			
Less: current portion	(351)			
Long-term capital lease obligation	$ 784			

Rental expense (including rental expense incurred under operating lease agreements) was $5.6 million, $5.4 million and $5.8 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Our subsidiary, Mettiki (WV), entered into a capital lease agreement with Joy Technologies Inc., d/b/a Joy Mining Machinery, a Delaware corporation, on May 22, 2006, with an in-service date of November 20, 2006. The lease is a 5-year noncancelable lease with monthly rental payments of $40,390 and has one renewal period for 2 years with monthly rental payments of $22,140. The effective interest rate on the capital lease is 6.195%.

Contractual Commitments In connection with planned capital projects, we have contractual commitments of approximately $116.1 million at December 31, 2008. As of December 31, 2008, we had commitments to purchase, from external production sources, coal at an estimated cost up to $13.6 million in 2009 and $7.4 million in 2010.

General Litigation Various lawsuits, claims and regulatory proceedings incidental to our business are pending against the ARLP Partnership. We record an accrual for a potential loss related to these matters when, in management s opinion, such loss is probable and reasonably estimable. Based on known facts and circumstances, we believe the ultimate outcome of these outstanding lawsuits, claims and regulatory proceedings will not have a material adverse effect on our financial condition, results of operations or liquidity. However, if the results of these matters were different from management s current opinion and in amounts greater than our accruals, then they could have a material adverse effect.

Other During September 2008, we completed our annual property and casualty insurance renewal with various insurance coverages effective as of October 1, 2008. Available capacity for underwriting property insurance continues to be limited as a result of insurance carrier losses in the mining industry worldwide. As a result, we have elected to retain a participating interest in our commercial property insurance program at an average rate of approximately 14.7% in the overall $75.0 million of coverage, representing 22% of the primary $50.0 million layer. We do not participate in the second layer of $25.0 million in excess of $50.0 million.

The 14.7% participation rate for this year s renewal is consistent with our prior year participation. The aggregate maximum limit in the commercial property program is $75.0 million per occurrence of which, as a result of our participation, we are responsible for a maximum amount of $11.0 million for each occurrence, excluding a $1.5 million deductible for property damage, a $5.0 million aggregate deductible for extra expense and a 60-day waiting period for business interruption. We can make no assurances that we will not experience significant insurance claims in the future, which as a result of our level of participation in the commercial property program, could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future.

In November 2005, we settled a contract dispute with ICG, LLC (ICG). Under this settlement, which was effective August 1, 2005, Pontiki, one of our subsidiaries, shipped coal in approximately ratable monthly quantities until the remaining obligation of 1,681,303 tons under a coal supply agreement with ICG was complete. This shipment obligation was completed in April 2007. As part of this settlement, we also executed a new coal sales agreement with ICG whereby Alliance Coal agreed to purchase approximately 887,000 tons of coal from ICG. Approximately 236,000 and 588,000 tons were purchased and sold at a profit during the years ended December 31, 2007 and 2006, respectively. Consequently, as of December 31, 2007, we had fully satisfied our coal sales agreement with ICG.

At certain of our operations, property tax assessments for several years are under audit by various state tax authorities. We believe that we have recorded adequate liabilities based on reasonable estimates of any property tax assessments that may be ultimately assessed as a result of these audits.

21. CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS

We have 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 from major customers, including transportation revenues, which exceed ten percent of total revenues, are as follows (in thousands):

		Year Ended December 31,		
	Segment (Note 22)	2008	2007	2006
Customer A	Northern Appalachia	$ 161,359	$ 24,446	$ 43,156
Customer B	Illinois Basin	131,198	65,660	50,926
Customer C	Illinois Basin	127,439	75,373	144,946
Customer D	Illinois Basin	121,550	115,796	74,413

Trade accounts receivable from these customers totaled approximately $42.1 million and $32.8 million at December 31, 2008 and 2007, respectively. Our bad debt experience has historically been insignificant. Financial conditions of our customers could result in a material change to our bad debt expense in future periods. We have various coal agreements with our significant customers with expiration dates ranging from 2013 to 2023.

22. SEGMENT INFORMATION

We operate in the eastern U.S. as a producer and marketer of coal to major utilities and industrial users. We have four reportable segments: the Illinois Basin, Central Appalachia, Northern Appalachia and Other and Corporate. The first three segments correspond to the three major coal producing regions in the eastern U.S. Coal quality, coal seam height, mining and transportation methods and regulatory issues are similar within each of these three segments.

The Illinois Basin segment is comprised of Webster County Coal s Dotiki mining complex, Gibson County Coal s Gibson North mining complex, Hopkins County Coal s Elk Creek mining complex, White County Coal s Pattiki mining complex, Warrior s mining complex, the Gibson South s property, certain properties of Alliance Resource Properties and a mining complex currently under construction at River View (Note 3). We are in the process of permitting the Gibson South property for future mine development.

The Central Appalachian segment is comprised of Pontiki s and MC Mining s mining complexes.

The Northern Appalachian segment is comprised of Mettiki (MD) s mining complex, Mettiki (WV) s Mountain View mining complex, two small third-party mining operations, a mining complex currently under construction at Tunnel Ridge and the Penn Ridge property. We are in the process of permitting the Penn Ridge property for future mine development.

Other and Corporate includes marketing and administrative expenses, the Mt. Vernon dock activities, coal brokerage activity, MAC and Matrix Design and certain properties of Alliance Resource Properties. Segment results for the years ended December 31, 2008, 2007 and 2006 are presented below.

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	Illinois Basin	Central Appalachia	Northern Appalachia	Other and Corporate	Elimination (1)	Consolidated
			(in thousands)			
Operating segment results for the year ended December 31, 2008 were as follows:						
Total revenues (2)	$ 748,369	$ 207,645	$ 187,603	$ 23,546	$ (10,614)	$ 1,156,549
Segment Adjusted EBITDA Expense (3)	522,575	157,575	134,800	20,441	(10,636)	824,755
Segment Adjusted EBITDA (4)	194,410	52,812	39,480	8,264	22	294,988
Total assets	543,175	88,745	136,515	262,278	(73)	1,030,640
Capital expenditures	141,843	11,303	19,986	3,350		176,482
Operating segment results for the year ended December 31, 2007 were as follows:						
Total revenues (2)	$ 662,643	$ 194,635	$ 163,351	$ 17,507	$ (4,802)	$ 1,033,334
Segment Adjusted EBITDA Expense (3)	429,563	145,759	116,037	19,112	(4,802)	705,669
Segment Adjusted EBITDA (4)	208,658	58,937	35,478	(1,605)		301,468
Total assets	450,047	105,826	128,557	17,366	(73)	701,723
Capital expenditures (5)	87,118	13,313	16,024	3,135		119,590
Operating segment results for the year ended December 31, 2006 were as follows:						
Total revenues (2)	$ 634,602	$ 185,966	$ 121,962	$ 27,293	$ (2,266)	$ 967,557
Segment Adjusted EBITDA Expense (3)	405,045	143,176	78,727	21,351	(2,266)	646,033
Segment Adjusted EBITDA (4)	206,209	40,050	29,911	5,475		281,645
Total assets	354,320	101,775	121,620	57,247		634,962
Capital expenditures	112,365	22,579	43,035	10,651		188,630

(1) The elimination column represents the elimination of intercompany transactions and is primarily comprised of sales from MAC and Matrix Design to our mining operations.

(2) Revenues included in the Other and Corporate column are primarily attributable to Mt. Vernon transloading revenues, administrative service revenues from affiliates, Matrix Design revenues, MAC rock dust revenues (2008 and 2007 only) and brokerage sales (2007 and 2006 only).

(3) Segment Adjusted EBITDA Expense includes operating expenses, outside coal purchases and other income. Transportation expenses are excluded as these expenses are passed through to our customers and consequently we do not realize any gain or loss on transportation revenues.

The following is a reconciliation of consolidated Segment Adjusted EBITDA Expense to operating expenses (excluding depreciation, depletion and amortization) (in thousands):

	Year Ended December 31, 2008	2007	2006
Segment Adjusted EBITDA Expense	$ 824,755	$ 705,669	$ 646,033
Outside coal purchases	(23,776)	(21,969)	(19,213)
Other income	875	1,385	936
Operating expenses (excluding depreciation, depletion and amortization)	$ 801,854	$ 685,085	$ 627,756

(4) Segment Adjusted EBITDA is defined as net income before net interest expense, income taxes, depreciation, depletion and amortization, minority interest, cumulative effect of accounting change and general and administrative expense. Consolidated Segment Adjusted EBITDA is reconciled to net income below (in thousands).

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	Year Ended December 31, 2008	2007	2006
Consolidated Segment Adjusted EBITDA	$ 294,988	$ 301,468	$ 281,645
General and administrative	(37,176)	(34,479)	(30,884)
Depreciation, depletion and amortization	(105,278)	(85,310)	(66,489)
Interest expense, net	(18,418)	(9,952)	(9,175)
Income tax (expense) benefit	480	(1,669)	(2,443)
Cumulative effect of accounting change			112
Minority interest (expense)	(420)	332	161
Net income	$ 134,176	$ 170,390	$ 172,927

(5) Capital expenditures do not include acquisitions of coal reserves and other assets in the Illinois Basin of $29.8 million and $53.3 million for the years ended December 31, 2008 and 2007, respectively, separately reported in our consolidated statements of cash flows.

23. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

A summary of our quarterly operating results for 2008 and 2007 is as follows (in thousands, except unit and per unit data):

		Quarter Ended March 31, 2008	June 30, 2008 (1)	September 30, 2008	December 31, 2008
Revenues		$ 283,588	$ 276,224	$ 285,790	$ 310,947
Income from operations		45,322	39,532	35,166	31,639
Income before income taxes and minority interest		42,649	36,729	29,381	25,357
Net income		43,163	36,697	29,136	25,180
Basic net income per limited partner unit (2)		$ 0.76	$ 0.67	$ 0.48	$ 0.32
Diluted net income per limited partner unit (2)		$ 0.76	$ 0.67	$ 0.48	$ 0.32
Weighted average number of units outstanding	basic	36,578,263	36,613,458	36,613,458	36,613,458
Weighted average number of units outstanding	diluted	36,753,837	36,747,965	36,761,292	36,728,262

		Quarter Ended March 31, 2007	June 30, 2007 (3)	September 30, 2007	December 31, 2007
Revenues		$ 257,071	$ 263,309	$ 260,526	$ 252,428
Income from operations		47,415	48,928	41,815	42,136
Income before income taxes, cumulative effect of accounting change and minority interest		46,032	46,822	39,172	39,701
Net income		45,540	46,237	38,685	39,928
Basic net income per limited partner unit		$ 0.79	$ 0.80	$ 0.70	$ 0.77
Diluted net income per limited partner unit		$ 0.79	$ 0.80	$ 0.70	$ 0.76
Weighted average number of units outstanding	basic	36,540,485	36,550,659	36,550,659	36,550,659
Weighted average number of units outstanding	diluted	36,765,573	36,794,912	36,801,186	36,825,948

(1) The comparability of our June 30, 2008 quarterly results were affected by the following items: i) gain on sale of non-core coal reserves of $5.2 million, ii) gain of $1.9 million on settlement of claims relating to the 2005 failure of the vertical belt system at our Pattiki mine, and iii) gain of $2.8 million on settlement of claims against the third-party that provided security services at the time of the MC Mining mine

fire (Note 4).

(2) The sum of per unit net income per limited partner by quarter for the year 2008 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 third and fourth quarter of the year ended December 31, 2008. See Note 12 for further discussion of this calculation.

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(3) The comparability of our June 30, 2007 quarterly results were affected by a net gain of $11.5 million and a reduction in operating expenses of approximately $0.8 million resulting from an insurance settlement of claims relating to the MC Mining mine fire (Note 4).

24. SUBSEQUENT EVENTS

Other than those events described in Notes 10 and 14, there were no other subsequent events.

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SCHEDULE II

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006

	Balance At Beginning of Year	Additions Charged to Income	Deductions	Balance At End of Year
		(in thousands)		
2008				
Allowance for doubtful accounts	$	$	$	$
2007				
Allowance for doubtful accounts	$	$	$	$
2006				
Allowance for doubtful accounts	$	$	$	$

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. We maintain controls and procedures designed to ensure that information required to be disclosed in the reports we file with the SEC, is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosures. 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 report. This evaluation was performed by our management, with the participation of our Chief Executive Officer and Chief Financial Officer. Based on this evaluation of our disclosure controls and procedures as of the end of the period covered by this report, our Chief Executive Officer and Chief Financial Officer concluded that these controls and procedures are effective.

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 ARLP 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 ARLP 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 ARLP Partnership s internal control over financial reporting is designed to provide reasonable assurance to our management and Board of Directors of our managing general partner regarding the preparation and fair presentation of published financial statements. Our controls are designed to provide reasonable assurance that the ARLP 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 ARLP Partnership s internal control over financial reporting. Management concluded that the design and operations of our internal controls over financial reporting at December 31, 2008 are effective and provide reasonable assurance the books and records accurately reflect the transactions of the ARLP Partnership.

Because of our 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 our internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework*. Based on its assessment, management concluded that, as of December 31, 2008, the ARLP Partnership s internal control over financial reporting was effective based on those criteria, and management believes that we have no material internal control weaknesses in our financial reporting process.

Deloitte & Touche LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2008, as stated in their report which is included herein.

Changes in Internal Controls Over Financial Reporting. There has been no change in our internal controls over financial reporting (as defined in Rule 13a-15(f) or Rule 15d-15(f) in the three months ended December 31, 2008 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

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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 internal control over financial reporting of Alliance Resource Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2008, 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, included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, 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, 2008 and 2007 and the related consolidated statements of income, cash flows and Partners capital for each of the three years in the period ended December 31, 2008, and financial statement schedule as of and for the year ended December 31, 2008 of the Partnership and our report dated March 2, 2009 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP

Tulsa, Oklahoma
March 2, 2009

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE 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 current and certain former executive officers and members of the Board of Directors 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	58	President, Chief Executive Officer and Director
Brian L. Cantrell	49	Senior Vice President and Chief Financial Officer
R. Eberley Davis	51	Senior Vice President, General Counsel and Secretary
Robert G. Sachse	60	Executive Vice President Marketing
Charles R. Wesley [1]	54	Executive Vice President and Director
Thomas M. Wynne [2]	52	Senior Vice President and Chief Operating Officer
Michael J. Hall [3]	64	Director and Member of Audit* and Compensation Committees
John P. Neafsey [4]	69	Chairman of the Board and Member of Compensation and Conflicts* Committees
John H. Robinson [5]	58	Director and Member of Audit, Compensation* and Conflicts Committees
Wilson M. Torrence [6]	67	Director and Member of Audit, Conflicts and Compensation Committees
Merribel S. Ayres [7]	57	Director and Member of Conflicts and Compensation Committees

* Indicates Chairman of Committee

1 Mr. Wesley was elected to the Board of Directors effective January 27, 2009 and elected Executive Vice President effective March 1, 2009.

2 Mr. Wynne was elected Senior Vice President and Chief Operating Officer effective March 1, 2009.

3 Mr. Hall was elected to the Compensation Committee effective January 27, 2009.

4 Mr. Neafsey resigned from the Audit Committee effective April 24, 2008.

5 Mr. Robinson resigned from the Conflicts Committee effective April 24, 2008 and was re-elected effective January 27, 2009.

6 Mr. Torrence was elected to the Audit Committee effective April 24, 2008 and to the Compensation Committee effective January 27, 2009.

7 Ms. Ayres resigned from the Board of Directors effective January 13, 2009. Prior to her resignation, Ms. Ayres served as a member of the Compensation and Conflicts Committees.

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. Mr. Craft also serves as President, Chief Executive Officer and Chairman of the Board of Directors of AGP, the general partner of AHGP. 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. He is a former Chairman of the National Coal Council, a Board and Executive Committee Member and Chairman of the Safety, Health and Human Resources Committee of the National Mining Association, a Director of American Coalition for Clean Coal Electricity, a Director of BOK Financial Corporation (NASDAQ: BOKF), a member of the Board of Trustees for the University of Tulsa and a Director of the Tulsa Community Foundation. Mr. Craft holds a Bachelor of Science degree in Accounting and a Juris Doctorate 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.

Brian L. Cantrell has been Senior Vice President and Chief Financial Officer since October 2003. Mr. Cantrell also serves as Senior Vice President and Chief Financial Officer of AGP, the general partner of AHGP. 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 Masters of Accountancy and Bachelor of Accountancy from the University of Oklahoma.

R. Eberley Davis has been Senior Vice President, General Counsel and Secretary since February 2007. Mr. Davis also serves as Senior Vice President, General Counsel and Secretary of AGP, the general partner of AHGP. Mr. Davis has over 24 years experience in the coal and energy industries. From 2003 to February 2007, Mr. Davis practiced law in the Lexington, Kentucky office of Stoll Keenon Ogden PLLC. Prior to joining Stoll Keenon Ogden, Mr. Davis was Vice President, General Counsel and Secretary of Massey Energy Company for one year. Mr. Davis also served in various positions, including Vice President and General Counsel, for Lodestar Energy, Inc. from 1993 to 2002. Mr. Davis is an alumnus of the University of Kentucky, where he received a Bachelor of Arts degree in Economics and his Juris Doctorate degree. He also holds a Masters of Business Administration degree from the University of Kentucky. Mr. Davis is a Trustee of the Energy and Mineral Law Foundation, and a member of the American, Kentucky and Fayette County Bar Associations.

Robert G. Sachse has been Executive Vice President since August 2000. Effective November 1, 2006, Mr. Sachse assumed responsibility for our coal marketing, sales and transportation functions. Mr. Sachse was also Vice Chairman of our managing general partner from August 2000 to January 2007. 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 Doctorate degree from the University of Tulsa.

Charles R. Wesley became a Director in January 2009 and was elected Executive Vice President effective March 1, 2009. Mr. Wesley has served in a variety of capacities since joining the company in 1974, most recently as Senior Vice President Operations since August 1996. 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 Directors of the Kentucky Mining Institute. Mr. Wesley holds a Bachelor of Science degree in Mining Engineering from the University of Kentucky.

Thomas M. Wynne became Vice President and Chief Operating Officer effective March 1, 2009. Mr. Wynne joined the company in 1981 as a mining engineer and has held a variety of positions with the company prior to his appointment in July 1998 as Vice President Operations. Mr. Wynne has served the coal industry on the National Executive Committee for National Mine Rescue and is currently a member of the Coal Safety Committee for the National Mining Association. Mr. Wynne holds a Bachelor of Science degree in Mining Engineering from the University of Pittsburgh and a Masters of Business Administration degree from West Virginia University.

Michael J. Hall became a Director in March 2003. Mr. Hall is Chairman of the Board of Directors of Matrix Service Company (Matrix) (NASDAQ: MTRX). Previously, Mr. Hall served as President and Chief Executive Officer of Matrix from March 2005 until he retired in November 2006. Mr. Hall also served as Vice President Finance and Chief Financial Officer, Secretary and Treasurer of Matrix from September 1998 to May 2004. Mr. Hall became a Director of Matrix in October 1998, and was elected Chairman of its Board in November 2006. 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 is Chairman of the Board of Directors of Integrated Electrical Services, Inc. (NASDAQ: IESC) and has served in that capacity since May, 2006, and is a member of its audit, compensation and nominating/governance committees. Mr. Hall holds a Bachelor of Science degree in Accounting from Boston College and a Masters of Business Administration from Stanford University. Mr. Hall is Chairman of the Audit Committee and a member of the Compensation Committee. Since March, 2006, Mr. Hall has also been a Director and Chairman of the audit committee of AGP, the general partner of AHGP.

John P. Neafsey has served as Chairman of the Board of Directors 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 and Chairman of the audit committee for The West Pharmaceutical Services Company and Chairman and a member of the audit committee of Constar, Inc., Trustee Emeritus and Presidential Counselor, Cornell University, and Overseer of Cornell-Weill Medical Center. Mr. Neafsey holds Bachelor and Masters of Science degrees in Engineering and a Masters of Business Administration degree from Cornell University. Mr. Neafsey is Chairman of the Conflicts Committee and a member of the Compensation Committee.

John H. Robinson became a Director in December 1999. Mr. Robinson is Chairman of Hamilton Ventures, LLC. From 2003 to 2004, he was Chairman of EPC Global, Ltd., an engineering staffing 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, Inc. 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 and a member of its audit and compensation committees, and he is a Director of the Federal Home Loan Bank of Des Moines, also serving on its audit and compensation committees. Mr. Robinson is also a Director of Comark Building Systems, Inc. and Olsson Associates. He holds Bachelor and Masters 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 Compensation Committee and a member of the Audit Committee.

Wilson M. Torrence became a Director in January 2007. Mr. Torrence retired from Fluor Corporation in 2006 as a Senior Vice President of Project Development and Investments and is currently performing investment and business consulting services for clients in various energy related businesses. Mr. Torrence was employed at Fluor from 1989 to 2006 where, among other roles, he was responsible for the global Project Development, Investment and Structured Finance Group and served as Chairman of Fluor s Investment Committee. In that position, Mr. Torrence had executive responsibility for Fluor s global activities in developing and arranging third-party financing for some of Fluor s clients construction projects. Prior to joining Fluor in 1989, Mr. Torrence was President and CEO of Combustion Engineering Corporation s Waste to Energy Division and, during that time, also served as Chairman of the Institute of Resource Recovery, a Washington-based industry advocacy organization. Mr. Torrence began his career at Mobil Oil Corporation, where he held several executive positions, including Assistant Treasurer of Mobil s International Marketing and Refining Division and Chief Financial Officer of Mobil Land Development Company. More recently, from October 2006 to March 2007, Mr. Torrence served as Chief Financial Officer and as a Director of Cleantech America, LLC, a private company involved in development of central station solar generating plants. Mr. Torrence holds Bachelor and Masters degrees in Business Administration from Virginia Tech University. Mr. Torrence is a member of the Audit, Compensation and Conflicts Committees.

Merribel S. Ayres became a Director in January 2007 and resigned effective January 13, 2009. Ms. Ayres is President of Lighthouse Consulting Group, a privately held firm that provides government affairs and communication expertise, as well as management consulting and business development services, focusing primarily on energy and environmental policy. From 1988 to 1996, Ms. Ayres served as Chief Executive Officer of the National Independent Energy Producers, a Washington, DC trade association representing the competitive power supply industry. Ms. Ayres is a member of the Aspen Institute Energy Policy Forum and the Deans Alumni Leadership Counsel of the Harvard Kennedy School. Ms. Ayres holds a Bachelor of Arts degree in English Literature from Bryn Mawr College, a post-graduate degree from Trinity College in Dublin, Ireland, and received advanced leadership training at the Harvard Kennedy School. In addition, Ms. Ayres is a Director of the United States Energy Association (USEA). She also serves on the Board of Directors of CMS Energy Corporation (NYSE:CMS), a Michigan-based company that has as its primary business operations an electric and natural gas utility, natural gas pipeline systems, and independent power generation. Ms. Ayres was a member of the Compensation and Conflicts Committees.

Audit Committee

The Audit Committee is comprised of three non-employee members of the Board of Directors (currently, Mr. Hall, Mr. Robinson and Mr. Torrence). 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 NASDAQ Stock Market, LLC, all current Audit Committee members are financially literate, and Mr. Hall qualifies as an audit committee financial expert under the applicable rules promulgated pursuant to the Exchange Act.

Report of the Audit Committee

The Audit Committee of MGP oversees our financial reporting process on behalf of the Board of Directors. Management has primary responsibility for the financial statements and the reporting process including the systems of internal controls. The Audit Committee has 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 SEC pursuant to the Securities Act of 1933 (the Securities Act) and the Exchange Act (i.e., Forms 10-K, 10-Q, and 8-K);
- press releases and other communications by us to the public concerning earnings, financial condition and results of operations, including changes in distribution policies or practices affecting the holders of our units, if such review is not undertaken by the Board of Directors;
- 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 met eight times during 2008. 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, 2008, (d) performing a self-assessment of the committee itself, (e) reviewing the Audit Committee charter, and (f) reviewing the overall scope, plans and findings of our 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.

Our 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 our 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 the Statement of Auditing Standards (SAS) 114, *The Auditor s Communication with Those Charged with Governance*, as may be modified or supplemented. The Audit Committee received written disclosures and the letter from Deloitte & Touche LLP required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent accountant s communication with the audit committee regarding independence, and has discussed with Deloitte & Touche LLP its independence from management and the ARLP 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, 2008 for filing with the SEC.

Members of the Audit Committee:

Michael J. Hall, Chairman
John H. Robinson
Wilson M. Torrence

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 Investor Information at www.arlp.com and is available in print without charge to any unitholder who requests it. Such requests should be directed to Investor Relations at (918) 295-7674. 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, 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.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act, 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 upon a review of the copies of the forms furnished to us and written representations from certain reporting persons, we believe that during 2008 none of our officers and directors were delinquent with respect to any of the filing requirements under Rule 16(a).

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. Prior to May 15, 2006, substantially all of our executive officers were employees of record of our managing general partner. During that time, our managing general partner was 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. Please see Item 13. Certain Relationships and Related Transactions, and Director Independence *Administrative Services*.

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ITEM 11. EXECUTIVE COMPENSATION
Compensation Discussion and Analysis

Introduction

The Compensation Committee oversees the compensation of our managing general partner s executive officers, including the President and Chief Executive Officer, our principal executive officer, the Senior Vice President and Chief Financial Officer, our principal financial officer, and the three most highly compensated executive officers for 2008, each of whom is named in the Summary Compensation Table (collectively, the Named Executive Officers). The discussion below reflects decisions, philosophy and executive compensation that were determined by a prior composition of the Compensation Committee. The current Compensation Committee has reviewed and shares the philosophy described below, and it will continue to evaluate and update that philosophy to ensure that our compensation objectives remain relevant to enhancing our performance and that our Named Executive Officers compensation continues to achieve that end.

The Named Executive Officers are employees of our operating subsidiary, Alliance Coal. Some of the Named Executive Officers devote a portion of their time to the business of one or more related parties and, to the extent they do so, Alliance Coal is reimbursed for such services by those related parties pursuant to an administrative services agreement. Please see Item 13. Certain Relationships and Related Transactions, and Director Independence *Administrative Services.* We do not have employment agreements with any of our Named Executive Officers.

Compensation Objectives and Philosophy

The compensation of our Named Executive Officers is designed to achieve two key objectives: (i) provide a competitive compensation opportunity to allow us to recruit and retain key management talent, and (ii) motivate and reward the executive officers for creating sustainable, capital-efficient growth in distributable cash flow to maximize our distributions to our unitholders. In making decisions regarding executive compensation, the Compensation Committee reviews current compensation levels of other companies in the coal industry and other peers, considers our President and Chief Executive Officer s assessment of each of the other executives, and uses its discretion to determine an appropriate total compensation package of base salary and short-term and long-term incentives. The Compensation Committee intends for each executive officer s total compensation to be competitive in the market place and to effectively motivate the individual. Based upon its review of our overall executive compensation program, the Compensation Committee believes the program is appropriately applied to our managing general partner s executive officers and is necessary to attract and retain the executive officers who are essential to our continued development and success, to compensate those executive officers for their contributions and to enhance unitholder value. Moreover, the Compensation Committee believes the total compensation opportunities provided to our managing general partner s executive officers create alignment with our long-term interests and those of our unitholders. As a result, we do not maintain stock ownership requirements for our Named Executive Officers.

Setting Executive Compensation

Role of the Compensation Committee

The Compensation Committee discharges the Board of Directors responsibilities relating to our managing general partner s executive compensation program. The Compensation Committee oversees our compensation and benefit plans and policies, administers our incentive bonus and equity participation plans, and reviews and approves annually all compensation decisions relating to our Named Executive Officers. The Compensation Committee is empowered by the Board of Directors and by the Compensation Committee s charter to make all decisions regarding compensation for the Named Executive Officers without ratification or other action by the Board of Directors. The Compensation Committee has the authority to secure services for executive compensation matters, legal advice, or other expert services, both from within and outside the company. While the Compensation Committee is empowered to delegate all or a portion of its duties to a subcommittee, it has not done so.

The Compensation Committee is composed of all of our directors who have been determined to be independent by the Board of Directors in accordance with applicable NASDAQ Stock Market, LLC and SEC regulations, presently Messrs. Robinson, Hall, Neafsey and Torrence.

Role of Executive Officers

Each year, the President and Chief Executive Officer submits recommendations to the Compensation Committee for adjustments to the salary, bonuses and long-term equity incentive awards payable to Named Executive Officers, excluding himself. The President and Chief Executive Officer bases his recommendations on his assessment of the executive s performance, experience, demonstrated leadership, job knowledge and management skills. Historically, and in 2008, the Compensation Committee and the President and Chief Executive Officer have been substantially aligned on decisions regarding compensation of the Named Executive Officers. As executive officers are promoted or hired during the year, the President and Chief Executive Officer makes compensation recommendations to the Compensation Committee and works closely with the Compensation Committee to ensure that all compensation arrangements for executive officers are consistent with our compensation philosophy and are approved by the Compensation Committee. At the direction of the Compensation Committee, the President and Chief Executive Officer and the Senior Vice President, General Counsel and Secretary attend certain meetings and work sessions of the Compensation Committee.

Role of Compensation Consultants

The Compensation Committee engaged Mercer (US) Inc. (Mercer) as an outside compensation consultant to assist it in collecting and analyzing peer group compensation information and in assessing the competitiveness of our compensation program for 2008. Mercer took instructions from and reported to the Chairman of the Compensation Committee. Mercer reviewed published survey data and peer group proxy information, and provided a comparative analysis of competitive practices regarding base salaries, short-term incentives, total cash compensation, long-term incentives and total direct compensation.

Mercer analyzed multiple survey sources published by Mercer and Watson Wyatt, reflecting industrial organizations where possible, to determine market pay practices. Mercer s proxy analysis included industry peers Peabody Energy Corp, CONSOL Energy Inc., Arch Coal, Inc., Massey Energy Company, Alpha Natural Resources Inc., Foundation Coal Holdings Inc., Patriot Coal Corp., International Coal Group Inc., James River Coal Company and Westmoreland Coal Company. Mercer also reviewed proxy information of master limited partnership or regional peers Penn Virginia Resource Partners, L.P., Natural Resource Partners, L.P., Williams Companies, ONEOK Partners, Magellan Midstream Partners, Atlas America and SemGroup Energy Partners. This peer group was selected by Mercer, reviewed by the President and Chief Executive Officer, and approved by the Compensation Committee.

Use of Peer Group Comparisons and Survey Data

The Compensation Committee believes that it is important to review and compare our performance with that of peer companies in the coal industry, and reviews the composition of the peer group annually. In setting executive compensation for 2008, the Compensation Committee reviewed the compensation information compiled by Mercer. The Compensation Committee uses the peer group and survey data as a point of reference for comparative purposes, but it is not the determinative factor for the compensation of our Named Executive Officers. The Compensation Committee exercises discretion in determining the nature and extent of the use of comparative pay data.

Consideration of Equity Ownership

Two of our Named Executive Officers Mr. Craft, the President and Chief Executive Officer, and Mr. Wesley, the Senior Vice President-Operations are evaluated and treated differently with respect to compensation than our other Named Executive Officers. Each of Messrs. Craft and Wesley and their respective trusts or other related entities own significant equity positions in AHGP, which owns MGP, the incentive distribution rights in ARLP and, as of December 31, 2008, 42.5% of ARLP s outstanding common units. Because of these ownership positions, the interests of each of Messrs. Craft and Wesley are directly aligned with those of our unitholders. Mr. Craft has not received an increase in base salary since 2002 and did not receive a STIP bonus or LTIP award in 2006, 2007 or 2008. Mr. Wesley has not received an increase in base salary since 2005, did not receive a STIP bonus in 2006 or 2007 and did not receive an LTIP award in 2007 or 2008.

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Compensation Components

Overview

The principal components of compensation for our Named Executive Officers include:

- base salary;
- annual cash incentive bonus awards under the STIP; and
- awards of restricted common units under the LTIP.

The relative amount of each component is not based on any formula, but rather is based on the recommendation of the President and Chief Executive Officer, subject to the discretion of the Compensation Committee to make any modifications it deems appropriate.

Each of our Named Executive Officers also receives supplemental retirement benefits through the SERP. In addition, all of the executive officers are entitled to customary benefits available to all of our employees, including group medical, dental, and life insurance and participation in our profit sharing and savings plan. Our profit sharing and savings plan is a defined contribution plan and includes an employer matching contribution of 75% on the first 3% of eligible compensation (as defined by the IRS) contributed by the employee, an employer non-matching contribution of 0.75% of eligible compensation, and an employer supplemental contribution of 5% of eligible compensation.

Base Salary

When reviewing base salaries, the Compensation Committee s policy is to consider the individual s experience, tenure and performance, the individual s level of responsibility, the position s complexity and its importance to us in relation to other executive positions, our financial performance, and competitive pay practices. The Compensation Committee also considers comparative compensation data of companies in our peer group and the recommendation of the President and Chief Executive Officer of our managing general partner. Base salaries are reviewed annually to ensure continuing consistency with market levels, and adjustments to base salaries reflect movement in the competitive market as well as individual performance.

Annual Cash Incentive Bonus Awards

The STIP is designed to assist us in attracting, retaining and motivating qualified personnel by rewarding management, including the Named Executive Officers, and selected other salaried employees with cash awards for our achieving an annual financial performance target. The annual performance target is recommended by the President and Chief Executive Officer and approved by the Compensation Committee, typically in January of each year. The performance measure is subject to equitable adjustment in the sole discretion of the Compensation Committee to reflect the occurrence of any significant events during the year.

The performance target historically has been EBITDA-derived, with items added or removed from the EBITDA calculation to ensure that the performance target reflects the pure operating results of the core mining business. (EBITDA is defined as net income before net interest expense, income taxes, depreciation, depletion and amortization and minority interest.) The aggregate cash available for awards under the STIP each year is dependent on our actual financial results for the year compared to the annual performance target, and it increases in relationship to our adjusted EBITDA exceeding the minimum threshold. The Compensation Committee may determine satisfactory results and adjust the size of the pay-out pool in its sole discretion. For 2008, the Compensation Committee approved a minimum financial performance target of $198.4 million in EBITDA from current operations, normalized by excluding any charges for unit-based compensation expense, and we exceeded the target.

Payments for individual executive officers each year are determined by and in the discretion of the Compensation Committee. As it does when reviewing base salaries, in determining individual payments the Compensation Committee considers its assessment of the individual s performance, comparative compensation data of companies in our peer group and the recommendation of the President and Chief Executive Officer. The compensation expense associated with STIP awards is recognized in the year earned, with the cash awards payable in the first quarter of the following calendar year. Termination of employment of an executive officer for any reason prior to payment of a cash award will result in forfeiture of any right to the award, unless and to the extent waived by the Compensation Committee in its discretion.

Equity Awards under the LTIP

Equity compensation pursuant to the LTIP is a key component of our executive compensation program. Our LTIP is sponsored by Alliance Coal. Under the LTIP, grants may be made of either (a) restricted units or (b) options to purchase common units, although to date, no grants of options have been made. The Compensation Committee has authority to determine the participants to whom restricted units are granted, the number of restricted units to be granted to each such participant, and the conditions under which the restricted units may become vested, including the duration of any vesting period. Annual grant levels for designated participants (including the Named Executive Officers) are recommended by our managing general partner s President and Chief Executive Officer, subject to review and approval by the Compensation Committee. Amounts realized from prior grants, including amounts realized due to changes in the value of our common units, are not considered in setting grant levels or other compensation for Named Executive Officers.

Restricted units granted under the LTIP vest at the end of a stated period from the grant date (which is currently approximately three years for all outstanding restricted units), provided we achieve an aggregate performance target for that period. The performance target is based on a normalized EBITDA measure, with that measure typically being the same as the STIP measure for the year of the grant. The target, however, requires achieving an aggregate performance level for the three-year period as compared to aggregate budgeted performance for that period. Historically, we have issued grants under the LTIP at the beginning of each year, with the exceptions of new employees who begin employment with us at some other time and job promotions that may occur at some other time. In 2008, we also issued grants in October in lieu of issuing grants at the beginning of 2009. The compensation expense associated with LTIP grants is recognized over the vesting period in accordance with SFAS No. 123R.

Our managing general partner s policy is to grant restricted common units pursuant to the LTIP to serve as a means of incentive compensation for performance and not primarily as an opportunity for equity participation with respect to our common units. Therefore, no consideration will be payable by the plan participants upon receipt of the 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 us in the open market at a price equal to the then prevailing price, or will be units already owned or newly issued by us, or any combination of the foregoing. 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 at the end of a period of time as determined by the Compensation Committee, which is currently approximately three years after the grant date for all outstanding restricted units, provided we achieve the aggregate performance target for that period. 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, determines otherwise. The number of units actually distributed upon satisfaction of the applicable vesting requirements is reduced to cover 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 distribution. Pursuant to the distribution equivalent rights provision of the LTIP, all grants of restricted units include the contingent right to receive quarterly cash distributions in an amount equal to the cash distributions we make to unitholders during the vesting period.

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 on terms determined by the Compensation Committee. 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. If a grantee s employment is terminated for any reason prior to the vesting of any unit options, those unit options will be automatically forfeited, unless the Compensation Committee, in its sole discretion, provides otherwise.

Grant Timing. The Compensation Committee does not time, nor has the Compensation Committee in the past timed, the grant of long-term equity incentive awards in coordination with the release of material non-public information. Instead, long-term equity incentive awards are granted only at the time or times dictated by our normal compensation process as developed by the Compensation Committee.

Effect of a Change in Control. Upon a change in control as defined in the LTIP, all awards of restricted units and options under the LTIP shall automatically vest and become payable or exercisable, as the case may be, in full. In this regard, all restricted periods shall terminate and all performance criteria, if any, shall be deemed to have been achieved at the maximum level. The LTIP defines a change in control as one of the following: (1) any sale, lease, exchange or other transfer of all or substantially all of our assets or our managing general partner s assets to any person; (2) the consolidation or merger of our managing general partner with or into another person pursuant to a transaction in which the outstanding voting interests of our managing general partner are changed into or exchanged for cash, securities or other property, other than any such transaction where (a) the outstanding voting interests of our managing general partner is changed into or exchanged for voting stock or interests of the surviving corporation or its parent and (b) the holders of the voting interests of our managing general partner immediately prior to such transaction own, directly or indirectly, not less than a majority of the voting stock or interests of the surviving corporation or its parent immediately after such transaction; or (3) a person or group being or becoming the beneficial owner of more than 50% of all voting interests of our managing general partner then outstanding.

Amendments and Termination. Our Board of Directors or the Compensation Committee may, in its discretion, terminate the LTIP at any time with respect to any common units for which a grant has not previously been made. Except as required by the rules of the exchange on which the common units may be listed at that time, our Board of Directors or the Compensation Committee may alter or amend the LTIP in any manner from time to 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 Board of Directors or the Compensation Committee may, in its discretion, establish such additional compensation and incentive arrangements as it deems appropriate to motivate and reward our employees.

Supplemental Executive Retirement Plan

We maintain the SERP to help attract and motivate key employees, including the Named Executive Officers. The SERP is sponsored by Alliance Coal. Participation in the SERP aligns the interest of each Named Executive Officer with the interests of our unitholders because all allocations made to participants under the SERP are made in the form of phantom common units of ARLP. The Compensation Committee approves the SERP participants and their percentage allocations, and can amend or terminate the plan at any time.

Under the terms of the SERP, participants are entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to his or her percentage allocation multiplied by the sum of base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution profit sharing and savings plan for the participant that year. A participant s cumulative notional phantom unit account balance earns the equivalent of common unit distributions. The calculated distributions are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant s termination or death in cash equal to then current fair market value of the phantom units credited to the participant s notional account under the SERP. The fair market value of a phantom unit is the average closing price of our common units for the ten trading days immediately preceding the applicable allocation or distribution date.

Upon any recapitalization, reorganization, reclassification, split of common units, distribution or dividend of securities on common units, or consolidation or merger, or sale of all or substantially all of our assets or other similar transaction which is effected in such a way that holders of common units are entitled to receive (either directly or upon subsequent liquidation) cash, securities or assets with respect to or in exchange for common units, the Compensation Committee shall, in its sole discretion (and upon the advice of financial advisors as may be retained by the Compensation Committee), immediately adjust the notional balance of phantom units in each Named Executive Officer s SERP account to equitably credit the fair value of the change in the common units and/or the distributions (of cash, securities or other assets) received or economic enhancement realized by the holders of the common units.

An executive officer who participates in the SERP shall be entitled to receive an allocation under the SERP for the year in which his employment is terminated on the occurrence of any of the following events:

(1) the executive officer s employment is terminated other than for cause;

(2) the executive officer terminates employment for good reason;

(3) a change of control of us or our managing general partner occurs and, as a result, an executive officer s employment is terminated (whether voluntary or involuntary);

(4) death of the executive officer;

(5) attaining retirement age of 65 years for any executive officer; and

(6) incurring a total and permanent disability, which shall be deemed to occur if an executive officer is eligible to receive benefits under the terms of the long-term disability program maintained by us.

This allocation for the relevant year in which an executive officer s termination occurs shall equal the executive officer s eligible compensation for such year (including any severance amount, if applicable) multiplied by his percentage allocation under the SERP, reduced by any supplemental contribution that was made to our defined contribution profit sharing and savings plan for the participant that year.

Trading in Derivatives

It is our managing general partner s policy that directors and all officers, including the Named Executive Officers, may not purchase or sell options on ARLP s common units.

Compensation Committee Report

The Compensation Committee has submitted the following report for inclusion in this Annual Report on Form 10-K:

Our Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis contained in this Annual Report on Form 10-K with management. Based on our Compensation Committee s review of and the discussions with management with respect to the Compensation Discussion and Analysis, our Compensation Committee recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2008.

The foregoing report is provided by the following directors, who constitute all the members of the Compensation Committee:

Members of the Compensation Committee:

John H. Robinson, Chairman
Michael J. Hall
John P. Neafsey
Wilson M. Torrence

Notwithstanding anything to the contrary set forth in any of our previous filings under the Securities Act or the Exchange Act, that incorporate future filings, including this Annual Report on Form 10-K, in whole or in part, the foregoing Compensation Committee Report shall not be deemed to be filed with the SEC or incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that we specifically incorporate it by reference.

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Summary Compensation Table for 2008

Name and Principal Position	Year	Salary (2)	Bonus (3)	Unit Awards (4)	Option Awards (1)	Non-Equity Incentive Plan Compensation (5)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (1)	All Other Compensation (6)	Total
Joseph W. Craft III,	2008	$ 334,828	$	$	$	$	$	$ 181,459	$ 516,287
President, Chief Executive Officer	2007	334,828		372,000				205,989	912,817
and Director	2006	334,828		1,066,400				302,821	1,704,049
Brian L. Cantrell,	2008	218,619		205,230		170,000		82,192	676,041
Senior Vice President - Chief	2007	210,000		183,028		100,000		64,208	557,236
Financial Officer	2006	202,115		241,573		125,000		68,825	637,513
R. Eberley Davis	2008	236,369	70,000	149,340		180,000		80,846	716,555
Senior Vice President, General									
Counsel and Secretary									
Robert G. Sachse,	2008	261,971		216,084		190,000		98,962	767,017
Executive Vice President -	2007	250,000	185,000	150,483		110,000		92,326	787,809
Marketing									
Charles R. Wesley,	2008	236,280		94,558		200,000		113,478	644,316
Executive Vice President and	2007	236,280		232,818				116,265	585,363
Director	2006	236,280		482,859				161,731	880,870

(1) Column is not applicable.

(2) Some of the Named Executive Officers devote a portion of their time to the business of one or more related parties and, to the extent they do so, the base salary of those executive officers is reimbursed to Alliance Coal by those related parties pursuant to an administrative services agreement. Please see Item 1. Business Employees *Administrative Services Agreement*. For 2008, the percentage of base salary reimbursed to Alliance Coal was 5% for Mr. Craft, 12% for Mr. Cantrell, 14% for Mr. Davis, and 1% for Mr. Sachse. For 2007, the percentage of base salary reimbursed to Alliance Coal was 5% for Mr. Craft, 15% for Mr. Cantrell and 5% for Mr. Sachse. For 2006, the percentage of base salary reimbursed to Alliance Coal was 14% for Mr. Craft and 22% for Mr. Cantrell.

(3) Amounts represent a retention bonus paid to Mr. Davis in 2008 and Mr. Sachse in 2007.

(4) The 2008 amounts represent the compensation expense recognized in 2008 in accordance with SFAS No. 123R associated with LTIP grants made in 2008, 2007, and 2006. The 2007 amounts represent the compensation expense recognized in 2007 in accordance with SFAS No. 123R associated with LTIP grants made in 2007, 2006, and 2005. The 2006 amounts represent the compensation expense recognized in 2006 in accordance with SFAS No. 123R associated with LTIP grants made in 2006, 2005 and 2004. Please see Item 8. Financial Statements and Supplementary Data Note 14. Compensation Plans for an explanation of the valuation assumptions we use in applying SFAS No. 123R. Also, please see Item 11. Compensation Discussion and Analysis Compensation Program Components *Equity Awards under the LTIP*.

(5) Amounts represent the STIP bonus earned for the respective year. STIP payments are made in the first quarter of the year following the year in which they are earned. Other than this bonus, there were no other applicable bonuses earned or deferred associated with year 2008. Please see Item 11. Compensation Discussion and Analysis Compensation Program Components *Annual Incentive Bonus Awards*.

(6) For Mr. Sachse, the 2007 amount includes perquisites and other personal benefits totaling $11,473, comprising club dues of $7,473 and tax preparation fees of $4,000. Otherwise, for all Named Executive Officers, the amounts represent the sum of the (a) SERP phantom unit contributions valued at the market closing price on the date the phantom unit was granted, (b) distribution equivalent rights received on non vested LTIP restricted units and (c) profit sharing savings plan employer contribution. For 2008, the amounts were for Mr. Craft, $145,627, $17,550 and $18,282, respectively; for Mr. Cantrell, $18,064, $48,344 and $15,784, respectively; for Mr. Davis, $29,208, $34,336 and $17,302, respectively; for Mr. Sachse, $34,012, $46,550 and $18,400, respectively; for Mr. Wesley, $70,149, $24,929 and

$18,400, respectively. For 2007, the amounts were for Mr. Craft, $121,989, $66,000 and $18,000, respectively; for Mr. Cantrell, $14,963, $33,990 and $15,255,

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respectively, for Mr. Sachse, $36,343, $26,510 and $18,000, respectively; and for Mr. Wesley, $57,730, $40,535 and $18,000, respectively. For 2006, the amounts were for Mr. Craft, $120,101, $165,120 and $17,600, respectively; for Mr. Cantrell, $16,360, $37,728 and $14,737, respectively; and for Mr. Wesley, $68,819, $75,312 and $17,600, respectively. No Named Executive Officer, other than Mr. Sachse in 2007, received perquisites or personal benefits with a total value in excess of $10,000.

Grants of Plan-Based Awards Table for 2008

			Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Unit Awards: Number of Units	All Other Option Awards: Number of Securities Underlying Options	Exercise or Base Price of Options Awards	Grant Date Fair Value of Unit Awards
Name	**Grant Date**	**Approved Date**	**Threshold (1)**	**Target (1)**	**Maximum (1)**	**Threshold (4)**	**Target (2)**	**Maximum (4)**	**(3)**	**(1)**	**(1)**	**(5)**
Joseph W. Craft, III	January 29, 2008	January 29, 2008										$
	February 14, 2008	(6)							733			29,210
	May 15, 2008	(6)							639			29,138
	August 14, 2008	(6)							694			31,785
	October 28, 2008	October 28, 2008										
	November 14, 2008	(6)							1,133			30,818
	December 31, 2008	January 29, 2008							918			24,676
									4,117			145,627
Brian L. Cantrell	January 29, 2008	January 29, 2008					5,800					209,554
	February 14, 2008	(6)							22			877
	May 15, 2008	(6)							19			866
	August 14, 2008	(6)							21			962
	October 28, 2008	October 28, 2008					7,125					199,928
	November 14, 2008	(6)							34			925
	December 31, 2008	January 29, 2008							537			14,435
							12,925		633			427,547
R. Eberley Davis	January 29, 2008	January 29, 2008					5,800					209,554
	February 14, 2008	(6)							4			159
	May 15, 2008	(6)							4			182
		(6)							4			183

	August 14, 2008				
	October 28, 2008	October 28, 2008	7,125		199,928
	November 14, 2008	(6)		6	163
	December 31, 2008	January 29, 2008		1,061	28,520
			12,925	1,079	438,689
Robert G. Sachse	January 29, 2008	January 29, 2008	5,800		209,554
	February 14, 2008	(6)		16	638
	May 15, 2008	(6)		14	638
	August 14, 2008	(6)		15	687
	October 28, 2008	October 28, 2008	7,125		199,928
	November 14, 2008	(6)		25	680
	December 31, 2008	January 29, 2008		1,167	31,369
			12,925	1,237	443,494
Charles R. Wesley	January 29, 2008	January 29, 2008			
	February 14, 2008	(6)		350	13,948
	May 15, 2008	(6)		305	13,908
	August 14, 2008	(6)		331	15,160
	October 28, 2008	October 28, 2008			
	November 14, 2008	(6)		541	14,715
	December 31, 2008	January 29, 2008		462	12,419
				1,989	70,150

(1) Column not applicable.

(2) These awards are grants of restricted units pursuant to our LTIP. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*.

(3) These awards are phantom units added to the participant s SERP notional account balance. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Supplemental Executive Retirement Plan*.

(4) Grants of restricted units under our LTIP are not subject to minimum thresholds, targets or maximum payout conditions. However, the vesting of these grants is subject to meeting certain financial tests. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*.

(5) We calculated the fair value of LTIP awards using a value of $36.13 per unit for the January 1, 2008 grants and $28.06 per unit for the October 28, 2008 grants, the unit price applicable under SFAS No. 123R for 2008 grants. We calculated the fair value of SERP phantom unit awards using the market closing price on the date the phantom unit award was granted. Phantom units granted under the SERP vest on the date granted.

(6) In accordance with the provisions of the SERP, a participant s cumulative notional phantom unit account balance earns the equivalent of common unit distributions when ARLP pays a distribution, which is added to the account balance in the form of phantom units. These contributions are in accordance with the SERP plan document, which has been approved by the Compensation Committee. Therefore, these contributions are not separately approved by the Compensation Committee.

Narrative Disclosure Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Annual Cash Incentive Bonus Awards

Under the STIP, our Named Executive Officers are eligible for cash awards for our achieving an annual financial performance target. The annual performance target is recommended by the President and Chief Executive Officer of our managing general partner and approved by the Compensation Committee, typically in January of each year. The performance target historically has been EBITDA-derived, with items added or removed from the EBITDA calculation to ensure that the performance target reflects the pure operating results of the core mining business. (EBITDA is calculated as net income before net interest expense, income taxes, depreciation, depletion and amortization and minority interest.) The aggregate cash available for awards under the STIP each year is dependent on our actual financial results for the year compared to the annual performance target, and the cash available increases in relationship to our adjusted EBITDA exceeding the minimum threshold. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Annual Incentive Bonus Awards*.

Long-Term Incentive Plan

Under the LTIP, grants may be made of either (a) restricted units or (b) options to purchase common units, although to date, no grants of options have been made. Annual grant levels for designated participants (including the Named Executive Officers) are recommended by our managing general partner s President and Chief Executive Officer, subject to the review and approval of the Compensation Committee. Restricted units granted under the LTIP vest at the end of a stated period from the grant date (which is currently approximately three years for all outstanding restricted units), provided we achieve an aggregate performance target for that period. The performance target is based on a normalized EBITDA measure, with that measure typically being the same as the STIP measure for the year of the grant. The target, however, requires achieving an aggregate performance level for the three-year period as compared to aggregate budgeted performance for the period. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*.

Supplemental Executive Retirement Plan

Under the terms of the SERP, participants are entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to his or her percentage allocation multiplied by the sum of base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution profit sharing and savings plan for the participant that year. A participant s cumulative notional phantom unit account balance earns the equivalent of common unit distributions. The calculated distributions are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant s termination or death in cash equal to then current fair market value of the phantom units credited to the participant s notional account under the SERP. The fair market value of a phantom unit is the average closing price of our common units for the ten trading days immediately preceding the applicable allocation or distribution date. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Supplemental Executive Retirement Plan*.

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Salary and Bonus in Proportion to Total Compensation

The following table shows the total of salary and bonus in proportion to total compensation from the Summary Compensation Table:

Name	Year	Salary and Bonus ($)	Total Compensation ($)	Salary and Bonus as a % of Total Compensation
Joseph W. Craft III	2008	$ 334,828	$ 516,287	64.9%
	2007	334,828	912,817	36.7%
	2006	334,828	1,704,049	19.6%
Brian L. Cantrell	2008	218,619	676,041	32.3%
	2007	210,000	557,236	37.7%
	2006	202,115	637,513	31.7%
R. Eberley Davis	2008	306,369	716,555	42.8%
Robert G. Sachse	2008	261,971	767,017	34.2%
	2007	435,000	787,809	55.2%
Charles R. Wesley	2008	236,280	644,316	36.7%
	2007	236,280	585,363	40.4%
	2006	236,280	880,870	26.8%

Outstanding Equity Awards at Fiscal Year-End 2008 Table

Name	Number of Securities Underlying Unexercised Options Exercisable (1)	Number of Securities Underlying Unexercised Options Unexerciseable (1)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (1)	Option Exercise Price (1)	Option Exercise Date (1)	Number of Units That Have Vested (1)	Market Value of Units That Have Not Vested (1)	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights That Have Not Vested (2)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested (3)
Joseph W. Craft III									$
Brian L. Cantrell								23,025	618,912
R. Eberley Davis								18,725	503,328
Robert G. Sachse								23,125	621,600
Charles R. Wesley								7,275	195,552

(1) Column is not applicable.

(2) Amounts represent restricted units awarded under the LTIP that were not vested as of December 31, 2008. Subject to our achieving financial performance targets, the units will or did vest as follows: For Mr. Cantrell, 4,300 units on January 1, 2009, 5,800 units on January 1, 2010, 5,800 units on January 1, 2011, and 7,125 units on January 1, 2012; for Mr. Davis, 5,800 units on January 1, 2010, 5,800 units on January 1, 2011, and 7,125 units on January 1, 2012; for Mr. Sachse, 4,400 units on January 1, 2009, 5,800 units on January 1, 2010, 5,800 units on January 1, 2011, and 7,125 units on January 1, 2012; and for Mr. Wesley, 7,275 units on January 1, 2009. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*.

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(3) Stated values are based on $26.88 per unit, the closing price of our common units on December 31, 2008, the final market trading day of 2008.

Option Exercises and Unit Vested Table for 2008

	Option Awards		Unit Awards	
Name	**Number of Units Acquired on Exercise (1)**	**Value Realized on Exercise (1)**	**Number of Units Acquired on Vesting (2)**	**Value Realized on Vesting (2)**
Joseph W. Craft III			30,000	$ 1,098,600
Brian L. Cantrell			5,350	195,917
R. Eberley Davis				
Robert G. Sachse			1,850	67,747
Charles R. Wesley			11,150	408,313

(1) Column is not applicable.

(2) Amounts represent the number and value of restricted units granted under the LTIP that vested in 2008. All of these units vested on January 1, 2008 and are valued at $36.62 per unit, the closing price on January 2, 2008, the first market trading date of 2008. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*.

Pension Benefits Table for 2008

Name	**Plan Name**	**Year**	**Number of Years Credited Service (1)**	**Present Value of Accumulated Benefit (2)**	**Payments During Last Fiscal Year**
Joseph W. Craft III	SERP	2008		$ 1,378,917	$
Brian L. Cantrell	SERP	2008		54,163	
R. Eberley Davis	SERP	2008		35,025	
Robert G. Sachse	SERP	2008		60,184	
Charles R. Wesley	SERP	2008		658,399	

(1) Column not applicable because no provision of the SERP is affected by years of service.

(2) Amounts represent the participant s cumulative notional account balance of phantom units valued at $26.88, the closing price of our common units on December 31, 2008, the final market trading day of 2008. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Supplemental Executive Retirement Plan*.

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Narrative Discussion Relating to the Pension Benefits Table for 2008

Supplemental Executive Retirement Plan

Under the terms of the SERP, participants are entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to their percentage allocation multiplied by the sum of base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution profit sharing and savings plan for the participant that year. A participant s cumulative notional phantom unit account balance earns the equivalent of common unit distributions. The calculated distributions are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant s termination or death in cash equal to then current fair market value of the phantom units credited to the participant s notional account under the SERP. The fair market value of a phantom unit is the average closing price of our common units for the ten trading days immediately preceding the applicable allocation or distribution date. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Supplemental Executive Retirement Plan*.

Potential Payments Upon a Termination or Change of Control

Each of the Named Executive Officers is eligible to receive accelerated vesting and payment under the LTIP and SERP upon certain terminations of employment or upon our change in control. For a discussion of what constitutes a change in control under the LTIP and the SERP, please see Item 11. Compensation Discussion and Analysis Compensation Components Equity Awards Under the LTIP and Supplemental Executive Retirement Plan above. The amounts each of the Named Executive Officers could receive under the SERP have been previously disclosed in Item 11. Pension Benefits Table for 2008 and the amounts each of the Named Executive Officers could receive under the LTIP have been previously disclosed in Item 11. Outstanding Equity Awards at Fiscal Year-End 2008 Table , in each case assuming the triggering event occurred on December 31, 2008. The exact amount that any Named Executive Officer would receive could only be determined with certainty upon an actual termination or change in control.

Director Compensation

The compensation of the directors of our managing general partner, MGP, is set by the Board of Directors upon recommendation of the Compensation Committee. Mr. Craft and Mr. Wesley, our only employee directors, receive no director compensation. The directors of MGP devote 100% of their time as directors of MGP to the business of the ARLP Partnership.

Director Compensation Table for 2008

Name	Fees earned or Paid in Cash ($)	Unit Awards ($) (2)(4)	Option Awards ($)(1)	Non-Equity Incentive Plan Compensation ($)(1)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(1)	All Other Compensation ($)(3)	Total ($)
Merribel S. Ayres	$ 90,000	$ 21,036	$	$	$	$	$ 111,036
Michael J. Hall	75,000	35,313				9,877	120,190
John P. Neafsey		187,388				9,877	197,265
John H. Robinson	90,000	93,296				9,877	193,173
Wilson M. Torrence	60,000	58,956					118,956

(1) Column is not applicable.

(2) Amounts represent the compensation expense recognized in 2008 in accordance with SFAS No. 123R associated with LTIP grants made in 2006, deferrals of annual retainer and automatically deferred compensation. Please see Item 8. Financial Statements and Supplementary Data Note 14. Compensation Plans for an explanation of our valuation assumptions used in applying SFAS No. 123R. Please see *Narrative*

to Director Compensation Table, below. Beginning in 2007, our Directors no longer receive grants under the LTIP.

(3) Amounts represent distribution equivalent rights payments received by the directors during 2008 on non-vested LTIP restricted units, plus $5,000 in matching charitable contributions made by us. We match individual contributions of $25 or more to educational institutions and not-for-profit organizations on a one-to-one basis up to $5,000 per individual, per calendar year.

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(4) At December 31, 2008, each director had the following number of "phantom" ARLP common units credited to his or her notional account under the deferred compensation plan:

Name	Directors Deferred Compensation Plan (in Units)
Merribel S. Ayres	557
Michael J. Hall	419
John P. Neafsey	21,039
John H. Robinson	18,468
Wilson M. Torrence	4,134

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Narrative to Directors Compensation Table

Our directors compensation includes an annual cash retainer paid quarterly in advance on a pro rata basis (the Annual Retainer). The Annual Retainer for calendar year 2008 was $90,000. Directors have the option to defer all or part of the Annual Retainer pursuant to the MGP s Amended and Restated Deferred Compensation Plan for Directors (the Deferred Compensation Plan) by completing an election form prior to the beginning of each calendar year. Mr. Neafsey elected to defer his annual retainer in 2008 and Mr. Torrence elected to defer part of his. In addition to the Annual Retainer, for 2008 Directors received equity-based compensation that is automatically deferred under the Deferred Compensation Plan. The equity-based compensation for 2008 was $20,000 for each director other than Mr. Hall, with an additional $10,000 for each Board and Committee chairman, other than Mr. Hall (without duplication), and is credited quarterly in advance on a pro rata basis. At Mr. Hall s request, his Annual Retainer for 2008 was reduced to $75,000 and his equity-based compensation was set at $15,000. Mr. Hall, who is chairman of our Audit Committee, is also a director and chairman of the audit committee of AGP, the general partner of AHGP, and received like compensation for his service in those roles.

Pursuant to the Deferred Compensation Plan, for both deferred amounts of Annual Retainer and automatic deferrals of equity-based compensation, a notional account is established and credited with phantom common units of ARLP. The number of phantom units credited is determined by dividing the amount deferred by the average closing unit price for the ten trading days immediately preceding the deferral date. When quarterly cash distributions are made with respect to ARLP common units, phantom distributions equal to such quarterly distribution are credited to the notional account as additional phantom common units of ARLP. Accounts under the Deferred Compensation Plan will be paid in cash equal to the number of phantom units then credited to the director s account multiplied by the average closing unit price for the ten trading days immediately preceding the payment date.

The Deferred Compensation Plan was amended effective October 28, 2008 to provide that, for plan years beginning on or after January 1, 2009, directors may elect to receive payment of the account resulting from deferrals during that plan year either (a) on the January 1 on or next following his or her separation from service as a director or (b) on the earlier of a specified January 1 or the January 1 on or next following his or her separation from service. The payment election must be made prior to each plan year; if no election is made, the account will be paid on the January 1 on or next following the Director s separation from service. In addition, provision was made for a special, one-time election with respect to all pre-2009 plan year account balances. For those accounts, directors were permitted to elect, on or before December 31, 2008, to receive payment of all or part of the balances either (a) on the January 1 on or next following his or her separation from service as a director, or (b) on the earlier of a specified January 1 or the January 1 on or next following his or her separation from service, or (c) in up to 10 annual installments beginning January 1, 2009 (with any unpaid balance paid upon separation from service).

The Deferred Compensation Plan is administered by the Compensation Committee, and the Board of Directors may change or terminate the plan at any time; provided, however, that accrued benefits under the plan cannot be impaired.

Upon any recapitalization, reorganization, reclassification, split of common units, distribution or dividend of securities on ARLP common units, our consolidation or merger, or sale of all or substantially all of our assets or other similar transaction which is effected in such a way that holders of common units are entitled to receive (either directly or

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upon subsequent liquidation) cash, securities or assets with respect to or in exchange for ARLP common units, the Compensation Committee shall, in its sole discretion (and upon the advice of financial advisors as may be retained by the Compensation Committee), immediately adjust the notional balance of phantom units in each director s account under the Deferred Compensation Plan to equitably credit the fair value of the change in the ARLP common units and/or the distributions (of cash, securities or other assets) received or economic enhancement realized by the holders of the ARLP common units.

Our Board of Directors has established a policy that each non-employee director will attain, by January 1, 2014 or five years following such person s election to the Board of Directors, and thereafter maintain during service on the Board of Directors, ownership of equity of ARLP (including phantom equity ownership under the Deferred Compensation Plan) with value equal to or greater than three times the Annual Retainer amount.

Compensation Committee Interlocks and Insider Participation

Mr. Craft is a Director and the President and Chief Executive Officer of our managing general partner and is Chairman of the Board of Directors, President and Chief Executive Officer of AGP, the general partner of AHGP. Otherwise, none of our executive officers serves as a member of the Board of Directors or Compensation Committee of any entity that has one or more of its executive officers serving as a member of the Board of Directors or Compensation Committee of our managing general partner.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

The following table sets forth certain information as of February 16, 2009, regarding the beneficial ownership of common units held by (a) each director of our managing general partner, (b) each executive officer of our managing general partner identified in the Summary Compensation Table included in Item 11. Executive Compensation above, (c) all such directors and executive officers as a group, and (d) each person known by our managing general partner to be the beneficial owner of 5% or more of our common units. Our managing general partner is owned by AHGP (which is reflected as a 5% common unitholder in the table below), and approximately 80% of the equity of AHGP is owned by members of management and certain former members of management. Our special general partner is a wholly-owned subsidiary of ARH, which is indirectly wholly-owned by Mr. Craft. The address of each of AHGP, ARH, our managing general partner, our special general partner, and unless otherwise indicated in the footnotes to the table below, each of the directors and executive officers reflected in the table below is 1717 South Boulder Avenue, Suite 400, Tulsa, Oklahoma 74119. Unless otherwise indicated in the footnotes to the table below, the common units reflected as being beneficially owned by our managing general partner s directors and named executive officers are held directly by such directors and officers. The percentage of common units beneficially owned is based on 36,661,029 common units outstanding as of February 16, 2009.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Directors and Executive Officers		
Joseph W. Craft III (1)	15,902,620	43.38%
Michael J. Hall	29,951	*
John P. Neafsey	46,620	*
John H. Robinson	4,300	*
Wilson M. Torrence	800	*
Brian L. Cantrell (2)	16,989	*
R. Eberley Davis		
Robert G. Sachse	21,213	*
Charles R. Wesley III	111,836	*
All directors and executive officers as a group (9 persons)	16,134,329	44.01%
5% Common Unit Holders		
Alliance Holdings GP, L.P. (3)	15,544,169	42.40%
M&G Investment Funds 1 (4)	2,655,929	7.24%

* Less than one percent.

(1) Mr. Craft s common units consist of (i) 357,451 common units held directly by him, (ii) 1,000 common units held by his son, and (iii) 15,544,169 common units held by AHGP. Mr. Craft is a director, and through his

ownership of C-Holdings, LLC, the sole owner of AGP, the general partner of AHGP, and he holds, directly or indirectly, or may be deemed to be the beneficial owner of, a majority of the outstanding common units of AHGP. AHGP owns approximately 42.4% of our common units as of February 16, 2009. Mr. Craft disclaims beneficial ownership of the common units held by AHGP except to the extent of his pecuniary interest therein.

(2) Of the common units referenced above, 14,170 common units are subject to a pledge granted by Mr. Cantrell in favor of Wachovia Bank, N.A. as lender under a Loan Agreement, dated as of July 9, 2008.

(3) See footnote (1) above and the paragraph preceding the above table for explanation of the relationship between AHGP, Mr. Craft and us.

(4) The information in the above table with respect to M&G Investment Funds 1 is based on a Schedule 13G/A filing made by it with the Securities and Exchange Commission. The Schedule 13G/A is dated as of December 31, 2008. The address for M&G Investment Funds 1 is Governor s House, Laurence Pountney Hill, London, EC4R 0HH.

Equity Compensation Plan Information

Plan Category	Number of units to be issued upon exercise/vesting of outstanding options, warrants and rights as of December 31, 2008	Weighted-average exercise price of outstanding options, warrants and rights	Number of units remaining available for future issuance under equity compensation plans as of December 31, 2008
Equity compensation plans approved by unitholders:			
Long-Term Incentive Plan	395,695	N/A	(16,984) (1)

(1) As of February 16, 2009 there were 7,420 units remaining available for future issuance under the LTIP. The increase from December 31, 2008 was the result of settlement in cash for satisfaction of tax withholding obligations of a portion of the units granted in the 2006 LTIP awards that vested on January 1, 2009. The number of units available will also be increased upon the vesting of the units granted in the 2007 and 2008 LTIP awards for the same reason.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Certain Relationships and Related Transactions

As of December 31, 2008, AHGP owned 15,544,169 common units representing 42.5% of our common units and our incentive distribution rights. 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 AHGP s ownership of 42.5% of our common units, effectively gives our general partners the ability to veto some of our actions and to control our management.

Certain of our officers and directors are also officers and/or directors of AHGP, including Mr. Craft, the President and Chief Executive Officer of our managing general partner, Mr. Hall, a Director, member of the Compensation Committee and Chairman of the Audit Committee of our managing general partner, Mr. Cantrell, the Senior Vice President and Chief Financial Officer of our managing general partner, and Mr. Davis, the Senior Vice President, General Counsel and Secretary of our managing general partner.

Transactions Between Us, SGP, SGP Land, ARH, ARH II and AHGP

The Board of Directors of our managing general partner and its Conflicts Committee review each of our related-party transactions to determine that each such transaction reflects market-clearing terms and conditions customary in the coal industry. As a result of these reviews, the Board of Directors and the Conflicts Committee approved each of the transactions described below as fair and reasonable to us and our limited partners.

Administrative Services

In connection with AHGP s IPO in 2006, ARLP entered into an Administrative Services Agreement with our managing general partner, our Intermediate Partnership, AHGP and its general partner AGP, and ARH II. Under the Administrative Services Agreement, certain employees, including some executive officers, provide administrative services for AHGP, AGP and ARH II and their respective affiliates. We are reimbursed for services rendered by our employees on behalf of these entities as provided under the Administrative Services Agreement. We billed and recognized administrative service revenue under this agreement for the year ended December 31, 2008 of $0.4 million from AHGP and $0.5 million from ARH II. Concurrently in 2006, AHGP and AGP joined as parties to our Omnibus Agreement, discussed below, which addresses areas of non-competition between us and ARH, ARH II, SGP and our managing general partner.

Our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses incurred or payments made on behalf of us, including, but not limited to, management s salaries and related benefits (including incentive compensation), and accounting, budgeting, 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 to us by our managing general partner and its affiliates were approximately $0.3 million for the year ended December 31, 2008. The executive officers of our managing general partner are employees of and paid by Alliance Coal, and the reimbursement described above does not include any compensation expenses associated with them.

Managing General Partner Contribution

During 2008, an affiliated entity controlled by Mr. Craft contributed 25,898 common units AHGP valued at approximately $0.6 million at the time of contribution and $0.8 million of cash to AHGP for the purpose of funding certain expenses associated with our employee compensation programs. Upon AHGP s receipt of this contribution it immediately contributed the same to its subsidiary MGP, our managing general partner, which in turn contributed the same to our subsidiary Alliance Coal. As provided under our partnership agreement we made a special allocation of certain general and administrative expenses equal to the amount of the contribution to our managing general partner.

SGP Land, LLC

SGP Land is owned by our special general partner, which is owned indirectly by Mr. Craft.

On May 2, 2007, Alliance Coal, our operating subsidiary, entered into a time sharing agreement with SGP Land concerning the use of aircraft owned by SGP Land. In accordance with the provisions of the time sharing agreement as amended, we reimbursed SGP Land $0.7 million for the year ended December 31, 2008 for use of the aircraft.

On January 28, 2008, effective January 1, 2008, we acquired, through our subsidiary Alliance Resource Properties, additional rights to approximately 48.2 million tons of coal reserves located in western Kentucky from SGP Land. The purchase price was $13.3 million. At the time of our acquisition, these reserves were leased by SGP Land to our subsidiaries, Webster County Coal, Warrior and Hopkins County Coal through mineral leases and sublease agreements that were assigned to Alliance Resource Properties by SGP Land in this transaction. Under the terms of those agreements, Webster County Coal, Warrior and Hopkins County Coal were required to pay SGP Land certain advance minimum royalties and other amounts that were recoupable against earned royalties otherwise due to SGP Land. As of the effective date of the transaction, the remaining recoupable balances of such payments totaled $7.6 million. Webster County Coal, Warrior, and Hopkins County Coal also reimbursed SGP Land for its base lease obligations, including advance minimum royalties due the base lessors. As of the effective date of the transaction, the remaining recoupable balance of the advance minimum royalties due the base lessors was $0.4 million. The recoupable balances of advance minimum royalties and other payments at the time of the acquisition, other than $0.4 million paid to the base lessors, are eliminated in our consolidated financial statements.

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 of $0.3 million until $6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. MC Mining paid royalties of $0.3 million during the year ended December 31, 2008. As of December 31, 2008, $1.5 million of advance minimum royalties paid under the lease is available for recoupment.

SGP

In 2005, Tunnel Ridge entered into a coal lease agreement with the SGP, our special general partner, requiring advance minimum royalty payments of $3.0 million per year. As of December 31, 2008, Tunnel Ridge had paid $12.0 million of advance minimum royalty payments pursuant to the lease. The advance royalty payments are fully recoupable against earned royalties. Tunnel Ridge also controls surface land and other tangible assets under a separate lease agreement with the SGP. Under the terms of the lease agreement, Tunnel Ridge has paid and will continue to pay the SGP an annual lease payment of $0.2 million. The lease agreement has an initial term of four years, which may be extended to be coextensive with the term of the coal lease. Lease expense was $0.2 million for the year ended December 31, 2008.

We have a noncancelable operating lease arrangement with the SGP for the coal preparation plant and ancillary facilities at the Gibson mining complex. Under the terms of the lease, we will make monthly payments of approximately $0.2 millions through January 2011. Lease expense incurred for the year ended December 31, 2008 was $2.6 million.

We have agreements with two banks to provide letters of credit in an aggregate amount of $31.0 million. At December 31, 2008, we had $29.0 million in outstanding letters of credit under these agreements. The SGP guarantees $5.0 million of these outstanding letters of credit. The SGP does not charge us for this guarantee.

Omnibus Agreement

Concurrent with the closing of our initial public offering, we entered into an omnibus agreement with ARH 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, ARH 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, ARH has the ability to purchase businesses, the majority value of which is not mining, marketing or transporting coal, provided ARH 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 ARH at the closing of our initial public offering. Except as provided above, ARH and its controlled affiliates are prohibited from engaging in activities wherein they compete directly with us. In addition to its non-competition provisions, the agreement also provides for indemnification of us against liabilities associated with certain assets and businesses of ARH which were disposed of or liquidated prior to consummating our initial public offering. In May 2006, in connection with the closing of the AHGP IPO, the omnibus agreement was amended to include AHGP and AGP as parties to the agreement.

Director Independence

As a publicly traded limited partnership listed on the NASDAQ Global Select Market, we are required to maintain a sufficient number of independent directors on the board of our managing general partner to satisfy the audit committee requirement set forth in NASDAQ Rule 4350(d)(2). Rule 4350(d)(2) requires us to maintain an audit committee of at least three members, each of whom must, among other requirements, be independent as defined under NASDAQ Rule 4200(a)(15) and meet the criteria for independence set forth in Rule 10A-3(b)(1) under the Exchange Act (subject to the exemptions provided in Rule 10A-3(c)).

In 2008, the Board of Directors of our managing general partner affirmatively determined that the members of the Audit Committee of our managing general partner Messrs. Hall, Robinson and Torrence are independent directors as defined under applicable NASDAQ and Exchange Act rules. Please see Item 10. Directors, Executive Officers and Corporate Governance of the Managing General Partner Audit Committee.

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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 Fees. Fees for audit services provided during the years ended December 31, 2008 and 2007 were $0.7 million and $0.8 million, 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 Fees. Fees for audit-related services provided during the years ended December 31, 2008 and 2007, were $34,225 and $50,150, respectively. Audit-related services consist primarily of consultations concerning financial accounting and reporting standards.

Tax Fees. There were no fees for tax services from our independent registered public accounting firm as of December 31, 2008. Fees for tax services provided during the year ended December 31, 2007 were $0.2 million. 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 years ended December 31, 2008 and 2007, respectively.

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.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) Financial Statements.

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

(a)(2) Financial Statement Schedules.

Schedule II Valuation and Qualifying Accounts Years ended December 31, 2008, 2007 and 2006, 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 Current 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 23, 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)).
3.9	Amendment No. 1 to 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 Current Report on Form 8-K filed with the Commission on August 1, 2006, File No. 000-26823).
3.10	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L. P. dated October 25, 2007. (Incorporated by reference to Exhibit 3.10 of the Registrant s Current Report on Form 10-K for the year ended December 31, 2007 (File No. 000-26823).

3.11	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., dated April 14, 2008 (Incorporated by reference to Exhibit 3.1 of the Registrant s Current Report on Form 8-K filed with the Commission on April 18, 2008, File No. 000-26823).
4.1	Form of Common Unit Certificate (Included as Exhibit A to the Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., included in this Exhibit Index as Exhibit 3.1).
10.1	Note Purchase Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC and the purchasers named therein. (Incorporated by reference to Exhibit 10.2 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823).
10.2	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).
10.3	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).
10.4	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).
10.5	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).
10.6	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).
10.7	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).
10.8	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).
10.9	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).

10.10[1]	Amended and Restated Alliance Coal, 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).
10.11[1]	First Amendment to the Alliance Coal, 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).
10.12[1]	Alliance Coal, 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).
10.13[1]	Alliance Coal, 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)).
10.14[1]	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)).
10.15	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)).
10.16	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).
10.17	Amendment No. 4 dated October 25, 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 Current Report on Form 8-K filed with the Commission on October 26, 2005, File No. 000-26823).
10.18	Guaranty by Alliance Coal, LLC dated October 25, 2005. (Incorporated by reference to Exhibit 10.28 of the Registrant s Annual Report on Form 10-K filed with the Commission on March 16, 2006, File No. 000-26823).
10.19[2]	Financial Covenants Agreement dated October 25, 2005 by and between Seminole Electric Corporation, Inc. and Alliance Coal, LLC. (Incorporated by reference to Exhibit 10.29 of the Registrant s Annual Report on Form 10-K filed with the Commission on March 16, 2006, File No. 000-26823).
10.20	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).
10.21	Agreement for the Supply of Coal to the Mt. 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 the Registrant s Current Report on Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823).

10.22(2)	Amendment No. 1 to the Agreement for the supply of coal to Mt. Storm Power Station, made effective January 1, 2007, between Virginia Electric and Power Company and Alliance Coal, LLC. (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed with the Commission on February 20, 2007, File No. 000-26823).
10.23(2)	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 Current Report on Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823).
10.24(2)	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 Current Report on Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823).
10.25(2)	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 Current Report on Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823).
10.26(2)	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 Current Report on Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823).
10.27(2)	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 Current Report on Form 8-K filed with the Commission on August 5, 2005, File No. 000-26823).
10.28(2)	Memorandum of Understanding dated January 17, 2005 between VEPCO and Mettiki. (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K filed with the Commission on January 19, 2005, File No. 000-26823).
10.29(2)	Memorandum of Understanding, made effective January 1, 2007, between Virginia Electric and Power Company, and Alliance Coal, LLC, Mettiki Coal (WV), LLC and Mettiki Coal, LLC. (Incorporated by reference to Exhibit 10.33 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006, File No. 000-26823).
10.30(2)	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 Registrant s Current Report on Form 8-K filed with the Commission on January 19, 2005, File No. 000-26823).
10.31	Coal Feedstock Supply Agreement dated October 26, 2001, between Synfuel Solutions Operating LLC and Hopkins County Coal, LLC (Incorporated by reference to Exhibit 10.27 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2001, File No. 000-26823).
10.32	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).
10.33(2)	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).
10.34	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).

*10.35	Amended and Restated Charter for the Audit Committee of the Board of Directors dated February 23, 2009.
10.36	Amendment No. 2 to Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Fifth Third Bank (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed with the Commission on May 16, 2006, File No. 000-26823).
10.37	Second Amendment to the Omnibus Agreement dated May 15, 2006 by and among Alliance Resource Partners, L.P., Alliance Resource GP, LLC, Alliance Resource Management GP, LLC, Alliance Resource Holdings, Inc., Alliance Resource Holdings II, Inc., AMH-II, LLC, Alliance Holdings GP, L.P., Alliance GP, LLC and Alliance Management Holdings, LLC. (Incorporated by reference to Exhibit 10.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, File No. 000-26823).
10.38	Administrative Services Agreement dated May 15, 2006 among Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC, Alliance Resource Holdings II, Inc., Alliance Holdings GP, L.P. and Alliance GP, LLC. (Incorporated by reference to Exhibit 10.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, File No. 000-26823).
10.39(2)	Restated and Amended Feedstock Agreement No. 2, dated June 1, 2006, between Alliance Coal, LLC and Mount Storm Coal Supply, LLC (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed with the Commission on July 13, 2006, File No. 000-26823).
*10.40	Amended and Restated Charter for the Compensation Committee of the Board of Directors dated January 27, 2009.
10.41(1)	First Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan (Incorporated by reference to Exhibit 10.50 of the Registrant s Annual Report on Form 10-K filed with the Commission on March 1, 2007, File No. 000-26823).
10.42(1)	Second Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan. (Incorporated by reference to Exhibit 10.50 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2007, File No. 000-26823).
10.43(1)	Second Amendment to the Amended and Restated Alliance Coal, LLC Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.51 of the Registrant s Annual Report on Form 10-K filed with the Commission on March 1, 2007, File No. 000-26823).
10.44(1)	First Amendment to the Alliance Coal, LLC Short-Term Incentive Plan (Incorporated by reference to Exhibit 10.52 of the Registrant s Annual Report on Form 10-K filed with the Commission on March 1, 2007, File No. 000-26823).
10.45(1)	Second Amendment to the Alliance Coal, LLC Short-Term Incentive Plan. (Incorporated by reference to Exhibit 10.53 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2007, File No. 000-26823).
10.46	First Amendment to the Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors (Incorporated by reference to Exhibit 10.53 of the Registrant s Annual Report on Form 10-K filed with the Commission on March 1, 2007, File No. 000-26823).
10.47	Second Amendment to the Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors. (Incorporated by reference to Exhibit 10.55 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2007, File No. 000-26823).

10.48	Second Amended and Restated Credit Agreement, dated as of September 25, 2007, among Alliance Resource Operating Partners, L.P. as Borrower and the Initial Lenders, Initial Issuing Banks and Swing Line Bank and J.P. Morgan Chase Bank, N.A. as Paying Agent and Citicorp USA, inc. and JP Morgan Chase Bank, N.A. as Co-Administrative Agents and Citigroup Global markets Inc. and J.P. Morgan Securities Inc. as Joint Lead Arrangers and Joint Bookrunners (Incorporated by reference to Exhibit 99.1 of the Registrant s Current Report on Form 8-K filed with the Commission on September 27, 2007, File No. 000-26823).
10.49	Note Purchase Agreement, 6.28% Senior Notes Due June 26, 2015, and 6.72% Senior Notes due June 26, 2018, dated as of June 26, 2008, by and among Alliance Resource Operating Partners, L.P. and various investors (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed with the Commission on July 1, 2008, File No. 000-26823).
10.50	First Amendment, dated as of June 26, 2008, to the Note Purchase Agreement, dated August 16, 1999, 8.31% Senior Notes due August 20, 2014, by and among Alliance Resource Operating Partners, L.P. (as successor to Alliance Resource GP, LLC) and various investors. (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K filed with the Commission on July 1, 2008, File No. 000-26823).
10.51	Letter Amendment No. 1, dated as of June 26, 2008, to the Second Amended and Restated Credit Agreement, dated as of September 25, 2007, among Alliance Resource Operating Partners, L.P. as Borrower, the Initial Lenders, Initial Issuing Banks and Swing Line Bank, in each case as named therein, JPMorgan Chase Bank, N.A. as Paying Agent, Citicorp USA, Inc. and JPMorgan Chase Bank, N.A. as Co-Administrative Agents, and Citigroup Global Markets Inc. and J.P. Morgan Securities, Inc. as Joint Lead Arrangers and Joint Bookrunners. (Incorporated by reference to Exhibit 99.1 of the Registrant s Current Report on Form 8-K filed with the Commission on July 1, 2008, File No. 000-26823).
*10.52(1)	Third Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan.
*10.53(1)	Second Amendment to the Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors.
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-8, Registration Statement No. 333-85258.
* 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 2, 2009, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
* 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 2, 2009, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
* 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 2, 2009, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* 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 2, 2009, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*	Filed herewith (or furnished, in the case of Exhibits 32.1 and 32.2).

(1) Denotes management contract or compensatory plan or arrangement.
(2) Portions of this exhibit have been omitted pursuant to a request for confidential treatment under Rule 24b-2 of the Securities Exchange Act of 1934, as amended, and the omitted material has been separately filed with the Securities and Exchange Commission.

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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 2, 2009.

ALLIANCE RESOURCE PARTNERS, L.P.

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

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

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

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

Signature	Title	Date
/s/ Joseph W. Craft III Joseph W. Craft III	President, Chief Executive Officer, and Director (Principal Executive Officer)	March 2, 2009
/s/ Brian L. Cantrell Brian L. Cantrell	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 2, 2009
/s/ Michael J. Hall Michael J. Hall	Director	March 2, 2009
/s/ John P. Neafsey John P. Neafsey	Director	March 2, 2009
/s/ John H. Robinson John H. Robinson	Director	March 2, 2009
/s/ Wilson M. Torrence Wilson M. Torrence	Director	March 2, 2009
/s/ Charles R. Wesley Charles R. Wesley	Executive Vice President and Director	March 2, 2009