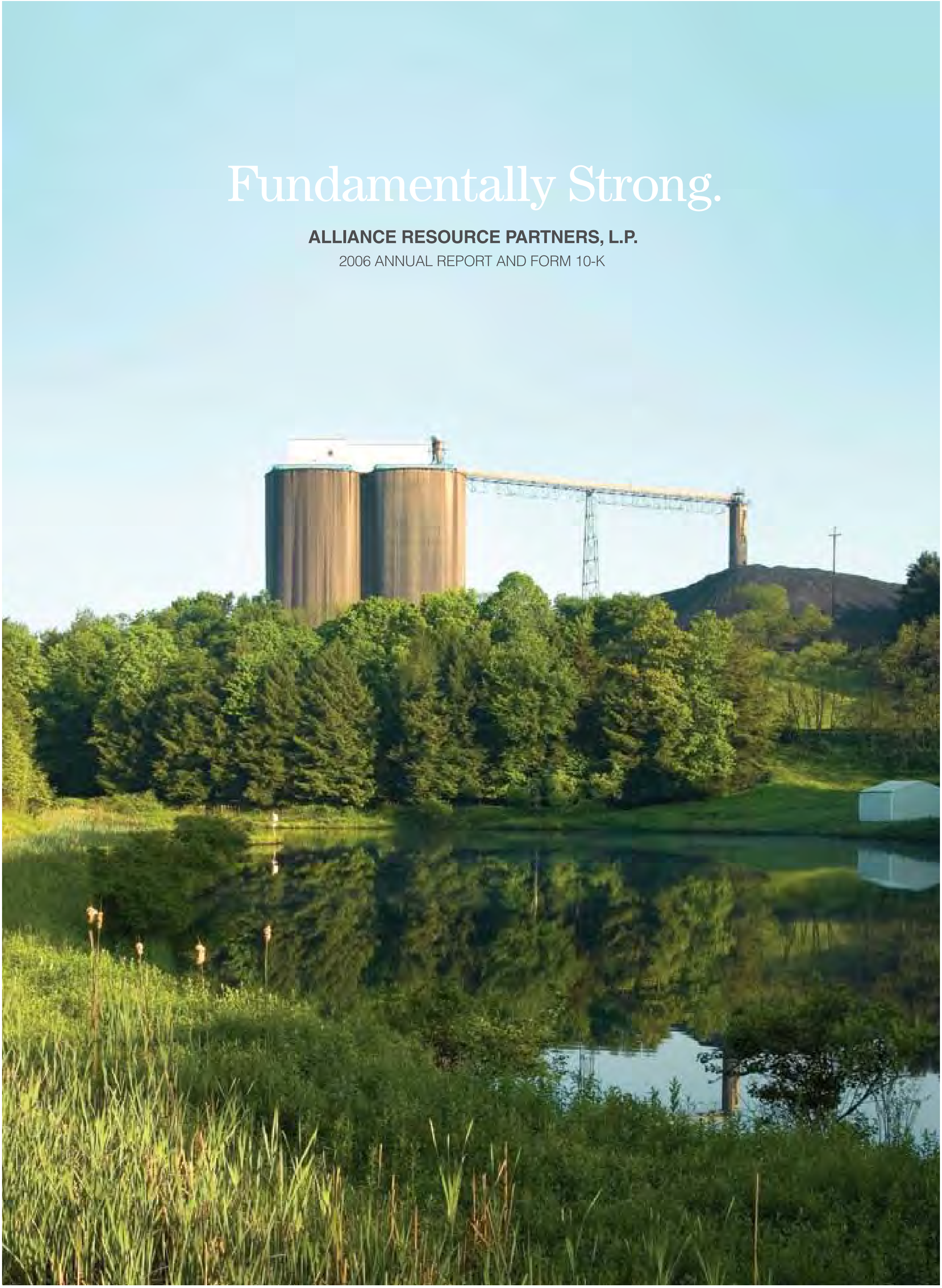
# Fundamentally Strong.

**ALLIANCE RESOURCE PARTNERS, L.P.**

2006 ANNUAL REPORT AND FORM 10-K



## FINANCIAL HIGHLIGHTS

| MILLIONS EXCEPT PER UNIT AND PER TON AMOUNTS | 2006 | 2005 |
|---|---|---|
| **OPERATING DATA** | | |
| TONS SOLD | 24.4 | 22.8 |
| TONS PRODUCED | 23.7 | 22.3 |
| REVENUES PER TON SOLD | $ 38.02 | $ 35.07 |
| COST PER TON SOLD | $ 27.78 | $ 25.00 |
| **FINANCIAL DATA** | | |
| REVENUES | $ 967.6 | $ 838.7 |
| INCOME FROM OPERATIONS | $ 183.3 | $ 173.9 |
| NET INCOME | $ 172.9 | $ 160.0 |
| ADJUSTED BASIC NET INCOME PER LP UNIT[2][3] | $ 4.07 | $ 4.07 |
| ADJUSTED DILUTED NET INCOME PER LP UNIT[2][3] | $ 4.03 | $ 3.99 |
| BASIC NET INCOME PER LP UNIT[2] | $ 3.06 | $ 2.89 |
| DILUTED NET INCOME PER LP UNIT[2] | $ 3.03 | $ 2.84 |
| TOTAL ASSETS | $ 635.0 | $ 532.7 |
| TOTAL DEBT | $ 144.0 | $ 162.0 |
| NET CASH PROVIDED BY OPERATING ACTIVITIES | $ 250.9 | $ 193.6 |

[2] The weighted average basic units outstanding for the years ended December 31, 2006 and 2005, were 36,425,350 and 36,288,527, respectively, and on a fully diluted basis, were 36,810,383 and 36,977,061, respectively.

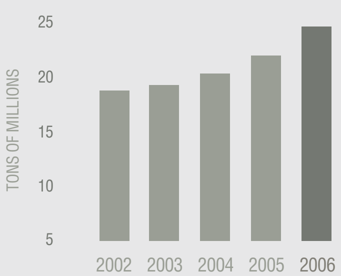
[3] See page 16 of the 2006 Annual Report for Adjusted Basic and Diluted Net Income per LP unit definition, a reconciliation of Adjusted Basic and Diluted Net Income per LP unit to Basic and Diluted Net Income per LP unit and Management's reason why disclosure of Adjusted Basic and Diluted Net Income per LP unit is useful to investors.

Alliance Resource Partners, L.P.

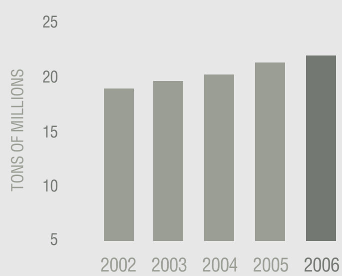
# Core Strengths and Investment Highlights.

## Alliance Resource Partners again delivered on its promise of growth with record results in all key financial and operating areas.

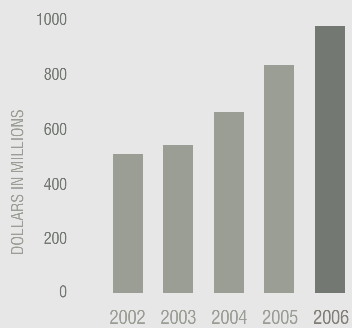
**Revenues**. In 2006 revenues of $967.6 million were up 15.4% from 2005 revenues of $838.7 million.
**Net income**. 2006 net income increased 8.1% to $172.9 million compared to 2005 net income of $160.0 million.
**EBITDA**[(1)]. EBITDA (net income before net interest expense, income taxes, depreciation, depletion and amortization, minority interest and cumulative effect of accounting change) was up 9.0% to $250.8 million from 2005 EBITDA[(1)] of $230.1 million.
**Distribution**. Unitholder distributions increased 17.4% during 2006 to a current annualized rate of $2.16 per unit.



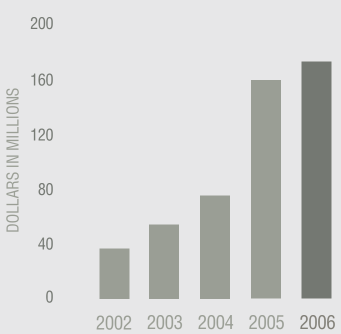

**TONS OF COAL SOLD**
2002-2006



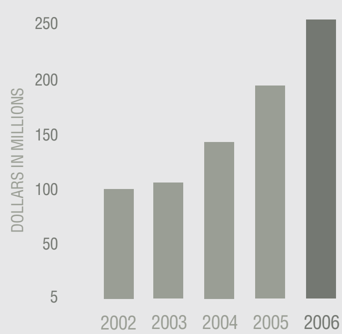

**TONS OF COAL PRODUCED**
2002-2006



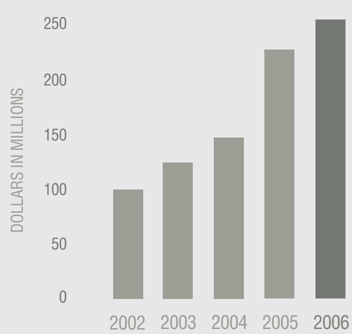

**REVENUES**
2002-2006




**NET INCOME**
2002-2006




**CASH FLOW FROM OPERATIONS**
2002-2006




**EBITDA**[(1)]
2002-2006

[(1)] See page 15 of the 2006 Annual Report for EBITDA definition, a reconciliation of EBITDA to Net Income and Management's reason why disclosure of EBITDA is useful to investors.

Alliance Resource Partners, L.P.

# Coal Mining Complexes.


Current Mining Operation | Future Growth Project | Transfer Terminal

1 | **PATTIKI COMPLEX**
Pattiki Mine

**Type**: Underground
**Method**: Continuous Mining
**Coal Type**: High-sulfur
**Transportation**: EVWR & Barge

2 | **RIVER VIEW COMPLEX**
(Updating existing permits)

**Type**: Underground
**Method**: Continuous Mining
**Coal Type**: High-sulfur

3 | **DOTIKI COMPLEX**
Dotiki Mine

**Type**: Underground
**Method**: Continuous Mining
**Coal Type**: High-sulfur
**Transportation**: CSX, PAL, Truck & Barge

4 | **MOUNT VERNON TRANSFER TERMINAL**

**Operation**: Ohio River Rail to Barge Transloading Facility
Rail Service: CSX, EVWR & PAL

5 | **WARRIOR COMPLEX**
Warrior Mine

**Type**: Underground
**Method**: Continuous Mining
**Coal Type**: High-sulfur
**Transportation**: CSX, PAL & Truck

6 | **HOPKINS COMPLEX**
Elk Creek Mine

**Type**: Underground
**Method**: Continuous Mining
**Coal Type**: High-sulfur
**Transportation**: CSX, PAL & Truck

7 | **GIBSON COMPLEX**
Gibson North Mine

**Type**: Underground
**Method**: Continuous Mining
**Coal Type**: Low-sulfur
**Transportation**: Truck & Barge

Gibson South Mine
(Permitting in process)

**Type**: Underground
**Method**: Continuous Mining
**Coal Type**: Medium-sulfur

8 | **PONTIKI COMPLEX**
Excel No. 2 & Van Lear Mines

**Type**: Underground
**Method**: Continuous Mining
**Coal Type**: Low-sulfur
**Transportation**: NS & Truck

9 | **MC MINING COMPLEX**
Excel No. 3 Mine

**Type**: Underground
**Method**: Continuous Mining
**Coal Type**: Low-sulfur
**Transportation**: CSX & Truck

10 | **TUNNEL RIDGE COMPLEX**
(Permitting in process)

**Type**: Underground
**Method**: Longwall and Continuous Mining
**Coal Type**: High-sulfur

11 | **PENN RIDGE COMPLEX**
(Initiating permitting process)

**Type**: Underground
**Coal Type**: High-sulfur

12 | **METTIKI COMPLEX**
Mountain View Mine

**Type**: Underground
**Method**: Longwall and Continuous Mining
**Coal Type**: Medium-sulfur
**Transportation**: CSX & Truck

# To Our Fellow Unitholders.

There are four words from the Chief Executive Officer of a publicly-held entity that never grow old: “We’re pleased to report.” While some would consider those four words a cliché, they are appropriate when the reporting involves the sixth consecutive record year for Alliance Resource Partners.

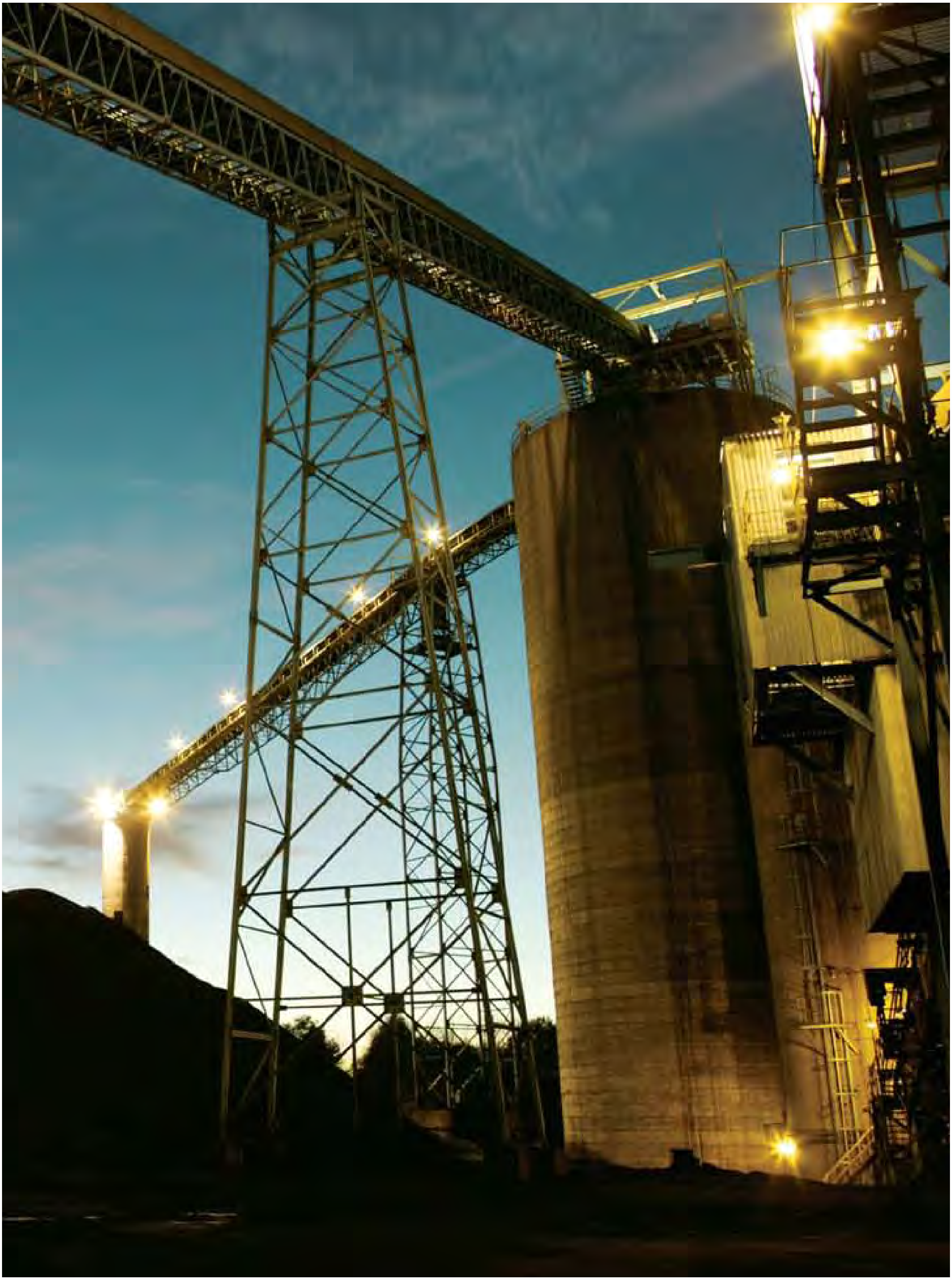
Indeed, we again delivered on our promise of growth, and we’re pleased to report:

- Record revenues of $967.6 million up 15.4% from 2005 revenues of $838.7 million.
- Record net income of $172.9 million up 8.1% from 2005 net income of $160.0 million.
- Record EBITDA(1) (net income before net interest expense, income taxes, depreciation, depletion and amortization, minority interest and cumulative effect of accounting change) of $250.8 million up 9.0% from 2005 EBITDA(1) of $230.1 million.
- Current quarterly distribution to unitholders of $0.54 per unit, an annualized rate of $2.16 per unit, compared to an annualized rate of $1.84 at the end of 2005. This represents an increase in cash distributions to unitholders of 17.4% over the past twelve months.
- Record tons sold of 24.4 million up 7.0% from 22.8 million in 2005.
- Record average coal sales prices per ton of $36.79 up 9.3% from 2005.

We are proud of the outstanding financial and operating performance delivered by the Partnership during 2006, and that our management, which cumulatively owns approximately 44% of Alliance Resource Partners, clearly shares with you the goals of every investor in the Partnership. Stated simply the goals are two-fold: 1. return on one’s investment, and 2. appreciation of that investment—i.e., a higher price per unit.

The first goal is one that Alliance Resource Partners is proud to have fulfilled. Over the past four years, for example, we have increased quarterly cash distributions to our unitholders by 106%, an annual compounded growth rate of nearly 20%.

The second goal, at least during this past fiscal year, was not attained. Why? The coal sector was, to put it mildly, out of favor with the equity market this past year.



# Continued Growth and Consistency.

Coal remains the energy resource of choice as this country's electricity is provided by 50% coal, 19% nuclear, 18% natural gas, and 7% hydroelectric. It remains the least volatile, least expensive, and is the most abundant fossil fuel in the United States.

While the market drove coal equities down during 2006, the long-term fundamentals, which originally brought favorable attention to this segment, were remarkably unchanged. Coal remains the energy resource of choice as 50% of this country's electricity generation is provided by coal compared to 19% nuclear, 18% natural gas, and 7% hydroelectric. Obviously, like any commodity, coal prices will fluctuate and occasionally the equity market is disturbed by short-term price cycles. But, as even a cursory analysis will show, coal continues to be the least volatile and most abundant fossil fuel in the United States.

Moving from a coal industry perspective to our own point-of-view, we constantly work toward creating sustainable and consistent growth through a variety of strategies. For example, our strategy of maintaining a significant long-term contract position with our customer results in greater predictability of sales volume and price and has historically provided us with less volatility during market fluctuations.

With our customers' installation of scrubber technology to meet the increased clean air standards of our country, we believe the demand for scrubber-quality, or high-sulfur, coal will increase in the future. As a result, our future remains bright as we continue to focus our efforts on securing the permits and long-term coal sales commitments needed to bring our growth projects at River View, Gibson South, Tunnel Ridge and Penn Ridge into production.

These four projects, along with our current operations in the Illinois Basin and Northern Appalachian regions, leave Alliance Resource Partners well positioned to take advantage of the growth we anticipate in these markets. In addition, we continue to be alert to further growth through acquisitions that would enhance our operating portfolio.

As our country continues to focus on energy independence, coal will play an important role in the generation of secure, reliable, low-cost domestic energy. The construction of a new generation of efficient, coal-fired power plants and advances in cost-effective coal-to-liquids and coal-to-gas technologies are evidence of the role of coal in our country's energy future. Coal is a sound investment, today and tomorrow, and our record supports such a judgment.

# FUNDAMENTAL STRENGTHS

* DIVERSITY IN GEOGRAPHY[4] AND PRODUCT.[5]
* EFFICIENT, LOW-COST OPERATING HISTORY.
* CONSISTENT GROWTH – SIX CONSECUTIVE YEARS OF RECORD RESULTS.
* LONG-TERM RELATIONSHIPS WITH ELECTRIC UTILITIES AND INDUSTRIAL CUSTOMERS.
* FOURTH LARGEST COAL PRODUCER IN THE EASTERN UNITED STATES.[6]
* VISIBLE INVENTORY OF GROWTH PROJECTS.
* PROVEN TRACK RECORD OF EXECUTING GROWTH STRATEGY.
* STRONG ECONOMIC ALIGNMENT WITH UNITHOLDERS.

(4) Diversity in geography (we are well-positioned in three of the United States' coal producing areas)
(5) and product (our reserves include low-sulfur, medium-sulfur, and scrubber quality, or high-sulfur coal).
(6) Platts coal data as of September 30, 2006.

Fundamentally Strong

# Our Primary Objective is Unchanged.

And that is to create sustainable, capital-efficient growth in distributable cash flow that will enable growth in distributions for Alliance unitholders. We will do that by continuing to be results oriented with confidence that our long-term promise and performance will be recognized by the equity market.

With ever increasing needs for energy security and economic growth in our country, the fundamentals that have been the strength of Alliance Resource Partners remain unchanged. Coal, as the United States' most abundant energy resource, is uniquely positioned to not only meet the expanded demands of industry and consumers, but to help reduce reliance upon imported energy resources.

Coal is our country's first line of defense in the battle for increased energy independence. As research and technology continue to advance and current applications accelerate, coal will continue to become increasingly compatiable with environmentally sound policies.

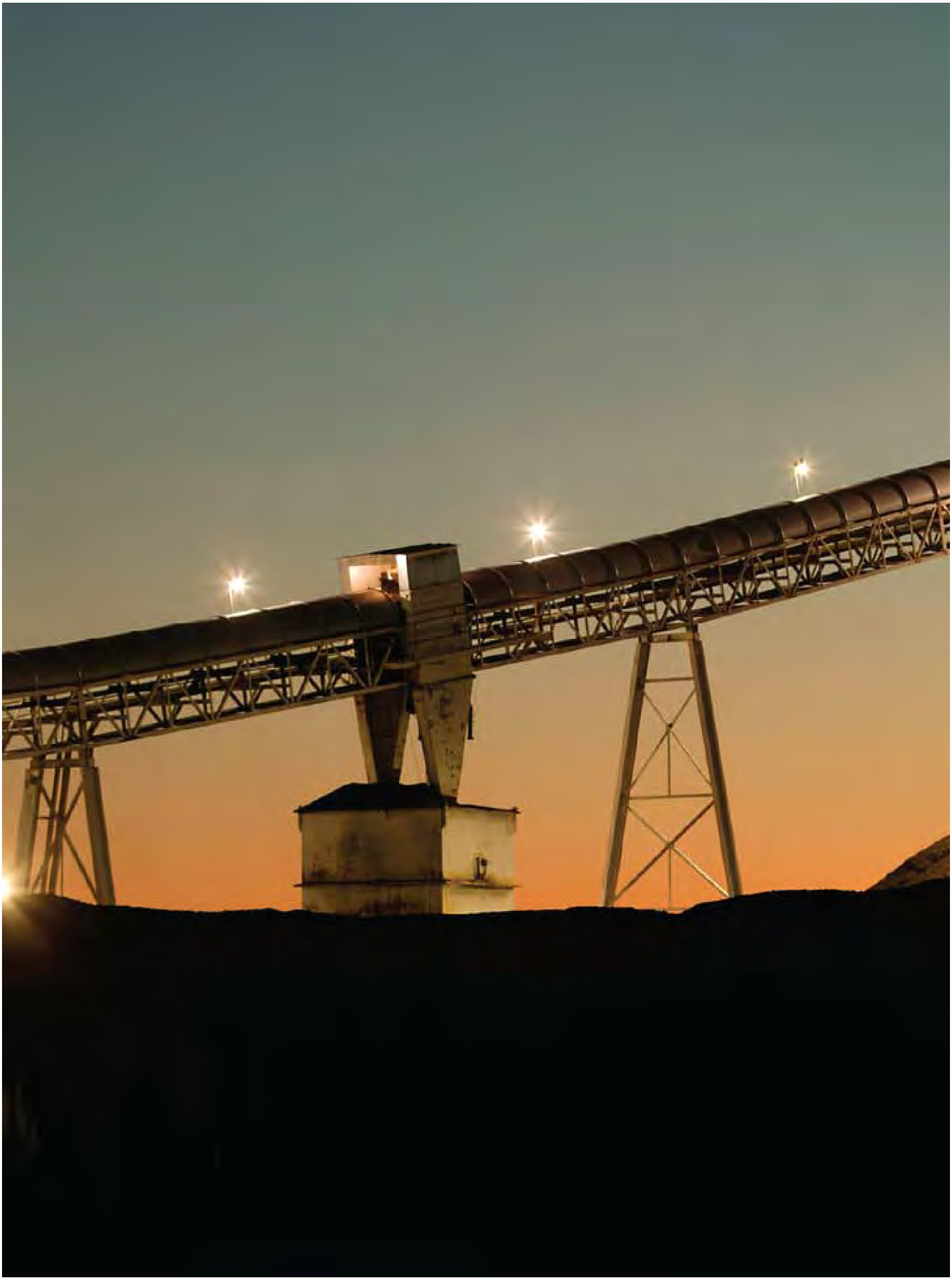
Meanwhile, it is important to remember the strong position of Alliance Resource Partners in this sector of the domestic energy industry.

**Fundamental Strengths**

* Diversity in geography and product.
* Efficient, low-cost operating history.
* Consistent growth—six consecutive years of record results.
* Long-term relationships with electric utilities and industrial customers.
* Fourth largest coal producer in the eastern United States.
* Visible inventory of growth projects.
* Proven track record of executing growth strategy.
* Strong economic alignment with unitholders.

(Geographically, we are well-positioned in three of the four United States' coal producing areas, and our reserves include low-sulfur, medium-sulfur, and scrubber quality, or high-sulfur coal).

By achieving numerous operating highlights during 2006, we continued to build toward a bright future for Alliance Resource Partners.



# Progress as Planned.

## Alliance Resource Partners completed several major projects during 2006. Three of the most significant included activities at our Elk Creek, Mountain View and Pontiki Mines.

We completed development of our Elk Creek Mine in Hopkins County, Kentucky, during 2006 and are operating that mine at full production as 2007 begins. As you may recall, the Elk Creek Mine replaces the Newcoal surface mining operation, which was depleted at the end of 2005. As planned, we used some of the Newcoal infrastructure in the development of underground operations at Elk Creek.

During the year we completed the development of our Mountain View Mine in West Virginia. As planned, we completed coal production operations at the Mettiki D-Mine in Maryland and transitioned our longwall operation across the state line to Mountain View during the fourth quarter of 2006. The Mountain View Mine is now successfully operating as scheduled and continues to use the Mettiki complex surface facilities in Maryland.

We also successfully moved our production operations at the Pontiki Complex in East Kentucky to the Van Lear seam and the Albridge Branch area of the Pond Creek seam. In addition, we began construction of a rail load out facility at our Gibson County Mine. Completion of this rail facility will provide Gibson County with access to expanded market opportunities.

# Safety Enhancing Projects.

Our safety performance has consistently been industry leading. We continuously seek to improve the safety of our operations through an emphasis on training and a commitment to innovative uses of the best available technology. During 2006, we concentrated our efforts on three safety-enhancing projects.

We have installed proprietary Miner Tracking Systems at all operations. Our Miner & Equipment Tracking System, or METS, is an electronic safety and tracking system designed specifically for mining environments to track underground personnel and equipment.

The system is an invaluable tool for increasing safety, productivity, and efficiency of mining operations. We're additionally pleased to report that the Mine Safety and Health Administration has approved METS, and other coal companies have shown an interest in acquiring this tracking system for their own operations.

Reliable, accurate communication is essential to a safe operating environment and last year we completed a state-of-the-art Leaky Feeder mine communications system at all Alliance Resource Partners' operations.

We have also installed fiber optic-based mine monitoring systems at all operations to enhance our ability to constantly evaluate key safety measurements within our mines.

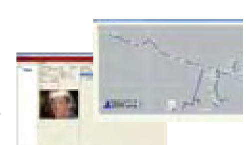
## METS

**MINER EQUIPMENT & TRACKING SYSTEM**

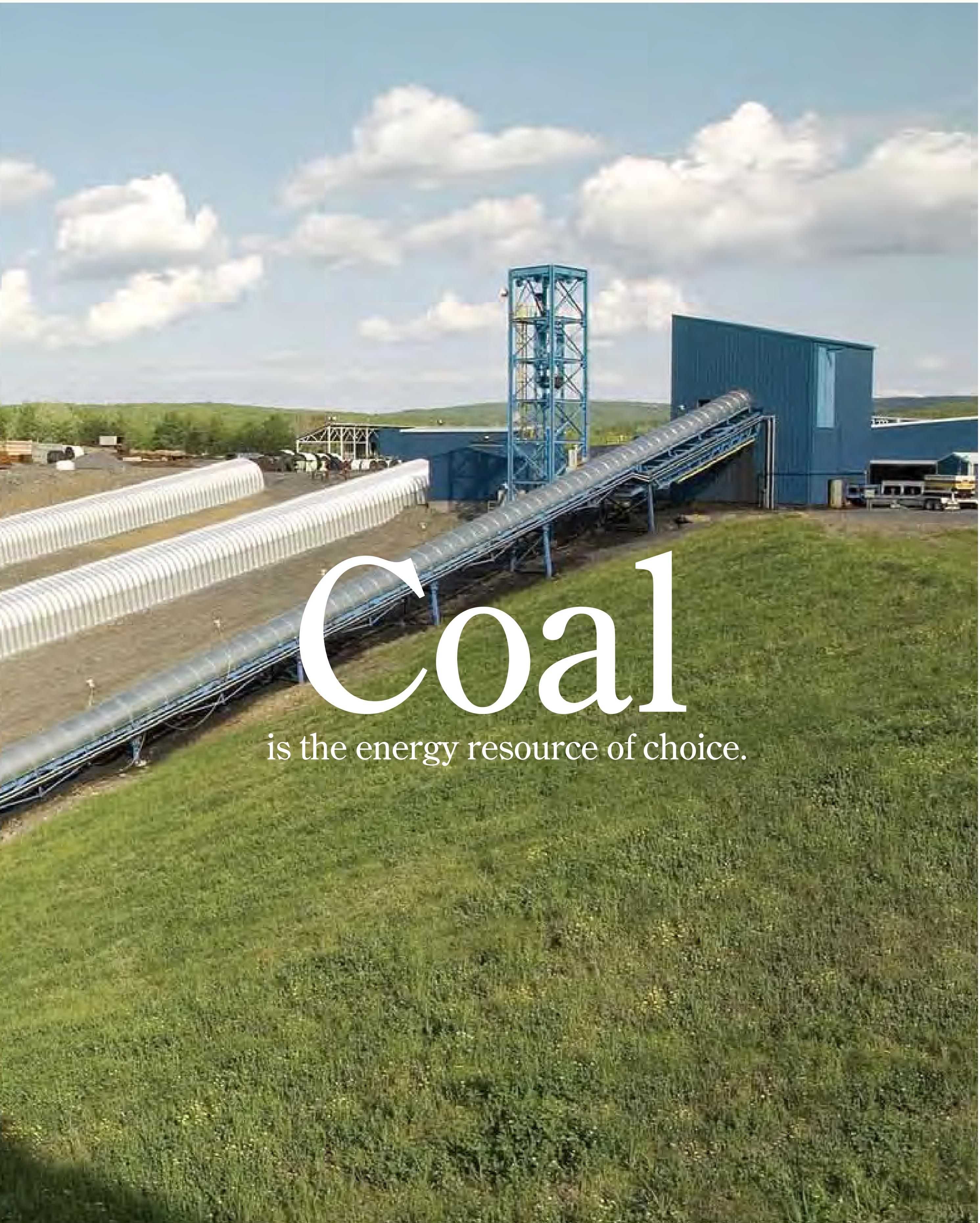
***RFID Tags*** *Transmits an identifying signal to readers.*

***Readers*** *Receive transmission from tags and relay information to server.*

***Server*** *Receives tag information from readers and stores data for workstations.*



***Staging Monitor*** *Used to display miners in staging area and verify tag operation.*



# Coal

is the energy resource of choice.

# Our Board of Directors.

As 2007 began, our Partnership welcomed two new members to our board of directors as three veteran directors retired from the board. We are pleased that all of our retiring board members will continue to serve the Partnership in the future as one assumes additional senior management responsibilities and two remain available to provide advice and counsel.

**Merribel S. Ayres and Wilson M. Torrence have joined the board**. Ms. Ayres has been a leader in the Washington D.C. business and public policy community for more than two decades and founded the Lighthouse Consulting Group in 1996. Mr. Torrence retired from Fluor Corporation in 2006 as a senior vice president and is now providing investment and business consulting services for clients in various energy-related businesses. Both of these new board members bring a wealth of diverse experience as well as specialized knowledge in various energy-related endeavors.

**Retiring from the board are John J. MacWilliams, Preston R. Miller and Robert G. Sachse**. Both Messrs. MacWilliams and Miller have been valuable members of our board since 1996 and we're pleased they will continue to be involved with the partnership by providing advice and counsel as we pursue our strategic growth initiatives. Meanwhile, I'm pleased that Mr. Sachse, whose coal industry experience dates to 1982 and who formerly served as chief operating officer of MAPCO, Inc., will take on an expanded role with the partnership as executive vice president with a primary focus on marketing and strategic growth opportunities.

Fundamentally Strong

# A Bright Future.

We are confident in the fundamental strength of both our industry and our Partnership. And our confidence is built upon the sound foundation of six consecutive years of record results and strong distribution growth to unitholders.

So far as the future is concerned, we will continue to be dedicated to creating sustainable increases in cash flow that results in continued distribution growth to our unitholders. We will demonstrate that dedication through continued focus on the long-term. As a result, our production growth will be commensurate with a sound economy, the growth of our customers, as well as the addition of new customers. With our attractive position in scrubber-quality coal and our identified development projects at River View, Gibson South, Tunnel Ridge and Penn Ridge, we believe we are in a position to continue to growth internally at a sustainable pace.

External growth through acquisition opportunities is another option as we look to the future. Alliance Resource Partners has the balance sheet, financial resources, cash flow and an experienced management team with the potential to grow by acquisitions should the right opportunities be found.

As we look forward, coal will continue to play a major role in our country's energy future. We will continue to advocate the need for research and technology development to ensure environmentally responsible mining as well as use of our natural resources.

We are confident in the fundamental strength of both our industry and our Partnership. Our confidence is built upon the sound foundation of six consecutive years of record results and strong distribution growth to unitholders. The future for the industry and Alliance Resource Partners continues to be bright—we're pleased to report.

**Joseph W. Craft III**
President and Chief Executive Officer
April 20, 2007

**Reconciliation of GAAP "Cash Flows Provided by Operating Activities" to non-GAAP "EBITDA" and Reconciliation of Non-GAAP "EBITDA" to GAAP "Net Income" (in thousands).**

EBITDA 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).

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, | | | | |
|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2003 | 2002 |
| Cash flows provided by operating activities | $ 250,923 | $ 193,618 | $ 145,055 | $ 110,312 | $ 101,306 |
| Long-term incentive plan | (4,112) | (8,193) | (20,320) | (7,687) | (2,338) |
| Reclamation and mine closing | (2,101) | (1,918) | (1,622) | (1,341) | (1,365) |
| Coal inventory adjustment to market | (319) | (573) | (488) | (687) | (48) |
| Net gain (loss) on sale of property, plant and equipment | 1,188 | (179) | 332 | 885 | 41 |
| Loss on retirement of damaged vertical belt equipment | - | (1,298) | - | - | - |
| Other | (1,119) | (580) | (587) | (532) | 973 |
| Net effect of working capital changes | (5,317) | 34,770 | 7,915 | (553) | (11,376) |
| Interest expense, net | 9,175 | 11,816 | 14,963 | 15,981 | 16,360 |
| Income taxes | 2,443 | 2,682 | 2,641 | 2,577 | (1,094) |
| EBITDA | 250,761 | 230,145 | 147,889 | 118,955 | 102,459 |
| Depreciation, depletion and amortization | (66,489) | (55,637) | (53,664) | (52,495) | (52,408) |
| Interest expense, net | (9,175) | (11,816) | (14,963) | (15,981) | (16,360) |
| Income taxes | (2,443) | (2,682) | (2,641) | (2,577) | 1,094 |
| Cumulative effect of accounting change | 112 | - | - | - | - |
| Minority interest | 161 | - | - | - | - |
| Net income | $ 172,927 | $ 160,010 | $ 76,621 | $ 47,902 | $ 34,785 |

**Reconciliation of GAAP "Net Income per Limited Partner Unit" reflecting the impact of EITF 03-6 to non-GAAP "Adjusted Net Income per Limited Partner Unit"**

Net income per limited partner unit as dictated by *Emerging Issues Task Force ("EITF") Issue No. 03-6, Participating Securities and the Two-Class Method under FASB Statement No. 128*, is theoretical and pro forma in nature and does not reflect the economic probabilities of whether earnings for an accounting period would or could be distributed to unitholders. The Partnership Agreement does not provide for the distribution of net income, rather, it provides for the distribution of available cash, which is a contractually defined term that generally means all cash on hand at the end of each quarter after establishment of sufficient cash reserves required to operate the Partnership in a prudent manner. Accordingly, the distributions we have paid historically and will pay in future periods are not impacted by net income per limited partner unit as dictated by EITF 03-6.

In addition to net income per limited partner unit as calculated in accordance with EITF 03-6, we intend to continue to present "adjusted net income per limited partner unit," as reflected in the table below. "Adjusted net income per limited partner unit," as presented in the table below, is defined as net income after deducting the amount allocated to the general partners' interests, including the managing general partner's incentive distribution rights, divided by the weighted average number of outstanding limited partner units during the period.

As part of this calculation, in accordance with the cash distribution requirements contained in the Partnership Agreement, Partnership net income is first allocated to the managing general partner based on the amount of incentive distributions attributable to the period. The remainder is then allocated between the limited partners and the general partners based on their respective percentage ownership in the Partnership. Adjusted net income per limited partner unit 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 actual operation of our Partnership Agreement with respect to the rights of the general and limited partners participation in distributions,
- the financial performance of our assets without regard to financing methods or capital structure; and 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.

Our method of computing adjusted net income per limited partner unit may not be the same method used to compute similar measures reported by other companies and may be computed differently by us in different contexts.

| | YEAR ENDED DECEMBER 31, | |
|---|---|---|
| | 2006 | 2005 |
| Net income per Limited Partner Unit - | | |
| Basic | $ 3.06 | $ 2.89 |
| Diluted | $ 3.03 | $ 2.84 |
| Dilutive impact of theoretical distribution of earnings pursuant to EITF 03-6 - | | |
| Basic | $ 1.01 | $ 1.18 |
| Diluted | $ 1.00 | $ 1.15 |
| Adjusted Net Income Per Limited Partner Unit - | | |
| Basic | $ 4.07 | $ 4.07 |
| Diluted | $ 4.03 | $ 3.99 |

Form 10-K

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, 2006

OR

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

FOR THE TRANSITION PERIOD FROM _____________TO_____________

COMMISSION FILE NO.: 0-26823

# ALLIANCE RESOURCE PARTNERS, L.P.

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

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

1717 SOUTH BOULDER AVENUE, SUITE 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 | 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. [X] Yes [ ] No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

[ ] Yes [X] No

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

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

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

Large Accelerated Filer [X]   Accelerated Filer [ ]   Non-Accelerated Filer [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). [ ] Yes [X] No

The aggregate value of the common units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $736,276,929 as of June 30, 2006, 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 28, 2007, 36,550,659 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 and Section 21E of the Exchange Act and 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 forward-looking 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;
- fluctuation in coal prices, which could adversely affect our operating results and cash flows;
- risks associated with the expansion of our operations and properties;
- deregulation of the electric utility industry or the effects of any adverse change in the domestic coal industry, electric utility industry, or general economic conditions;
- dependence on significant customer contracts, including renewing customer contracts upon expiration of existing contracts;
- customer bankruptcies and/or cancellations or breaches to existing contracts;
- customer delays or defaults in making payments;
- fluctuations in coal demand, prices and availability due to labor and transportation costs and disruptions, equipment availability, governmental regulations and other factors;
- our productivity levels and margins that we earn on our coal sales;
- greater than expected increases in raw material costs;
- greater than expected shortage of skilled labor;
- any unanticipated increases in labor costs, adverse changes in work rules, or unexpected cash payments associated with post-mine reclamation and workers' compensation claims;
- any unanticipated increases in transportation costs and risk of transportation delays or interruptions;
- greater than expected environmental regulation, costs and liabilities;
- a variety of operational, geologic, permitting, labor and weather-related factors;
- risks associated with major mine-related accidents, such as mine fires, or interruptions;
- results of litigation, 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;
- legislation, regulatory and court decisions;
- the impact from provisions of The Energy Policy Act of 2005;
- replacement of coal reserves;
- a loss or reduction of the direct or indirect benefit from certain state and federal tax credits, including non-conventional source fuel 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.

**Significant Relationships Referenced in this Annual Report**

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

# PART I

## ITEM 1. BUSINESS

### General

We are a diversified producer and marketer of coal to major United States utilities and industrial users. We began mining operations in 1971 and, since then, have grown through acquisitions and internal development to become what we believe to be the fourth largest coal producer in the eastern United States. At December 31, 2006, we had approximately 633.9 million tons of reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. In 2006, we produced 23.7 million tons of coal and sold 24.4 million tons of coal of which 30.0% was low-sulfur coal, 13.9% was medium-sulfur coal and 56.1% was high-sulfur coal. In 2006, approximately 96.1% of our medium- and high-sulfur coal was sold to utility plants with installed pollution control devices, also known as "scrubbers," to remove sulfur dioxide. We classify low-sulfur coal as coal with a sulfur content of less than 1%, medium-sulfur coal as coal with a sulfur content between 1% and 2%, and high-sulfur coal as coal with a sulfur content of greater than 2%.

At December 31, 2006, we operated eight mining complexes in Illinois, Indiana, Kentucky, Maryland, and West Virginia. Three of our mining complexes supplied coal feedstock and provided services to third-party coal synfuel facilities located at or near these complexes. We also operated 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 existing, adjacent or neighboring properties.

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) (formerly known as Alliance Coal Corporation), 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, our President and Chief Executive Officer.

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 own and become the 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." Upon the closing of the AHGP IPO, AHGP owned, directly and indirectly, 100% of the members’ interest of MGP, a 0.001% managing interest in Alliance Coal, the incentive distribution rights in ARLP and 15,550,628 common units of ARLP. In November 2006, AHGP contributed 6,459 common units of ARLP to MGP and MGP contributed these ARLP units to us in exchange for a general partner interest in our Intermediate Partnership. The unit contribution by MGP was necessary for it to maintain its 1.0001% general partner interest in the Intermediate Partnership.

Our internet address is www.arlp.com, and we make available on our internet website our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and Forms 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. Our "Code of Ethics" for our chief executive officer and our senior financial officers is also posted on our website.

**Recent Developments**

*New Mine Safety Laws and Regulations.* In 2006, the U.S. Congress, as well as several state legislatures (including those in West Virginia, Illinois and Kentucky), passed new legislation addressing mine safety practices and imposing stringent new mine safety and accident reporting requirements and increasing civil and criminal penalties for violations of mine safety laws. In addition, the Mine Safety and Health Administration (MSHA), which monitors compliance with federal laws, published a final rule addressing mine safety equipment, training, and emergency reporting requirements. Although we are unable to quantify the impact, implementing and complying with these new laws and regulations have and are expected to continue to have an adverse impact on the results of our operations and financial position. Please read "—Mine Health and Safety Laws."

**Mining Operations**

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

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| **Regions and Complexes** | **2006** | **2005** | **2004** | **2003** | **2002** |
| | (tons in millions) | | | | |
| Illinois Basin: | | | | | |
| Dotiki, Warrior, Pattiki, Hopkins and Gibson complexes | 16.9 | 15.7 | 13.6 | 12.3 | 12.1 |
| Central Appalachian: | | | | | |
| Pontiki and MC Mining complexes | 3.5 | 3.3 | 3.6 | 3.6 | 3.0 |
| Northern Appalachian: | | | | | |
| Mettiki complex | 3.3 | 3.3 | 3.2 | 3.3 | 2.9 |
| Total | 23.7 | 22.3 | 20.4 | 19.2 | 18.0 |

***Illinois Basin Operations***

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. We have approximately 1,600 employees in the Illinois Basin and currently operate five mining complexes. Additionally, we host a coal synfuel facility at two of our mining complexes.

*Dotiki Complex.* 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. In 2004, the preparation plant throughput capacity was increased to 1,300 tons of raw coal an hour. Capacity was increased principally to accommodate a change in customer requirements for washed coal rather than raw coal.

Coal from the Dotiki complex is shipped via the CSX and PAL railroads and by truck on U.S. and state highways. Our primary customers for coal produced at Dotiki are Northern Indiana Public Service Company (NIPSCO), Seminole Electric Cooperative, Inc. (Seminole), and Tennessee Valley Authority (TVA), the latter two of which purchase our coal pursuant to long-term contracts for use in their scrubbed generating units.

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

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

We have entered into long-term agreements with SSO to host and operate its coal synfuel facility currently located at Warrior, supply the facility with coal feedstock, assist SSO with the marketing of coal synfuel and provide other services. These agreements, which expire on December 31, 2007, provide us with coal sales, rental and service fees from SSO based on the synfuel facility throughput tonnages. These amounts are dependent on the ability of SSO's members to use certain qualifying tax credits applicable to the facility. As discussed above, we sell most of the coal produced at Warrior to SSO, while Alliance Coal Sales, a division of Alliance Coal, assists SSO with the sale of its coal synfuel to our customers pursuant to a sales agency agreement. Certain of these services are performed by Alliance Service, Inc. (Alliance Service), a wholly-owed subsidiary of Alliance Coal. Alliance Service is subject to federal and state income taxes.

On April 23, 2006, SSO temporarily suspended operation of the synfuel facility due to the increase in the wellhead price of domestic crude oil. SSO resumed operation of the synfuel facility May 11, 2006. SSO again temporarily suspended operation of the synfuel facility due to the increase in the wellhead price of domestic crude oil, effective after production on July 31, 2006, after which SSO resumed production on September 5, 2006. During the suspension periods, we sold coal directly to SSO's synfuel customers under the "back up" coal-supply agreements referred to above. SSO has advised us that the continued operation of the synfuel facility is dependant upon the future price of crude oil. Non-conventional source fuel tax credits are subject to a pro-rata phase-out or reduction if the annual average wellhead price per barrel for all domestic crude oil as determined by the Secretary of the Treasury exceeds certain levels.

For 2006, the incremental annual net income benefit from the combination of the various coal synfuel-related agreements associated with the facility located at Warrior was approximately $21.6 million, assuming that coal pricing would not have increased without the availability of synfuel. The term of each of these agreements is subject to early cancellation pursuant to provisions customary for transactions of these types, including provisions permitting cancellation due to the unavailability of synfuel tax credits, the termination of associated coal synfuel sales contracts, and the occurrence of certain force majeure events. Therefore, the continuation of the revenues and incremental net income benefit associated with the coal synfuel production facility cannot be assured. Pursuant to our agreement with SSO, we are not obligated to make retroactive adjustments or reimbursements if SSO's tax credits are disallowed.

*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. Our Pattiki complex utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. The preparation plant has a throughput capacity of 1,000 tons of raw coal an hour.

Coal from the Pattiki complex is shipped via the Evansville Western and CSX railroads. Two of our primary customers for coal produced at Pattiki have been NIPSCO and Seminole for use in their scrubbed generating units. Pattiki production is also shipped via rail to our Mt. Vernon transloading facility for sale to utilities capable of receiving barge deliveries. In 2007, Pattiki expects to ship a significant portion of its production to Seminole, TVA, Corn Products International, Inc., and Tampa Electric Company.

*Hopkins Complex.* Hopkins County Coal's mining complex, which we acquired in January 1998, is located near the city of Madisonville in Hopkins County, Kentucky. During 2006, Hopkins County Coal ceased production from its Newcoal surface mine, which is being reclaimed, and continued with the development of its Elk Creek mine in the underground reserves leased by Hopkins County Coal in 2005.

The Elk Creek mine, an underground mining complex using continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal, emerged from development in the second quarter of 2006 with production from the operation of three mining units. Elk Creek has the capacity to increase production by adding a fourth unit should conditions in the marketplace so warrant. Operating at the three-unit level, we expect annual production to be approximately 2.6 million tons.

We are utilizing both existing and newly constructed coal handling and other surface facilities at Hopkins County Coal to process and ship coal produced from the Elk Creek mine. In conjunction with the development of the Elk Creek mine, Hopkins County Coal constructed a new preparation plant with a throughput capacity of 1,200 tons of raw coal an hour. Hopkins County Coal’s Elk Creek production can be shipped via the CSX and PAL railroads and by truck on U.S. and state highways.

*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 a throughput capacity of 700 tons of raw coal an hour. We refer to the reserves mined at this location as the "Gibson North" reserves. We also control undeveloped reserves in Gibson County that are not contiguous to the reserves currently being mined, which we refer to as the "Gibson South" reserves.

Production from Gibson is a low-sulfur coal that historically has been primarily shipped via truck approximately 10 miles on U.S. and state highways to Gibson’s principal customer, PSI Energy Inc. (d/b/a Duke Energy Indiana, Inc.), a subsidiary of Cinergy Corporation (d/b/a Duke Energy Corporation). Gibson’s production is also trucked to our Mt. Vernon transloading facility for sale to utilities capable of receiving barge deliveries. We are in the process of constructing a new rail loop at Gibson with access to both the CSX and Norfolk Southern railroads, which we currently anticipate will expand the market for coal produced at Gibson beginning mid-year 2007.

In January 2005, Gibson County Coal entered into long-term agreements with PC Indiana Synthetic Fuel #2, L.L.C. (PCIN) to host its coal synfuel facility, supply the facility with coal feedstock, assist PCIN with the marketing of coal synfuel and provide other services. The synfuel facility commenced operations at Gibson in May 2005. A significant portion of Gibson’s production is sold to PCIN. The agreements, which will expire on December 31, 2007, provide us with coal sales, rental and service fees from PCIN based on the synfuel facility throughput tonnages. These amounts are dependent on the ability of PCIN’s members to use certain qualifying tax credits applicable to the facility.

On May 11, 2006, PCIN temporarily suspended operation of the synfuel facility due to the increase in the wellhead price of domestic crude oil. PCIN resumed operation of the synfuel facility on September 27, 2006. During the suspension period, we sold coal directly to PCIN’s synfuel customers under "back up" coal-supply agreements, which automatically provide for the sale of our coal to these customers in the event that they do not purchase coal synfuel from PCIN. PCIN has advised us that the continued operation of the synfuel facility is dependant upon the future price of crude oil.

For 2006, the incremental annual net income benefit from the combination of the various coal synfuel related agreements associated with the facility located at Gibson was approximately $3.5 million, assuming that coal pricing would not have increased without the availability of synfuel. The term of each of these agreements is subject to early cancellation pursuant to provisions customary for transactions of these types, including the unavailability of synfuel tax credits, the termination of associated coal synfuel sales contracts, and the occurrence of certain force majeure events. Therefore, revenues and incremental net income associated with the coal synfuel production facility cannot be assured. Pursuant to our agreement with PCIN, we are not obligated to make retroactive adjustments or reimbursements if PCIN’s tax credits are disallowed.

We have partially completed the permitting process for the Gibson South reserves and continue to actively evaluate its development. Capital expenditures required to develop the Gibson South reserves are estimated to be in the range of approximately $100 million to $110 million, excluding capitalized interest and capitalized mine development costs associated with net cost related to incidental production. 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." Assuming sufficient sales commitments are obtained and the permitting process continues as anticipated, initial production could commence in 2008 to 2010. When the Gibson South mine reaches full production capacity, we expect annual production of approximately 2.7 million to 3.1 million tons. Definitive development commitment for Gibson South is dependent upon final approval by the board of directors of our managing general partner (Board of Directors).

*River View.* In April, 2006, we acquired 100% of the membership interest in River View Coal, LLC (River View) from ARH. River View currently controls, through coal leases or direct ownership, approximately 110.0 million tons of 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. River View is in the process of updating its existing permits and evaluating the timing and manner of future development of the reserve. Capital expenditures required to develop the River View reserves are estimated to be in the range of approximately $130 million to $160 million, excluding capitalized interest and capitalized mine development costs associated with net cost related to incidental production. 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." Assuming sufficient sales commitments are obtained and the permitting process continues as anticipated, initial production could commence in 2008 to 2010. When the River View mine reaches full production capacity, we expect annual production of approximately 3.1 million to 4.6 million tons. Definitive development commitment for River View is dependant upon final approval of 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 producing low-sulfur coal.

*Pontiki Complex.* Our subsidiary, Pontiki Coal, LLC (Pontiki), owns an underground mining complex located near the city of Inez in Martin County, Kentucky. We constructed the mine in 1977. Pontiki owns the mining complex and leases the reserves, and Excel Mining, LLC (Excel), an affiliate of Pontiki, conducts all mining operations. Our Pontiki operation utilizes continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal. The preparation plant has a throughput capacity of 900 tons of raw coal an hour. In the fourth quarter of 2005, Pontiki migrated some of its mining units from the Pond Creek seam into the Van Lear seam, and full production in the Van Lear seam was reached in the second quarter of 2006. As a result, production at Pontiki is now roughly 50% Pond Creek seam coal and 50% Van Lear seam coal. Coal produced in 2006 remained low sulfur, but because of changes in geology and production from the Van Lear seam, it no longer met 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 in large part to electric utilities located in the southeastern United States and also to industrial or stoker users throughout the eastern United States via the Norfolk Southern railroad or by truck via U.S. and state highways to various docks on the Big Sandy River in Kentucky.

*MC Mining Complex.* Our subsidiary, MC Mining, LLC (MC Mining), owns an underground mining complex located near the city of Pikeville in Pike County, Kentucky. We acquired the mine in 1989. MC Mining owns the mining complex and leases the reserves, and Excel, an affiliate of MC Mining, conducts all mining operations. The operation utilizes continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal. The preparation plant has a throughput capacity of 1,000 tons of raw coal an hour. Substantially all of the coal produced at MC Mining in 2006 met or exceeded the compliance requirements of Phase II of the CAA. Production from the mine is shipped via the CSX railroad or by truck via U.S. and state highways to various docks on the Big Sandy River. MC Mining sells its low-sulfur production primarily under short-term contracts and into the spot market.

On December 26, 2004, MC Mining was temporarily idled as a result of a mine fire. The fire was successfully extinguished and the affected area of the mine was completely isolated behind permanent barriers. Production resumed on February 21, 2005. For more information on the MC Mining mine fire, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

***Northern Appalachian Operations***

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

*Mettiki (MD) Operation.* For the past 29 years, our subsidiary, Mettiki Coal, LLC (Mettiki (MD)), has 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 of 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 in the Bakerstown seam) on properties controlled by Mettiki (MD) and another of our subsidiaries, Backbone Mountain, LLC, will continue to be processed at the Mettiki complex and will supplement 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, which has a throughput capacity of 1,350 tons of raw coal an hour, will continue coal processing activities. A portion of the Mettiki (WV) production will be transported to this preparation plant for processing, and then trucked to a newly constructed 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.

On June 15, 2006, Mettiki (MD) was issued a Notice of Violation by the Maryland Department of the Environment (MDE) for alleged exceedances of permitted sulfur dioxide emissions. These alleged exceedances occurred between May 23, 2006 and June 12, 2006 at the Mettiki (MD) Thermal Coal Dryer associated with our longwall mining operation located in Garrett County, Maryland. This self-reported violation was promptly corrected and Mettiki (MD) demonstrated its compliance to the satisfaction of MDE. Under applicable Maryland law, civil penalties of up to $25,000 per day of violation may be assessed. Mettiki (MD) is currently in negotiations with MDE to resolve this matter and, while the final penalty amount may exceed $100,000, we do not expect the final assessment to have a material impact on our operations or financial condition.

*Mettiki (WV) Operation.* In July 2005, Mettiki (WV) began continuous miner development in 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. Production from the Mountain View mine will be transported by truck either to the Mettiki (MD) preparation plant or to the coal blending facility at the VEPCO Mt. Storm Power Station.

Historically, our primary customer for the medium-sulfur coal produced at Mettiki (MD) has been VEPCO, which purchased the coal pursuant to a long-term contract for use in the scrubbed generating units at its Mt. Storm Power Station in West Virginia. A seven-year agreement to supply coal to the VEPCO Mt. Storm Power Station from the Mountain View mine was negotiated and finalized in June 2005. The agreement also serves as a "back up" coal-supply agreement with VEPCO for the sale of our coal in the event that VEPCO does not purchase coal synfuel from Mt. Storm Coal Supply, LLC (Mt. Storm Coal Supply).

Production from the Mountain View mine is primarily supplied to Mt. Storm Coal Supply for its synfuel facility, which is located at the Mt. Storm Power Station, pursuant to an agreement between Alliance Coal and Mt. Storm Coal Supply. This agreement will terminate at the end of 2007 in conjunction with the termination of the synfuel tax credit program, and, until that time, its continuation cannot be assured because the agreement is subject to early cancellation pursuant to provisions customary for transactions of this type, including the unavailability of synfuel tax credits, the termination of associated coal synfuel sales contracts, and the occurrence of certain force majeure events. Pursuant to our agreement with Mt. Storm Coal Supply, we are not obligated to make retroactive adjustments or reimbursements to the extent Mt. Storm Coal Supply’s tax credits are disallowed. For 2006, the incremental annual net income benefit from this agreement was approximately $1.3 million.

On July 18, 2006, Mt. Storm Coal Supply temporarily suspended operation of the synfuel facility due to the increase in the wellhead price of domestic crude oil. Mt. Storm Coal Supply resumed full operation of the synfuel facility on October 9, 2006. During the suspension period, we sold coal directly to VEPCO under the "back up" coal-supply agreement referred to above.

*Penn Ridge Coal.* In December of 2005, our subsidiary, Penn Ridge Coal, LLC (Penn Ridge), entered into a coal lease and sales agreement with affiliates of Allegheny Energy, Inc. (Allegheny), to pursue development of Allegheny's Buffalo coal reserve in Washington County, Pennsylvania. The Buffalo coal reserve lease is estimated to include approximately 55 million tons of high-sulfur coal in the Pittsburgh No. 8 seam. We have initiated the permitting process for the Buffalo Coal reserves and are actively evaluating its development. Capital expenditures required to develop the Penn Ridge reserves are estimated to be in the range of approximately $165 million to $175 million, excluding capitalized interest and capitalized mine development costs associated with net cost related to incidental production. For more information about mine development costs, please read "Mine Development Cost" under "Item 8. Financial Statements and Supplementary Data – Note 2. Summary of Significant Accounting Policies." Assuming sufficient sales commitments are obtained and the permitting process continues as anticipated, initial production could commence in 2009 to 2011. When the Penn Ridge mine reaches full production capacity, we expect annual production of up to 5.0 million tons. Definitive development commitment for Penn Ridge is dependent upon final approval of the Board of Directors.

*Tunnel Ridge.* Our subsidiary, Tunnel Ridge, LLC (Tunnel Ridge), controls, through a coal lease agreement with our special general partner, approximately 70 million tons of high-sulfur coal in the Pittsburgh No. 8 coal seam in West Virginia and Pennsylvania. An underground mining permit was issued by the West Virginia Department of Environmental Protection on February 12, 2007, and we have submitted applications for all other permits necessary to conduct operations, which currently are under review. Capital expenditures required to develop the Tunnel Ridge reserves are estimated to be in the range of approximately $195 million to $210 million, excluding capitalized interest and capitalized mine development costs associated with net cost related to incidental production. For more information about mine development costs, please read "Mine Development Cost" under "Item 8. Financial Statements and Supplementary Data – Note 2. Summary of Significant Accounting Policies." Assuming sufficient sales commitments are obtained and the permitting process continues as anticipated, initial production could commence in 2008 to 2010. When the Tunnel Ridge mine reaches full production capacity, we expect annual production of up to 6.0 million tons. Definitive development commitment for Tunnel Ridge is dependent upon final approval of the Board of Directors.

## Other Operations

### *Mt. Vernon Transfer Terminal, LLC*

Our subsidiary, Mt. Vernon Transfer Terminal, LLC (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 2006, the terminal loaded approximately 2.3 million tons for Pattiki and Gibson customers and for third-party shippers.

### *Coal Brokerage*

As markets allow, we buy coal from non-affiliated producers principally throughout the eastern United States, which we then resell, both directly and indirectly, primarily to utility customers. We purchased and sold approximately 22,000 tons of coal from non-affiliated producers in 2006. We have a policy of matching our outside coal purchases and sales to minimize market risks associated with buying and reselling coal. Purchased coal that is delivered to our operations and commingled with our production is not classified as brokerage coal.

### *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 the mine; 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. We did not receive significant revenue in 2006 from 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 the future, we may also receive revenue from the sale of limestone products by our affiliate, Mid-America Carbonates, LLC (MAC), although presently we do not anticipate the additional revenue, if any, being material.

### *Reportable Segments*

Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," and Note 21. Segment Information under "Item 8. Financial Statements and Supplementary Data—Note 21. Segment Information" for information concerning our reportable segments.

## Coal Marketing and Sales

As is customary in the coal industry, we have entered into long-term coal supply agreements with many of our customers. These arrangements are mutually beneficial to us and our customers in that they provide greater predictability of sales volumes and sales prices. In 2006, approximately 91.7% and 88.8% 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 2006 to 2023. Our total nominal commitment under significant long-term contracts for existing operations was approximately 104.3 million tons at December 31, 2006, and is expected to be delivered as follows: 22.1 million tons in 2007, 16.0 million tons in 2008, 13.8 million tons in 2009, 13.8 million tons in 2010, and 38.6 million tons thereafter during the remaining terms of the relevant coal supply agreements. The total commitment of coal under contract is an approximate number because, in some instances, our contracts contain provisions that could cause the nominal total commitment to increase or decrease by as much as 20%. The contractual time commitments for customers to nominate future purchase volumes under these contracts are sufficient to allow us to balance our sales commitments with prospective production capacity. In addition, the nominal total commitment can otherwise change because of price reopener provisions contained in certain of these long-term contracts.

The 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 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 two largest customers in 2006 were TVA and SSO. Sales to these customers in the aggregate accounted for approximately 29.9% of our 2006 total revenues, and sales to each of these customers accounted for approximately 10.0% or more of our 2006 total revenues.

**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. 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, such as Columbia and Venezuela.

Additionally, coal competes with other fuels such as petroleum, natural gas, hydropower and nuclear energy for steam and electrical power generation. Over time, costs and other factors, such as safety and environmental consideration, relating to these alternative fuels 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 4% to 39% of the delivered cost of a customer's coal. As a consequence, the availability and cost of transportation constitute important factors in the marketability of coal. We believe our mines are located in favorable geographic locations that minimize transportation costs for our customers. Typically, our customers pay the transportation costs from the contractual F.O.B. point (free-on-board point), which is the standard practice in the industry and is generally from the mine to the customer's plant. In 2006, the largest volume transporter of our coal shipments, including coal synfuel shipped by SSO, was the CSX railroad, which moved approximately 26.8% of our tonnage over its rail system.

The practices of, and rates set by, the railroad serving a particular mine or customer might affect, either adversely or favorably, our marketing efforts with respect to coal produced from the relevant mine.

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

***Mining Permits and Approvals***

Numerous governmental permits or approvals are required for mining operations. We may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production of coal may have upon the environment. 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. Future legislation and administrative regulations may emphasize more heavily the protection of the environment and, as a consequence, our activities may be more closely regulated. Future legislation and regulations, as well as differing interpretations or more stringent enforcement of existing laws and regulations, may require substantial increases in equipment and operating costs, or cause delays, interruptions or terminations of operations, the extent and/or impact of any of which cannot be predicted.

Under some circumstances, substantial fines and penalties, including revocation of mining permits, may be imposed under the laws 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.

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

***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 comprehensive safety and health standards on numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations, and other matters. MSHA monitors compliance with these federal laws and regulations. In addition, as part of the FMSHA, the Black Lung Benefits Act 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. Our competitors in all of the areas in which we operate are subject to the same laws and regulations.

Recent mining accidents resulting in fatalities in West Virginia and Kentucky have received national attention and have prompted responses at both the national and state level, leading to increased scrutiny of current industry safety practices and procedures at all mining operations. For example, on March 9, 2006, MSHA published new emergency rules on mine safety, which addressed mine safety equipment, training, and emergency reporting requirements; the rules became effective immediately upon their publication in the *Federal Register*. Building on MSHA's regulatory efforts, Congress passed the Mine Improvement and New Emergency Response Act of 2006 (MINER Act), which was signed into law on June 15, 2006. The MINER Act significantly amends the FMSHA, requiring improvements in mine safety practices, 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 published a final rule, which, among other things, revised the emergency rules to comport with the requirements of the Act. The final rule became effective on December 8, 2006. At the state level, West Virginia enacted legislation in January 2006 imposing stringent new mine safety and accident reporting requirements and increasing civil and criminal penalties for violations of mine safety laws. Other states, including Illinois, Pennsylvania, and Kentucky, have either proposed or passed similar bills and resolutions addressing mine safety practices, and it is possible that additional mine safety bills may be passed at some point in the future. Although we are unable to quantify the impact, implementing and complying with these new laws and regulations has and is expected to continue to have an adverse impact on our results of operation and financial position.

***Black Lung Benefits Act***

The Federal Black Lung Benefits Act (BLBA), levies a tax on production of $1.10 per ton for underground-mined coal and $0.55 per ton for surface-mined coal, but not to exceed 4.4% of the applicable sales price, in order to compensate miners who are totally disabled due to black lung disease and some survivors of miners who died from this disease, and who were last employed as miners prior to 1970 or subsequently where no responsible coal mine operator has been identified for claims. In addition, BLBA provides that some claims for which coal operators had previously been responsible are or will become obligations of the government trust funded by the tax. The Revenue Act of 1987 extended the termination date of this tax from January 1, 1996, to the earlier of January 1, 2014, or the date on which the government trust becomes solvent. For miners last employed as miners after 1969 and who are determined to have contracted black lung, we self-insure the potential cost of compensating such miners using actuarially determined 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 actuarially determined 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. The act also created a second benefit fund for miners who retired between July 21, 1992, and September 30, 1994, and whose former employers are no longer in business. Because of our union-free status, we are not required to make payments to retired miners under CIRHBA, with the exception of limited payments made on behalf of predecessors of MC Mining. However, in connection with the sale of the coal assets acquired by 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. The Act 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. The Act 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, 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, during fiscal years 2008 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.

### ***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, 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 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, or CAIR, which will permanently cap nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. beginning in 2009 and 2010, respectively. CAIR requires these states to achieve the required nitrogen oxide and sulfur dioxide emission reductions by requiring power plants to either participate in an EPA-administered "cap-and-trade" program that caps 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 establishes a two-part, nationwide cap on mercury emissions from coal-fired power plants beginning in 2010. If fully implemented, CAMR would permit 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 are the subject of ongoing litigation. If CAIR and CAMR survive the pending legal challenges, the additional costs that may be associated with the implementation of these new rules at operating coal-fired power generation facilities may render coal a less attractive fuel source.

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

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

The Department of Justice, on behalf of 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***

The Kyoto Protocol to the United Nations Framework Convention on Climate Change calls for developed nations to reduce their emissions of greenhouse gases to 5% below 1990 levels by 2012. Carbon dioxide, which is a major by-product of the combustion of coal and other fossil fuels, is subject to the Kyoto Protocol. The Kyoto Protocol went into effect on February 16, 2005, for those nations that ratified the treaty.

Although the United States is not participating in the Kyoto Protocol, the current session of Congress is considering climate control legislation, including multiple bills introduced in the Senate that would restrict greenhouse gas emissions. Several states have already adopted legislation, regulations and/or regulatory initiatives to reduce emissions of greenhouse gases. For instance, California recently adopted the "California Global Warming Solutions Act of 2006," which requires the California Air Resources Board to achieve a 25% reduction in emissions of greenhouse gases from sources in California by 2020. Additionally, on November 29, 2006, the U.S. Supreme Court heard arguments in a case appealed from the U.S. Circuit Court of Appeals for the District Columbia, *Massachusetts, et al. v. EPA*, in which the appellate court held that the EPA had discretion under the CAA to refuse to regulate carbon dioxide emissions from mobile sources. Passage of climate control legislation by Congress or a Supreme Court reversal of the appellate decision could result in federal regulation of carbon dioxide emissions and other greenhouse gases. Any federal or state restrictions on emissions of greenhouse gases that may be imposed in areas of the United States in which we conduct business could adversely affect our operations and demand for our services.

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

***Water Discharge***

The Federal Clean Water Act (CWA) and similar state and local laws and regulations affect coal mining operations by imposing restrictions on effluent discharge into waters. Regular monitoring, as well as compliance with reporting requirements and performance standards, 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 wetlands permits required under CWA Section 404 as it has traditionally been interpreted by the responsible agencies. However, mitigation requirements under existing and possible future wetlands permits may vary considerably. For that reason, the setting of post-mine reclamation accruals for such mitigation projects is difficult to ascertain with certainty. At this time, we do not anticipate any increase in such requirements or in post-mining reclamation accrual requirements. 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.

Recent federal district court decisions in West Virginia, and related litigation filed in federal district court in Kentucky, have created uncertainty regarding the future ability to obtain certain general permits authorizing the construction of valley fills for the disposal of overburden from mining operations. A July 2004 decision by the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Bulen* enjoined the Huntington District of the U.S. Army Corps of Engineers from issuing further permits pursuant to Nationwide Permit 21, which is a general permit issued by the U.S. Army Corps of Engineers (Corps of Engineers) to streamline the process for obtaining permits under Section 404 of the CWA. The Fourth Circuit Court of Appeals issued a decision on November 23, 2005, vacating the district court decision in *Bulen* and remanding the case to the lower court for further argument. In addition, on February 22, 2006, the Fourth Circuit Court of Appeals denied Ohio Valley Environmental Coalition’s request for a rehearing en banc. A similar lawsuit, *Kentucky Riverkeeper v. Rowlette*, has been filed in federal district court in Kentucky that seeks to enjoin the issuance of permits pursuant to Nationwide Permit 21 by the Louisville District of the U.S. Army Corps of Engineers. We do not operate any mines located within the Southern District of West Virginia and currently only utilize Nationwide Permit 21 at one location in Indiana. In the event current or future litigation contesting the use of Nationwide Permit 21 is successful, we may be required to apply for individual discharge permits pursuant to Section 404 of the CWA in areas 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.

On September 22, 2005, environmental groups led by the Ohio Valley Environmental Coalition filed suit in the Federal District Court for the Southern District of West Virginia challenging the Corps of Engineers’ authority to issue

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

Each 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 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 our customers or us to modify existing operations, the extent of which we cannot accurately or reasonably predict.

The Federal Safe Drinking Water Act (SDWA) and its state equivalents affect coal mining operations by imposing requirements on the underground injection of fine coal 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.

***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 Conversation and Recovery Act (RCRA) and corresponding state laws regulating hazardous waste affect coal mining operations by imposing requirements for the generation, transportation, treatment, storage, disposal, and cleanup of hazardous wastes. Many mining wastes are excluded from the regulatory definition of hazardous wastes, and coal mining operations covered by SMCRA permits are by statute exempted from RCRA permitting. RCRA also allows 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. It is unclear at this time how federal regulators will view this report or whether they will propose federal regulations under either SMCRA or RCRA. As a result, 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.

**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, our managing general partner and its affiliates employ approximately 2,500 employees, including approximately 130 corporate employees and approximately 2,370 employees involved in active mining operations. Our work-force is entirely union-free. We believe that relations with our employees are generally good.

## 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 conservation measures; and
- prevailing economic conditions.

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

- the level of capital expenditures we make;
- 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;
- 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 factors, we cannot guarantee that we will have sufficient available cash to pay a specific level of cash distributions to our unitholders. Furthermore, you should be aware that 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 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 the 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, 2006, AHGP owned 15,544,169 of our common units. AHGP also owns our managing general partner. If AHGP were to sell and/or distribute our common units to the holders of its equity interests in the future, 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 owners of our managing general partner 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, 2006, 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. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect that we are separate from AHGP and entities that control AHGP, our credit ratings and risk profile could be adversely affected if the ratings and risk profiles of such entities 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. AHGP owns 42.7% of our 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, 2006, AHGP and its affiliates held approximately 42.7% of our outstanding units. Consequently, it will be particularly difficult for our managing general partner to be removed without the consent of AHGP and its affiliates. As a result, the price at which our unit's trade may be lower because of the absence or reduction of a takeover premium in the trading price.

Furthermore, unitholders' voting rights are further 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, Item 8. Financial Statements and Supplementary Data – Note 18. Related Party Transactions and Item 11.

Executive Compensation – Compensation Discussion and Analysis, Administrative Services Agreement with Alliance Holdings GP, L.P."

***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 partner generally has 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 partner. 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 Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, 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.

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

Our partnership agreement requires the managing general partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, the partnership agreement permits the managing general partner to reduce available cash by establishing cash reserves 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 its own interests to the detriment of unitholders.***

As of December 31, 2006, AHGP and its affiliates directly and indirectly owned an aggregate limited partner interest of approximately 42.5% of the limited partner interests in us. 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 its affiliates over the interests of the unitholders. The nature of these conflicts includes the following considerations:

- Remedies available to unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. 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 the 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.
- 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.

**Risks Related to 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;
- the price and availability of alternative fuels;
- weather conditions;
- the proximity to, and capacity of, transportation facilities;
- worldwide economic conditions;
- domestic and foreign governmental regulations and taxes; and
- the effect of worldwide energy conservation measures.

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

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

In 2006, we derived a material amount of our net income under long-term synfuel-related agreements with SSO, PCIN and Mt. Storm Coal Supply (see discussions under "Warrior Complex," "Gibson Complex" and "Mettiki (WV)" in Item 1, Business). These agreements are dependent on the ability of the synfuel facility's owner to use certain qualifying federal income tax credits available to the facility and are subject to early cancellation in certain circumstances, including in the event that these synfuel tax credits become unavailable to the owner. In 2006, the incremental benefit to us from these synfuel-related agreements was approximately $26.4 million. If, because of budgetary shortfalls or any other reason, the federal government was to significantly reduce or eliminate synfuel tax credits, it could negatively impact our results of operations and reduce our cash available for distributions.

Non-conventional source fuel tax credits are subject to a pro-rata phase-out or reduction if the annual average wellhead price per barrel for all domestic crude oil (the reference price) as determined by the Secretary of the Treasury exceeds certain levels. The reference price is not subject to regulation by the United States Government. The reference price for a calendar year is typically published in April of the following year. For example, for qualified fuel sold during the 2005 calendar year, the reference price was $50.26. The pro-rata reduction of non-conventional source fuel tax credits for 2005 would have begun if the reference price was approximately $53.00 per barrel, with a complete phase-out or reduction of non-conventional synfuel tax credits if the reference price reached approximately $69.00 per barrel. In 2006, SSO, PCIN and Mt. Storm Coal Supply temporarily suspended operation of the synfuel facilities located at the Warrior, Gibson, and Mettiki complexes as a result of the increase in the wellhead price of domestic crude oil. During the suspension periods, we sold coal directly to the customers of SSO, PCIN and Mt. Storm Coal Supply under "back up" coal supply agreements. While these suspensions had no material impact on our results of operations in 2006, we could experience a material reduction of revenues associated with non-conventional source fuel facilities in the future if non-conventional source fuel tax credits become unavailable to the owners of the non-conventional source fuel facilities we service as a result of the rise in the wellhead price per barrel of crude oil above specified levels. The non-conventional synfuel tax credit is scheduled to expire on December 31, 2007.

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

Several states in which we operate or our utility customers reside have established a statutory framework for tax credits against income, franchise, or severance taxes, which have benefited, directly or indirectly, coal operators or customers purchasing coal mine production from within the applicable state. The state statutes authorizing these tax credits are scheduled to expire in accordance with their term provisions. Furthermore, these state statutes or our ability to benefit, directly or indirectly, from them may be subject to challenge by third parties. One of the states in which we operate, Maryland, has established a statutory framework for tax credits against income or franchise taxes that have benefited, directly or indirectly, coal operators or customers purchasing coal produced from mines within that state. In 2006, the indirect benefit of the Maryland tax credit to us was approximately $7.3 million. Although this credit is not set to expire by its terms in the near future, recent legislative and interpretive changes, as well as our reduced coal production in Maryland, likely will delay and reduce the amount of the benefit, if any, of the tax credit to us in 2007. In addition, legislation may be proposed in the future that would eliminate this credit. If the Maryland statutes expire or any challenges are successful, we would lose the benefits of these credits. Therefore, if our operations do not produce increased cash flow sufficient to replace any lost benefits, our cash available for distribution could be adversely affected.

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

We compete with other large coal producers and hundreds of small coal producers in various regions of the United States for domestic sales. The industry has undergone significant consolidation over the last decade. This consolidation has led to several competitors having significantly larger financial and operating resources than we have. In addition, we compete to some extent with western surface coal mining operations that have a much lower per ton cost of production and produce low-sulfur coal. Over the last 20 years, growth in production from western coal mines has substantially exceeded growth in production from the east. Declining prices 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 cheaper construction costs compared to coal-fired plants and because natural gas is a cleaner burning fuel. The domestic electric utility industry accounts for approximately 90% of domestic coal consumption. The amount of coal consumed by the domestic electric utility industry is affected primarily by the overall demand for electricity, the price and availability of competing fuels for power plants such as nuclear, natural gas and fuel oil as well as hydroelectric power, and environmental and other governmental regulations. 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.

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

A substantial decrease in the amount of coal sold by us pursuant to long-term contracts would reduce the certainty of the price and amounts of coal sold and subject our revenue stream to increased volatility. If that were to happen, changes in spot market coal prices 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 2006, we sold approximately 91.7% 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 specified events. These events are called "force majeure" events. Some of these events that are specific to the coal industry include:

- our inability to deliver the quantities or qualities of coal specified;
- changes in the CAA rendering use of our coal inconsistent with the customer’s pollution control strategies; and
- the occurrence of events beyond the reasonable control of the affected party, including labor disputes, mechanical malfunctions and changes in government regulations.

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

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

Federal, state and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from 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 "Regulation and Laws—Air Emissions" and "Regulations and Laws—Carbon Dioxide Emissions."

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

During 2006, we derived approximately 29.9% of our total revenues from two customers, which individually accounted for 10% or more of our 2006 total revenues. If we were to lose any of these customers without finding replacement customers willing to purchase an equivalent amount of coal on similar terms, or if these customers were to change the amounts of coal purchased or the terms, including pricing terms, on which they buy coal from us, it could have a material adverse effect on our business, financial condition and results of operations.

***Litigation 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 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 and flooding;
- 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. For example, during the past three years, three loss incidents have occurred at our mine complexes. For details on these incidents and their negative effect on our results of operations, please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Pattiki Vertical Belt Incident," "—MC Mining Fire Incident" and "—Dotiki Fire Incident." Prolonged disruption of production at any of our mines would result in a decrease in our revenues and profitability, which could be material. Decreases in our profitability as a result of the factors described above could materially adversely impact our quarterly or annual results.

We carry commercial (including business interruption and extra expense) property insurance policies; however, these risks may not be fully covered by these insurance policies. Available capacity for underwriting property insurance continues to be limited as a result of insurance carrier losses in the mining industry and our recent insurance claims history (*e.g.*, MC Mining Fire Incident and Dotiki Fire Incident). As a result, in conjunction with the September 2006 renewal of our property and casualty insurance policies, we elected to retain a participating interest along with our insurance carriers at an average rate of approximately 14.7% in the overall $75.0 million commercial property program. The 14.7% participation rate for this year's renewal exceeds the approximate 10% participation level from last year. 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 conditions, results of operations and ability to purchase property insurance in the future. For additional information on our property and casualty insurance program, please "Item 8. Financial Statements and Supplementary Data – Note 19. Commitments and Contingencies, Other."

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

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

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

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

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

Mining companies must obtain numerous 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. 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 "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 U.S. Army 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. 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 "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 United States inherently more expensive on a per-mile basis than coal shipments originating in the western United States. Historically, high coal transportation rates from the western coal producing areas into certain eastern markets limited the use of western coal in those markets. Lower or higher rail rates from the western coal producing areas to markets served by eastern U.S. coal producers have created major competitive challenges, as well as opportunities for eastern coal producers. In the event of lower transportation costs, the increased competition could have a material adverse effect on our business, financial condition and results of operations.

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

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

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.

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

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

Expansion 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.

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

Historically, a portion of our growth and operating results have been from acquisitions. Our future growth could be limited if we are unable to continue to make acquisitions, or if we are unable to successfully integrate the companies, businesses or properties we acquire. We may not be successful in consummating any acquisitions and the consequences of 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.

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

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

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

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

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

- geological and mining conditions, which may not be fully identified by available exploration data and/or differ from our experiences in areas where we currently mine;
- the percentage of coal in the ground ultimately recoverable;
- historical production from the area compared with production from other producing areas;

- the assumed effects of regulation by governmental agencies; and
- assumptions concerning future coal prices, operating costs, capital expenditures, severance and excise taxes and development and reclamation costs.

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

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

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

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

Our coal mining operations continue to be 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 have risen significantly in recent years, and historically, the prices of scrap steel, natural gas and coking coal consumed in the production of iron and steel have fluctuated. In 2006, we continued to experience increases in the cost of materials and supplies, particularly consumables such as steel, copper and power. There may be acts of nature or terrorist attacks or threats that could also increase the costs of raw materials. If the price of steel, petroleum products or other raw materials increase, our operational expenses will increase and could have a significant negative impact on our profitability.

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

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

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

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

We have long-term indebtedness, consisting of our outstanding 8.31% senior unsecured notes. At December 31, 2006, our total indebtedness outstanding was $144.0 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, it fails to meet a coverage test based on the ratio of our consolidated debt to our consolidated cash flow.

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

***Federal and state laws require bonds to secure our obligations related to 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.***

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.

***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 the 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 (or judicial interpretations or more stringent enforcement of existing laws and 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.

As a result of recent mining accidents that caused fatalities in West Virginia and Kentucky, Congress and several state legislatures (including those in West Virginia, Illinois and Kentucky) 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 "Regulation and Laws."

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

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

**Tax Risks to Our Common Unitholders**

***If we were to become subject to entity-level taxation for federal or state tax purposes, 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 IRS on this matter.

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

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity level taxation. For example, because of widespread state budget deficits 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.

***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.***

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 foreign persons owning our units face unique tax issues that may result in adverse tax consequences to them.***

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

***We 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.

***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. Our counsel has not rendered an opinion on the state and local tax consequences of an investment in our units.

***The sale or exchange of 50% or more of our capital and profits interests within a 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. The transactions surrounding AHGP's initial public offering, which closed on May 15, 2006, represented a sale or exchange of approximately 42.3% of the total interests in our capital and profits interests. We believe, and have taken the position, that the transactions surrounding AHGP's initial public offering, together with all other common units sold within the prior twelve-month period, represented a sale or exchange of 50% or more of the total interest in our capital and profits interests. Our termination for federal income tax purposes will result, among other things, in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income for the year in which the termination occurs. The impact of this termination to our unitholders is reflected in the amount of taxable income we expect to be allocated to our unitholders as a result of an investment in our common units. Although the amount of increase cannot be estimated because it depends upon numerous factors including the timing of the termination, the amount could be material. Our termination will not affect our classification as a partnership for federal income tax purposes, but instead, we will be treated as a new partnership for tax purposes. As a new partnership, we must make new tax elections and could be subject to penalties if we are unable to substantiate that a termination occurred.

## ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

## ITEM 2. PROPERTIES

### Coal Reserves

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

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

At December 31, 2006, we had approximately 633.9 million tons of coal reserves. All of the estimates of reserves which are presented in this Annual Report on Form 10-K are of proven and probable reserves (as defined below). For information on the locations of our mines, please read "Mining Operations" under "Item 1. Business."

The following table sets forth reserve information, at December 31, 2006, about each of our mining operations:

| Operations | Mine Type | Heat Content (Btus per pound) | Proven and Probable Reserves: Pounds $SO_2$ per MMbtu <1.2 | 1.2-2.5 | >2 5 | Total | Reserve Assignment: Assigned | Unassigned |
|---|---|---|---|---|---|---|---|---|
| | | | (tons in millions) | | | | | |
| ***Illinois Basin Operations*** | | | | | | | | |
| Dotiki (KY) | Underground | 12,300 | - | - | 86.7 | 86.7 | 86.7 | - |
| Warrior (KY) | Underground | 12,500 | - | - | 13.9 | 13.9 | 13.9 | - |
| Hopkins (KY) | Underground | 12,000 | - | - | 55.7 | 55.7 | 35.5 | 20.2 |
| | / Surface | | - | - | 7 8 | 7.8 | 7.8 | - |
| River View (KY) | Underground | 11,800 | - | - | 110 0 | 110.0 | 110.0 | - |
| Pattiki (IL) | Underground | 11,700 | - | - | 44.4 | 44.4 | 44.4 | - |
| Gibson (North) (IN) | Underground | 11,500 | - | 26.7 | 5.1 | 31.8 | 31.8 | - |
| Gibson (South) (IN) | Underground | 11,600 | - | 18.6 | 64.1 | 82.7 | - | 82.7 |
| Region Total | | | - | 45.3 | 387.7 | 433.0 | 330.1 | 102.9 |
| ***Central Appalachian Operations*** | | | | | | | | |
| Pontiki (KY) | Underground | 12,800 | 5.7 | 11.0 | - | 16.7 | 16.7 | - |
| MC Mining (KY) | Underground | 12,800 | 18.9 | - | 1.8 | 20.7 | 20.7 | - |
| Region Total | | | 24 6 | 11.0 | 1.8 | 37.4 | 37.4 | - |
| ***Northern Appalachian Operations*** | | | | | | | | |
| Mettiki (MD) | Underground | 13,000 | - | 4.2 | 10.2 | 14.4 | 14.4 | - |
| Mountain View (WV) | Underground | 13,000 | - | 6.9 | 15.0 | 21.9 | 21.9 | - |
| 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 | | | - | 11.1 | 152.4 | 163.5 | 163.5 | - |
| Total | | | 24 6 | 67.4 | 541.9 | 633.9 | 531.0 | 102.9 |
| % of Total | | | 3.9% | 10.6% | 85.5% | 100.0% | 83.8% | 16.2% |

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

Reserve estimates will change from time to time to reflect mining activities, additional analysis, new engineering and geological data, acquisition or divestment of reserve holdings, modification of mining plans or mining methods, and other factors. Weir International Mining Consultants performed an overview audit of 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 24.6 million tons of reserves listed as <1.2 pounds of $SO_2$ per MMbtu are compliance coal.

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

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

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

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 – 22.6 million tons, Pattiki – 4.8 million tons, Hopkins County Coal –

1.8 million tons, River View – 20.9 million tons, Gibson (North) –0.9 million tons, Gibson (South) – 11.1 million tons, Warrior – 9.1 million tons, Tunnel Ridge – 7.0 million tons, Penn Ridge – 3.4 million tons and Pontiki – 0.2 million tons.

We lease most of our reserves and generally have the right to maintain leases in force until the exhaustion of the mineable and merchantable leased coal 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.

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

| | | Tons Produced | | | | |
|---|---|---|---|---|---|---|
| **Operations** | **Location** | **2006** | **2005** | **2004** | **Transportation** | **Equipment** |
| | | (tons in millions) | | | | |
| ***Illinois Basin Operations*** | | | | | | |
| Dotiki | Kentucky | 4.7 | 4.7 | 4.8 | CSX, PAL, truck, barge | CM |
| Warrior | Kentucky | 4.5 | 4.1 | 3.1 | CSX, PAL, truck | CM |
| Hopkins | Kentucky | 1.6 | 0.9 | 0.2 | CSX, PAL, truck | AU, DL, CM |
| Pattiki | Illinois | 2.5 | 2.6 | 2.5 | CSX, barge | CM |
| Gibson (North) | Indiana | 3.6 | 3.4 | 3.0 | Truck, barge | CM |
| Region Total | | 16.9 | 15.7 | 13.6 | | |
| ***Central Appalachian Operations*** | | | | | | |
| Pontiki | Kentucky | 1.6 | 1.7 | 1.7 | NS, truck | CM |
| MC Mining | Kentucky | 1.9 | 1.6 | 1.9 | CSX, truck | CM |
| Region Total | | 3.5 | 3.3 | 3.6 | | |
| ***Northern Appalachian Operations*** | | | | | | |
| Mettiki | Maryland | 2.8 | 3.3 | 3.2 | Truck, CSX | LW, CM, CS |
| Mountain View | West Virginia | 0.5 | - | - | Truck, CSX | LW, CM |
| Region Total | | 3.3 | 3.3 | 3.2 | | |
| TOTAL | | 23.7 | 22.3 | 20.4 | | |

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

## ITEM 3. LEGAL PROCEEDINGS

We are subject to various types of litigation in the ordinary course of our business. 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 (*e.g.*, relating to, among other things, coal quality, quantity, pricing and the existence of force majeure conditions) 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 19. 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. 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.

On June 15, 2006, Mettiki (MD) was issued a Notice of Violation by MDE for alleged exceedances of permitted sulfur dioxide emissions. These alleged exceedances occurred between May 23, 2006 and June 12, 2006, at the Mettiki (MD) Thermal Coal Dryer associated with the longwall mining operation, located in Garrett County, Maryland. This self-reported violation was promptly corrected and Mettiki (MD) demonstrated to the satisfaction of MDE that it is in compliance with MDE regulations. Under applicable Maryland law, civil penalties of up to $25,000 per day of violation may be assessed. Mettiki (MD) is currently in negotiations with MDE to resolve this matter and, while the final penalty amount may exceed $100,000, we do not expect the final assessment to have a material impact on our operations or financial condition.

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

None.

# PART II

## ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The common units representing limited partners' interests are listed on the NASDAQ Global Select Market under the symbol "ARLP". The common units began trading on August 20, 1999. On February 28, 2007, the closing market price for the common units was $34.70 per unit. As of February 28, 2007, there were 36,550,659 common units outstanding. There were approximately 22,506 record holders and beneficial owners (held in street name) of common units at December 31, 2006.

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 2005 | $40.495 | $30.100 | $0.3750 (paid May 13, 2005) |
| 2nd Quarter 2005 | $38.300 | $27.750 | $0.4125 (paid August 12, 2005) |
| 3rd Quarter 2005 | $48.410 | $35.550 | $0.4125 (paid November 14, 2005) |
| 4th Quarter 2005 | $46.600 | $35.450 | $0.4600 (paid February 14, 2006) |
| 1st Quarter 2006 | $40.700 | $33.680 | $0.4600 (paid May 15, 2006) |
| 2nd Quarter 2006 | $43.790 | $34.000 | $0.5000 (paid August 14, 2006) |
| 3rd Quarter 2006 | $39.000 | $33.840 | $0.5000 (paid November 14, 2006) |
| 4th Quarter 2006 | $37.450 | $33.590 | $0.5400 (paid February 14, 2007) |

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

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

### Equity Compensation Plans

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

## ITEM 6. SELECTED FINANCIAL DATA

Our historical financial data below were derived from our audited consolidated financial statements as of and for the years ended December 31, 2006, 2005, 2004, 2003 and 2002. We acquired Warrior from ARH Warrior Holdings, Inc. (ARH Warrior Holdings), a subsidiary of ARH, in February 2003. Because the Warrior acquisition was between entities under common control, it is accounted for at historical cost in a manner similar to that used in a pooling of interests. Accordingly, the financial statements as of and for the year ended December 31, 2002, have been restated to reflect the combined historical results of operations, financial position, and cash flows of the ARLP Partnership and Warrior. ARH Warrior Holdings acquired the assets that comprise Warrior on January 26, 2001.

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

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2003 | 2002 |
| **Statements of Income:** | | | | | |
| Sales and operating revenues | | | | | |
| Coal sales | $ 895 8 | $ 768 9 | $ 599 4 | $ 501 6 | $ 479 5 |
| Transportation revenues | 39 9 | 39 1 | 29 8 | 19 5 | 19 0 |
| Other sales and operating revenues | 31 9 | 30 7 | 24 1 | 21 6 | 20 4 |
| Total revenues | 967 6 | 838 7 | 653 3 | 542 7 | 518 9 |
| **Expenses:** | | | | | |
| Operating expenses | 627 8 | 521 5 | 436 4 | 368 8 | 367 5 |
| Transportation expenses | 39 9 | 39 1 | 29 8 | 19 5 | 19 0 |
| Outside purchases | 19 2 | 15 1 | 9 9 | 8 5 | 10 1 |
| General and administrative | 30 9 | 33 5 | 45 4 | 28 3 | 20 3 |
| Depreciation, depletion and amortization | 66 5 | 55 6 | 53 7 | 52 5 | 52 4 |
| Net gain from insurance settlement (1) | - | - | (15 2) | - | - |
| Total expenses | 784 3 | 664 8 | 560 0 | 477 6 | 469 3 |
| Income from operations | 183 3 | 173 9 | 93 3 | 65 1 | 49 6 |
| Interest expense (net of interest capitalized) | (12 2) | (14 6) | (15 8) | (16 3) | (16 6) |
| Interest income | 3 0 | 2 8 | 0 8 | 0 3 | 0 2 |
| Other income | 0 9 | 0 6 | 1 0 | 1 4 | 0 5 |
| Income before income taxes, cumulative effect of accounting change and minority interest | 175 0 | 162 7 | 79 3 | 50 5 | 33 7 |
| Income tax expense (benefit) | 2 4 | 2 7 | 2 7 | 2 6 | (1 1) |
| Income before cumulative effect of accounting change and minority interest | 172 6 | 160 0 | 76 6 | 47 9 | 34 8 |
| Cumulative effect of accounting change (2) | 0 1 | - | - | - | - |
| Minority interest | 0 2 | - | - | - | - |
| Net income | $ 172 9 | $ 160 0 | $ 76 6 | $ 47 9 | $ 34 8 |
| General Partners' interest in net income | $ 24 6 | $ 12 4 | $ 3 3 | $ 0 3 | $ (0 8) |
| Limited Partners' interest in net income | $ 148 3 | $ 147 6 | $ 73 3 | $ 47 6 | $ 35 6 |
| Basic net income per limited partner unit | $ 3 06 | $ 2 89 | $ 1 76 | $ 1 30 | $ 1 14 |
| Basic net income per limited partner unit before accounting change | $ 3 06 | $ 2 89 | $ 1 76 | $ 1 30 | $ 1 14 |
| Diluted net income per limited partner unit | $ 3 03 | $ 2 84 | $ 1 71 | $ 1 26 | $ 1 11 |
| Weighted average number of units outstanding-basic | 36,425,350 | 36,288,527 | 35,881,896 | 35,161,468 | 30,810,622 |
| Weighted average number of units outstanding-diluted | 36,810,383 | 36,977,061 | 36,874,336 | 36,325,678 | 31,685,416 |
| **Balance Sheet Data:** | | | | | |
| Working capital (deficit) | $ 37 4 | $ 76 1 | $ 54 2 | $ 16 4 | $ (15 8) |
| Total assets | 635 0 | 532 7 | 412 8 | 336 5 | 316 9 |
| Long-term obligations (3) | 127 5 | 144 0 | 162 0 | 180 0 | 195 0 |
| Total liabilities | 386 5 | 376 9 | 357 6 | 323 9 | 355 7 |
| Partners' capital (deficit) | 248 5 | 155 8 | 55 2 | 12 6 | (38 8) |
| **Other Operating Data:** | | | | | |
| Tons sold | 24 4 | 22 8 | 20 8 | 19 5 | 18 4 |
| Tons produced | 23 7 | 22 3 | 20 4 | 19 2 | 18 0 |
| Revenues per ton sold (4) | $ 38 02 | $ 35 07 | $ 29 98 | $ 26 83 | $ 27 17 |
| Cost per ton sold (5) | $ 27 78 | $ 25 00 | $ 23 64 | $ 20 80 | $ 21 63 |
| **Other Financial Data:** | | | | | |
| Net cash provided by operating activities | $ 250 9 | $ 193 6 | $ 145 1 | $ 110 3 | $ 101 3 |
| Net cash used in investing activities | (137 7) | (110 2) | (77 6) | (77 8) | (56 9) |
| Net cash used in financing activities | (108 5) | (82 6) | (46 4) | (31 3) | (46 4) |
| EBITDA (6) | 250 7 | 230 1 | 147 9 | 119 0 | 102 5 |
| Maintenance capital expenditures (7) | 67 8 | 56 7 | 31 6 | 30 0 | 29 0 |

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

(2) Represents the cumulative effect of the 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 purchases and general and administrative expenses divided by tons sold.

(6) EBITDA 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).

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, | | | | |
|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2003 | 2002 |
| Cash flows provided by operating activities | $ 250,923 | $ 193,618 | $ 145,055 | $ 110,312 | $ 101,306 |
| Long-term incentive plan | (4,112) | (8,193) | (20,320) | (7,687) | (2,338) |
| Reclamation and mine closing | (2,101) | (1,918) | (1,622) | (1,341) | (1,365) |
| Coal inventory adjustment to market | (319) | (573) | (488) | (687) | (48) |
| Net gain (loss) on sale of property, plant and equipment | 1,188 | (179) | 332 | 885 | 41 |
| Loss on retirement of damaged vertical belt equipment | - | (1,298) | - | - | - |
| Other | (1,119) | (580) | (587) | (532) | 973 |
| Net effect of working capital changes | (5,317) | 34,770 | 7,915 | (553) | (11,376) |
| Interest expense, net | 9,175 | 11,816 | 14,963 | 15,981 | 16,360 |
| Income taxes | 2,443 | 2,682 | 2,641 | 2,577 | (1,094) |
| EBITDA | 250,761 | 230,145 | 147,889 | 118,955 | 102,459 |
| Depreciation, depletion and amortization | (66,489) | (55,637) | (53,664) | (52,495) | (52,408) |
| Interest expense, net | (9,175) | (11,816) | (14,963) | (15,981) | (16,360) |
| Income taxes | (2,443) | (2,682) | (2,641) | (2,577) | 1,094 |
| Cumulative effect of accounting change | 112 | - | - | - | - |
| Minority interest | 161 | - | - | - | - |
| Net income | $ 172,927 | $ 160,010 | $ 76,621 | $ 47,902 | $ 34,785 |

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

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

### General

The following discussion of our financial condition and results of 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 steam coal to major U.S. utilities and industrial users. In 2006, our total production was 23.7 million tons and our total sales were 24.4 million tons. The coal we produced in 2006 was approximately 30.0% low-sulfur coal, 13.9% medium-sulfur coal and 56.1% 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%.

At December 31, 2006, we had approximately 633.9 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. Three of our mining complexes supplied coal feedstock and provided services to third-party coal synfuel facilities located at or near these complexes. We also operated a coal loading terminal on the Ohio River at Mt. Vernon, Indiana.

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

In 2006, approximately 88.6% of our sales tonnage was consumed by electric utilities (or coal synfuel facilities whose ultimate customers are electric utilities) with the balance consumed by cogeneration plants and industrial users. In 2006, approximately 91.7% of our sales tonnage, including approximately 88.8% 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 2006, approximately 96.1% of our medium- and high-sulfur coal was sold to utility plants with installed pollution control devices, also known as scrubbers, to remove sulfur dioxide.

In 2006, we reported record net income of $172.9 million, an increase of 8.1% over 2005 net income of $160.0 million. These results were primarily attributable to expanded production capacity and higher average coal sales prices, which benefits were partially offset by increased operating expenses described below.

We are currently anticipating coal production for 2007 to increase approximately 6.0% over 2006 production levels to a range of 24.7 to 25.2 million tons. Despite the current weakness in spot market prices for coal, we expect our average coal sales price per ton to increase modestly in 2007, by approximately 4.0% - 5.0% over our 2006 average coal sales price per ton, due to recent re-pricing of several lower priced long-term coal sales contracts at higher market prices. Based on these anticipated increases in coal production and coal sales prices, we are currently estimating 2007 revenues to increase approximately 8.0% over 2006 revenues to a range of $985.0 to $1,015.0 million, excluding transportation revenues. Total coal sales volume open to market pricing includes approximately 3.2 million tons in 2007, 13.1 million tons in 2008 and 20.8 million tons in 2009.

**Analysis of Historical Results of Operations**

*2006 Compared with 2005*

| | December 31, | | December 31, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (in thousands) | | (per ton sold) | |
| Tons sold | 24,351 | 22,849 | N/A | N/A |
| Tons produced | 23,738 | 22,290 | N/A | N/A |
| Coal Sales | $ 895,823 | $ 768,958 | $ 36.79 | $ 33.65 |
| Operating Expenses and Outside Purchases | $ 646,969 | $ 536,601 | $ 26.57 | $ 23.48 |

*Coal sales*. Coal sales increased 16.5% to $895.8 million for 2006 from $769.0 million for 2005. The increase of $126.8 million reflected increased sales volumes (contributing $50.5 million of the increase) and higher average coal sales prices (contributing $76.3 million of the increase). Tons sold increased 6.6%, or 1.5 million tons, to 24.4 million tons for 2006 from 22.8 million tons in 2005, as a result of increased tons produced. Tons produced increased 6.5% to 23.7 million tons for 2006 from 22.3 million tons in 2005, which primarily reflects the impact of production capacity expansion capital investments and increased third-party purchased coal volume. Average coal sales prices increased 9.3%, or $3.14 per ton sold in 2006 as compared to 2005, primarily attributable to higher pricing on long-term sales contracts, higher coal quality shipments and the 2006 coal spot market demand.

*Operating expenses.* Operating expenses increased 20.4% to $627.8 million in 2006 from $521.5 million in 2005. The increase of $106.3 million primarily resulted from increased operating expenses associated with additional coal sales of 1.5 million tons, including the following specific factors:

- Labor and benefit costs increased $38.5 million reflecting increased headcount, primarily in response to expanding production capacity, pay rate increases, adverse workers compensation claims developments and escalating health care costs;

- Materials, supplies and maintenance costs increased $39.1 million and $8.6 million, respectively, reflecting increased production and industry-wide increased costs for the products and services used in the mining process (particularly consumables such as copper, steel and power);

- Contract mining costs increased $3.9 million, primarily reflecting increased production volume at two small third-party mining operations at Mettiki (MD);

- Production taxes and royalties (which were incurred as a percentage of coal sales or directly correlated to volume) increased $6.8 million;

- Property insurance costs increased $3.8 million;

- Increased expenses of $13.4 million in 2006 were associated with the purchase of tons under the settlement agreement we entered into with ICG, LLC (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 our purchase of coal from ICG are combined. Therefore, the excess of our purchase price from ICG over Pontiki's sales price to ICG is reported as an operating expense in Other and Corporate Segment Adjusted EBITDA. For more information about the ICG settlement agreement, please read "Other" under "Item 8. Financial Statements and Supplementary Data – Note 19. Commitments and Contingencies"; and

- The 2006 operating expenses were decreased by $9.0 million more than the decrease in 2005, reflecting greater costs incurred and capitalized in the mine development process offset by revenues received for coal produced incidental with the mine development process. See Note 2. Summary of Significant Accounting Policies - Mine Development Costs to the Consolidated Financial Statements included in "Item 8, Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

*Other sales and operating revenues*. Other sales and operating revenues are principally comprised of rental and service fees from coal synfuel production facilities, Mt. Vernon transloading revenues and administrative service revenue from affiliates. Other sales and operating revenues increased 3.8% to $31.9 million in 2006 from $30.7 million in 2005. The increase of $1.2 million was primarily attributable to $0.9 million of administrative service revenues associated with the administrative service agreement with affiliates executed in 2006 and $0.7 million of additional transloading revenues attributable to increased transloading volumes at Mt. Vernon. These increases were partially offset by decreases in service fees from coal synfuel production facilities.

*Outside purchases*. Outside purchases increased $4.1 million to $19.2 million in 2006 from $15.1 million in 2005. The increase was principally attributable to coal supply agreements with third-party suppliers in the Central and Northern Appalachian operations ($3.3 million and $3.5 million, respectively), primarily to supplement production capacity during periods of mine transition and development, offset by reduced coal purchases in the Illinois Basin operations ($3.7 million).

*General and administrative*. General and administrative expenses for 2006 decreased to $30.9 million compared to $33.5 million for 2005. The decrease of $2.6 million was primarily related to lower unit-based incentive compensation expense associated with the Long-Term Incentive Plan (LTIP) in addition to the Short-Term Incentive Plan (STIP). Prior to our adoption of SFAS No. 123R, effective January 1, 2006, using the "modified prospective" transition method, our LTIP expense was impacted by period-to-period changes in our common unit price.

*Depreciation, depletion and amortization*. Depreciation, depletion and amortization increased to $66.5 million in 2006 compared to $55.6 million in 2005. The increase of $10.9 million was primarily attributable to additional depreciation expense associated with increased capital expenditures incurred in certain production capacity expansion projects and infrastructure investments, including development of the Elk Creek mine at Hopkins County Coal, Pontiki's development of the Van Lear seam and the transition to the Albridge Branch area of the Pond Creek seam.

*Interest expense*. Interest expense, net of capitalized interest, decreased to $12.2 million in 2006 from $14.6 million in 2005. The decrease of $2.4 million was principally attributable to the increased capitalization of interest expense in 2006 compared to 2005 related to capital projects and mine development costs, along with reduced interest expense associated with the August 2006 and 2005 scheduled principal payments of $18.0 million, respectively, on our senior notes. We had no borrowings under the credit facility during 2006 or 2005.

*Interest Income.* Interest income of $3.0 million for 2006 was comparable with $2.8 million for 2005.

*Transportation revenues and expenses*. Transportation revenues and expenses increased 2.1% to $39.9 million in 2006 from $39.1 million for 2005. The increase of $0.8 million was primarily attributable to increased shipments to customers that reimburse us for transportation costs rather than arranging and paying for transportation directly with transportation providers. Transportation services are a pass-through to our customers. Consequently, we do not realize any margin on transportation revenues.

*Income before income taxes, cumulative effect of accounting change and minority interest*. Income before income taxes, cumulative effect of accounting change and minority interest increased 7.6% to $175.1 million for 2006 compared to $162.7 million for 2005. The increase was primarily attributable to increased sales volumes as a result of expanded production capacity, higher average coal sales prices and reduced general and administrative expenses, partially offset by higher operating expenses.

*Income tax expense.* Income tax expense decreased to $2.4 million for 2006 from $2.7 million for 2005, resulting from decreased volumes at the third-party coal synfuel facilities.

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

*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.

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 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 loss was $161,000 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 21. Segment Information" for more information concerning our reportable segments. Our 2006 Segment Adjusted EBITDA increased $18.0 million, or 6.8%, to $281.6 million from 2005 Segment Adjusted EBITDA of $263.6 million. Segment Adjusted EBITDA, tons sold, coal sales, other sales and operating revenues and Adjusted Segment EBITDA Expense by segment are as follows (in thousands):

| | Year Ended December 31, | | | |
|---|---|---|---|---|
| | **2006** | **2005** | **Increase (Decrease)** | |
| Segment Adjusted EBITDA | | | | |
| Illinois Basin | $ 206,209 | $ 183,075 | $ 23,134 | 12.6% |
| Central Appalachia | 40,050 | 41,583 | (1,533) | (3.7)% |
| Northern Appalachia | 29,911 | 36,047 | (6,136) | (17.0)% |
| Other and Corporate | 5,475 | 2,924 | 2,551 | 87.2% |
| Total Segment Adjusted EBITDA (1) | $ 281,645 | $ 263,629 | $ 18,016 | 6.8% |
| Tons sold | | | | |
| Illinois Basin | 17,354 | 16,264 | 1,090 | 6.7% |
| Central Appalachia | 3,552 | 3,249 | 303 | 9.3% |
| Northern Appalachia | 3,423 | 3,330 | 93 | 2.8% |
| Other and Corporate | 22 | 6 | 16 | (3) |
| Total tons sold | 24,351 | 22,849 | 1,502 | 6.6% |
| Coal sales | | | | |
| Illinois Basin | $ 587,087 | $ 504,916 | $ 82,171 | 16.3% |
| Central Appalachia | 182,922 | 153,615 | 29,307 | 19.1% |
| Northern Appalachia | 106,628 | 106,997 | (369) | (0.3)% |
| Other and Corporate | 19,186 | 3,430 | 15,756 | (3) |
| Total coal sales | $ 895,823 | $ 768,958 | $ 126,865 | 16.5% |
| Other sales and operating revenues | | | | |
| Illinois Basin | $ 24,168 | $ 24,493 | $ (325) | (1.3)% |
| Central Appalachia | 304 | 282 | 22 | 7.8% |
| Northern Appalachia | 2,010 | 2,163 | (153) | (7.1)% |
| Other and Corporate | 5,373 | 3,753 | 1,620 | 43.2% |
| Total other sales and operating revenues | $ 31,855 | $ 30,691 | $ 1,164 | 3.8% |
| Segment Adjusted EBITDA Expense | | | | |
| Illinois Basin | $ 405,045 | $ 346,335 | $ 58,710 | 17.0% |
| Central Appalachia | 143,176 | 112,313 | 30,863 | 27.5% |
| Northern Appalachia | 78,727 | 73,112 | 5,615 | 7.7% |
| Other and Corporate | 19,085 | 4,260 | 14,825 | (3) |
| Total Segment Adjusted EBITDA Expense (2) | $ 646,033 | $ 536,020 | $ 110,013 | 20.5% |

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

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

(3) Percentage increase was significantly greater than 100%.

Illinois Basin – Segment Adjusted EBITDA for 2006 (as defined in reference (1) to the table above) increased 12.6%, to $206.2 million from 2005 Segment Adjusted EBITDA of $183.1 million. The increase of $23.1 million was primarily attributable to increased coal sales which rose by $82.2 million, or 16.3%, to $587.1 million during 2006 as compared to $504.9 million in 2005. Increased coal sales in 2006 reflected higher average coal sales price per ton which increased $2.78 per ton to $33.83 per ton (contributing $48.2 million of the increase in coal sales) and increased tons sold of 1.1 million tons (contributing $34.0 million of the increase in coal sales). The price increase was the combined result of improved market demand and higher quality coal shipments. Other sales and operating revenues decreased $0.3 million, primarily due to a decrease in rent and service fees associated with decreased synfuel volumes at our third-party coal synfuel facilities. Total Segment Adjusted EBITDA Expense in 2006 increased 17.0% to $405.0 million from $346.3 million in 2005. On a per ton sold basis, 2006 Segment Adjusted EBITDA Expense rose to $23.34 per ton or 9.6% over the 2005 Segment Adjusted EBITDA Expense of $21.30 per ton. The increase in Segment Adjusted EBITDA Expense in 2006 compared to 2005 reflected the impact of cost increases described above under consolidated operating expenses. The Illinois Basin costs have been negatively impacted primarily by increased labor costs as certain operations expanded capacity potential, higher costs of roof control resulting from pricing, mining conditions, more aggressive regulatory requirements, and increased equipment maintenance costs, among others. Additionally, the Illinois Basin costs increased due to the continued ramp-up to full production capacity at the Elk Creek mine, which emerged from development in the second quarter of 2006, as well as certain periods of adverse mining conditions encountered at the Pattiki mine.

Central Appalachia – Segment Adjusted EBITDA for 2006 (as defined in reference (1) to the table above) decreased $1.5 million, or 3.7%, to $40.1 million as compared to 2005 Segment Adjusted EBITDA of $41.6 million. The decrease was primarily attributable to higher operating expenses, partially offset by increased coal sales of $29.3 million, reflecting higher average coal sales price per ton of $51.49 in 2006, which increased $4.22 per ton (contributing $15.0 million of the increase in coal sales), and increased tons sold in 2006 of 303,000 tons (which contributed $14.3 million of the increase in coal sales). Segment Adjusted EBITDA Expense in 2006 increased 27.5% to $143.2 million from $112.3 million in 2005. On a per ton basis, 2006 Segment Adjusted EBITDA Expense rose by $5.74, or 16.6%, to $40.30 per ton reflecting the impact of the cost increases described above under consolidated operating expenses and outside purchases, as well as the net impact of insurance recovery benefits of $10.7 million reported in 2005 related to the MC Mining Fire Incident. The Central Appalachian operations have been negatively impacted by increased labor and workers compensation costs, higher volumes of purchased coal, higher costs of roof control resulting from pricing, mining conditions, more aggressive regulatory requirements, increased equipment maintenance costs and increased property insurance costs. Additionally, the increased costs of the Central Appalachian operations reflect the continuing ramp-up of production in Pontiki's Van Lear seam and the transition to the Albridge Branch area of the Pond Creek seam.

Northern Appalachia – Segment Adjusted EBITDA for 2006 (as defined in reference (1) to the table above) decreased $6.1 million, or 17.0%, to $29.9 million as compared to 2005 Segment Adjusted EBITDA of $36.0 million. This decrease is the combined result of a 3.0%, or $0.98 per sold ton decrease in coal sales price per ton from $32.13 per sold ton in 2005 to $31.15 per sold ton in 2006, and a 4.8% or $1.05 per sold ton increase in Segment Adjusted EBITDA Expense from $21.95 per sold ton in 2005 to $23.00 per sold ton in 2006. The lower average sales price was primarily attributable to a decrease in spot market demand and price and fewer tons sold in higher priced export markets during 2006. Segment Adjusted EBITDA Expense for 2006 increased 7.7% to $78.7 million as compared to $73.1 million in 2005, primarily as a result of increased purchased coal volume, higher environmental costs, increased roof control costs resulting from pricing, an increased ratio of panel development mining as compared to longwall mining, increased coal transportation expense associated with the transition from the Maryland longwall operation to the Mountain View longwall operation, higher West Virginia severance taxes and the loss of certain Maryland state tax benefits.

Other and Corporate- The increase in coal sales and Segment Adjusted EBITDA Expense primarily reflects the coal sales and operating expenses attributable to the brokerage coal purchases and coal sales associated with the ICG settlement agreement referred to above under consolidated operating expenses.

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

| | Year Ended December 31, | |
|---|---|---|
| | 2006 | 2005 |
| Segment Adjusted EBITDA | $ 281,645 | $ 263,629 |
| General & administrative | (30,884) | (33,484) |
| Depreciation, depletion and amortization | (66,489) | (55,637) |
| Interest expense, net | (9,175) | (11,816) |
| Income taxes | (2,443) | (2,682) |
| Cumulative effect of accounting change | 112 | - |
| Minority interest | 161 | - |
| Net income | $ 172,927 | $ 160,010 |

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

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

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

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

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

- Contract mining costs increased $7.5 million reflecting the addition of two small third-party mining operations at Mettiki (MD);

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

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

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

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

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

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

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

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

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

*Interest expense*. Interest expense decreased to $14.6 million in 2005 from $15.8 million in 2004. The decrease of $1.2 million was principally attributable to the capitalization of interest expense related to capital projects and mine development costs, along with reduced interest expense associated with the August 2005 scheduled principal payments of $18.0 million, respectively, on our senior notes. We had no borrowings under the credit facility during 2005 or 2004.

*Interest income.* Interest income increased to $2.8 million for 2005 from $0.8 million in 2004. The increase of $2.0 million resulted from increased interest income earned on marketable securities.

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

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

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

*Segment Information*. Please read "Item 8. Financial Statements and Supplementary Data—Note 21. Segment Information" for more information concerning our reportable segments. Our 2005 Segment Adjusted EBITDA increased $70.3 million, or 36.4%, to $263.6 million from 2004 Segment Adjusted EBITDA of $193.3 million. Segment Adjusted EBITDA, tons sold, coal sales, operating revenues and Adjusted Segment EBITDA Expense by segment are as follows (in thousands):

| | **Year Ended December 31,** | | | |
|---|---|---|---|---|
| | **2005** | **2004** | **Increase (Decrease)** | |
| Segment Adjusted EBITDA | | | | |
| Illinois Basin | $ 183,075 | $ 121,763 | $ 61,312 | 50.4% |
| Central Appalachia | 41,583 | 28,953 | 12,630 | 43.6% |
| Northern Appalachia | 36,047 | 41,141 | (5,094) | (12.4)% |
| Other and Corporate | 2,924 | 1,432 | 1,492 | (3) |
| Total Segment Adjusted EBITDA (1) | $ 263,629 | $ 193,289 | $ 70,340 | 36.4% |
| Tons sold | | | | |
| Illinois Basin | 16,264 | 13,760 | 2,504 | 18.2% |
| Central Appalachia | 3,249 | 3,781 | (532) | (14.1)% |
| Northern Appalachia | 3,330 | 3,282 | 48 | 1.5% |
| Other and Corporate | 6 | - | 6 | - |
| Total tons sold | 22,849 | 20,823 | 2,026 | 9.7% |
| Coal sales | | | | |
| Illinois Basin | $ 504,916 | $ 356,307 | $ 148,609 | 41.7% |
| Central Appalachia | 153,615 | 143,160 | 10,455 | 7.3% |
| Northern Appalachia | 106,997 | 99,932 | 7,065 | 7.1% |
| Other and Corporate | 3,430 | - | 3,430 | - |
| Total coal sales | $ 768,958 | $ 599,399 | $ 169,559 | 28.3% |
| Other sales and operating revenues | | | | |
| Illinois Basin | $ 24,493 | $ 19,087 | $ 5,406 | 28.3% |
| Central Appalachia | 282 | 187 | 95 | 50.8% |
| Northern Appalachia | 2,163 | 2,127 | 36 | 1.7% |
| Other and Corporate | 3,753 | 2,672 | 1,081 | 40.5% |
| Total other sales and operating revenues | $ 30,691 | $ 24,073 | $ 6,618 | 27.5% |
| Segment Adjusted EBITDA Expense | | | | |
| Illinois Basin | $ 346,335 | $ 268,848 | $ 77,487 | 28.8% |
| Central Appalachia | 112,313 | 114,394 | (2,081) | (1.8)% |
| Northern Appalachia | 73,112 | 60,917 | 12,195 | 20.0% |
| Other and Corporate | 4,260 | 1,241 | 3,019 | (3) |
| Total Segment Adjusted EBITDA Expense (2) | $ 536,020 | $ 445,400 | $ 90,620 | 20.3% |

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

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

(3) Percentage increase was greater than 100%.

Illinois Basin – Segment Adjusted EBITDA for 2005 increased 50.4%, to $183.1 million from 2004 Segment Adjusted EBITDA of $121.8 million. The increase of $61.3 million was primarily attributable to increased coal sales which rose by $148.6 million, or 41.7%, to $504.9 million during 2005 as compared to $356.3 million in 2004. Increased coal sales in 2005 reflect higher average coal sales prices per ton which increased $5.15 per ton to $31.05 per ton (contributing $83.8 million of the increase in coal sales) and increased tons sold of 2.5 million tons (contributing $64.8 million of the increase in coal sales). Other sales and operating revenues increased $5.4 million, primarily due to $4.5 million of revenues associated with the coal synfuel facility that began operating at Gibson in 2005. Total Segment Adjusted EBITDA Expense for 2005 increased 28.8% to $346.3 million from $268.8 million in 2004. On a per ton sold basis, 2005 Segment Adjusted EBITDA Expense rose to $21.30 per ton, an increase of 9.0% over the 2004 Segment Adjusted EBITDA Expense per ton of $19.54 per ton. The increase in 2005 Segment Adjusted EBITDA Expense in 2005 compared to 2004 primarily reflects the impact of cost increases described above under consolidated operating expenses and outside purchases, partially offset by the benefit of increased tons produced, which increased 2.2 million tons in 2005 to 15.7 million tons. Segment Adjusted EBITDA for the year 2004 includes $15.2 million reported as the net gain from insurance settlement associated with the Dotiki Fire Incident described below.

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

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

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

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

*Pattiki Vertical Belt Incident*

On June 14, 2005, White County Coal's Pattiki mine was temporarily idled following the failure of the vertical conveyor belt system (the Vertical Belt Incident) used in conveying raw coal out of the mine. White County Coal surface personnel detected a failure of the vertical conveyor belt on June 14, 2005, and immediately shut down operation of all underground conveyor belt systems. White County Coal's efforts to repair the vertical belt system progressed sufficiently to allow the Pattiki mine to resume initial production operations on July 21, 2005. Repairs to the vertical belt conveyor system and ancillary equipment have been completed, and production of raw coal has returned to levels that existed prior to the occurrence of the Vertical Belt Incident. Our operating expenses were increased by $2.9 million for the year ended December 31, 2005, to reflect the estimated direct expenses attributable to the Vertical Belt Incident, which estimate included a $1.3 million retirement of the damaged vertical belt equipment. We have not identified currently any significant additional costs compared to the original cost estimates. We conducted an analysis of a number of possible alternatives to mitigate the losses arising from the Vertical Belt Incident, including review of the Vertical Belt System Design, Supply, and Oversight of Installation Contract ("Installation Contract"), dated December 7, 2000, between White County Coal and Lake Shore Mining, Inc. (and subsequently assigned to Frontier-Kemper Contractors, Inc. (Frontier-Kemper) by Lake Shore Mining, Inc.). On January 19, 2006, White County Coal filed suit against Frontier-Kemper in the White County, Illinois, Circuit Court, alleging breach of the Installation Contract and seeking to recover damages incurred as a result of the Vertical Belt Incident. That litigation is in the discovery phase, and presently we can make no assurance of the amount or timing of recovery, if any. Concurrent with the renewal of our commercial property (including business interruption) insurance policies effective on October 1, 2006, White County Coal confirmed with the current underwriters of the commercial property insurance coverage that it would not file a formal insurance claim for losses arising from or in connection with the Vertical Belt Incident.

*MC Mining Fire*

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

We maintain commercial property (including business interruption and extra expense) insurance policies with various underwriters, which policies are renewed annually in October and provide for self-retention and various applicable deductibles, including certain monetary and/or time element forms of deductibles (collectively, the "2005 Deductibles") and 10% co-insurance (2005 Co-Insurance). We believe such insurance coverage will cover a substantial portion of the total cost of the disruption to MC Mining's operations. However, concurrent with the renewal of our commercial property (including business interruption) insurance policies concluded on September 30, 2006, MC Mining confirmed with the current underwriters of the commercial property insurance coverage that any negotiated settlement of the losses arising from or in connection with the MC Mining Fire Incident would not exceed $40.0 million (inclusive of co-insurance and deductible amounts). Until the claim is resolved ultimately, through the claim adjustment process, settlement, or litigation, with the applicable underwriters, we can make no assurance of the amount or timing of recovery of insurance proceeds.

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

Following the initial two submittals by us to a representative of the underwriters of our estimate of the expenses and losses (including business interruption losses) incurred by MC Mining and other affiliates arising from or in connection with the MC Mining Fire Incident (MC Mining Insurance Claim), on September 15, 2005, we filed a third estimate of our expenses and losses, with an update through July 31, 2005. Partial payments of $4.0 million and $12.2 million were received in 2006 and 2005, respectively. These amounts are net of the 2005 Deductibles and 2005 Co-Insurance. The accounting for these partial payments and future payments, if any, made to us by the underwriters will be subject to the accounting methodology described below. On March 23, 2006, we filed a third partial proof of loss for the period through July 31, 2005 of $4.0 million. We continue to evaluate our potential insurance recoveries under the applicable insurance policies in the following areas:

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

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

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

Pursuant to the accounting methodology described above, we have recorded as an offset to operating expenses, $0.4 million and $10.7 million in 2006 and 2005, respectively, from the $16.2 million of partial payments described above. These amounts represent the current estimated insurance recovery of actual costs incurred, net of the 2005 Deductibles and 2005 Co-Insurance. The remaining $5.1 million of partial payments are included in other current liabilities in the consolidated financial statements as of December 31, 2006, and cannot be recognized as a gain until the claim is settled. We continue to discuss the MC Mining Insurance Claim and the determination of the total claim amount with representatives of the underwriters. The MC Mining Insurance Claim will continue to be developed as additional information becomes available and we have completed our assessment of the losses (including the methodologies associated therewith) arising from or in connection with the MC Mining Fire Incident. At this time, based on the magnitude and complexity of the MC Mining Insurance Claim, we are unable to reasonably estimate the total amount of the MC Mining Insurance Claim as well as our exposure, if any, for amounts not covered by our insurance program.

*Dotiki Mine Fire*

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

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

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

**Ongoing Acquisition Activities**

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

**Liquidity and Capital Resources**

*Liquidity*

We generally satisfy our working capital requirements and fund our capital expenditures and debt service obligations from cash generated from operations and borrowings under our revolving credit facility. We believe that the cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated capital expenditures (other than major capital improvements or acquisitions), scheduled debt payments and distribution payments. Our ability to satisfy our obligations and planned expenditures will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry, some of which are beyond our control.

We earn a material amount of income by supplying three coal synfuel facilities with coal feedstock. For 2006, the incremental net income benefit from the combination of the various coal synfuel-related agreements was approximately $26.4 million, assuming that coal pricing would not have increased without the availability of synfuel. We have previously entered into agreements with the owners of these coal synfuel production facilities: (1) SSO, related to its coal synfuel facility located at our Warrior mining complex in Hopkins County, Kentucky; (2) PCIN, related to its coal synfuel facility located at our Gibson mining complex in Gibson County, Indiana; and (3) Mt. Storm Coal Supply, related to its coal synfuel facility located at VEPCO's Mt. Storm Power Station, which is adjacent to our Mettiki complex in Garrett County, Maryland. SSO, PCIN, and Mt. Storm Coal Supply are collectively referred to below as Coal Synfuel Owners.

We receive revenues from coal sales, rental, marketing and other services provided to the Coal Synfuel Owners pursuant to various long-term agreements associated with their respective coal synfuel facilities. Each of these agreements, which expire on December 31, 2007, is dependent on the ability of the Coal Synfuel Owners to use certain qualifying federal income tax credits available to their respective coal synfuel facilities and are subject to early cancellation if the synfuel tax credits become unavailable due to a rise in the price of domestic crude oil or otherwise. Pursuant to our agreements with the Coal Synfuel Owners, we are not obligated to make retroactive adjustments or reimbursements if synfuel credits are disallowed.

Due to the increase in wellhead price of domestic crude oil, the operational status of our synfuel operations during 2006 has been sporadic. As of the date of this report, each of our Coal Synfuel Owners are operating and are currently producing coal synfuel. Each of the Coal Synfuel Owners has advised us that future operation of their respective synfuel facilities is dependent on the future price of crude oil. During the suspension of operations at the coal synfuel production facilities located at Warrior, Gibson and Mettiki, respectively, we sold coal directly to the Coal Synfuel Owners' customers under "back-up" coal supply agreements, which automatically provide for the sale of our coal in the event these customers do not purchase coal synfuel.

One of the states in which we operate, Maryland, has established a statutory framework for tax credits against income or franchise taxes, which tax credit has benefited, directly or indirectly, coal operators or customers purchasing coal produced from mines within that state. Our indirect benefit of the Maryland tax credit was $7.3 million for the year ended December 31, 2006. Although this tax credit is not set to expire by its terms in the near future, recent legislative and interpretive changes, as well as our reduced coal production in Maryland, likely will delay and reduce the amount of the benefit, if any, of the tax credit to us in 2007. In addition, legislation may be proposed in the future that would eliminate the credit.

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

*Cash Flows*

Cash provided by operating activities was $250.9 million in 2006, compared to $193.6 million in 2005. The increase in cash provided by operating activities was attributable principally to an increase in net income combined with a favorable change in operating assets and liabilities in 2006 compared to an unfavorable change in 2005. The principle difference in the change in operating assets and liabilities in 2006 as compared to 2005 relates to a reduced use of cash in 2006 compared to 2005 associated with trade receivables. The change in trade receivables was partially offset by a reduced change in accounts payable.

Net cash used in investing activities was $137.7 million in 2006, compared to $110.2 million in 2005. The increase in cash used in investing activities is primarily attributable to an increase in capital expenditures associated with our Elk Creek and Mountain View mines, the River View acquisition, the Gibson rail loop project and additional reserves acquired in Eastern Kentucky. This increase in capital expenditures was partially offset by increased proceeds from marketable securities, net of marketable securities purchases, during 2006.

Net cash used in financing activities was $108.5 million for 2006 compared to $82.6 million for 2005. The increase is primarily attributable to increased distributions to partners in 2006.

We have various commitments primarily related to long-term debt, including capital leases, operating lease commitments related to buildings and equipment, obligations for estimated reclamation and mine closing costs, capital project commitments, and pension funding. We expect to fund these commitments with cash generated from operations, proceeds from the sale of marketable securities, and borrowings under our revolving credit facility. The following table provides details regarding our contractual cash obligations as of December 31, 2006 (in thousands):

| Contractual Obligations | Total | Less than 1 year | 2-3 years | 4-5 years | After 5 years |
|---|---|---|---|---|---|
| Long-term debt | $ 144,000 | $ 18,000 | $ 36,000 | $ 36,000 | $ 54,000 |
| Future interest obligations on long-term debt | 53,849 | 11,966 | 19,446 | 13,462 | 8,975 |
| Operating leases | 13,872 | 3,920 | 6,527 | 3,425 | - |
| Capital leases(1) | 2,947 | 485 | 969 | 962 | 531 |
| Reclamation obligations (excluding discount effect of $47.5 million for reclamation liability) | 98,434 | 3,070 | 4,449 | 3,887 | 87,028 |
| Purchase obligations for capital projects | 15,227 | 15,227 | - | - | - |
| Coal purchase commitments | 25,249 | 25,249 | - | - | - |
| | $ 353,578 | $ 77,917 | $ 67,391 | $ 57,736 | $ 150,534 |

(1) Includes amounts classified as interest and maintenance cost.

We expect to contribute $1.2 million to the defined benefit pension plan (Pension Plan) during 2007. We estimate our income tax cash requirements to be approximately $2.8 million in 2007.

*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, 2006 (dollars in thousands):

| | Reclamation Obligation | Workers' Compensation Obligation | Other | Total |
|---|---|---|---|---|
| Surety bonds | $ 56,088 | $ - | $ 1,936 | $ 58,024 |
| Letters of credit | - | 15,322 | 22,048 | 37,370 |

*Capital Expenditures*

Capital expenditures increased to $188.6 million in 2006 compared to $119.9 million in 2005. See discussion of "Cash Flows" above concerning the increase in capital expenditures.

We currently project that our average annual maintenance capital expenditures will be approximately $2.75 per ton. Our anticipated total capital expenditures for 2007 are $100.0 to $115.0 million. 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. Based on our recent operating results, current cash position, anticipated future cash flows, and sources of financing that we expect will be available to us, we do not expect that we will experience any significant liquidity constraints in the foreseeable future.

*Notes Offering and Credit Facility*

Our Intermediate Partnership has $144.0 million principal amount of 8.31% senior notes due August 20, 2014, payable in eight remaining equal annual installments of $18.0 million with interest payable semiannually (Senior Notes). On April 13, 2006, our Intermediate Partnership entered into a $100.0 million revolving credit facility (ARLP Credit Facility), which expires in 2011. The ARLP Credit Facility replaced an $85.0 million credit facility that would have expired September 2006. 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. The initial applicable margin for borrowings under the ARLP Credit Facility is 0.875% with respect to London Interbank Offered Rate (LIBOR) borrowings. Letters of credit can be issued under the ARLP Credit Facility not to exceed $50.0 million. Outstanding letters of credit reduce amounts available under the ARLP Credit Facility. At December 31, 2006, we had letters of credit of $10.8 million outstanding under the ARLP Credit Facility. We had no borrowings outstanding under the ARLP Credit Facility at December 31, 2006.

The Senior Notes and ARLP Credit Facility are guaranteed by all of the subsidiaries of our Intermediate Partnership. The Senior Notes and ARLP Credit Facility contain various restrictive and affirmative 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 Senior Notes and the ARLP Credit Facility also require the Intermediate Partnership to remain in control of a certain amount of mineable coal based on a ratio of the amount of total mineable tons controlled by the Intermediate Partnership relative to its annual production. The ARLP Credit Facility limits the amount of total operating lease obligations to $15.0 million payable in any period of 12 consecutive months. In addition, the Senior Notes and the ARLP Credit Facility require the 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 both the ARLP Credit Facility and Senior Notes at December 31, 2006.

We have previously entered into and have maintained specific agreements with two banks to provide additional letters of credit in an aggregate amount of $31.0 million to maintain surety bonds to secure our obligations for reclamation liabilities and workers' compensation benefits. At December 31, 2006, we had $26.6 million in letters of credit outstanding under these agreements. Our special general partner guarantees $5.0 million of these outstanding letters of credit.

*Insurance*

During September 2006, we completed our annual property and casualty insurance renewal with various insurance coverages effective as of October 1, 2006. Available capacity for underwriting property insurance continues to be limited as a result of insurance carrier losses in the mining industry and our recent insurance claims history (e.g., MC Mining Fire Incident and Dotiki Fire Incident). As a result, we have elected to retain a participating interest along with our insurance carriers at an average rate of approximately 14.7% in the overall $75.0 million commercial property program representing 35% of the primary $30.0 million layer and 2.5% of the second layer representing $20.0 million in excess of the $30.0 million primary layer. We do not participate in the third layer of $25.0 million excess of $50.0 million.

The 14.7% participation rate for this year's renewal exceeds the approximate 10% participation level from last year. The aggregate maximum limit in the commercial property program is $75.0 million per occurrence of which, as a result of our participation, we would be 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. As a result of our increased participation in the property program and higher deductible levels, property premiums paid to the insurance carriers were reduced by approximately 14.5%. 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.

**Critical Accounting Policies**

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based upon our financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. 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 rental and service fees associated with agreements to host and operate third-party coal synfuel facilities and to assist with the coal synfuel marketing and other related services. These non-coal sales revenues are recognized as the services are performed. Transportation revenues are recognized in connection with incurring the corresponding costs of transporting coal to customers through third-party carriers for which we are directly reimbursed through customer billings.

*Long-Lived Assets*

We review the carrying value of long-lived assets whenever events or changes in circumstances indicate that the carrying amount may not be recoverable based upon estimated undiscounted future cash flows. The amount of impairment is measured by the difference between the carrying value and the fair value of the asset. 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 over the estimated life of the mine. 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.

*Reclamation and Mine Closing Costs*

SMCRA and similar state statutes require that mined property be restored in accordance with specified standards and an approved reclamation plan. We record the liability for the estimated cost of future mine reclamation and closing procedures on a present value basis when incurred, and the associated cost is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to 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. We had accrued liabilities of $50.9 million and $41.3 million for these costs at December 31, 2006 and 2005, respectively. The liability for mine reclamation and closing procedures is sensitive to changes in cost estimates and estimated mine lives. For additional information on our reclamation and mine closing costs, please read "Item 8. Financial Statements and Supplementary Data. – Note 15. Reclamation and Mine Closing Costs."

*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. The liability for traumatic injury claims is the estimated present value of current workers' compensation benefits, based on an annual independent actuarial study. The actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including development patterns, mortality, medical costs and interest rates. We had accrued liabilities of $45.7 million and $37.0 million for these costs at December 31, 2006 and 2005, respectively. A one-percentage-point reduction in the discount rate would have increased the liability at December 31, 2006 approximately $3.0 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 estimated black lung liability is based on an annual actuarial study performed by an independent actuary. The actuarial calculations are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and interest rates. We had accrued liabilities of $26.8 million and $23.8 million for these benefits at December 31, 2006 and 2005, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2006 by approximately $0.9 million. Under the service cost method used to estimate our black lung benefits liability, actuarial gains or losses attributable to changes in actuarial assumptions, such as the discount rate, are amortized over the remaining service period of active miners.

**Universal Shelf**

In April 2002, we filed with the Securities and Exchange Commission a universal shelf registration statement allowing us to issue from time-to-time up to an aggregate of $200 million of debt or equity securities. At February 15, 2007, we had approximately $143.0 million available under this registration statement.

**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 100% of the membership interest in River View for approximately $1.65 million from ARH. At the time, River View 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 April 2006, River View purchased such assets and assumed reclamation liabilities of $2.9 million. River View controls, through coal leases or direct ownership, approximately 110.0 million tons of high-sulfur coal reserves in the No. 7, No. 9 and No. 11 coal seams located in Union County, Kentucky.

*Tunnel Ridge, LLC Acquisition*

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

Because the River View and Tunnel Ridge acquisitions were between entities under common control, they have been accounted for at historical cost.

*Administrative Services*

In connection with the closing of the AHGP IPO, we entered into an administrative services agreement (Administrative Services Agreement) between our managing general partner, our Intermediate Partnership, AHGP and its general partner Alliance GP, LLC, (AGP) and Alliance Resource Holdings II, Inc. (ARH II), the indirect parent of SGP. Under the Administrative Services Agreement, certain employees including executive officers are providing administrative services to our managing general partner, AHGP, AGP, ARH II and their respective affiliates. We will be 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 $315,000, for the period from May 15, 2006 to December 31, 2006 from AHGP and $620,000 from ARH for the year ended December 31, 2006. This administrative service revenue is included in other sales and operating revenues in the consolidated statements of income. Concurrently, 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 $4,181,000, $14,069,000 and $28,536,000 for the years ended December 31, 2006, 2005 and 2004, respectively. The decrease from 2005 to 2006 was attributable to certain employees and the sponsorship of the LTIP, STIP and Supplemental Executive Retirement Plan (SERP), being transferred to Alliance Coal effective May 15, 2006. The decrease from 2004 to 2005 was primarily attributable to lower compensation accruals for the LTIP, STIP and SERP. The amounts billed by our managing general partner include $2,934,000, $10,559,000 and $24,242,000 for the years ended December 31, 2006, 2005 and 2004, respectively, for the LTIP, STIP and SERP.

*SGP Land, LLC*

Webster County Coal has a mineral lease and sublease with SGP Land, LLC (SGP Land), a subsidiary of the SGP, requiring annual minimum royalty payments of $2.7 million, payable in advance through 2013 or until $37.8 million of cumulative annual minimum and/or earned royalty payments have been paid. Webster County Coal paid royalties of $3,005,000, $3,449,000, and $4,611,000 for the years ended December 31, 2006, 2005, and 2004, respectively. As of December 31, 2006, Webster County Coal has recouped, against earned royalties otherwise due, all but $2,629,000 of the advance minimum royalty payments made under the lease.

Warrior has a mineral lease and sublease with SGP Land. Under the terms of the lease, Warrior paid in arrears an annual minimum royalty of $2,270,000 until $15,890,000 of cumulative annual minimum and/or earned royalty payments were paid. The annual minimum royalty periods extend from October 1st through the end of the following September 30, expiring September 30, 2007. In 2006, Warrior's cumulative total of annual minimum royalties and/or earned royalty payments exceeded $15,890,000, therefore the annual minimum royalty payment of $2,270,000 is no longer required. Warrior paid royalties of $5,061,000, $3,627,000, and $2,561,000 for the years ended December 31, 2006, 2005, and 2004, respectively. As of December 31, 2006, Warrior has recouped, against earned royalties otherwise due, all advance minimum royalty payments made in accordance with these lease terms.

Hopkins County Coal has 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 $684,000 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, are fully recoupable against future earned royalty payments. Hopkins County Coal paid advance minimum royalties and/or option fees of $684,000 during each of the years ended December 31, 2006 and 2005, respectively. As of December 31, 2006, $4,369,000 of advance minimum royalties and/or option fees paid under the Coal Lease Agreements is available for recoupment, and management expects that it will be recouped against future production.

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 $5,038,000, $6,379,000 and $5,428,000 for the years ended December 31, 2006, 2005, and 2004, respectively, for the base lease obligations. As of December 31, 2006, Webster County Coal, Warrior, and Hopkins County Coal have 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 $323,000.

In 2001, SGP Land, as successor in interest to an unaffiliated third-party, entered into an amended mineral lease with MC Mining. Under the terms of the lease, MC Mining has paid and will continue to pay an annual minimum royalty of $300,000 until $6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. MC Mining paid royalties of $300,000 and $600,000 during the years ended December 31, 2006 and 2005, respectively (the 2004 annual minimum royalty obligation of $300,000 was paid in January 2005 rather than in December 2004). As of December 31, 2006, $900,000 of advance minimum royalties paid under the lease is available for recoupment, and management expects that it will be recouped against future production.

*SGP*

As noted above, 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 obligation of $3.0 million until the earlier of January 1, 2033 or the exhaustion of the mineable and merchantable leased coal. We paid advance minimum royalties of $3.0 million during each of 2006 and 2005, which management expects 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 $240,000. 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 $240,000 for the year ended December 31, 2006.

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 $216,000 through January 2011. Lease expense incurred for each of the three years in the period ended December 31, 2006 was $2,595,000.

We previously entered into and have maintained agreements with two banks to provide letters of credit in an aggregate amount of $31.0 million. At December 31, 2006, we had $26.6 million in outstanding letters of credit under these agreements. The SGP guarantees $5.0 million of these outstanding letters of credit. Historically, we have compensated the SGP for a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. During 2003, the SGP agreed to waive the guarantee fee in exchange for a parent guarantee from the Intermediate Partnership and Alliance Coal on the mineral leases and subleases with Webster County Coal and Warrior described above. Since the guarantee is made on behalf of entities within the consolidated partnership, the guarantee has no fair value under FIN No. 45, *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 $146.2 million and $115.5 million at December 31, 2006 and 2005. These accruals were chiefly comprised of workers' compensation benefits, black lung benefits, and costs associated with reclamation and mine closings. These obligations are self-insured. The accruals of these items were based on estimates of future expenditures based on current legislation, related regulations and other developments. Thus, from time to time, our results of operations may be significantly affected by changes to these liabilities. Please see "Item 8. Financial Statements and Supplementary Data. - Note 15. Reclamation and Mine Closing Costs and Note 16. Pneumoconiosis ("Black Lung") Benefits."

**Pension Plan**

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

Our pension expense was approximately $3,243,000 and $3,006,000 for the years ended December 31, 2006 and 2005, respectively. The pension expense is based upon a number of actuarial assumptions, including an expected long-term rate of return on our Pension Plan assets of 8.0% and 8.0% and discount rates of 5.60% and 5.75% for the years ended December 31, 2006 and 2005, respectively. Our actual return on plan assets was 12.2% and 7.2% for the years ended December 31, 2006 and 2005, respectively. Additionally, we base our determination of pension expense on an unsmoothed market-related valuation of assets equal to the fair value of assets, which immediately recognizes all investment gains or losses.

In developing our expected long-term rate of return assumption, we evaluated input from our investment manager, including their review of asset class return, expectations by economists, and an independent actuary. Our advisors base the projected returns on broad equity and both indices. At December 31, 2006, our expected long-term rate of return assumption was 7.75% determined by the above factors and based on an asset allocation assumption of 80.0% with equity securities, with an expected long-term rate of return of 10.4%, and 20.0% with fixed income securities, with an expected long-term rate of return of 5.3%. The Pension Plan trustee regularly reviews our actual asset allocation in accordance with our investment guidelines and periodically rebalances our investments to our targeted allocation when considered appropriate. The investment committee annually reviews our asset allocation with the compensation committee of our managing general partner (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. The duration of the bonds that comprise this index is comparable to the duration of the benefit obligation in the Pension Plan. The discount rate determined on this basis decreased from 5.60% at December 31, 2005 to 5.55% at December 31, 2006.

We estimate that our Pension Plan expense and cash contributions will be approximately $3,274,000 and $1,200,000, respectively, in 2007. Future actual pension expense and contributions will depend on future investment performance, changes in future discount rates and various other factors related to the employees participating in the Pension Plan.

Lowering the expected long-term rate of return assumption by 1.0% (from 8.0% to 7.0%) at December 31, 2005 would have increased our pension expense for the year ended December 31, 2006 by approximately $286,000. Lowering the discount rate assumption by 0.5% (from 5.60% to 5.10%) at December 31, 2005 would have increased our pension expense for the year ended December 31, 2006 by approximately $517,000.

**Inflation**

Generally, inflation in the U.S. has been relatively low in recent years. However, over the course of the last three years, our results have been significantly impacted by price inflation as it relates to many of the components of our operating expenses such as fuel, steel, maintenance expense and labor. If the prices for which we sell our coal do not increase in step with rising costs, our margins will be reduced.

## New Accounting Standards

In November 2004, the FASB issued SFAS No. 151, *Inventory Costs*. SFAS No. 151 is an amendment of Accounting Research Bulletin (ARB) No. 43, Chapter 4, Paragraph 5 that deals with inventory pricing. SFAS No. 151 clarifies the accounting for abnormal amounts of idle facility expenses, freight, handling costs, and spoilage. Under previous guidance, Chapter 4 Paragraph 5 of ARB No. 43, items such as idle facility expense, excessive spoilage, double freight, and rehandling costs might be considered to be so abnormal, under certain circumstances, as to require treatment as current period charges. This statement eliminates the criterion of "so abnormal" and requires that those items be recognized as current period charges. Also, SFAS No. 151 requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. Our adoption of SFAS No. 151 on January 1, 2006 did not have a material impact on our consolidated financial statements.

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123R, *Share-Based Payment*, using the "modified prospective" transition method. SFAS No. 123R permits companies to adopt its requirements using either a "modified prospective" method, or a "modified retrospective" method. Under the "modified prospective" method permitted by SFAS No. 123R, compensation cost is recognized in the financial statements beginning with the effective date, of all share-based payments granted after that date, and based on the requirements of SFAS No. 123, *Accounting for Stock-Based Compensation*, for all unvested awards granted prior to the effective date of SFAS No. 123R. The requirements of SFAS No. 123R, under the "modified retrospective" method, are the same as under the "modified prospective" method, but also permits entities to restate financial statements of previous periods based on pro forma disclosures made in accordance with SFAS No. 123. We used the modified prospective method of adoption provided under SFAS No. 123R and, therefore, did not restate prior period results.

Prior to the adoption of SFAS No. 123R, we accounted for compensation expense attributable to the non-vested restricted common units granted under the LTIP using the intrinsic value method prescribed in Accounting Principles Board Opinion ("APB") No. 25, *Accounting for Stock Issued to Employees* and the related FIN No. 28, *Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans*. Compensation cost for the restricted common units was recorded on a pro-rata basis, as appropriate given the "cliff vesting" nature of the grants, based upon the current market value of the ARLP common units at the end of each period. Because we had previously expensed share-based payments using the current market value of the ARLP common units at the end of each period, the adoption of SFAS No. 123R did not have a material impact on our consolidated results of operations.

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

In June 2006, the FASB issued FIN No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*. This interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*. The interpretation prescribes a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return and also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The provisions of FIN No. 48 are effective for fiscal years beginning after December 15, 2006. We do not expect the adoption of FIN No. 48 to have a material impact on our consolidated financial statements.

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 United States of America, 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. We are currently evaluating the requirements of SFAS No. 157 and have not yet determined the impact on our consolidated financial statements.

In September 2006, the FASB issued 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).* SFAS No. 158 requires an employer to recognize the over-funded or under-funded status of a defined benefit postretirement plan (other than a multi-employer plan) as an asset or liability on its statement of financial position. SFAS No. 158 also requires an employer to recognize changes in that funded status in the year in which the changes occur through comprehensive income. In addition, SFAS No. 158 requires an employer to measure the funded status of a plan as of the date of its year-end statement of financial position. SFAS No. 158 requirements to recognize the funded status of a benefit plan and new disclosure requirements are effective as of December 31, 2006. The requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. Other than the reclass of accrued pension benefits from current to long-term liabilities, the adoption of SFAS No. 158 did not have a material impact on our consolidated financial statements.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements*, which provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. SAB No. 108 is effective as of December 31, 2006. The adoption of SAB No. 108 did not have a material impact on our consolidated financial statements.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We have significant long-term coal supply agreements. Virtually all of the long-term coal supply agreements are subject to price adjustment provisions, which permit an increase or decrease periodically in the contract price to principally reflect changes in specified price indices or items such as taxes, royalties or actual production costs. For additional discussion of coal supply agreements, please see "Item 1. Business. – Coal Marketing and Sales" and "Item 8. Financial Statements and Supplementary Data. – Note 20. 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. Our earnings are not materially affected by changes in interest rates. We had no borrowings outstanding under the ARLP Credit Facility during 2006 or at December 31, 2006.

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, 2006, and 2005. The carrying amounts and fair values of financial instruments are as follows (in thousands):

| **Expected Maturity Dates as of December 31, 2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **Thereafter** | **Total** | **Fair Value December 31, 2006** |
|---|---|---|---|---|---|---|---|---|
| Senior Notes fixed rate | $ 18,000 | $ 18,000 | $ 18,000 | $ 18,000 | $ 18,000 | $ 54,000 | $ 144,000 | $ 156,179 |
| Weighted Average interest rate | 8.31% | 8 31% | 8.31% | 8.31% | 8.31% | 8.31% | | |

| **Expected Maturity Dates as of December 31, 2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **Thereafter** | **Total** | **Fair Value December 31, 2005** |
|---|---|---|---|---|---|---|---|---|
| Senior Notes fixed rate | $ 18,000 | $ 18,000 | $ 18,000 | $ 18,000 | $ 18,000 | $ 72,000 | $ 162,000 | $ 176,254 |
| Weighted Average interest rate | 8.31% | 8 31% | 8.31% | 8.31% | 8.31% | 8.31% | | |

## 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, 2006 and 2005, and the related consolidated statements of income, cash flows and Partners' capital (deficit) and comprehensive income for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2006, 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 February 28, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Partnership's internal control over financial reporting and an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ *Deloitte & Touche LLP*

Tulsa, Oklahoma
February 28, 2007

**ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES**

**CONSOLIDATED BALANCE SHEETS**
**DECEMBER 31, 2006 AND 2005**
**(In thousands, except unit data)**

| **ASSETS** | **December 31, 2006** | **December 31, 2005** |
|---|---|---|
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ 36,789 | $ 32,054 |
| Trade receivables, net | 96,558 | 94,495 |
| Other receivables | 3,378 | 2,330 |
| Due from affiliates | 25 | - |
| Marketable securities | 260 | 49,242 |
| Inventories | 20,224 | 17,270 |
| Advance royalties | 4,629 | 2,952 |
| Prepaid expenses and other assets | 8,225 | 8,934 |
| Total current assets | 170,088 | 207,277 |
| PROPERTY, PLANT AND EQUIPMENT: | | |
| Property, plant and equipment, at cost | 819,991 | 635,086 |
| Less accumulated depreciation, depletion and amortization | (383,284) | (330,672) |
| Total property, plant and equipment - net | 436,707 | 304,414 |
| OTHER ASSETS: | | |
| Advance royalties | 22,135 | 16,328 |
| Other long-term assets | 6,032 | 4,668 |
| Total other assets | 28,167 | 20,996 |
| TOTAL ASSETS | $ 634,962 | $ 532,687 |
| **LIABILITIES AND PARTNERS' CAPITAL** | | |
| CURRENT LIABILITIES: | | |
| Accounts payable | $ 57,879 | $ 53,473 |
| Due to affiliates | 1,414 | 8,795 |
| Accrued taxes other than income taxes | 14,618 | 13,177 |
| Accrued payroll and related expenses | 14,698 | 12,466 |
| Accrued pension benefit | - | 7,588 |
| Accrued interest | 4,264 | 4,855 |
| Workers' compensation and pneumoconiosis benefits | 7,704 | 7,740 |
| Current capital lease obligation | 339 | - |
| Other current liabilities | 13,786 | 5,120 |
| Current maturities, long-term debt | 18,000 | 18,000 |
| Total current liabilities | 132,702 | 131,214 |
| LONG-TERM LIABILITIES: | | |
| Long-term debt, excluding current maturities | 126,000 | 144,000 |
| Pneumoconiosis benefits | 26,315 | 23,293 |
| Accrued pension benefit | 6,191 | - |
| Workers' compensation | 38,488 | 30,050 |
| Reclamation and mine closing | 47,825 | 38,716 |
| Due to affiliates | 994 | 6,940 |
| Long-term capital lease obligation | 1,512 | - |
| Minority interest | 839 | - |
| Other liabilities | 5,616 | 2,697 |
| Total long-term liabilities | 253,780 | 245,696 |
| Total liabilities | 386,482 | 376,910 |
| COMMITMENTS AND CONTINGENCIES | | |
| PARTNERS' CAPITAL: | | |
| Limited Partners - Common Unitholders 36,419,847 and 36,426,306 units outstanding, respectively | 549,005 | 461,068 |
| General Partners' deficit | (293,569) | (298,270) |
| Unrealized loss on marketable securities | - | (68) |
| Accumulated other comprehensive income/minimum pension liability | (6,956) | (6,953) |
| Total Partners' capital | 248,480 | 155,777 |
| TOTAL LIABILITIES AND PARTNERS' CAPITAL | $ 634,962 | $ 532,687 |

See notes to consolidated financial statements.

**ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES**

**CONSOLIDATED STATEMENTS OF INCOME**
**FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004**
**(In thousands, except unit and per unit data)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| SALES AND OPERATING REVENUES: | | | |
| Coal sales | $ 895,823 | $ 768,958 | $ 599,399 |
| Transportation revenues | 39,879 | 39,069 | 29,817 |
| Other sales and operating revenues | 31,855 | 30,691 | 24,073 |
| Total revenues | 967,557 | 838,718 | 653,289 |
| EXPENSES: | | | |
| Operating expenses | 627,756 | 521,488 | 436,471 |
| Transportation expenses | 39,879 | 39,069 | 29,817 |
| Outside purchases | 19,213 | 15,113 | 9,913 |
| General and administrative | 30,884 | 33,484 | 45,400 |
| Depreciation, depletion and amortization | 66,489 | 55,637 | 53,664 |
| Net gain from insurance settlement | - | - | (15,217) |
| Total operating expenses | 784,221 | 664,791 | 560,048 |
| INCOME FROM OPERATIONS | 183,336 | 173,927 | 93,241 |
| Interest expense (net of interest capitalized of $1,558, $566 and $-, respectively) | (12,177) | (14,617) | (15,816) |
| Interest income | 3,002 | 2,801 | 853 |
| Other income | 936 | 581 | 984 |
| INCOME BEFORE INCOME TAXES, CUMULATIVE EFFECT OF ACCOUNTING CHANGE, AND MINORITY INTEREST | 175,097 | 162,692 | 79,262 |
| INCOME TAX EXPENSE | 2,443 | 2,682 | 2,641 |
| INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE AND MINORITY INTEREST | 172,654 | 160,010 | 76,621 |
| CUMULATIVE EFFECT OF ACCOUNTING CHANGE | 112 | - | - |
| MINORITY INTEREST | 161 | - | - |
| NET INCOME | $ 172,927 | $ 160,010 | $ 76,621 |
| GENERAL PARTNERS' INTEREST IN NET INCOME | $ 24,594 | $ 12,409 | $ 3,324 |
| LIMITED PARTNERS' INTEREST IN NET INCOME | $ 148,333 | $ 147,601 | $ 73,297 |
| BASIC NET INCOME PER LIMITED PARTNER UNIT | $ 3.06 | $ 2.89 | $ 1.76 |
| DILUTED NET INCOME PER LIMITED PARTNER UNIT | $ 3.03 | $ 2.84 | $ 1.71 |
| DISTRIBUTIONS PAID PER COMMON AND SUBORDINATED UNIT | $ 1.92 | $ 1.58 | $ 1.24 |
| WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING – BASIC | 36,425,350 | 36,288,527 | 35,881,896 |
| WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING – DILUTED | 36,810,383 | 36,977,061 | 36,874,336 |

See notes to consolidated financial statements.

**ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004**
**(In thousands)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | | |
| Net income | $ 172,927 | $ 160,010 | $ 76,621 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, depletion and amortization | 66,489 | 55,637 | 53,664 |
| Long-term incentive plan | 4,112 | 8,193 | 20,320 |
| Reclamation and mine closings | 2,101 | 1,918 | 1,622 |
| Coal inventory adjustment to market | 319 | 573 | 488 |
| Net (gain)/loss on sale of property, plant and equipment | (1,188) | 179 | (332) |
| Loss on retirement of damaged vertical belt equipment | - | 1,298 | - |
| Minority interest | (161) | - | - |
| Cumulative effect of accounting change | (112) | - | - |
| Other | 1,119 | 580 | 587 |
| Changes in operating assets and liabilities: | | | |
| Trade receivables | (2,051) | (37,528) | (20,593) |
| Other receivables | (1,048) | (693) | 294 |
| Inventories | (3,851) | (4,004) | 200 |
| Prepaid expenses and other assets | 757 | (4,584) | (913) |
| Advance royalties | (6,484) | (4,396) | (1,307) |
| Accounts payable | 1,677 | 13,115 | 8,678 |
| Due to affiliates | (1,762) | (3,265) | (6,126) |
| Accrued taxes other than income taxes | 1,441 | 2,435 | 367 |
| Accrued payroll and related benefits | 1,659 | 736 | 635 |
| Pneumoconiosis benefits | 3,022 | 3,460 | 2,702 |
| Workers' compensation | 8,402 | 4,715 | 3,849 |
| Other | 3,555 | (4,761) | 4,299 |
| Total net adjustments | 77,996 | 33,608 | 68,434 |
| Net cash provided by operating activities | 250,923 | 193,618 | 145,055 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | |
| Property, plant and equipment: | | | |
| Capital expenditures | (188,630) | (119,881) | (54,713) |
| Changes in accounts payable and accrued liabilities | 2,776 | 9,364 | - |
| Proceeds from sale of property, plant and equipment | 1,401 | 198 | 687 |
| Purchase of marketable securities | (19,447) | (63,448) | (49,271) |
| Proceeds from marketable securities | 68,497 | 63,589 | 23,537 |
| Proceeds from assumption of liability | - | - | 2,112 |
| Payments for acquisition of businesses | (2,289) | - | - |
| Net cash used in investing activities | (137,692) | (110,178) | (77,648) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | |
| Cash contribution by General Partners | 2 | 143 | 3 |
| Payments on long-term debt | (18,000) | (18,000) | - |
| Payment of debt issuance costs | (690) | - | - |
| Equity contribution received by Mid-America Carbonates, LLC | 1,000 | - | - |
| Distributions to Partners | (90,808) | (64,706) | (46,389) |
| Net cash used in financing activities | (108,496) | (82,563) | (46,386) |
| NET CHANGE IN CASH AND CASH EQUIVALENTS | 4,735 | 877 | 21,021 |
| CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD | 32,054 | 31,177 | 10,156 |
| CASH AND CASH EQUIVALENTS AT END OF PERIOD | $ 36,789 | $ 32,054 | $ 31,177 |
| SUPPLEMENTAL CASH FLOW INFORMATION: | | | |
| CASH PAID FOR: | | | |
| Cash paid for interest | $ 13,760 | $ 15,160 | $ 15,229 |
| Cash paid for taxing authorities | $ 2,400 | $ 3,025 | $ 2,150 |
| NON-CASH ACTIVITY: | | | |
| Purchase of property, plant and equipment | $ 12,140 | $ 9,364 | $ - |
| Asset acquired by capital lease | $ 1,862 | $ - | $ - |
| Market value of common units issued to Long-Term Incentive Plan participants upon vesting | $ - | $ 6,988 | $ 13,680 |

See notes to consolidated financial statements.

## ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL (DEFICIT) AND COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004
(In thousands, except unit data)

| | Number of Limited Partner Units | | Limited Partners' Capital | | General Partners' Capital (Deficit) | Unrealized Gain (Loss) | Minimum Pension Liability/Accumulated Other Comprehensive Income | Total Partners' Capital (Deficit) |
|---|---|---|---|---|---|---|---|---|
| | Common | Subordinated | Common | Subordinated | | | | |
| Balance at January 1, 2004 | 29,385,054 | 6,422,532 | $ 263,071 | $ 58,411 | $ (305,034) | $ (102) | $ (3,789) | $ 12,557 |
| Comprehensive income: | | | | | | | | |
| Net income | - | - | 60,685 | 12,612 | 3,324 | - | - | 76,621 |
| Unrealized gain | - | - | - | - | - | 48 | - | 48 |
| Minimum pension liability | - | - | - | - | - | - | (1,333) | (1,333) |
| Total comprehensive income | - | - | 60,685 | 12,612 | 3,324 | 48 | (1,333) | 75,336 |
| Issuance of units to Long-Term Incentive Plan participants upon vesting | 462,252 | - | 13,680 | - | - | - | - | 13,680 |
| General Partners contribution | - | - | - | - | 3 | - | - | 3 |
| Retirement of common units contributed by our Managing General Partner | (8,958) | - | (265) | - | 265 | - | - | - |
| Distribution to Partners | - | - | (36,548) | (7,988) | (1,853) | - | - | (46,389) |
| Subordinated units conversion to common units | 6,422,532 | (6,422,532) | 63,035 | (63,035) | - | - | - | - |
| Balance at December 31, 2004 | 36,260,880 | - | 363,658 | - | (303,295) | (54) | (5,122) | 55,187 |
| Comprehensive income: | | | | | | | | |
| Net income | - | - | 147,601 | - | 12,409 | - | - | 160,010 |
| Unrealized loss | - | - | - | - | - | (14) | - | (14) |
| Minimum pension liability | - | - | - | - | - | - | (1,831) | (1,831) |
| Total comprehensive income | - | - | 147,601 | - | 12,409 | (14) | (1,831) | 158,165 |
| Issuance of units to Long-Term Incentive Plan participants upon vesting | 165,426 | - | 6,988 | - | - | - | - | 6,988 |
| General Partners contribution | - | - | - | - | 143 | - | - | 143 |
| Distribution to Partners | - | - | (57,179) | - | (7,527) | - | - | (64,706) |
| Balance at December 31, 2005 | 36,426,306 | - | 461,068 | - | (298,270) | (68) | (6,953) | 155,777 |
| Comprehensive income: | | | | | | | | |
| Net income | - | - | 148,333 | - | 24,594 | - | - | 172,927 |
| Unrealized gain | - | - | - | - | - | 68 | - | 68 |
| Other comprehensive income | - | - | - | - | - | - | (3) | (3) |
| Total comprehensive income | - | - | 148,333 | - | 24,594 | 68 | (3) | 172,992 |
| Common unit – based compensation under Long-Term Incentive Plan | - | - | 10,517 | - | - | - | - | 10,517 |
| General Partner contribution | - | - | - | - | 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 |

See notes to consolidated financial statements.

## 1. ORGANIZATION AND PRESENTATION

*Significant Relationships referenced in Notes to Consolidated Financial Statements*

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

*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") (formerly known as Alliance Coal Corporation), 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, our President and Chief Executive Officer. The SGP is a Delaware limited liability company, which holds a 0.01% general partner interest in each of ARLP and the Intermediate Partnership. We lease certain assets, including coal reserves and certain surface facilities, owned by SGP (Note 18).

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 own and become the controlling member of MGP. AHGP completed its initial public offering ("AHGP IPO") on May 15, 2006. Upon the closing of the AHGP IPO, AHGP owned directly and indirectly 100% of the members' interest of MGP, a 0.001% managing interest in Alliance Coal, the incentive distribution rights in ARLP and 15,550,628 common units of ARLP. In November 2006, AHGP contributed 6,459 common units of ARLP to MGP, and MGP contributed these ARLP units to ARLP in exchange for a general partner interest in our Intermediate Partnership. The unit contribution by MGP was necessary for it to maintain its 1.0001% general partner interest in the Intermediate Partnership.

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 Service, Inc., Backbone Mountain, LLC, Excel Mining, LLC ("Excel"), Gibson County Coal, LLC ("Gibson County Coal"), Hopkins County Coal, LLC ("Hopkins County Coal"), Matrix Design Group, LLC, 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 Coal"), 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").

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

The accompanying consolidated financial statements include the accounts and operations of the limited partnerships, limited liability companies and corporation disclosed above and present the financial position as of December 31, 2006 and 2005 and the results of their operations, cash flows and changes in partners' capital (deficit) and comprehensive income for each of the three years in the period ended December 31, 2006. All material intercompany transactions and accounts of the ARLP Partnership have been eliminated.

## 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

***Fair Value of Financial Instruments—***The carrying amounts for accounts receivable, marketable securities, and accounts payable approximate fair value because of the short maturity of those instruments. At December 31, 2006 and 2005, the estimated fair value of long-term debt, including current maturities, was approximately $156.2 million and $176.3 million, respectively. The estimated fair value of long-term debt is based on interest rates that we believe are currently available to us for issuance of debt with similar terms and remaining maturities.

***Cash and Cash Equivalents—***Cash and cash equivalents include cash on hand and on deposit, including highly liquid investments with maturities of three months or less. We had restricted cash and cash equivalents of $1,937,000 and $1,858,000 at December 31, 2006 and 2005, respectively, which are included in other assets in the consolidated balance sheets. The restricted cash and cash equivalents are held in escrow and secure reclamation bonds.

***Cash Management—***We presented book overdrafts of $11,291,000 and $10,526,000 at December 31, 2006 and 2005, respectively, in accounts payable in the consolidated balance sheets.

***Marketable Securities—***We currently classify all marketable securities as available for sale securities. At December 31, 2006 and 2005, the cost of marketable securities is reported at fair value with unrealized gains and losses reported as a component of Partners' capital until realized (Note 6).

***Inventories—***Coal inventories are stated at the lower of cost or market on a first-in, first-out basis. Supply inventories are stated at the lower of cost or market on an average cost basis, less a reserve for obsolete and surplus items.

***Property, Plant and Equipment—***Additions and replacements constituting improvements, are capitalized. Maintenance, repairs, and minor replacements are expensed as incurred. Depreciation and amortization are computed principally on the straight-line method based upon the estimated useful lives of the assets or the estimated life of each mine, whichever is less, ranging from 2 to 12 years. Depreciable lives for mining equipment and processing facilities range from 2 to 12 years. Depreciable lives for land and land improvements and depletable lives for mineral rights range from 2 to 12 years. Depreciable lives for buildings, office equipment and improvements range from 2 to 12 years. Gains or losses arising from retirements are included in current operations. Depletion of mineral rights is provided on the basis of tonnage mined in relation to estimated recoverable tonnage. At December 31, 2006 and 2005, land and mineral rights include $13,767,000 and $4,628,000, 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 over the estimated life of the mine. 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.

***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.

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

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

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

***Reclamation and Mine Closing Costs—***We record the liability for the estimated cost of future mine reclamation and closing procedures on a present value basis when incurred and the associated cost is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to 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. (Note 15).

***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 actuarial valuations.

***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. Our subsidiary, Alliance Service, Inc. ("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 IRS regarding our classification as a partnership for federal income tax purposes. Our tax basis in net assets exceeded the book basis in net assets by approximately $169.0 million and $130.0 million at December 31, 2006 and 2005, respectively.

***Revenue Recognition***—Revenues from coal sales are recognized when title passes to the customer as the coal is shipped. Some coal supply agreements provide for price adjustments based on variations in quality characteristics of the coal shipped. In certain cases, a customer's analysis of the coal quality is binding and the results of the analysis are received on a delayed basis. In these cases, 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 rental and service fees associated with agreements to host and operate third-party coal synfuel facilities and to assist with the coal synfuel marketing and other related services. These non-coal sales revenues are recognized as the services are performed. Transportation revenues are recognized in connection with us incurring the corresponding costs of transporting coal to customers through third-party carriers for which we are directly reimbursed through customer billings.

***Common Unit-Based Compensation*****—**Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123R, *Share-Based Payment*, using the "modified prospective" transition method. SFAS No. 123R permits companies to adopt its requirements using either a "modified prospective" method, or a "modified retrospective" method. Under the "modified prospective" method permitted by SFAS No. 123R, compensation cost is recognized in the financial statements beginning with the effective date, of all share-based payments granted after that date, and based on the requirements of SFAS No. 123, *Accounting for Stock-Based Compensation*, for all unvested awards granted prior to the effective date of SFAS No. 123R. The requirements of SFAS No. 123R, under the "modified retrospective" method, are the same as under the "modified prospective" method, but also permits entities to restate financial statements of previous periods based on pro forma disclosures made in accordance with SFAS No. 123. We used the modified prospective method of adoption provided under SFAS No. 123R and, therefore, did not restate prior period results.

Prior to the adoption of SFAS No. 123R, we accounted for compensation expense attributable to the non-vested restricted common units granted under the Long-Term Incentive Plan ("LTIP") using the intrinsic value method prescribed in Accounting Principles Board Opinion ("APB") No. 25, *Accounting for Stock Issued to Employees* and the related FASB Interpretation ("FIN") No. 28, *Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans*. Compensation cost for the restricted common units was recorded on a pro-rata basis, as appropriate given the "cliff vesting" nature of the grants, based upon the current market value of the ARLP common units at the end of each period. Because we had previously expensed share-based payments using the current market value of the ARLP common units at the end of each period, the adoption of SFAS No. 123R did not have a material impact on our consolidated results of operations.

Consistent with the 2005 and 2004 disclosure requirements of SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*, an amendment of SFAS No. 123, the following table demonstrates that compensation cost for the non-vested restricted units granted under the LTIP is the same under the intrinsic value method and the provisions of SFAS No. 123 (in thousands, except per unit data):

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

***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, EITF Issue 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, Subordinated Units and common unit equivalents outstanding, which primarily include restricted units granted under the LTIP (Note 14).

***New Accounting Standards—*** In November 2004, the FASB issued SFAS No. 151, *Inventory Costs*. SFAS No. 151 is an amendment of Accounting Research Bulletin ("ARB") No. 43, Chapter 4, Paragraph 5 that deals with inventory pricing. SFAS No. 151 clarifies the accounting for abnormal amounts of idle facility expenses, freight, handling costs, and spoilage. Under previous guidance, Chapter 4 Paragraph 5 of ARB No. 43, items such as idle facility expense, excessive spoilage, double freight, and rehandling costs might be considered to be so abnormal, under certain circumstances, as to require treatment as current period charges. This statement eliminates the criterion of "so abnormal" and requires that those items be recognized as current period charges. Also, SFAS No. 151 requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. Our adoption of SFAS No. 151, on January 1, 2006, did not have a material impact on our consolidated financial statements.

We adopted SFAS No. 123R effective on January 1, 2006. We used the "modified prospective" method of adoption provided under SFAS No. 123R and, therefore, did not restate prior period results (Note 14).

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

In June 2006, the FASB issued FIN No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*. This interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*. The interpretation prescribes a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return and also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The provisions of FIN No. 48 are effective for fiscal years beginning after December 15, 2006. We do not expect the adoption of FIN No. 48 to have a material impact on our consolidated financial statements.

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 United States of America, 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. We are currently evaluating the requirements of SFAS No. 157 and have not yet determined the impact on our consolidated financial statements.

In September 2006, the FASB issued 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).* SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multi-employer plan) as an asset or liability on its statement of financial position. SFAS No. 158 also requires an employer to recognize changes in that funded status in the year in which the changes occur through comprehensive income. In addition, SFAS No. 158 requires an employer to measure the funded status of a plan as of the date of its year-end statement of financial position. SFAS No. 158 requirements to recognize the funded status of a benefit plan and new disclosure requirements are effective as of December 31, 2006. The requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. Other than the reclass of accrued pension benefits from current to long-term liabilities, the adoption of SFAS No. 158 did not have a material impact on our consolidated financial statements.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") No. 108, *Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements*, which provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. SAB No. 108 is effective as of December 31, 2006. The adoption of SAB No. 108 did not have a material impact on our consolidated financial statements.

***Reclassifications—***Certain reclassifications have been made to the 2005 and 2004 cash flow presentation of the LTIP, due to affiliates, and net (gain)/loss on sale of property, plant and equipment, which are reported separately within cash flows from operating activities to conform to the 2006 presentation.

**3. ACQUISITIONS**

*River View Coal, LLC*

In April 2006, we acquired 100% of the membership interest in River View Coal, LLC ("River View") for approximately $1.65 million from ARH. At the time, River View 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 April 2006, River View purchased such assets and assumed reclamation liabilities of $2.9 million. River View controls through coal leases or direct ownership approximately 110.0 million tons of high sulfur coal reserves in the No. 7, No. 9 and No. 11 coal seams, located in Union County, Kentucky.

*Tunnel Ridge, LLC*

In January 2005, we acquired 100% of the limited liability company member interests of Tunnel Ridge for approximately $500,000 and the assumption of reclamation liabilities from ARH. Tunnel Ridge controls, through a coal lease agreement with our special general partner, an estimated 70 million tons of high-sulfur coal in the Pittsburgh No. 8 coal seam underlying approximately 9,400 acres of land located in Ohio County, West Virginia and Washington County, Pennsylvania. Under the terms of the coal lease, beginning on January 1, 2005, Tunnel Ridge has paid and will continue to pay our special general partner an advance minimum royalty of $3.0 million per year. The advance royalty payments are fully recoupable against earned royalties (Note 18). Tunnel Ridge also controls surface land and other tangible assets under a separate lease agreement with the SGP.

The River View and Tunnel Ridge 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 these 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 River View and Tunnel Ridge transactions as fair and reasonable to us and our limited partners. Because River View and Tunnel Ridge acquisitions were between entities under common control, they were accounted for at historical cost.

*Lodestar Assets*

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

## 4. MINE FIRE INCIDENTS

*MC Mining Mine Fire*

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

We maintain commercial property (including business interruption and extra expense) insurance policies with various underwriters, which policies are renewed annually in October and provide for self-retention and various applicable deductibles, including certain monetary and/or time element forms of deductibles (collectively, the "2005 Deductibles") and 10% co-insurance ("2005 Co-Insurance"). We believe such insurance coverage will cover a substantial portion of the total cost of the disruption to MC Mining's operations. However, concurrent with the renewal of our commercial property (including business interruption) insurance policies concluded on September 30, 2006, MC Mining confirmed with the current underwriters of the commercial property insurance coverage that any negotiated settlement of the losses arising from or in connection with the MC Mining Fire Incident would not exceed $40.0 million (inclusive of co-insurance and deductible amounts). Until the claim is resolved ultimately, through the claim adjustment process, settlement, or litigation, with the applicable underwriters, we can make no assurance of the amount or timing of recovery of insurance proceeds.

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

Following the initial two submittals by us to a representative of the underwriters of our estimate of the expenses and losses (including business interruption losses) incurred by MC Mining and other affiliates arising from or in connection with the MC Mining Fire Incident ("MC Mining Insurance Claim"), on September 15, 2005, we filed a third estimate of our expenses and losses, with an update through July 31 2005. Partial payments of $4.0 million and $12.2 million were received in 2006 and 2005, respectively. These amounts are net of the 2005 Deductibles and 2005 Co-Insurance. The accounting for these partial payments and future payments, if any, made to us by the underwriters will be subject to the accounting methodology described below. On March 23, 2006, we filed a third partial proof of loss for the period through July 31, 2005 of $4.0 million. Currently, we continue to evaluate our potential insurance recoveries under the applicable insurance policies in the following areas:

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

2. Damage to MC Mining mine property - The net book value of property destroyed of $154,000, was written off in the first quarter of 2005 with a corresponding amount recorded as an estimated insurance recovery, since such recovery is considered probable. Any insurance proceeds from the claims relating to the MC Mining mine property (other than amounts relating to the matters discussed in 1. above) that exceed the net book value of

such damaged property are expected to result in a gain. The anticipated gain will be recorded when the MC Mining Insurance Claim is resolved and/or proceeds are received.

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

Pursuant to the accounting methodology described above, we have recorded as an offset to operating expenses, $0.4 million and $10.7 million in 2006 and 2005, respectively from the $16.2 million of partial payments described above. These amounts represent the current estimated insurance recovery of actual costs incurred, net of the 2005 Deductibles and 2005 Co-Insurance. The remaining $5.1 million of partial payments are included in other current liabilities in the consolidated financial statements as of December 31, 2006 and cannot be recognized as a gain until the claim is settled. We continue to discuss the MC Mining Insurance Claim and the determination of the total claim amount with representatives of the underwriters. The MC Mining Insurance Claim will continue to be developed as additional information becomes available and we have completed our assessment of the losses (including the methodologies associated therewith) arising from or in connection with the MC Mining Fire Incident. At this time, based on the magnitude and complexity of the MC Mining Insurance Claim, we are unable to reasonably estimate the total amount of the MC Mining Insurance Claim as well as our exposure, if any, for amounts not covered by our insurance program.

*Dotiki Mine Fire*

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

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

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

## 5. VERTICAL BELT FAILURE

On June 14, 2005, our White County Coal Pattiki mine was temporarily idled following the failure of the vertical conveyor belt system (the "Vertical Belt Incident") used in conveying raw coal out of the mine. White County Coal surface personnel detected a failure of the vertical conveyor belt on June 14, 2005 and immediately shut down operation of all underground conveyor belt systems. White County Coal's efforts to repair the vertical belt system progressed sufficiently to allow the Pattiki mine to resume initial production operations on July 21, 2005. Repairs to the vertical belt conveyor system and ancillary equipment have been completed, and production of raw coal has returned to levels that existed prior to the occurrence of the Vertical Belt Incident. Our operating expenses were increased by $2.9 million for the year ended December 31, 2005, to reflect the estimated direct expenses attributable to the Vertical Belt Incident, which estimate included a $1.3 million retirement of the damaged vertical belt equipment. We have not identified currently any significant additional costs compared to the original cost estimates. We conducted an analysis of a number of possible alternatives to mitigate the losses arising from the Vertical Belt Incident, including review of the Vertical Belt System Design, Supply, and Oversight of Installation Contract ("Installation Contract"), dated December 7, 2000, between White County Coal and Lake Shore Mining, Inc. (and subsequently assigned to Frontier-Kemper Contractors, Inc. ("Frontier-Kemper") by Lake Shore Mining, Inc.). On January 19, 2006, White County Coal filed suit against

Frontier-Kemper in the White County, Illinois, Circuit Court, alleging breach of the Installation Contract and seeking to recover damages incurred as a result of the Vertical Belt Incident. That litigation is in the discovery phase, and presently we can make no assurance of the amount or timing of recovery, if any. Concurrent with the renewal of our commercial property (including business interruption) insurance policies effective on October 1, 2006, White County Coal confirmed with the current underwriters of the commercial property insurance coverage that it would not file a formal insurance claim for losses arising from or in connection with the Vertical Belt Incident.

## 6. MARKETABLE SECURITIES

Marketable securities include Federal home loan discount notes. The Federal home loan discount notes had a cumulative unrealized loss reflected in Partners' capital of $68,000 at December 31, 2005.

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

| | 2006 | 2005 |
|---|---|---|
| Federal home loan discount notes | $ 260 | $ 49,242 |
| Total marketable securities | $ 260 | $ 49,242 |

## 7. INVENTORIES

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

| | 2006 | 2005 |
|---|---|---|
| Coal | $ 8,410 | $ 6,538 |
| Supplies (net of reserve for obsolescence of $646 and $68, respectively) | 11,814 | 10,732 |
| Total inventory | $ 20,224 | $ 17,270 |

## 8. PROPERTY, PLANT AND EQUIPMENT

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

| | 2006 | 2005 |
|---|---|---|
| Mining equipment and processing facilities | $ 572,935 | $ 461,005 |
| Land and mineral rights | 39,323 | 26,694 |
| Buildings, office equipment and improvements | 74,979 | 57,943 |
| Construction in progress | 41,916 | 29,699 |
| Mine development costs | 90,838 | 59,745 |
| | 819,991 | 635,086 |
| Less accumulated depreciation, depletion and amortization | (383,284) | (330,672) |
| Total property plant and equipment - net | $ 436,707 | $ 304,414 |

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 $1,862,000, 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. Amortization expense and accumulated amortization related to our capital lease was $52,000 in 2006.

## 9. LONG-TERM DEBT

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

| | 2006 | 2005 |
|---|---|---|
| Senior notes | $ 144,000 | $ 162,000 |
| Less current maturities | (18,000) | (18,000) |
| Total long-term debt | $ 126,000 | $ 144,000 |

Our Intermediate Partnership has $144.0 million principal amount of 8.31% senior notes due August 20, 2014, payable in eight remaining equal annual installments of $18.0 million with interest payable semiannually ("Senior Notes"). On April 13, 2006, our Intermediate Partnership entered into a $100.0 million revolving credit facility ("ARLP Credit Facility"), which expires in 2011. The ARLP Credit Facility replaced an $85.0 million credit facility that would have expired September 2006. 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. As of December 31, 2006, the applicable margin for borrowings under the ARLP Credit Facility was 0.875% with respect to London Interbank Offered Rate ("LIBOR") borrowings. Letters of credit can be issued under the ARLP Credit Facility not to exceed $50.0 million. Outstanding letters of credit reduce amounts available under the ARLP Credit Facility. At December 31, 2006, we had letters of credit of $10.8 million outstanding under the ARLP Credit Facility. We had no borrowings outstanding under the ARLP Credit Facility at December 31, 2006.

The Senior Notes and ARLP Credit Facility are guaranteed by all of the subsidiaries of our Intermediate Partnership. The Senior Notes and ARLP Credit Facility contain various restrictive and affirmative 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 Senior Notes and the ARLP Credit Facility also require the Intermediate Partnership to remain in control of a certain amount of mineable coal based on a ratio of the amount of total mineable tons controlled by our Intermediate Partnership relative to its annual production. In addition, the Senior Notes and the ARLP Credit Facility 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 both the ARLP Credit Facility and Senior Notes at December 31, 2006.

We have previously entered into and have maintained specific agreements with two banks to provide additional letters of credit in an aggregate amount of $31.0 million to maintain surety bonds to secure our obligations for reclamation liabilities and workers' compensation benefits. At December 31, 2006, we had $26.6 million in letters of credit outstanding under these agreements. Our special general partner guarantees $5.0 million of these outstanding letters of credit (Note 18).

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

| **Year Ending December 31,** | |
|---|---|
| 2007 | $ 18,000 |
| 2008 | 18,000 |
| 2009 | 18,000 |
| 2010 | 18,000 |
| 2011 | 18,000 |
| Thereafter | 54,000 |
| | $ 144,000 |

## 10. DISTRIBUTIONS OF AVAILABLE CASH AND CONVERSION OF SUBORDINATED UNITS

We will 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 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 distributions 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 incentive distribution rights 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, 2006, 2005 and 2004, we allocated to our managing general partner incentive distributions of $21,567,000, $9,397,000 and $1,828,000, respectively. The following table summarizes the quarterly per unit distribution paid during the respective quarter.

| | Year | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| First Quarter | $ 0.4600 | $ 0.3750 | $ 0.2813 |
| Second Quarter | $ 0.4600 | $ 0.3750 | $ 0.3125 |
| Third Quarter | $ 0.5000 | $ 0.4125 | $ 0.3250 |
| Fourth Quarter | $ 0.5000 | $ 0.4125 | $ 0.3250 |

Our partnership agreement provides for the conversion of the subordinated units into common units after meeting certain financial tests. We satisfied, in two stages, the financial tests that resulted in the subordinated units being converted into common units. First, we satisfied certain financial tests that provided for the early conversion of one-half of the subordinated units (i.e. 6,422,530 subordinated units) to common units in September 2003. Second, we satisfied the final conversion financial tests for converting the remaining subordinated units (i.e. 6,422,532 subordinated units) to common units in September 2004. The Board of Directors and the Conflicts Committee approved management's determination that both the early conversion financial tests and the final conversion financial tests were met. As a result, one-half of the subordinated units converted into common units on November 15, 2003 and the remaining one-half of the subordinated units converted into common units on November 2, 2004.

On January 29, 2007, we declared a quarterly distribution of $0.54 per unit, totaling approximately $26,977,000 (which includes our managing general partner’s incentive distributions), on all our common units outstanding, which was paid on February 14, 2007, to all unitholders of record on February 7, 2007.

## 11. INCOME TAXES

Our subsidiary, Alliance Service, is subject to federal and state income taxes. Alliance Service's income 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 Group, LLC ("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. Components of income tax expense are as follows (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| Current: | | | |
| Federal | $ 2,070 | $ 2,115 | $ 2,089 |
| State | 399 | 567 | 552 |
| | 2,469 | 2,682 | 2,641 |
| Deferred: | | | |
| Federal | (21) | - | - |
| State | (5) | - | - |
| | (26) | - | - |
| Income tax expense | $ 2,443 | $ 2,682 | $ 2,641 |

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, | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| Income taxes at statutory rate | $ 61,101 | $ 56,942 | $ 27,742 |
| Less: Income taxes at statutory rate on Partnership income not subject to income taxes | (58,923) | (54,527) | (25,409) |
| Increase/(decrease) resulting from: | | | |
| State taxes, net of federal income tax benefit | 318 | 346 | 333 |
| Other | (53) | (79) | (25) |
| Income tax expense | $ 2,443 | $ 2,682 | $ 2,641 |

## 12. NET INCOME PER LIMITED PARTNER UNIT

In March 2004, the FASB issued EITF Issue 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 was effective for fiscal periods beginning after March 31, 2004. 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 occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights held by our managing general partner, even though we make cash distributions on the basis of cash available for distributions 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, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Net income | $ 172,927 | $ 160,010 | $ 76,621 |
| Adjustments: | | | |
| General partner's priority distributions | (21,567) | (9,397) | (1,828) |
| General partners' 2% equity ownership | (3,027) | (3,012) | (1,496) |
| Limited partners' interest in net income | 148,333 | 147,601 | 73,297 |
| Additional earnings allocation to general partners' | (36,937) | (42,740) | (10,211) |
| Net income available to limited partners under EITF No. 03-6 | $ 111,396 | $ 104,861 | $ 63,086 |
| Weighted average limited partner units – basic | 36,425 | 36,289 | 35,882 |
| Basic net income per limited partner unit | $ 3.06 | $ 2.89 | $ 1.76 |
| Weighted average limited partner units – basic | 36,425 | 36,289 | 35,882 |
| Units contingently issuable: | | | |
| Restricted units for LTIP | 231 | 550 | 868 |
| Directors' compensation units | 42 | 37 | 32 |
| Supplemental Executive Retirement Plan | 112 | 101 | 92 |
| Weighted average limited partner units, assuming dilutive effect of restricted units | 36,810 | 36,977 | 36,874 |
| Diluted net income per limited partner unit | $ 3.03 | $ 2.84 | $ 1.71 |

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 priority income allocations for incentive distributions, if any, to our managing general partner, the holder of the incentive distributions rights pursuant to our partnership agreement, which are declared and paid following the close of each quarter (Note 10). 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.

## 13. EMPLOYEE BENEFIT PLANS

*Defined Contribution Plans*—Our employees currently participate in a defined contribution profit sharing and savings plan 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 earnings for certain employees not covered by the defined benefit plan described below. Our expense for this plan was approximately $4,551,000, $3,810,000 and $3,267,000 for the years ended December 31, 2006, 2005 and 2004, respectively.

*Defined Benefit Plans*—Employees at certain of our mining operations participate in a defined benefit plan (the "Pension Plan") that we sponsor. The benefit formula is a fixed dollar unit based on years of service.

The following sets forth changes in benefit obligations and plan assets for the years ended December 31, 2006 and 2005 and the funded status of the Pension Plan reconciled with the amounts reported in our consolidated financial statements at December 31, 2006 and 2005, respectively (dollars in thousands):

| | 2006 | 2005 |
|---|---|---|
| **Change in benefit obligations:** | | |
| Benefit obligations at beginning of year | $ 35,107 | $ 29,106 |
| Service cost | 3,224 | 3,007 |
| Interest cost | 1,949 | 1,660 |
| Actuarial loss | 1,466 | 1,745 |
| Benefits paid | (517) | (411) |
| Benefit obligation at end of year | 41,229 | 35,107 |
| **Change in plan assets:** | | |
| Fair value of plan assets at beginning of year | 27,519 | 23,307 |
| Employer contribution | 4,600 | 3,000 |
| Actual return on plan assets | 3,436 | 1,623 |
| Benefits paid | (517) | (411) |
| Fair value of plan assets at end of year | 35,038 | 27,519 |
| Funded status at the end of year | $ (6,191) | (7,588) |
| Unrecognized prior service cost | | 42 |
| Unrecognized actuarial loss | | 6,953 |
| Net amount recognized | | $ (593) |
| **Amounts recognized in balance sheet:** | | |
| Current liability | $ - | $ (7,588) |
| Non-current liability | (6,191) | - |
| | $ (6,191) | $ (7,588) |
| **Weighted-average assumptions as of December 31,** | | |
| Discount rate | 5.55 % | 5.60 % |
| Expected rate of return on plan assets | 7.75 % | 8.00 % |
| **Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31,** | | |
| Discount rate | 5.60 % | 5.75 % |
| Expected return on plan assets | 8.00 % | 8.00 % |
| **Weighted-average asset allocations as of December 31,** | | |
| Equity securities | 87% | 88 % |
| Fixed income securities | 12% | 11 % |
| Cash and cash equivalents | 1% | 1 % |
| | 100 % | 100 % |

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| **Components of net periodic benefit cost:** | | | |
| Service cost | $ 3,224 | $ 3,007 | $ 2,821 |
| Interest cost | 1,949 | 1,660 | 1,427 |
| Expected return on plan assets | (2,285) | (1,916) | (1,686) |
| Prior service cost | 42 | 48 | 48 |
| Net loss | 313 | 207 | 141 |
| Net periodic benefit cost | $ 3,243 | $ 3,006 | $ 2,751 |

Estimated future benefit payments as of December 31, 2006 are as follows (in thousands):

| **Year Ending December 31,** | |
|---|---|
| 2007 | $ 757 |
| 2008 | 933 |
| 2009 | 1,127 |
| 2010 | 1,344 |
| 2011 | 1,593 |
| 2012-2016 | 12,740 |
| | $ 18,494 |

The actuarial loss component of the change in benefit obligations for 2006 and 2005 was primarily attributable to reductions in the discount rate assumptions. Other than the reclassification of accrued pension benefits from current to long-term liabilities, the adoption of SFAS No. 158 did not have a material impact on our consolidated financial statements. We expect to contribute $1,200,000 to the Pension Plan in 2007. The estimated net actuarial loss, prior service cost, and transition obligation for the Pension Plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost during the 2007 fiscal year are $258,225, $0 and $0, respectively.

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.

| | **2006** | **2005** |
|---|---|---|
| **Amounts recognized in accumulated other comprehensive income consists of:** | | |
| Net actuarial loss | $ 6,956 | n/a |
| Total | $ 6,956 | n/a |

The compensation committee ("Compensation Committee") of the Board of Directors 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 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 imposes the following 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% of the total stock portfolio, (ii) the maximum investment in any one industry should not exceed 30% of the total stock portfolio, (iii) and the average credit quality of the bond portfolio should be at least AA with a maximum amount of non-investment grade debt of 10%.

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

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

The expected long-term rate of return assumption is developed based on input from an independent investment manager, including its review of asset class return, expectations by economists, and an independent actuary. Our advisors base the projected returns on broad equity and bond indices. The Pension Plan's expected long-term rate of return of 7.75% is determined by the above factors and an asset allocation assumption of 80.0% invested in equity securities, with an expected long-term rate of return of 10.4%, and 20.0% invested in fixed income securities, with an expected long-term rate of return of 5.3%. The Pension Plan was established effective January 1, 1997 and our initial contribution to the Pension Plan was made in 1998.

## 14. COMPENSATION PLANS

Effective January 1, 2000, our managing general partner adopted the LTIP for certain employees and directors of our managing general partner and its affiliates, who perform services for us. 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. Grants are made either of restricted units, which are "phantom" units that entitle the grantee to receive an ARLP common unit or an equivalent amount of cash upon the vesting of the phantom unit, or options to purchase ARLP common units. ARLP common units to be delivered upon the vesting of restricted units or to be issued upon exercise of a unit option will be acquired by our managing general partner in the open market at a price equal to the then prevailing price, or directly from an affiliate or any other third-party, including units newly issued by ARLP, units already owned by our managing general partner, or any combination of the foregoing. Our partnership agreement provides that our managing general partner be reimbursed for all costs incurred in acquiring these common units or in paying cash in lieu of common units upon vesting of the restricted units. On December 22, 2005, the Compensation Committee executed a unanimous consent resolution that, effective January 1, 2006, (a) all existing grants made under the LTIP prior to January 1, 2006 and subsequent thereto be settled, upon satisfaction of any applicable vesting requirements, in common units to the extent of net share settlement for minimum statutory income tax withholding requirements for each individual participant based upon the fair market value of the common units as of the date of payment and (b) any existing and prospective LTIP grants of restricted units receive quarterly distributions as provided in the distribution equivalent rights provision of the LTIP. Therefore, each LTIP participant has the contingent right to receive an amount equal to the cash distributions made by the ARLP Partnership during the vesting period. On January 24, 2007, the Compensation Committee executed a unanimous consent resolution amending the LTIP to transfer sponsorship of the LTIP to Alliance Coal effective May 15, 2006.

The aggregate number of units reserved for issuance under the LTIP is 1,200,000. Effective January 1, 2004, the Compensation Committee approved an amendment to the LTIP clarifying that any award that is forfeited, expires for any reason, or is paid or settled in cash, including the satisfaction of minimum statutory withholding requirements, rather than through the delivery of units will be available for future grants under the LTIP. Of the initial 1,200,000 units reserved for issuance under the LTIP, cumulative units of 1,092,780 were granted in years 2000, 2001, 2002 and 2003. Of those grants, 43,650 units were forfeited and 421,452 units were settled in cash rather than delivery of units, resulting in the net issuance of 627,678 common units under those grants. During 2004, 2005 and 2006, the Compensation Committee approved grants of 205,570 units, 114,390 units and 85,275 units, respectively, which will vest December 31, 2006, January 1, 2008 and January 1 2009, respectively, subject to the satisfaction of certain financial tests that management currently believes will be satisfied. Subsequent to the Compensation Committee's approval of the 2006 grants of 85,275 described above, an additional 5,425 grants were approved for new participants and existing participants who received a promotion during the year. These additional grants vest January 1, 2009 bringing the total 2006 grants to 90,700. As of December 31, 2006, 15,340 outstanding LTIP grants have been forfeited. On December 7, 2006, the Compensation Committee determined that the vesting requirements for the 2004 grants of 205,570 restricted units (net of 9,230 forfeitures) had been satisfied as of December 31, 2006. As a result of this vesting, on January 8, 2007, we issued 130,812 common units to the LTIP participants. The remaining units were settled in cash to satisfy the individual tax obligations of the LTIP participants. Consequently, after consideration of the December 31, 2006 vesting and subsequent issuance of 130,812 common units, 242,530 units remain available for issuance in the future, assuming that all grants currently issued and outstanding for 2005 and 2006 are settled with common units and no future forfeitures occur. On January 24, 2007, the Compensation Committee authorized additional grants up to 94,075 restricted units of which 89,875 have been issued and which will vest January 1, 2010, subject to the satisfaction of certain financial tests. This reduced the number of common units available from 242,530 to 152,655. For the period from January 1, 2006 to May 14, 2006 and for the years ended December 31, 2005 and 2004, our managing general partner charged us approximately $2,356,000, $8,193,000 and $20,320,000, respectively, attributable to the LTIP.

The intrinsic value of the 2005 and 2004 grants of $37.20 per LTIP grant at December 31, 2005 essentially equals the fair value at January 1, 2006 and, therefore, no incremental compensation expense was recognized upon adoption of SFAS No. 123R. 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. Consequently, the previously recognized liability reflected in the due to affiliates current and long-term accounts in our consolidated balance sheet at December 31, 2005 was reclassified to partners' capital upon adoption of SFAS No. 123R on January 1, 2006. The fair value of the 2006 grants is based upon the intrinsic value at the date of grant which was $37.79 on a weighted average basis.

A summary of non-vested LTIP grants as of and for the year ended December 31, 2006 is as follows:

| | |
|---|---|
| Non-vested grants at January 1, 2006 | 316,270 |
| Granted | 90,700 |
| Vested | - |
| Forfeited | (11,650) |
| Non-vested grants at December 31, 2006 | 395,320 |

As of December 31, 2006, there was $3,158,000 in total unrecognized compensation expense related to the non-vested LTIP grants. That expense is expected to be recognized over a weighted-average period of 1.4 years. As of December 31, 2006, the intrinsic value of the non-vested LTIP grants was $12,649,000.

The total obligation associated with the LTIP as of December 31, 2006, was $10,517,000 and is included in partners' capital-limited partners contained in our consolidated balance sheets. The total obligation associated with the LTIP as of December 31, 2005 was $6,517,000, and is included in the current and long-term liabilities due to affiliates contained in our consolidated balance sheets.

Effective January 1, 1997, our managing general partner adopted a Supplemental Executive Retirement Plan (the "SERP") for certain officers and key employees. The purpose of the SERP is to enhance our ability to retain specific officers and key employees, by providing them with the deferred compensation benefits contained in the SERP. The intent of the SERP is to align each participant's supplemental benefits under the SERP with the interests of our unitholders. All allocations made to participants under the SERP are made in the form of "phantom" units. The SERP is administered by the Compensation Committee. Our managing general partner is able to amend or terminate the plan at any time. Our managing general partner is entitled to reimbursement by us for its costs incurred under the SERP. On January 24, 2007, the Compensation Committee executed a unanimous consent resolution amending the SERP to transfer sponsorship of the SERP to Alliance Coal effective May 15, 2006. For the period from January 1, 2006 to May 14, 2006 and for the years ended December 31, 2005 and 2004, our managing general partner billed us approximately $587,000, $393,000 and $2,099,000, respectively, attributable to the SERP. The total accrued liability associated with the SERP plan was $4,134,000 as of December 31, 2006 and is included in other current and other long-term liabilities in the consolidated balance sheets. The total accrued liability associated with the SERP as of December 31, 2005 was $4,050,000, and is included in the long-term liability due to affiliates in our consolidated balance sheets.

## 15. RECLAMATION AND MINE CLOSING COSTS

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 have estimated the costs and timing of future reclamation and mine closing costs escalated for inflation, then discounted at a credit-adjusted risk free rate ranging from 4.22% to 6.0% and recorded the present value of those estimates.

On January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, which requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which it is incurred.

Discounting resulted in reducing the accrual for reclamation and mine closing costs by $47,539,000 and $29,339,000 at December 31, 2006 and 2005, respectively. Estimated payments of reclamation and mine closing costs as of December 31, 2006 are as follows (in thousands):

| **Year Ending December 31,** | |
|---|---|
| 2007 | $ 3,070 |
| 2008 | 3,071 |
| 2009 | 1,378 |
| 2010 | 3,187 |
| 2011 | 700 |
| Thereafter | 87,028 |
| Aggregate undiscounted reclamation and mine closing | 98,434 |
| Effect of discounting | (47,539) |
| Total reclamation and mine closing costs | 50,895 |
| Less: Current portion | (3,070) |
| Reclamation and mine closing costs | $ 47,825 |

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

| | **Year Ended December 31,** | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| Beginning balance | $ 41,313 | $ 34,018 | $ 23,466 |
| Accretion expense | 2,101 | 1,918 | 1,622 |
| Payments | (336) | (189) | (899) |
| Allocation of liability associated with acquisition, mine development and change in assumptions | 7,817 | 5,566 | 9,829 |
| Ending balance | $ 50,895 | $ 41,313 | $ 34,018 |

During the year ended December 31, 2006, the reclamation and mine closing cost liability increase of $7,817,000 was primarily attributable to the River View acquisition of $2,958,000 and new water treatment obligations and revisions in the cost estimates for existing water treatment obligations associated with Mettiki (WV) and Mettiki (MD) of $5,215,000. During the year ended December 31, 2005, the reclamation and mine closing cost liability increase was primarily attributable to an increase in the estimates of the cost to perform certain reclamation activities and, in particular, certain land restoration procedures associated with the Lodestar acquisition. Additionally, $411,000 of the 2005 increase was attributable to the Tunnel Ridge acquisition. During the year ended December 31, 2004, the reclamation and mine closing cost liability increase of $9,829,000 was primarily attributable to the Lodestar acquisition of $4,129,000 and the initial land disturbances associated with mine development at Mettiki (MD) and Mettiki (WV) of a combined $2,329,000. The liability also increased as the permitted refuse disposal areas were expanded at several existing operations and a comprehensive study related to water treatment costs was completed.

## 16. PNEUMOCONIOSIS ("BLACK LUNG") BENEFITS

Certain 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.

Pneumoconiosis ("black lung") benefits liability is calculated using the service cost method. Under the service cost method the calculation of the actuarial present value of the estimated black lung obligation is based on an actuarial study performed by an independent actuary. Actuarial gains or losses are amortized over the remaining service period of active miners. The discount rate used to calculate the estimated present value of future obligations was 4.8% and 4.23% at December 31, 2006 and 2005, respectively.

The following is a reconciliation of changes in benefit obligations at December 31, 2006 and 2005 (in thousands):

| | 2006 | 2005 |
|---|---|---|
| Benefit obligations at beginning of year | $ 23,795 | $ 20,335 |
| Service cost | 1,497 | 1,977 |
| Interest cost | 1,241 | 1,203 |
| Actuarial loss | 584 | 470 |
| Benefits and expense paid | (301) | (190) |
| Benefit obligations at end of year | $ 26,816 | $ 23,795 |

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

## 17. 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. The main purpose of the rock dust mill is to manufacture and sell rock dust. In coal mining, rock dust normally consists of finely milled limestone, which is applied to haulage ways and mine entries or corridors in such quantities that the combination of coal dust, rock dust and other dust forms an incombustible content. MAC and Alliance Coal have entered into a six year rock dust supply agreement in which MAC will supply the greater of 50,000 tons or 70% of the aggregate amount of rock dust used by our subsidiaries located in the Illinois Basin. For the first three years of the contract, our subsidiaries will purchase the rock dust at 125% of MAC’s actual production cost. Any rock dust tonnage purchased above 70% of the aggregate amount of rock dust used by our subsidiaries in the Illinois Basin will be priced at the prevailing market pricing. After three years, the price paid by our mines to MAC will reopen to market.

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 $839,000 as of December 31, 2006, which is recorded as minority interest on our consolidated balance sheet.

## 18. 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.

***Administrative Services—*** In connection with the closing of the AHGP IPO, we entered into an administrative services agreement, ("Administrative Services Agreement"), between our managing general partner, our Intermediate Partnership, AHGP and its general partner Alliance GP, LLC, ("AGP") and Alliance Resource Holdings II, Inc. ("ARH II"), the indirect parent of SGP. Under the Administrative Services Agreement, certain employees, including executive officers, are providing administrative services to our managing general partner, AHGP, AGP, ARH II and their respective affiliates. We will be 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 $315,000, for the period from May 15, 2006 to December 31, 2006 from AHGP and $620,000 from ARH for the year ended December 31, 2006. This administrative service revenue is included in other sales and operating revenues in the consolidated statements of income. Concurrently, 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 $4,181,000, $14,069,000 and $28,536,000 for the years ended December 31, 2006, 2005 and 2004, respectively. The decrease from 2005 to 2006 was attributable to certain employees and the sponsorship of the LTIP, Short-Term Incentive Plan ("STIP") and SERP being transferred to Alliance Coal effective May 15, 2006. The decrease from 2004 to 2005 was primarily attributable to lower compensation accruals for the LTIP, STIP and SERP. The amounts billed by our managing general partner include $2,934,000, $10,559,000 and $24,242,000 for the years ended December 31, 2006, 2005 and 2004, respectively, for the LTIP, STIP and SERP.

***SGP Land—***Webster County Coal has a mineral lease and sublease with SGP Land, LLC ("SGP Land"), a subsidiary of the SGP, requiring annual minimum royalty payments of $2.7 million, payable in advance through 2013 or until $37.8 million of cumulative annual minimum and/or earned royalty payments have been paid. Webster County Coal paid royalties of $3,005,000, $3,449,000, and $4,611,000 for the years ended December 31, 2006, 2005, and 2004, respectively. As of December 31, 2006, Webster County Coal has recouped, against earned royalties otherwise due, all but $2,629,000 of the advance minimum royalty payments made under the lease.

Warrior has a mineral lease and sublease with SGP Land. Under the terms of the lease, Warrior paid in arrears an annual minimum royalty of $2,270,000 until $15,890,000 of cumulative annual minimum and/or earned royalty payments were paid. The annual minimum royalty periods extend from October 1st through the end of the following September 30, expiring September 30, 2007. In 2006, Warrior's cumulative total of annual minimum royalties and/or earned royalty payments exceeded $15,890,000, therefore the annual minimum royalty payment of $2,270,000 is no longer required. Warrior paid royalties of $5,061,000, $3,627,000, and $2,561,000 for the years ended December 31, 2006, 2005, and 2004, respectively. As of December 31, 2006, Warrior has recouped, against earned royalties otherwise due, all advance minimum royalty payments made in accordance with these lease terms.

Hopkins County Coal has 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 $684,000 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, are fully recoupable against future earned royalty payments. Hopkins County Coal paid advance minimum royalties and/or option fees of $684,000 during each of the years ended December 31, 2006 and 2005, respectively. As of December 31, 2006, $4,369,000 of advance minimum royalties and/or option fees paid under the Coal Lease Agreements is available for recoupment, and management expects that it will be recouped against future production.

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 $5,038,000,

$6,379,000 and $5,428,000 for the years ended December 31, 2006, 2005, and 2004, respectively, for the base lease obligations. As of December 31, 2006, Webster County Coal, Warrior, and Hopkins County Coal have 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 $323,000.

In 2001, SGP Land, as successor in interest to an unaffiliated third-party, entered into an amended mineral lease with MC Mining. Under the terms of the lease, MC Mining has paid and will continue to pay an annual minimum royalty of $300,000 until $6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. MC Mining paid royalties of $300,000 and $600,000 during the years ended December 31, 2006 and 2005, respectively (the 2004 annual minimum royalty obligation of $300,000 was paid in January 2005 rather than in December 2004). As of December 31, 2006, $900,000 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 (Note 3). 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. We paid advance minimum royalties of $3.0 million during each of 2006 and 2005, which management expects 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 $240,000. 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 $240,000 for the year ended December 31, 2006.

We have a noncancelable operating lease arrangement with the SGP for the coal preparation plant and ancillary facilities at the Gibson mining complex. Based on the terms of the lease, we will make monthly payments of approximately $216,000 through January 2011. Lease expense incurred for each of the three years in the period ended December 31, 2006 was $2,595,000.

We previously entered into and have maintained agreements with two banks to provide letters of credit in an aggregate amount of $31.0 million (Note 9). At December 31, 2006, we had $26.6 million in outstanding letters of credit under these agreements. The SGP guarantees $5.0 million of these outstanding letters of credit. Historically, the Partnership has compensated the SGP for a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. During 2003 the SGP agreed to waive the guarantee fee in exchange for a parent guarantee from the Intermediate Partnership and Alliance Coal on the mineral leases and subleases with Webster County Coal and Warrior described above. Since the guarantee is made on behalf of entities within the consolidated partnership, the guarantee has no fair value under FIN No. 45, *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 100% of the membership interest in River View from ARH (Note 3).

## 19. 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 18) and a noncancelable lease for equipment under a capital lease obligation. Future minimum lease payments are as follows (in thousands):

| Year Ending December 31, | Capital Lease | Other Operating Leases | | |
|---|---|---|---|---|
| | | Affiliate | Others | Total |
| 2007 | $ 474 | $ 2,835 | $ 1,085 | $ 3,920 |
| 2008 | 456 | 2,835 | 674 | 3,509 |
| 2009 | 408 | 2,595 | 423 | 3,018 |
| 2010 | 360 | 2,595 | 409 | 3,004 |
| 2011 | 302 | 216 | 205 | 421 |
| Thereafter | 161 | - | - | - |
| Total future minimum lease payments | $ 2,161 | $ 11,076 | $ 2,796 | $ 13,872 |
| Less: Amount representing interest | (310) | | | |
| Present value of future minimum lease payments | 1,851 | | | |
| Less: Current portion | (339) | | | |
| Long-term capital lease obligation | $ 1,512 | | | |

Rental expense (including rental expense incurred under operating lease agreements) was $5,796,000, $6,390,000 and $6,112,000 for the years ended December 31, 2006, 2005 and 2004, 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%.

In October 2002, we entered into a master equipment lease. Our credit facilities limit the amount of total operating lease obligations to $15.0 million payable in any period of 12 consecutive months. This master equipment lease is subject to this limitation on lease obligations. We entered into nine operating leases during 2003 under the master equipment lease with lease terms ranging from three to six years. We did not enter into any new equipment leases under the master equipment lease during 2006, 2005 or 2004. We have exercised purchase options under the master equipment lease as they come available, which has partially contributed to the decrease in future lease commitments.

***Contractual Commitments—***In connection with planned capital projects, we have contractual commitments of approximately $15.2 million at December 31, 2006. As of December 31, 2006, we had commitments to purchase, from external production sources, coal at an estimated cost up to $25.2 million in 2007, which includes coal purchase obligations with ICG, LLC ("ICG") described below.

***General Litigation—*** We are involved in various lawsuits, claims and regulatory proceedings incidental to our business. Currently, we are not engaged in any litigation that we believe is material to our operations, including without limitation, any litigation relating to any of our long-term coal supply contracts or under the various environmental protection statutes to which we are subject. We provide for costs related to litigation and regulatory proceedings, including civil fines issued as part of the outcome of these proceedings, when a loss is probable and the amount is reasonably determinable. Although the ultimate outcome of these matters cannot be predicted with certainty, in the opinion of management, the outcome of any litigation matters to the extent not previously provided for or covered under insurance, is not expected to have a material adverse effect on our business, financial position or results of operations. Nonetheless, these matters or estimates that are based on current facts and circumstances, if resolved in a manner different from the basis on which management has formed its opinion, could have a material adverse effect on our financial position or results of operations.

***Other*** – During September 2006, we completed our annual property and casualty insurance renewal with various insurance coverages effective as of October 1, 2006. Available capacity for underwriting property insurance continues to be limited as a result of insurance carrier losses in the coal mining industry and our recent insurance claims history (*e.g.*, MC Mining Fire Incident, and Dotiki Fire Incident). As a result, we have elected to retain an average participating interest of approximately 14.7% along with our insurance carriers in the overall $75.0 million commercial property program representing 35% of the primary $30.0 million layer and 2.5% of the second layer representing $20.0 million in excess of the $30.0 million primary layer. We do not participate in the third layer of $25.0 million in excess of $50.0 million.

The 14.7% average participation rate for this year's renewal exceeds the approximate 10% average participation level from last year. The aggregate maximum limit in the commercial property program is $75.0 million per occurrence of which, as a result of our participation, we would be 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. As a result of our increased participation in the property program and higher deductible levels, property premiums paid to the insurance carriers were reduced by approximately 14.5%. 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.

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

The complaint alleged that from January 2004 to August 2004, Pontiki failed to deliver a total of 138,111 tons of coal that met the contract delivery and quality specifications resulting in an alleged loss of profits for ICG of $4.1 million. We are aware that certain deliveries under the Horizon Agreement were not made during 2004 for reasons including, but not limited to, force majeure events at Pontiki and ICG's failure to provide transportation services for the delivery of coal as required under the Horizon Agreement. In November 2005, we settled this contract dispute with ICG. Under this settlement, effective August 1, 2005, Pontiki will ship coal in approximately ratable monthly quantities until the remaining contract obligation of 1,681,303 tons is shipped, and this contract will terminate on or by December 31, 2006. Under the terms of the settlement, the existing coal supply agreement was amended to change the coal quality specifications and to exclude from the definition of "force majeure" the events of railroad car shortages and geological and quality issues with respect to coal. As part of this settlement, we also executed a new coal sales agreement with ICG whereby another subsidiary of ours will purchase 892,000 tons of coal from ICG. Approximately 63,000 tons and 588,000 tons were purchased and sold at a profit during 2005 and 2006, respectively, and the remaining 241,000 tons are expected to be purchased and sold at a profit the first half of 2007. These agreements were to expire on or by December 31, 2006. However, in the third quarter of 2006, ICG agreed to allow Pontiki to carryover any shortfall of tonnage under this contract into 2007.

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.

In June 2006, our Intermediate Partnership entered into a guarantee agreement in which it guaranteed the performance of a third-party with respect to an agreement to purchase electricity. The term of the guarantee expired January 31, 2007. Under the terms of the guarantee, if the third-party does not fulfill its payment obligation under the agreement to purchase electricity, our Intermediate Partnership is liable for the amounts not paid by the third-party. If our Intermediate Partnership were to become liable, the maximum amount of potential future payments is $2.0 million at December 31, 2006. The fair value of the guarantee is not considered material to our consolidated financial statements.

In March 2004, XL Specialty Insurance Company ("XL") filed litigation against ARH and us in state court of Oklahoma alleging that we and ARH had failed to indemnify XL for Alliance Coal's failure to pay certain annual premiums associated with four surety bonds issued to the State of Kentucky to secure Alliance Coal's self-insurance workers' compensation status. All four of these surety bonds were cancelled by XL in 2001 after it made the business decision to withdraw from the surety market. In the lawsuit, XL requested that the trial court determine, under two indemnity agreements, we and ARH be found jointly and severely liable to XL for bond premiums on the four cancelled surety bonds in the total principal amount of approximately $397,000, plus pre- and post-judgment interest. In answering the lawsuit, we and ARH filed a counterclaim against XL raising a number of affirmative defenses and counterclaiming for breach of contract and bad faith. In July 2006, a bench trial occurred in which XL alleged that Alliance Coal owed approximately $876,000 (including interest) through September 2005. In support of its counterclaim, we and ARH alleged damages of approximately $400,000 relating to certain increased costs associated with Alliance Coal's surety bond program. In September 2006, a decision adverse to us and ARH regarding this matter was received from the trial court. Accordingly, we have recorded a liability and expense to reflect the approximate damages determination made by the trial court for the period through September 30, 2005 and additional estimated expenses through December 31, 2006. We have appealed the state district court's determination to the Oklahoma Supreme Court. In addition, settlement discussions recently have been initiated between the parties. However, we cannot give assurance that the outcome of the appeal or settlement process will differ materially from our current estimated liability recorded.

## 20. 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, | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| Customer A | $ 144,946 | $ 88,525 | $ 33,933 |
| Customer B | 143,795 | 133,672 | 124,846 |

Trade accounts receivable from these customers totaled approximately $39.8 million and $40.1 million at December 31, 2006 and 2005, respectively. Our bad debt experience has historically been insignificant; however we established an allowance of $763,000 during 2001, due to our total credit exposure to Enron Corp., which filed for bankruptcy protection during December 2001. We received $114,000 in 2004 for our claim against Enron, which was recognized as a recovery in 2004. The remaining balance of $649,000 was written-off in 2004. Financial conditions of our customers could result in a material change to our bad debt expense in future periods. The coal supply agreements with Customers A and B expire in 2023 and 2007, respectively.

## 21. SEGMENT INFORMATION

We operate in the eastern United States as a producer and marketer of coal to major utilities and industrial users, also located in the eastern United States. We have the following three reportable segments: the Illinois Basin, Central Appalachia and Northern Appalachia. The segments also represent the three major coal deposits in the eastern United States. Coal quality, coal seam height, transportation methods and regulatory issues are similar within each of these three segments. The Illinois Basin segment is comprised of the Dotiki, Gibson, Hopkins, Pattiki and Warrior mines and the River View and Gibson South properties. The Central Appalachia segment is comprised of the Pontiki and MC Mining mines. The Northern Appalachia segment is comprised of the Mettiki and Mountain View mines, two small third-party mining operations, and the Tunnel Ridge and Penn Ridge properties. In late 2006, we completed the transition of longwall operations from the Mettiki mine to the Mountain View mine. We are in the process of permitting the River View, Gibson South, Tunnel Ridge and Penn Ridge properties for future mine development.

Other and Corporate includes marketing and administrative expenses, the Mt. Vernon activities, coal brokerage activity, MAC and Matrix Design. Operating segment results for the years ended December 31, 2006, 2005 and 2004 are presented below.

| | Illinois Basin | Central Appalachia | Northern Appalachia | Other and Corporate | Consolidated |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Operating segment results for the year ended December 31, 2006 were as follows: | | | | | |
| Total revenues (1) | $ 634,602 | $ 185,966 | $ 121,962 | $ 25,027 | $ 967,557 |
| Selected production expenses (2) | 344,267 | 124,083 | 67,353 | 18,497 | 554,200 |
| Segment Adjusted EBITDA (3) | 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 |
| Operating segment results for the year ended December 31, 2005 were as follows: | | | | | |
| Total revenues (1) | $ 553,908 | $ 157,203 | $ 120,423 | $ 7,184 | $ 838,718 |
| Selected production expenses (2) | 289,720 | 94,909 | 62,425 | 3,606 | 450,660 |
| Segment Adjusted EBITDA (3) | 183,075 | 41,583 | 36,047 | 2,924 | 263,629 |
| Total assets | 274,437 | 91,853 | 73,789 | 92,608 | 532,687 |
| Capital expenditures | 70,353 | 23,451 | 24,435 | 1,642 | 119,881 |
| Operating segment results for the year ended December 31, 2004 were as follows: | | | | | |
| Total revenues (1) | $ 391,005 | $ 147,361 | $ 112,251 | $ 2,672 | $ 653,289 |
| Selected production expenses (2) | 224,540 | 98,162 | 51,304 | 585 | 374,591 |
| Segment Adjusted EBITDA (3)(4) | 121,763 | 28,953 | 41,141 | 1,432 | 193,289 |
| Total assets | 216,739 | 64,241 | 46,168 | 85,636 | 412,784 |
| Capital expenditures | 32,870 | 14,465 | 6,605 | 773 | 54,713 |

(1) Revenues included in the Other and Corporate column are attributable to Mt. Vernon transloading revenues, brokerage coal sales for the years ended December 31, 2006, 2005 and 2004, respectively, and Matrix Design Group revenues for the year ended December 31, 2006.

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

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

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (in thousands) | |
| Reconciliation of Consolidated Segment Adjusted EBITDA to net income: | | | |
| Consolidated Segment Adjusted EBITDA | $ 281,645 | $ 263,629 | $ 193,289 |
| General & administrative | (30,884) | (33,484) | (45,400) |
| Depreciation, depletion and amortization | (66,489) | (55,637) | (53,664) |
| Interest expense, net | (9,175) | (11,816) | (14,963) |
| Income taxes | (2,443) | (2,682) | (2,641) |
| Cumulative effect of accounting change | 112 | - | - |
| Minority interest | 161 | - | - |
| Net income | $ 172,927 | $ 160,010 | $ 76,621 |

Reconciliation of Selected Production Expenses to Combined Operating Expenses and Outside Purchases:

| | | | |
|---|---|---|---|
| Selected Production Expenses | $ 554,200 | $ 450,660 | $ 374,591 |
| Production taxes and royalties | 92,769 | 85,941 | 71,793 |
| Combined operating expenses and outside purchases | $ 646,969 | $ 536,601 | $ 446,384 |

## 22. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

A summary of our quarterly operating results for 2006 and 2005 is as follows (in thousands, except unit and per unit data):

| | Quarter Ended | | | |
|---|---|---|---|---|
| | March 31, 2006 | June 30, 2006 | September 30, 2006 | December 31, 2006 |
| Revenues | $ 238,320 | $ 221,304 | $ 244,740 | $ 263,193 |
| Income from operations | 50,870 | 43,387 | 40,881 | 48,198 |
| Income before income taxes, cumulative effect of accounting change and minority interest | 48,896 | 41,054 | 38,939 | 46,208 |
| Net income | 48,249 | 40,550 | 38,640 | 45,488 |
| Basic net income per limited partner unit | $ 0.83 | $ 0.73 | $ 0.70 | $ 0.80 |
| Diluted net income per limited partner unit | $ 0.83 | $ 0.72 | $ 0.69 | $ 0.79 |
| Weighted average number of units outstanding – basic | 36,426,306 | 36,426,306 | 36,426,306 | 36,422,515 |
| Weighted average number of units outstanding – diluted | 36,765,016 | 36,797,407 | 36,824,613 | 36,852,765 |

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

Income from operations in the above table, for quarters prior to June 30, 2006, represents income from operations before interest expense.

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

## 23. Subsequent Event

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

## SCHEDULE II

## ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

## VALUATION AND QUALIFYING ACCOUNTS
## YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004

| | Balance At Beginning of Year | Additions Charged to Income | Deductions | Balance At End of Year |
|---|---|---|---|---|
| | (in thousands) | | | |
| **2006** | | | | |
| Allowance for doubtful accounts | $ | $ | $ | $ |
| **2005** | | | | |
| Allowance for doubtful accounts | $ - | $ - | $ - | $ - |
| **2004** | | | | |
| Allowance for doubtful accounts | $ 763 | $ - | $ 763 | $ - |

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

## 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 we are able to collect the information we are required to disclose in the reports we file with the U.S. Securities and Exchange Commission (SEC), and to process, summarize and disclose this information within the time periods specified in the rules of the SEC. An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Securities Exchange Act) was performed as of the end of the period covered by the date of this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based on 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 to ensure that the ARLP Partnership is able to collect, process and disclose the information we are required to disclose in the reports we file with the SEC within the required time periods.

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, 2006 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, 2006. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework*. Based on our assessment, Management concluded that, as of December 31, 2006, the ARLP Partnership's internal control over financial reporting is effective based on those criteria, and we believe that we have no material internal control weaknesses in our financial reporting process.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2006, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm, which also audited the Partnership's consolidated financial statements. Deloitte & Touche's attestation report on management's assessment of the Partnership's internal control over financial reporting appears below.

*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) that occurred in the three months ended December 31, 2006 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors of the Managing
General Partner and the Partners of
Alliance Resource Partners, L.P.:

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, that Alliance Resource Partners, L.P. and subsidiaries (the "Partnership") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Partnership's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that the Partnership maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, 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, 2006 and 2005 and the related consolidated statements of income, cash flows and Partners' capital (deficit) and comprehensive income for each of the three years in the period ended December 31, 2006 and the financial statement schedule listed in the Index at Item 15 of the Partnership, and our report dated February 28, 2007 expressed an unqualified opinion on those financial statements and financial statement schedule.

*/s/ Deloitte & Touche LLP*

Tulsa, Oklahoma
February 28, 2007

## ITEM 9B. OTHER INFORMATION

None.

## 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 the 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 | 56 | President, Chief Executive Officer and Director |
| Robert G. Sachse [1] | 58 | Executive Vice President and Vice Chairman of the Board |
| R. Eberley Davis [2] | 49 | Senior Vice President, General Counsel and Secretary |
| Thomas L. Pearson [3] | 53 | Senior Vice President – Law and Administration, General Counsel and Secretary |
| Charles R. Wesley | 52 | Senior Vice President – Operations |
| Brian L. Cantrell | 47 | Senior Vice President and Chief Financial Officer |
| Gary J. Rathburn [4] | 56 | Senior Vice President – Marketing |
| Michael J. Hall | 61 | Director and Member of the Audit* and Conflicts Committees |
| John J. MacWilliams [5] | 51 | Director |
| Preston R. Miller, Jr. [6] | 58 | Director and Member of the Compensation Committee |
| John P. Neafsey [7] | 67 | Chairman of the Board and Member of Audit, Compensation and Conflicts* Committees |
| John H. Robinson [8] | 56 | Director and Member of Audit and Compensation* Committees |
| Merribel S. Ayres | 55 | Director and Member of the Compensation Committee |
| Wilson M. Torrence | 65 | Director and Member of the Conflicts Committee |

* Indicates Chairman of Committee

[1] Effective November 1, 2006, Mr. Sachse assumed responsibilities for our coal marketing, sales and transportation functions. Effective January 5, 2007, Mr. Sachse retired from the Board of Directors of our managing general partner.

[2] Effective February 12, 2007, Mr. Davis was appointed as Senior Vice President, General Counsel and Secretary of our managing general partner by the Board of Directors of our managing general partner.

[3] Effective February 2, 2007, Mr. Pearson retired from his position as Senior Vice President – Law and Administration, General Counsel and Secretary of our managing general partner.

[4] Effective December 31, 2006, Mr. Rathburn retired from his position as Senior Vice President – Marketing of our managing general partner.

[5] Effective January 5, 2007, Mr. MacWilliams retired from the Board of Directors of our managing general partner.

[6] Effective January 5, 2007, Mr. Miller retired from the Board of Directors of our managing general partner. Prior to his retirement from the Board of Directors, Mr. Miller served as chairman of the Compensation Committee.

[7] Effective January 5, 2007, Mr. Neafsey was elected chairman of the Conflicts Committee.

[8] Effective January 5, 2007, Mr. Robinson was elected chairman of the Compensation Committee and resigned from his positions as chairman and a member of the Conflicts Committee.

*Joseph W. Craft III* has been President, Chief Executive Officer and a Director since August 1999 and has indirect majority ownership of our managing general partner. Mr. Craft also serves as President, Chief Executive Officer and a Director 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. Before joining MAPCO, Mr. Craft was an attorney at Falcon Coal Corporation and Diamond Shamrock Coal Corporation. He is past Chairman of the National Coal Council, a Board and Executive Committee Member of the National Mining Association, a Director of the Center for Energy and Economic Development, and a member of the Board of Trustees for the University of Tulsa. Mr. Craft holds a Bachelor of Science degree in Accounting and a Juris Doctor degree from the University of Kentucky. Mr. Craft also is a graduate of the Senior Executive Program of the Alfred P. Sloan School of Management at Massachusetts Institute of Technology.

*Robert G. Sachse* has been Executive Vice President since August 2000. Effective November 1, 2006, Mr. Sachse assumed the responsibilities 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. Prior to his current position, Mr. Sachse was Executive Vice President and Chief Operating Officer of MAPCO Inc. from 1996 to 1998 when MAPCO merged with The Williams Companies. Following the merger, Mr. Sachse had a two year non-compete consulting agreement with The Williams Companies. Mr. Sachse held various positions while with MAPCO Coal Inc. from 1982 to 1991, and was promoted to President of MAPCO Natural Gas Liquids in 1992. Mr. Sachse holds a Bachelor of Science degree in Business Administration from Trinity University and a Juris Doctor degree from the University of Tulsa.

*R. Eberley Davis* has been our Senior Vice President, General Counsel and Secretary since February 2007. Mr. Davis also serves as Senior Vice President, General Counsel and Secretary 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 B.A. degree in Economics and his J.D. degree. He also holds an M.B.A. 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.

*Thomas L. Pearson* was our managing general partner's Senior Vice President – Law and Administration, General Counsel and Secretary from August 1996 to February 2007. Mr. Pearson previously was Assistant General Counsel of MAPCO Inc., and served as General Counsel and Secretary of MAPCO Coal Inc. from 1989 to 1996. Before joining the company, he was General Counsel and Secretary of McLouth Steel Products Corporation, Corporate Counsel for Midland-Ross Corporation, and an attorney for Arter & Hadden, a law firm in Cleveland, Ohio. Mr. Pearson's current and past business, charitable and education involvement includes Trustee of the Energy and Mineral Law Foundation, Vice Chairman, Legal Affairs Committee, National Mining Association, and Member, Dean's Committee, The University of Iowa College of Law. Mr. Pearson holds a Bachelor of Arts degree in History and Communications from DePauw University and a Juris Doctor degree from The University of Iowa.

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

*Brian L. Cantrell* was named Senior Vice President and Chief Financial Officer in October 2003. Mr. Cantrell also serves as Senior Vice President and Chief Financial Officer 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 Master of Accountancy and Bachelor of Accountancy from the University of Oklahoma.

*Gary J. Rathburn* was our managing general partner's Senior Vice President – Marketing from August 1996 to December 2006. He joined MAPCO Coal Inc. as Manager of Brokerage Coals in 1980. Since that time, he has managed all phases of the marketing group involving transportation and distribution, international sales and the brokering of coal. Prior to joining the company, Mr. Rathburn was employed by Eastern Associated Coal Corporation in its International Sales and Brokerage groups. Active in many industry-related groups, he was a Director of The National Coal Association and Chairman of the Coal Exporters Association for several years. Mr. Rathburn holds a Bachelor of Arts degree in Political Science from the University of Pittsburgh and has participated in industry-related programs at the World Trade Institute, Princeton University and the Colorado School of Mines.

*Michael J. Hall* became a Director in March 2003 and currently services as chairman of the audit committee ("Audit Committee") and a member of the Conflicts Committee. Mr. Hall is also a Director and serves as Chairman of the Audit Committee of AHGP. Mr. Hall is Chairman of the Board of Directors of Matrix Service Company ("Matrix"). 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. 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. and a member of its audit and nominating/governance committees and has served in that capacity since May 2006. He also serves as Chairman of the Board of Directors of American Performance Funds and is a member of its audit and nominating committees and has served in that capacity since July 1990. Mr. Hall holds a Bachelor of Science degree in Accounting from Boston College and a Master of Business Administration from Stanford University.

*John J. MacWilliams* retired from the Board of Directors of our managing general partner in January 2007. Mr. MacWilliams is a Partner of The Tremont Group, LLC, a private equity investment firm founded in January 2003, located in Newton, MA., which has a specialized expertise in the energy industry. Mr. MacWilliams is also a General Partner of The Beacon Group, LP, which he joined in 1993, and has served as a Director since June 1996. As part of The Beacon Group, he co-manages two private equity funds focusing on the energy industry. Mr. MacWilliams' previous positions include serving as a General Partner of JP Morgan Partners, Executive Director of Goldman Sachs International in London, Vice President for Goldman Sachs & Co.'s Investment Banking Division in New York, and as an attorney at Davis Polk & Wardwell in New York. He also is a Director of Compagnie Generale de Geophysique. Mr. MacWilliams holds a Bachelor of Arts degree from Stanford University, Master of Science degree from Massachusetts Institute of Technology, and a Juris Doctor degree from Harvard Law School.

*Preston R. Miller, Jr.*, retired from the Board of Directors of our managing general partner in January 2007. Mr. Miller is a Partner of The Tremont Group, LLC, a private equity investment firm founded in January 2003, located in Newton, MA., which has a specialized expertise in the energy industry. Mr. Miller is a General Partner of The Beacon Group, LP, which he joined in 1993 and has served as a Director since June 1996. As a part of The Beacon Group, he co-manages a private equity fund focusing on the energy industry. Mr. Miller's previous positions include serving as a General Partner of JP Morgan Partners from June 2000 through December 2002, and was with Goldman Sachs & Co.'s from January 1979 through January 1993, most recently as Vice President in the Structured Finance Group in New York City, where he had global responsibility for coverage of the independent power industry, asset-backed power generation, and oil and gas financing. He also has a background in credit analysis, and was head of a revenue bond rating group at Standard & Poor's Corp. Mr. Miller holds a Bachelor of Arts degree from Yale University and a Master of Public Administration degree from Harvard University.

*John P. Neafsey* has served as Chairman since June 1996. Mr. Neafsey is President of JN Associates, an investment consulting firm formed in 1993. Mr. Neafsey served as President and CEO of Greenwich Capital Markets from 1990 to 1993 and a Director since its founding in 1983. Positions that Mr. Neafsey held during a 23-year career at The Sun

Company include Director; Executive Vice President responsible for Canadian operations, Sun Coal Company and Helios Capital Corporation; Chief Financial Officer; and other executive positions with numerous subsidiary companies. He is or has been active in a number of organizations, including the following: Director and Chairman of the audit committee for The West Pharmaceutical Services Company and Chairman and a member of the audit committee of Constar, Inc. and Lead Director of NES Rentals, Inc., Trustee Emeritus and Presidential Counselor, Cornell University, and Overseer of Cornell-Weill Medical Center. Mr. Neafsey holds Bachelor and Master of Science degrees in Engineering and a Master of Business Administration degree from Cornell University. Mr. Neafsey is chairman of the Conflicts Committee and a member of the Audit and Compensation Committees.

*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. Mr. Robinson is also a Director of Comark Building Systems, Inc. and Olsson Associates. Mr. Robinson holds Bachelor and Master of Science degrees in Engineering from the University of Kansas and is a graduate of the Owner-President-Management Program at the Harvard Business School. He is chairman of the Compensation Committee and a member of the Audit Committee.

*Merribel S. Ayres* became a Director in January 2007. 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 Harvard University's Kennedy School of Government. Ms. Ayres holds a B.A. in English Literature from Bryn Mawr College, a post-graduate degree from Trinity College in Dublin, Ireland, and received advanced leadership training at Harvard University's Kennedy School of Government. In addition, Ms. Ayres is a Director of the United States Energy Association (USEA), and 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 is a member of the Compensation 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. From 1989 to 2006, Mr. Torrence was responsible at Fluor 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. Mr. Torrence holds Bachelor and Masters degrees in Business Administration from Virginia Tech University. In addition, Mr. Torrence serves on the Board of Directors and as Chief Financial Officer of Cleantech America, LLC, a company involved in the development and commercialization of central station solar generated power projects. Mr. Torrence is a member of the Conflicts Committee.

**Audit Committee**

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

*Report of the Audit Committee*

The Audit Committee of MGP oversees our financial reporting process on behalf of the Board of Directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls. The Audit Committee has the responsibility for the appointment, compensation and oversight of the work of our independent registered public accounting firm and assists the Board of Directors by conducting its own review of our:

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

- press releases and other communications by 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;

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

- auditing, accounting and financial reporting processes generally.

In fulfilling its oversight and other responsibilities, the Audit Committee either met or took action in the form of written consents fourteen times during 2006. 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, 2006, (d) performing a self-assessment of the committee itself, (e) reviewing the Audit Committee charter, and (f) reviewing the overall scope, plans and finding of 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 SAS 61 (*Codification of Statement on Auditing Standards*, AU § 380), as may be modified or supplemented. The committee received written disclosures and the letter from Deloitte & Touche LLP required by Independence Standards Board No. 1., *Independence Discussions with Audit Committees*, as may be modified or supplemented, and has discussed with Deloitte & Touche LLP, its independence from management and the 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, 2006 for filing with the SEC.

Members of the Audit Committee:

Michael J. Hall, Chairman

John P. Neafsey

John H. Robinson

**Code of Ethics**

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

**Communications with the Board**

Unitholders or other interested parties can contact any director or committee of the board by writing to them c/o Senior Vice President, 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 Securities and Exchange Act of 1934, as amended, requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC initial reports of ownership and reports or changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms they file. Based solely upon a review of the copies of the forms furnished to us, or written representations from certain reporting persons, we believe that during 2006 none of our officers and directors were delinquent with respect to any of the filing requirements under Rule 16(a) other than Mr. Robert G. Sachse who did not timely file a Form 4 related to his gift of 300 units in March, but has since filed a Form 4 with respect to this transaction.

**Reimbursement of Expenses of our Managing General Partner and its Affiliates**

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

## ITEM 11. EXECUTIVE COMPENSATION

**Compensation Discussion and Analysis**

The following Compensation Discussion and Analysis ("CD&A") describes the material elements of compensation for our executive officers identified in the Summary Compensation Table.

*Overall Compensation Policy and Philosophy*

Our compensation policy is to offer a cash and equity-based compensation package that attracts and retains executive officers and aligns executive compensation with the interests of our unitholders on both a short- and long-term basis. As described in more detail below under "Compensation Policy and Program Components," the primary components of our executive compensation programs are base salary, annual incentive bonus awards under the STIP and equity participation in the form of restricted units under the LTIP.

Our compensation philosophy is to provide total compensation that is competitive with companies of similar size, including companies that produce and market coal and that compare favorably to us with regard to revenue, number of mines, type of mines (e.g., we compare primarily to coal companies with underground mines) and other financial and operating indicators by which we have historically measured our performance. In general, our policy is to target base salary at the middle of the competitive market place, and annual incentive bonus awards and equity participation are designed to give an executive the opportunity, based upon our overall performance, to achieve total compensation at the top quarter of the competitive market place.

The objectives of our executive compensation programs are to align compensation with our business objectives and performance and enable us to attract, retain and motivate qualified executive officers that contribute to our long-term success and that of our affiliates. Our primary business objective is to create sustainable, capital-efficient growth in distributable cash flow to maximize our distribution to our unitholders.

*Compensation Policy and Program Components*

The primary components of our executive compensation programs are:

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

Historically, each executive's compensation related to these components has been allocated in the following manner:

- approximately 40 – 50% in the form of base salary;
- approximately 15 – 20% in the form of annual incentive bonus awards under the STIP; and
- the remaining compensation in the form of equity participation or restricted units under the LTIP.

Some of the executive officers are also entitled to compensation pursuant to the SERP, and 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. In 2005, the executive officers and some additional members of senior management executed release and waiver forms terminating their employment agreements.

*Base Salary*

The Compensation Committee reviews and approves the base salary of our named executive officers, as well as our other officers and key employees. When reviewing base salaries, the Compensation Committee's policy is to consider the individual's performance, our past performance and the individual's contribution to that performance, the individual's level of responsibility and competitive pay practices. In general, base salaries are targeted at the middle of the competitive market place. As discussed above, we compare our total compensation programs to that of companies of similar size, including companies that produce and market coal and that compare favorably to us with regard to revenues, number of mines, type of mines and other financial and operating indicators by which we have historically measured our performance. This assessment considers relevant industry salary practices, the position's complexity and level of responsibility, its importance to us in relation to other executive positions, and the competitiveness of an executive's total compensation. Subject to the committee's approval, the level of an executive officer's base pay is determined on the basis of relative comparative compensation data and the CEO's assessment of the executive's performance, experience, demonstrated leadership, job knowledge and management skills. Historically, such surveys as the Cammock's Coal Industry Administrative Survey and the 2006 Tulsa Area Survey have been used in making these compensation decisions.

Base salaries are reviewed annually to ensure continuing consistency with market levels. Future adjustments to base salaries will reflect movement in the competitive market as well as individual performance.

*Annual Incentive Bonus Awards*

To provide discretionary annual incentive bonus awards, we maintain the STIP. The STIP, which is administered by the Compensation Committee, is designed to enhance our financial performance by rewarding management and selected salaried employees with cash awards for our achieving an annual financial performance objective. The annual performance objective for each year is recommended by our President and CEO and approved by the Compensation Committee prior to or during January of that year. The annual aggregate cash awards available under the STIP for employees eligible to receive such cash awards is determined by a formula dependent on our actual financial results for the year compared to the annual financial performance objective. Individual participants and payments each year are determined by and in the discretion of the Compensation Committee, which is able to amend the STIP at any time.

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

For fiscal year 2006, we exceeded our annual EBITDA target so that all of the 2006 STIP participants were eligible to receive a cash award at the discretion of the Compensation Committee. Cash awards are payable in the first quarter of the following calendar year.

Termination of employment of an executive officer participating in the STIP for any reason prior to a performance pay-out distribution will result in the executive officer’s forfeiture of any right, title or interest in a performance pay-out distribution under the STIP, unless and to the extent waived by the Compensation Committee in its discretion.

The Compensation Committee honored the request of Messrs. Craft and Wesley that they not receive a cash award under the STIP for 2006, even though both Mr. Craft and Mr. Wesley would have been entitled to a STIP bonus under the Compensation Policy and Program Components adjustment procedures described in the CD&A. Messrs. Pearson and Rathburn did not receive a STIP bonus for 2006 because they terminated their employment prior to the payment of the STIP bonus in the first quarter of 2007. Please see "Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations."

*Equity Participation*

Equity compensation in the form of restricted units is a key component of our executive compensation program. Under the LTIP administered by the Compensation Committee, annual grant levels for designated employees are recommended by the CEO. The grants are made either of (a) restricted units, which are "phantom units" that entitle a grantee to receive a common unit or at the discretion of the Compensation Committee an equivalent amount of cash upon the vesting of a phantom unit, or (b) options to purchase common units. Restricted units are vested over a stated period from the grant date**,** which is currently three years after the grant date for all outstanding restricted units. Our policy is to issue the common units pursuant to the LTIP to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity participation with respect to our common units. Therefore, no consideration will be payable by the plan participants upon receipt of the common units. To date, the Compensation Committee has not granted any unit options under the LTIP. A detailed description of the LTIP is provided below.

Effective January 1, 2000, our managing general partner adopted the LTIP for certain of our and our affiliates employees and directors who perform services for us. Our LTIP is currently sponsored by Alliance Coal.

The LTIP is administered by the Compensation Committee. Annual grant levels for designated participants are recommended by our President and CEO, subject to the review and approval of the Compensation Committee. As stated above, grants are made of either restricted units, which are "phantom" units that entitle the grantee to receive a common unit or an equivalent amount of cash upon the vesting of a phantom unit, or options to purchase common units. Common units to be delivered upon the vesting of restricted units or to be issued upon exercise of a unit option will be acquired by us in the open market at a price equal to the then prevailing price, or directly from ARH or any other third-party, including units newly issued by us, or use units already owned 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 over a period of time as determined by the Compensation Committee**,** which is currently three years after the grant date for all outstanding restricted units. However, if a grantee's employment is terminated for any reason prior to the vesting of any restricted units, those restricted units will be automatically forfeited, unless the Compensation Committee, in its sole discretion, provides otherwise.

Our policy is to issue the common units pursuant to the vesting of restricted units under the LTIP to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation in respect of the common units. Therefore, no consideration will be payable by the plan participants upon receipt of the common units, and we receive no remuneration for these units. The Compensation Committee, in it discretion, may grant distribution equivalent rights with respect to restricted units. Historically, we have issued restricted unit grants at the beginning of each year, with the exception of new employees that commence employment with us at some other time or job promotions that may occur at some other time.

*Unit Options.* We have not made any grants of unit options. The Compensation Committee, in the future, may decide to make unit option grants to employees and directors containing the specific terms as the Compensation Committee determines. When granted, unit options will have an exercise price set by the Compensation Committee which may be above, below or equal to the fair market value of a common unit on the date of grant. 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.

*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 is 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. Our Board of Directors or the Compensation Committee will also have the right to alter or amend the LTIP or any part of it from time to time, subject to unitholder approval as required by the exchange upon which the common units may be listed at that time; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the affected participant. In addition, our 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.

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

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

*Grant History.* During 2004, 2005 and 2006, the Compensation Committee approved grants of 205,570 units, 114,390 units and 90,700 units, respectively, which will vest December 31, 2006, January 1, 2008 and January 1 2009, respectively, subject to the satisfaction of certain financial tests that management currently believes will be satisfied. As of December 31, 2006, 15,340 outstanding LTIP grants have been forfeited. On December 7, 2006, the Compensation Committee determined that the vesting requirements for the 2004 grants of 205,570 restricted units (net of 9,230 forfeitures) had been satisfied. As a result of this vesting, on January 8, 2007, we issued 130,812 common units to the LTIP participants. The remaining units were settled in cash to satisfy the individual tax obligations of the LTIP participants. Consequently, after consideration of the December 31, 2006 vesting and subsequent issuance of 130,812 common units, 242,530 units remain available for issuance in the future, assuming that all grants currently issued and outstanding for 2005 and 2006 are settled with common units and no future forfeitures occur. On January 24, 2007, the Compensation Committee authorized additional grants up to 94,075 restricted units of which 89,875 have been issued and will vest January 1, 2010, subject to the satisfaction of certain financial tests. This reduced the number of common units available from 242,530 to 152,655.

*Long-Term Incentive Plan – Awards to Named Executive Officers in 2006*

| | **Number of Units (1)** | **Performance or Other Period Until Maturation or Payout (2)** |
|---|---|---|
| Joseph W. Craft III (3) | 0 | 36 Months |
| Brian L. Cantrell | 4,300 | 36 Months |
| Thomas L. Pearson | 4,400 | 36 Months |
| Charles R. Wesley | 7,275 | 36 Months |
| Gary J. Rathburn | 4,400 | 36 Months |

(1) Units granted under the LTIP will vest January 1, 2009, subject to certain financial tests.

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

(3) In 2006, the Compensation Committee, in consideration of Mr. Craft's significant ownership position in us, did not grant LTIP phantom units to him, even though he would have been entitled to receive LTIP phantom unit grants under the CEO Executive Compensation adjustment procedure described in the Compensation Discussion and Analysis. Please see "Item 11. Compensation Discussion and Analysis -- Compensation Policy and Program Components -- *CEO Executive Compensation*."

*Supplemental Executive Retirement Plan*

We maintain a SERP for certain officers and key employees. The objective of the SERP is to enhance our ability to retain specific officers and key employees, by providing them with the deferred compensation benefits contained in the SERP. The objective of the SERP is to align each participant's supplemental benefits under the SERP with the interests of our unitholders. All allocations made to participants under the SERP are made in the form of "phantom" units. The SERP is administered by the Compensation Committee, which is able to amend or terminate the plan at any time.

Upon any recapitalization, reorganization, reclassification, split of common units, distribution or dividend of securities on 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 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 executive officer's account, to the extent such executive officer participates in the SERP, 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 compensation for such year (including any severance amount, if applicable) multiplied by his certain percentage as determined under the SERP, less his contributions made under our profit sharing and saving plan on behalf of the executive officer, other than pre-tax contributions, matching contributions and profit-sharing contributions (as those terms are defined in such plan).

*CEO Executive Compensation*

In determining Mr. Craft's compensation, the Compensation Committee considered our financial performance and peer group compensation data, which is described in more detail above under "Overall Compensation Philosophy and Policies," as well as Mr. Craft's leadership, decision-making skills, experience, knowledge, communication with the Board of Directors and strategic recommendations. The Compensation Committee did not place any particular relative weight on any one of these factors, but our financial performance is generally given the most weight. The Compensation Committee's decisions regarding Mr. Craft's compensation are reported to and discussed with the Board of Directors meeting in executive session without Mr. Craft's participation. For fiscal year 2006, Mr. Craft served as our CEO. Effective June 1, 2002, Mr. Craft's annual salary was increased to $334,828 from $321,950, in which the adjustment was determined in the manner described above. The Compensation Committee honored Mr. Craft's request that his salary not be increased in 2003, 2004, 2005 and 2006 even though a salary increase would have been warranted under the compensation adjustment procedure described above. Any differences in Mr. Craft's annual salary as reported in the summary compensation table above are attributable to the effective date of the salary adjustment in the year 2002 and the number of weekly pay periods in a calendar year. The Compensation Committee also honored Mr. Craft's requests that he not receive a cash bonus under the STIP for 2006 and that he not receive any restricted units pursuant to the LTIP for 2006.

*Conclusion*

In making decisions regarding executive compensation, the Compensation Committee compares current compensation levels with those of other companies, including companies that produce and market coal and that compare favorably to us with regard to financial and operating indicators by which we have historically measured our performance. The Compensation Committee uses its discretion to determine a total compensation package of base salary, short-term and long-term incentives that are competitive with this group of peer companies. Based upon its review of our overall executive compensation program, the Compensation Committee believes the executive compensation program is appropriately applied to our executive officers and is necessary to 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. The Compensation Committee has concluded that the program's structure is appropriate, competitive and effective to serve the purposes for which it was established. Moreover, the Compensation Committee believes that the total compensation opportunities provided to our executive officers creates a commonality of interest and alignment of our long-term interests with that of our unitholders.

**Summary Compensation Table for 2006**

| Name and Principal Position | Year | Salary | Bonus (1) | Unit Awards (2) | Option Awards (1) | Non-Equity Incentive Plan Compensation (3) | Change in Pension Value and Nonqualified Deferred Compensation Earnings (1) | All Other Compensation (4) | Total |
|---|---|---|---|---|---|---|---|---|---|
| Joseph W Craft III, President, Chief Executive Officer and Director (5) | 2006 | $ 334,828 | $ - | $ 1,066,400 | $ - | $ - | $ - | $ 302,821 | $1,704,049 |
| Brian L Cantrell Senior Vice President - Chief Financial Officer | 2006 | 202,115 | - | 241,573 | | 125,000 | | 68,825 | 637,513 |
| Thomas L Pearson, Senior Vice President-Law and Administration, General Counsel and Secretary (7) | 2006 | 210,680 | - | 156,240 | | - | | 124,477 | 491,397 |
| Gary J Rathburn, Senior Vice President-Marketing (7) | 2006 | 184,680 | - | 158,720 | | - | | 116,273 | 459,673 |
| Charles R Wesley, Senior Vice President-Operations (6) | 2006 | 236,280 | - | 482,859 | | - | | 161,731 | 880,870 |

(1) Column is not applicable.

(2) Represents the compensation expense recognized in 2006 in accordance with SFAS No. 123R associated with 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 Policy and Program Components -- *Equity Participation*."

(3) Represents the STIP bonus earned for year 2006. STIP payments are made in the first quarter of the year following the year earned. Other than this bonus, there were no other applicable bonuses earned or deferred associated with year 2006. Please see "Item 11. Compensation Discussion and Analysis -- Compensation Policy and Program Components -- *Annual Incentive Bonus Awards*."

(4) Represents the sum of the (a) change in value of the SERP notional account balance, (b) distribution equivalent rights received on non vested LTIP phantom unit grants and (c) 401(K) employer contribution. For Mr. Craft, the amounts were $120,101, $165,120 and $17,600, respectively. For Mr. Cantrell, the amounts were $16,360, $37,728 and $14,737, respectively. For Mr. Pearson, the amounts were $63,287, $45,696 and $15,494, respectively. For Mr. Rathburn, the amounts were $56,537, $46,080 and $13,656, respectively. For Mr. Wesley, the amounts were $68,819, $75,312 and $17,600, respectively. Please see "Item 11. Compensation Discussion and Analysis -- Compensation Policy and Program Components -- *Supplemental Executive Retirement Plan*." No named executive officer received perquisites or personal benefits with a total value in excess of $10,000.

(5) In 2006, the Compensation Committee, in consideration of Mr. Craft's significant ownership position in us, did not award a STIP bonus and did not grant LTIP phantom units to him, even though he would have been entitled to a STIP bonus and to receive LTIP phantom unit grants under the CEO Executive Compensation adjustment procedure described in the Compensation Discussion and Analysis. Please see "Item 11. Compensation Discussion and Analysis -- Compensation Policy and Program Components -- *CEO Executive Compensation*." Mr. Craft does not receive any compensation for the services he performs as a director.

(6) In 2006, the Compensation Committee, in consideration of Mr. Wesley's significant ownership position in us, did not award a STIP bonus to him even though he would have been entitled to a STIP bonus under the Compensation Policy and Program Components adjustment procedures described in the CD&A.

(7) In 2006, Messrs. Pearson and Rathburn did not receive a STIP bonus because they terminated their employment prior to the payment of the STIP bonus in the first quarter of 2007.

## Grants of Plan-Based Awards Table for 2006

| | | | Estimated Future Payouts Under Non-Equity Incentive Plan Awards | | | Estimated Future Payouts Under Equity Incentive Plan Awards | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Name** | **Grant Date** | **Approved Date** | **Threshold (1)** | **Target (1)** | **Maximum (1)** | **Threshold (4)** | **Target (2)** | **Maximum (4)** | **All Other Unit Awards: Number of Units (3)** | **All Other Option Awards: Number of Securities Underlying Options (1)** | **Exercise or Base Price of Options Awards (1)** | **Grant Date Fair Value of Unit Awards (5)** |
| Joseph W Craft, III | January 1, 2006 | January 27, 2006 | | | | | - | | | | | $ - |
| | February 15, 2006 | (7) | | | | | | | 480 | | | 17,347 |
| | May 12, 2006 | (7) | | | | | | | 449 | | | 18,297 |
| | August 14, 2006 | (7) | | | | | | | 549 | | | 20,401 |
| | November 14, 2006 | (7) | | | | | | | 604 | | | 20,941 |
| | December 31, 2006 | (7) | | | | | | | 1,249 | | | 43,115 |
| | | | | | | | - | | 3,331 | | | 120,101 |
| Brian L Cantrell | January 1, 2006 | January 27, 2006 | | | | | 4,300 | | | | | 163,013 |
| | February 15, 2006 | (7) | | | | | | | 6 | | | 217 |
| | May 12, 2006 | (7) | | | | | | | 6 | | | 245 |
| | August 14, 2006 | (7) | | | | | | | 7 | | | 260 |
| | November 14, 2006 | (7) | | | | | | | 8 | | | 277 |
| | December 31, 2006 | (7) | | | | | | | 445 | | | 15,361 |
| | | | | | | | 4,300 | | 472 | | | 179,373 |
| Thomas L Pearson (6) | January 1, 2006 | January 27, 2006 | | | | | 4,400 | | | | | 166,804 |
| | February 15, 2006 | (7) | | | | | | | 228 | | | 8,240 |
| | May 12, 2006 | (7) | | | | | | | 213 | | | 8,680 |
| | August 14, 2006 | (7) | | | | | | | 261 | | | 9,699 |
| | November 14, 2006 | (7) | | | | | | | 287 | | | 9,950 |
| | December 31, 2006 | (7) | | | | | | | 774 | | | 26,718 |
| | | | | | | | 4,400 | | 1,763 | | | 230,091 |
| Gary J Rathburn (6) | January 1, 2006 | January 27, 2006 | | | | | 4,400 | | | | | 166,804 |
| | February 15, 2006 | (7) | | | | | | | 178 | | | 6,433 |
| | May 12, 2006 | (7) | | | | | | | 166 | | | 6,765 |
| | August 14, 2006 | (7) | | | | | | | 203 | | | 7,543 |
| | November 14, 2006 | (7) | | | | | | | 223 | | | 7,731 |
| | December 31, 2006 | (7) | | | | | | | 813 | | | 28,065 |
| | | | | | | | 4,400 | | 1,583 | | | 223,341 |
| Charles R Wesley | January 1, 2006 | January 27, 2006 | | | | | 7,275 | | | | | 275,795 |
| | February 15, 2006 | (7) | | | | | | | 225 | | | 8,132 |
| | May 12, 2006 | (7) | | | | | | | 211 | | | 8,598 |
| | August 14, 2006 | (7) | | | | | | | 258 | | | 9,587 |
| | November 14, 2006 | (7) | | | | | | | 284 | | | 9,846 |
| | December 31, 2006 | (7) | | | | | | | 946 | | | 32,656 |
| | | | | | | | 7,275 | | 1,924 | | | 344,614 |

(1) Column not applicable.

(2) Represents LTIP phantom unit grants. Please see "Item 11. Compensation Discussion and Analysis -- Compensation Policy and Program Components -- *Equity Participation*."

(3) Represents the number of phantom units added to the participant’s SERP notional account balance. Each participant’s SERP balance is maintained in the form of a notional phantom unit account. 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. Additionally, the notional account balance is increased annually for the amount of the annual SERP benefit. The annual SERP benefit is a function of a participant’s eligible earnings multiplied by an allocation percentage that is approved by the Compensation Committee. Please see "Item 11. Compensation Discussion and Analysis -- Compensation Policy and Program Components -- *Supplemental Executive Retirement Plan*."

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

(5) For LTIP phantom unit grants, represents the number of units valued at $37.91, the unit price applicable under SFAS No. 123R. For SERP phantom unit grants, represents the number of phantom units granted valued at the market closing price on the date the phantom unit was granted. SERP participants vest in the phantom units on the date phantom units are granted.

(6) In accordance with the provisions of the LTIP, Messrs. Pearson and Rathburn forfeited their January 1, 2006 grants upon their resignations in 2007. The value of the forfeitures for each of Messrs. Pearson and Rathburn was $166,804, based on the grant date fair value of $37.91 per unit.

(7) In accordance with the provisions of the SERP, participant's cumulative notional phantom unit account balance earns the equivalent of a phantom common unit distribution when ARLP pays a distribution. Additionally, the notional account balance is credited annually for the amount of the annual SERP benefit. These contributions are in accordance with the SERP plan document, which has been approved by the Compensation Committee. Therefore, these awards are not specifically approved by the Compensation Committee.

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

Annual Incentive Bonus Awards

To provide discretionary annual incentive bonus awards, we maintain the STIP. The STIP is designed to enhance the financial performance by rewarding management and selected salaried employees with cash awards for our achieving an annual financial performance objective. The annual performance objective for each year is recommended by our President and CEO and approved by the Compensation Committee prior to or during January of that year. The STIP is administered by the Compensation Committee. Individual participants and payments each year are determined by and in the discretion of the Compensation Committee, which is able to amend the plan at any time. These targets are established prior to the beginning of each fiscal year. Under the STIP and its related guidelines, our executive officers and other employees selected by the Compensation Committee are eligible for cash bonuses based upon the comparison of our actual performance results to an annual EBITDA target. EBITDA is defined as net income before net interest expense, income taxes and depreciation, depletion and amortization. The Compensation Committee has the discretion to adjust the calculated EBITDA to be consistent with the objectives of the STIP.

For fiscal year 2006, we exceeded our annual EBITDA target so that all of the 2006 STIP participants were eligible to receive a cash award at the discretion of the Compensation Committee and/or our CEO. Cash awards are payable in the first quarter of the following calendar year.

Long Term Incentive Plan

The LTIP is administered by the Compensation Committee. Annual grant levels for designated participants are recommended by our President and CEO, subject to the review and approval of the Compensation Committee. To-date, grants have been made only in the form of restricted units, which are "phantom" units that entitle the participant to receive a common unit or an equivalent amount of cash upon the vesting of a phantom unit. Grants have a three year vesting period, subject to our satisfying certain financial tests. We plan to issue common units to satisfy grants that vest, excluding amounts that are required to be paid in cash to satisfy statutorily mandated income tax withholdings. Please see "Item 11. Compensation Discussion and Analysis -- Compensation Policy and Program Components -- Equity Participation."

*Salary and Bonus in Proportion to Total Compensation*

The following table shows the proportion of salary and bonus to total compensation during 2006:

| Name | Salary and Bonus ($) | Total Compensation ($) | Salary and Bonus as a % of Total Compensation (1) |
|---|---|---|---|
| Joseph W. Craft III | $ 334,828 | $ 1,704,049 | 19.6% |
| Brian L. Cantrell | 202,115 | 637,513 | 31.7% |
| Thomas L. Pearson | 210,680 | 491,397 | 42.9% |
| Gary J. Rathburn | 184,680 | 459,673 | 40.2% |
| Charles R. Wesley | 236,280 | 880,870 | 26.8% |

(1) Percentages reflect base salary and bonus compared to total compensation from the Summary Compensation Table. As discussed previously, percentages historically allocated to base salary reflect allocations between base salary, STIP and LTIP only. Please see "Item 11. Compensation Discussion and Analysis—Compensation Policy and Program Components."

**Outstanding Equity Awards at Fiscal Year-End 2006 Table**

| Name | Date | Number of Securities Underlying Unexercised Options Exercisable (1) | Number of Securities Underlying Unexerciseable 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 | 2006 | | | | | | | | - | $ - |
| | 2005 | | | | | | | | 30,000 | 1,035,600 |
| | | | | | | | | | 30,000 | 1,035,600 |
| Brian L Cantrell | 2006 | | | | | | | | 4,300 | 148,436 |
| | 2005 | | | | | | | | 5,350 | 184,682 |
| | | | | | | | | | 9,650 | 333,118 |
| Thomas L Pearson (4) | 2006 | | | | | | | | 4,400 | 151,888 |
| | 2005 | | | | | | | | 6,800 | 234,736 |
| | | | | | | | | | 11,200 | 386,624 |
| Gary J Rathburn (4) | 2006 | | | | | | | | 4,400 | 151,888 |
| | 2005 | | | | | | | | 6,800 | 234,736 |
| | | | | | | | | | 11,200 | 386,624 |
| Charles R Wesley | 2006 | | | | | | | | 7,275 | 251,133 |
| | 2005 | | | | | | | | 11,150 | 384,898 |
| | | | | | | | | | 18,425 | 636,031 |

(1) Column is not applicable.

(2) Represents LTIP non-vested phantom units awards, which vest three years after the grant date. The year 2006 and 2005 unit grants vest on January 1, 2009 and January 1, 2008, respectively. Please see "Item 11. Compensation Discussion and Analysis -- Compensation Policy and Program Components -- *Equity Participation*."

(3) The units are valued at $34.52, the closing price on December 29, 2006, the final market trading day of 2006.

(4) In accordance with the provisions of the LTIP, Messrs. Pearson and Rathburn forfeited their 2006 and 2005 grants upon their resignations in 2007. The value of the forfeitures for each of Messrs. Pearson and Rathburn was $419,764, based on the grant date fair value of the grants.

**Option Exercises and Unit Vested Table during 2006**

| | 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 | | | 56,000 | $ 1,933,120 |
| Brian L. Cantrell | | | 10,000 | 345,200 |
| Thomas L. Pearson | | | 12,600 | 434,952 |
| Gary J. Rathburn | | | 12,800 | 441,856 |
| Charles R. Wesley | | | 20,800 | 718,016 |

(1) Column is not applicable.

(2) Represents the number and value of LTIP units that vested on December 31, 2006. The units in this table represent all unit awards that vested in fiscal year 2006. The units are valued at $34.52, the closing price on December 29, 2006, the final market trading day of 2006. The units were granted to participants on March 22, 2004, effective January 1, 2004. Please see "Item 11. Compensation Discussion and Analysis -- Compensation Policy and Program Components -- *Equity Participation*."

**Pension Benefits Table for 2006**

| 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 | 2006 | | $ 1,514,910 | $ - |
| Brian L. Cantrell | SERP | 2006 | | 33,519 | - |
| Thomas L. Pearson | SERP | 2006 | | 724,609 | - |
| Gary J. Rathburn | SERP | 2006 | | 571,617 | - |
| Charles R. Wesley | SERP | 2006 | | 723,021 | - |

(1) Column not applicable.

(2) Represents the participant's cumulative notional account balance of phantom units valued at $34.52, the closing price on December 29, 2006, the final market trading day of 2006. Please see "Item 11. Compensation Discussion and Analysis -- Compensation Policy and Program Components -- *Supplemental Executive Retirement Plan*."

*Supplemental Executive Retirement Plan*

We maintain a SERP for certain officers and key employees. Each participant's SERP balance is maintained in the form of a notional phantom unit account. 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. Additionally, the notional account balance is increased annually for the amount of the annual SERP benefit. The annual SERP benefit is a function of a participant's eligible earnings multiplied by an allocation percentage that is approved by the Compensation Committee. The cumulative vested SERP benefit is payable at the earlier of a decision by the Compensation Committee to terminate the SERP or a participant's termination of employment. The Compensation Committee can elect to meet the payout obligation in common units or cash. If the Compensation Committee uses cash, the participant may defer the payment over up to 15 years, with interest on the outstanding balance at 8 percent. If the Compensation Committee uses common units, such units will be issued to the participant within 30 days. We currently plan to satisfy SERP obligations in cash. Please see "Item 11. Compensation Discussion and Analysis -- Compensation Policy and Program Components -- Supplemental Executive Retirement Plan."

*Potential Payments upon Termination or Change of Control*

Termination of employment of an executive officer participating in the STIP for any reason prior to a performance pay-out distribution will result in the executive officer's forfeiture of any right, title or interest in a performance pay-out distribution under the STIP, unless and to the extent waived by the Compensation Committee in its discretion.

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 is 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.

*Restricted Units*. Restricted units will vest over a period of time as determined by the Compensation Committee**,** which is currently three years after the grant date for all outstanding restricted units. However, if a grantee's employment is terminated for any reason prior to the vesting of any restricted units, those restricted units will be automatically forfeited, unless the Compensation Committee, in its sole discretion, provides otherwise.

Upon any recapitalization, reorganization, reclassification, split of common units, distribution or dividend of securities on 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 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 executive officer's account, to the extent such executive officer participates in the SERP, 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 compensation for such year (including any severance amount, if applicable) multiplied by his certain percentage as determined under the SERP, less his contributions made under our profit sharing and saving plan on behalf of the executive officer, other than pre-tax contributions, matching contributions and profit-sharing contributions (as those terms are defined in such plan).

### Directors Compensation for 2006

| Name | Fees earned or Paid in Cash ($) | Unit Awards ($) (1)(3) | Option Awards ($) | Non-Equity Incentive Plan Compensation ($)(4) | Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) | All Other Compensation ($)(2) | Total ($) |
|---|---|---|---|---|---|---|---|
| Michael J Hall | | 107,624 | | | | 18,671 | $ 126,295 |
| John J MacWilliams | | 111,783 | | | | 13,056 | $ 124,839 |
| Preston R Miller | | 111,783 | | | | 13,056 | $ 124,839 |
| John P Neafsey | | 130,925 | | | | 18,056 | $ 148,981 |
| John H Robinson | | 135,115 | | | | 18,056 | $ 153,171 |
| Robert G Sachse | | 165,047 | | 25,000 | | 152,552 | $ 342,599 |

(1) Amounts represent the compensation expense recognized in 2006 in accordance with SFAS No. 123R for awards under the LTIP as well as amounts earned for the annual retainer under the directors compensation plan. 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. Under our managing general partner's Directors' Plan, each non-employee director was paid an annual retainer of $23,500 in 2006. The annual retainer is payable in ARLP common units to be paid on a quarterly basis, in advance, determined by dividing the pro rata annual retainer payable on such date by the closing sales price per common unit averaged over the immediately preceding ten trading days. Each non-employee director is eligible to participate in a deferred compensation plan that is administered by the Compensation Committee. Prior to the beginning of each plan year, each non-employee director may elect to defer all or a portion of his compensation until he ceases to be a member of the Board of Directors. For directors who elect to defer their compensation, a notional account is established and credited with "phantom" units equal to the number of ARLP common units deferred. In addition, when distributions are made with respect to common units, the notional account is credited with "phantom" units that are equal in amount to the distributions made with respect to the ARLP common units. All directors with the exception of Mr. Hall elected to defer their compensation in 2006.

Mr. Sachse's Unit Awards also include ARLP common units purchased on his behalf as part of his consulting agreement with ARLP.

(2) Amount represents Distribution Equivalent Right payments received by the directors during 2006. Note that Mr. Hall's Other Compensation also includes fees associated with ARLP purchasing ARLP common units on his behalf related to his directors' compensation. Messrs. Hall, Neafsey and Robinson's Other Compensation also includes $5,000, $5,000 and $5,000, respectively, in matching charitable contributions made by us. We will match gifts of individuals to educational institutions and not-for-profit organizations. Individual contributions of $25 or more will be matched on a one-to-one basis up to $5,000 per individual, per calendar year.

Mr. Sachse's Other Compensation also includes fees paid to Mr. Sachse in relation to his consulting agreement with ARLP. Mr. Sachse earned a fee of $12,500 per month. The consulting agreement was terminated in November 2006, thus Mr. Sachse was only paid 10 months of consulting fees. Mr. Sachse's Other Compensation also includes $156 in fees associated with ARLP purchasing ARLP common units on his behalf related to his consulting agreement as well as $10,390 associated with us purchasing health insurance on Mr. Sachse's behalf.

(3) At December 31, 2006, each director had the following number of ARLP common units outstanding under the Directors Compensation Plan:

| Name | Directors Compensation Plan (in Units) |
|---|---|
| Michael J. Hall | - |
| John J. MacWilliams | 2,577 |
| Preston R. Miller | 2,577 |
| John P. Neafsey | 13,229 |
| John H. Robinson | 15,573 |
| Robert G. Sachse | - |

The grant date fair value for 2006 LTIP grants for each director:

| | 2006 Grants | | | 2006 Mid-Year Grants | | |
|---|---|---|---|---|---|---|
| Name | Number of Units Granted | Grant Date Fair Value | Extended Value | Number of Units Granted | Grant Date Fair Value | Extended Value |
| Michael J  Hall | 1,500 | $ 37 91 | $ 56,865 | - | $ - | $ - |
| John J  MacWilliams | 1,500 | 37 91 | 56,865 | - | - | - |
| Preston R  Miller | 1,500 | 37 91 | 56,865 | - | - | - |
| John P  Neafsey | 1,500 | 37 91 | 56,865 | - | - | - |
| John H  Robinson | 1,500 | 37 91 | 56,865 | - | - | - |
| Robert G  Sachse | 1,500 | 37 91 | 56,865 | 2,900 | 35 30 | 102,370 |

(4) Represents the STIP bonus earned for year 2006. STIP payments are made in the first quarter of the year following the year earned. Other than this bonus, there were no other applicable bonuses earned or deferred associated with year 2006. Please see "Item 11. Compensation Discussion and Analysis -- Compensation Policy and Program Components -- Annual Incentive Bonus Awards."

The ARLP’s managing general partner’s Directors' Compensation Program (Directors' Plan) consists of two parts: (1) the payment of directors’ annual retainers and (2) deferrals of the annual retainers in phantom units by electing directors. Under the Directors’ Plan, each non-employee director was compensated with an annual retainer of $23,500 during 2006. The annual retainer is payable in common units to be paid on a quarterly basis in advance determined by dividing the pro rata annual retainer payable on such date by the closing sales price per common unit averaged over the immediately preceding ten trading days. Each non-employee director is eligible to participate in a deferred compensation plan that is administered by the Compensation Committee. Prior to the beginning of each plan year, each non-employee director may elect to defer all or a portion of his compensation until he ceases to be a member of the Board of Directors. A new election must be made for each plan year. For compensation deferred by a director, a notional account is established and credited with "phantom" units equal to the number of ARLP common units deferred. In addition, when distributions are made with respect to ARLP common units, the notional account is credited with "phantom" distributions with respect to phantom units that are equal in amount to the distributions made with respect to ARLP common units. The Board of Directors may change or terminate the deferred compensation plan at any time; provided, however, that accrued benefits under the deferred benefit plan cannot be impaired. Effective January 1, 2007, the annual retainer for 2007 was increased to $90,000, and directors can elect to be paid in either cash or choose to defer their annual retainer. The annual retainer will no longer be paid in ARLP common units. The annual retainer was increased in 2007 because historically, directors participated in the LTIP as part of their compensation. However, beginning in 2007, directors no longer participate in the LTIP.

Upon a participating director’s termination, we shall pay to such director (or to his or her beneficiary in case of the director’s death) (a) that number of ARLP common units equal to the number of phantom units then credited to the account, (b) an amount of cash equal to the then fair market value of the phantom units credited to his or her account, or (c) any combination thereof as determined by the Compensation Committee in its discretion.

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 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, to the extent such director participates in the Directors' 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.

Mr. Sachse had a consulting agreement with our managing general partner with an indefinite term, subject to termination by either party upon receipt of ninety-day advance written notice of termination. The consulting agreement provided that Mr. Sachse would serve as Executive Vice President of our managing general partner and devote his services on a part-time basis. In addition to compensation received under the Directors' Plan described above and LTIP, Mr. Sachse was entitled to receive an annual fee of $150,000, payable monthly in arrears. Mr. Sachse also was entitled to receive quarterly payments of $7,500, payable in ARLP common units. Effective November 1, 2006, Mr. Sachse expanded his role as Executive Vice President to assume responsibility of our coal marketing, sales and transportation functions. As a result of Mr. Sachse's expanded responsibilities, he resigned from the Board of Directors and will no longer be subject to the terms of the consulting agreement. Payments under the consulting agreement ceased in October 2006. Copies of Mr. Sachse's original consulting agreement and the letter agreement extending the term of the original agreement are exhibits hereto.

*Compensation Committee Structure and Responsibilities*

The Compensation Committee administers our executive compensation programs and was established to fulfill two purposes: (a) to discharge the Board of Directors' responsibilities relating to compensation of our managing general partner's directors and our executives and (b) to produce an annual report relating to this CD&A for inclusion in our Annual Report on Form 10-K. The current members of the Compensation Committee are Ms. Ayres and Messrs. Neafsey and Robinson. All three members of the Compensation Committee of the Board of Directors are "non-employee directors" as defined under the Securities Exchange Act of 1934, as amended (the Exchange Act), and the Internal Revenue Code. After reviewing any relationships the members of the Compensation Committee may have with us that might affect their independence, the Board of Directors has determined that all Compensation Committee members are "independent" as that concept is defined in Section 10A of the Exchange Act and all Compensation Committee members are "independent" as that concept is defined in the applicable rules of NASDAQ Stock Market, LLC. The primary responsibilities of the Compensation Committee are the following:

1. Review and recommend to the Board of Directors for approval corporate goals and individual objectives relative to our President and Chief Executive Officer's (CEO) compensation, and evaluate the CEO's performance in light of those goals and objectives and to set the CEO's compensation level based on this evaluation.

2. Review and recommend to the Board of Directors for approval corporate goals and objectives relative to our senior executive officers, including our named executive officers' compensation, evaluate our senior executive officers' performance in light of those goals and objectives, and to set the senior executive compensation levels based on this evaluation.

3. Review and approve, in consultation with senior management, our general compensation philosophy, strategy, policies and programs.

4. Review and approve, in consultation with senior management, our executive compensation programs including the establishment of salaries and other compensation for our CEO, Chief Financial Officer and the other executive officers, including those named in the Summary Compensation Table.

5. Review and approve our management incentive compensation plans, and equity-based plans, including, without limitation, our STIP, LTIP and SERP plans.

6. Review and recommend to the Board of Directors for approval grants of restricted units under the LTIP or other awards pursuant to such plan and any other equity-based plans, if applicable.

7. Periodically review senior management's recommendations with respect to our ERISA-qualified benefit plans and retirement programs.

8. Review perquisites, such as club membership fees and tax preparation expenses, or other personal benefits to our executive officers and directors, such as charitable matching contributions, and recommend any changes to our Board of Directors.

9. Review expense statements of executive officers.

10. To the extent we have any employment agreements or any of the following arrangements, review and approve any employment agreements or severance, termination or change of control arrangements to be made with any executive officer (We currently do not have any employment agreements or severance, termination or change of control arrangements).

11. Approve a policy regarding director compensation and recommend to our Board of Directors annual retainer amounts consistent with the director compensation policy.

12. In connection with our Annual Report on Form 10-K or other applicable SEC filing:

    (a) review and discuss with management the CD&A required by SEC Regulation S-K, Item 402. Based on such review and discussion, recommend to our Board of Directors that the CD&A be included in our Annual Report on Form 10-K or other applicable SEC filing.

    (b) prepare the Compensation Committee report in accordance with all applicable rules and regulations of the SEC for inclusion above the names of the members of the Compensation Committee in our Annual Report on Form 10-K. This report shall state the Compensation Committee (i) reviewed and discussed with management the CD&A and (ii) based on such review and discussion, recommended to our Board of Directors that the CD&A be included in our Annual Report on Form 10-K or other applicable SEC filing.

13. In its sole discretion, have the ability to retain experts, consultants and other advisors, including without limitation, independent counsel, compensation consulting firms and legal or other advisors as the Compensation Committee deems necessary, to aid in the Compensation Committee's discharge of its duties.

14. Perform such other activities consistent with the Compensation Committee's charter, our partnership agreement, our Certificate of Limited Partnership, governing law, the rules and regulations of NASDAQ Stock Market, LLC and such other requirements applicable to us as the Compensation Committee or our Board of Directors deem necessary or appropriate.

15. Review and reassess the adequacy of the Compensation Committee's charter annually and submit recommended changes, if any, to our Board of Directors for its consideration and approval.

16. Annually perform an evaluation of itself.

The Compensation Committee has a charter, which is filed with this Annual Report on Form 10-K. The charter may be revised with the approval of the Compensation Committee and our Board of Directors. The charter is reviewed annually by the Compensation Committee.

In performing its duties, the Compensation Committee receives and considers information and recommendations from the CEO, Mr. Joseph W. Craft III. The Compensation Committee shall have the resources and authority appropriate to discharge its duties and responsibilities, including the authority to select, retain, terminate, and approve the fees and other retention terms of special counsel or other experts, advisers or consultants, as it deems appropriate, without seeking approval of our Board of Directors or management. With respect to consultants retained to assist in the determination or evaluation of director, CEO or senior executive compensation, this authority shall be vested solely in the Compensation Committee.

The Compensation Committee may, in its discretion, delegate all or a portion of its duties and responsibilities to a subcommittee of the Compensation Committee. In particular, the Compensation Committee may delegate the approval of certain transactions to a subcommittee composed solely of one or more members of the Compensation Committee who are (i) "Non-Employee Directors" for the purposes of Rule 16b-3 under the Exchange Act, as in effect from time to time, and (ii) "outside directors" for the purposes of Section 162(m) of the Internal Revenue Code, as in effect from time to time.

Mr. Robinson, as chairperson of the Compensation Committee, is in charge of the Compensation Committee's meeting agendas. The Compensation Committee shall meet in person or telephonically at least once a year at a time and place determined by the Compensation Committee chairperson, with further meetings to occur, or actions to be taken by unanimous written consent, when deemed necessary or desirable by the Compensation Committee or its chairperson.

The Compensation Committee may invite such members of management to its meetings, as it may deem desirable or appropriate, consistent with the maintenance of the confidentiality of compensation discussions. Our President and CEO should not attend any meeting where the CEO's performance or compensation is discussed, unless specifically invited by the Compensation Committee.

Our management has engaged the following compensation consultants with regards to the respective matters described below and has submitted reports from such compensation consultants to the Compensation Committee for review. Our management has engaged Hewitt Associates, LLC as a compensation consultant to help advise on matters such as our pension plan (which does not apply to our named executive officers) and the appropriate allocation to participants under the SERP. Our management has engaged Cammock's Inc. to help survey coal industry salaries and benefits. Our management has also engaged gregory.w.group and InTrust Bank, N.A. as compensation consultants to help advise on our profit sharing and savings plan and our pension plan, respectively.

*Compensation Committee Activity*

For the fiscal year ended December 31, 2006, the Compensation Committee met three times and primarily focused its activities on the following specific items:

- review and approve corporate goals and objectives relative to our senior executive officers, including our named executive officers' compensation, evaluate our senior executive officers' performance in light of those goals and objectives, and to set the senior executive compensation levels based on this evaluation;
- the annual guidelines for the LTIP and STIP pertaining to eligibility, minimum thresholds, target objectives, target results, target payout groups, the respective percentage targets, vesting, grants, the payout formula, payouts and performance payments;
- approve wage increases for certain executive officers;
- the participants and allocation percentages under the SERP;
- discussion of termination of employment agreements by executive officers in 2005;
- impact of SFAS No. 123R on LTIP;
- review and approve modifications to our profit sharing and savings plan;
- review and approve modifications to our pension plan;
- the Directors' Annual Retainer and Deferred Compensation Plan; and
- the 2007 annual planned percent for merit increases for hourly and salary personnel.

On January 8, 2007, Ms. Ayres was elected by the Board of Directors as a member of the Compensation Committee, and Mr. Robinson was appointed by the Board of Directors as chairperson of the Compensation Committee. On January 8, 2007, Mr. Miller resigned from the Compensation Committee.

In 2007, the Compensation Committee reviewed an amendment to the Deferred Compensation Plan for Directors regarding the payment date of deferrals and reviewed amendments to the STIP, LTIP and SERP with respect to the transfer of the sponsorship of such plans from our managing general partner to Alliance Coal, one of our consolidated subsidiaries. The Compensation Committee also approved the STIP aggregate performance pay-out pool for 2006 and performance targets for 2007 and reviewed the Compensation Committee charter.

**Compensation Committee Report**

The compensation committee of our managing general partner (collectively, our or the "Committee") has submitted the following report for inclusion in this Annual Report on Form 10-K:

Our Committee has reviewed and discussed the Compensation Discussion and Analysis contained in this Annual Report on Form 10-K with management. Based on our Committee's review of and the discussions with management with respect to the Compensation Discussion and Analysis, our 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, 2006.

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

**Members of the Compensation Committee:**

Merribel S. Ayres
John P. Neafsey
John H. Robinson, Chairman

Notwithstanding anything to the contrary set forth in any of our previous filings under the Securities Act of 1933, as amended (the Securities Act), or the Securities Exchange Act of 1934, as amended (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 Securities and Exchange Commission 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.

*Administrative Services*

Prior to May 15, 2006, substantially all of our executive officers were employees of record of our managing general partner. During this time, our managing general partner did not receive any management fee or other compensation in connection with its management of us. However, our managing general partner and its affiliates performed services for us and were 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. Specifically, our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses they incur or payments they make on our behalf, including, but not limited to, management's salaries and related benefits (including incentive compensation), and accounting, budget, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers' compensation management, legal and information technology services. Our managing general partner determined in its sole discretion the expenses that were allocable to us. Total costs billed by our managing general partner and its affiliates to us were approximately $4,181,000, $14,069,000 and $28,536,000 for the years ended December 31, 2006, 2005, and 2004, respectively. On May 15, 2006, our executive officers became employees of record of Alliance Coal. Thus, we no longer reimburse our managing general partner for compensation expenses associated with our executive officers.

The decrease in compensation accruals in 2005 compared to 2004 was primarily attributable to fewer ARLP common units outstanding under the LTIP for 2005 as compared to 2004. The amounts billed by the managing general partner for the LTIP, STIP and SERP include $2,934,000, $10,559,000 and $24,242,000 for the years ended December 31, 2006, 2005 and 2004, respectively.

*Administrative Services Agreement with Alliance Holdings GP, L.P.*

In connection with the closing of AHGP's initial public offering, we entered into an administrative services agreement between our managing general partner, Alliance Coal, AGP, AHGP and ARH II. Under the administrative services agreement, certain personnel, including our executive officers, will perform administrative and commercial services for us and for AHGP and ARH II and their respective affiliates. The services performed by these personnel will include but not be limited to day-to-day operations, human resources, information technology and financial and accounting services. This administrative services agreement includes policies and procedures to protect and prevent inappropriate disclosure by shared personnel of commercial and other non-public information relation to us, AHGP and ARH II.

In accordance with this administrative services agreement, on or about December 1 of each year, Alliance Coal is required to submit for approval (1) the proposed allocation of costs and expenses for administrative service fees associated with personnel that perform administrative and commercial services for us, AHGP and ARH II and their respective affiliates and (2) a new estimate of certain shared fixed costs (e.g., office lease, telephone and office equipment lease), which was established at a fixed annual aggregate amount of $75,000, to the Board of Directors of each of our managing general partner, AGP, the general partner of AHGP, and ARH II. This proposed allocation of costs and expenses for administrative service fees associated with personnel reflects any changes in personnel of Alliance Coal, changes in each employee's compensation and Alliance Coal's good faith estimate of the time each such employee will spend performing services on behalf of each of the entities mentioned above, taking into account prior performance and future expectations. The proposed estimate of certain shared fixed costs reflects Alliance Coal's good faith estimate of the amount of fixed costs allocable to each of the entities mentioned above. Once approved by the Board of Directors of each of the entities, the proposed allocation of costs and expenses for administrative service fees associated with personnel and the proposed estimate of shared fixed costs become part of the administrative services agreement, and AHGP and ARH II and their respective affiliates pay the corresponding administrative service fees to us or Alliance Coal. In addition, Alliance Coal is required to prepare a schedule detailing the variance between the estimated allocation of time spent by its personnel on behalf of each of the entities mentioned above in the past year and submit such schedule for approval by the Board of Directors of each of the entities. Upon approval, the difference between the administrative service fee paid and the adjusted administrative service fee as determined by the variance schedule is paid or reimbursed by each entity to us or Alliance Coal within 60 days after the fiscal year end.

*Compensation Committee Interlocks and Insider Participation*

With the exception of AHGP, 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 15, 2007, 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 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 unit holder 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 Joseph W. Craft III. 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 executive officers are held directly by such directors and officers. The percentage of common units beneficially owned is based on 36,550,659 common units outstanding as of February 15, 2007.

| Name of Beneficial Owner | Common Units Beneficially Owned | Percentage of Common Units Beneficially Owned |
|---|---|---|
| **Directors and Executive Officers** | | |
| Joseph W. Craft III (1) | 15,927,330 | 43.58% |
| Merribel S. Ayres | - | * |
| Michael J. Hall | 26,601 | * |
| John P. Neafsey (2) | 47,951 | * |
| John H. Robinson (3) | 22,264 | * |
| Wilson M. Torrence (4) | 668 | * |
| Brian L. Cantrell (5) | 11,605 | * |
| Thomas L. Pearson ** (6) | 39,126 | * |
| Gary J. Rathburn ** (7) | 32,424 | * |
| Robert G. Sachse | 19,330 | * |
| Charles R. Wesley III (8) | 121,376 | * |
| All directors and executive officers as a group (11 persons) | 16,248,675 | 44.46% |
| | | |
| **5% Common Unit Holders** | | |
| Alliance Holdings GP, L.P. (9) | 15,544,169 | 42.53% |
| M&G Investment Funds 1 (10) | 1,840,000 | 5.03% |

* Less than one percent.

** Former executive officer

(1) Mr. Craft's common units consist of (i) 337,599 common units held directly by him, (ii) 1,000 common units held by his son, (iii) 44,562 vested common units issuable to him under our SERP, and (iv) 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 42.53% of our common units. Mr. Craft disclaims beneficial ownership of the common units held by AHGP except to the extent of his pecuniary interest therein.

(2) Mr. Neafsey's common units consist of (i) 33,850 common units held directly by him and (ii) 14,101 vested common units issuable to him under our Directors Plan.

(3) Mr. Robinson's common units consist of (i) 6,450 common units held directly by him and (ii) 15,814 vested common units issuable to him under the Directors Plan.

(4) The 668 common units reflected as beneficially owned by Mr. Torrence are vested common units issuable to him under the Directors Plan.

(5) Mr. Cantrell's common units consist of (i) 10,619 common units held directly by him and (ii) 986 vested common units issuable to him under the SERP.

(6) Mr. Pearson's common units consist of 39,126 common units held directly by him. Mr. Pearson was the former Senior Vice President – Law and Administration, General Counsel and Secretary of our managing general partners, and he resigned effective February 2, 2007.

(7) Mr. Rathburn's common units consist of 32,424 common units held directly by him. Mr. Rathburn was the former Senior Vice President – Marketing of our managing general partner, and he resigned effective December 31, 2006. The address for Mr. Rathburn is 5405 E. 119th Street, Tulsa, Oklahoma 74137.

(8) Mr. Wesley's common units consist of (i) 100,108 common units held directly by him and (ii) 21,268 vested common units issuable to him under the SERP.

(9) See footnote (1) above and the paragraph preceding the above table for explanation of the relationship between AHGP, Joseph W. Craft III and us.

(10) The information in the above table with respect to M&G Investment Funds 1 is based on a Schedule 13G filing made by it with the Securities and Exchange Commission. 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, 2006 | Weighted-average exercise price of outstanding options, warrants and rights | Number of units remaining available for future issuance under equity compensation plans as of December 31, 2006 |
|---|---|---|---|
| **Equity compensation plans approved by unitholders:** | | | |
| Long-Term Incentive Plan (1) | 198,980 | N/A | 242,530 |
| **Equity compensation plans not approved by unitholders:** | | | |
| Supplemental Executive Retirement Plan | 114,358 | N/A | 45,642 |
| Deferred Compensation Plan for Directors | 33,956 | N/A | 66,044 |

(1) On December 7, 2006, our Compensation Committee determined that the vesting requirements for the 2004 LTIP grants had been satisfied as of December 31, 2006. The ARLP common units associated with the 2004 LTIP grants were issued January 8, 2007. However, since the 2004 LTIP grants had vested on December 31, 2006, they are excluded from the "Number of units to be issued upon exercise/vesting of outstanding options, warrants and rights as of December 31, 2006" above.

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

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

### Certain Relationships and Related Transactions

As of February 15, 2007, 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 15,544,169 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 Joseph W. Craft III, our President and Chief Executive Officer, Michael J. Hall, a Director and Chairman of our Audit Committee, Brian L. Cantrell, our Senior Vice President and Chief Financial Officer, and R. Eberley Davis, our Senior Vice President, General Counsel and Secretary.

### 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.

*River View Coal, LLC Acquisition*

In April 2006, we acquired 100% of the membership interest in River View for approximately $1.65 million from ARH. At the time, River View 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 April 2006, River View purchased such assets and assumed reclamation liabilities of $2.9 million. River View controls, through coal leases or direct ownership, approximately 110.0 million tons of high-sulfur coal reserves in the No. 7, No. 9 and No. 11 coal seams located in Union County, Kentucky.

*Tunnel Ridge, LLC Acquisition*

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

Because the River View and Tunnel Ridge acquisitions were between entities under common control, they have been accounted for at historical cost.

*Administrative Services*

In connection with the closing of the AHGP IPO, we 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 executive officers are providing administrative services to our managing general partner, AHGP, AGP, ARH II and their respective affiliates. We will be 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

$315,000, for the period from May 15, 2006 to December 31, 2006 from AHGP and $620,000 from ARH for the year ended December 31, 2006. This administrative service revenue is included in other sales and operating revenues in the consolidated statements of income. Concurrently, 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 $4,181,000, $14,069,000 and $28,536,000 for the years ended December 31, 2006, 2005 and 2004, respectively. The decrease from 2005 to 2006 was attributable to certain employees and the sponsorship of the LTIP, STIP and SERP, being transferred to Alliance Coal effective May 15, 2006. The decrease from 2004 to 2005 was primarily attributable to lower compensation accruals for the LTIP, STIP and SERP. The amounts billed by our managing general partner include $2,934,000, $10,559,000 and $24,242,000 for the years ended December 31, 2006, 2005 and 2004, respectively, for the LTIP, STIP and SERP.

*SGP Land, LLC*

Webster County Coal has a mineral lease and sublease with SGP Land, a subsidiary of the SGP, requiring annual minimum royalty payments of $2.7 million, payable in advance through 2013 or until $37.8 million of cumulative annual minimum and/or earned royalty payments have been paid. Webster County Coal paid royalties of $3,005,000, $3,449,000, and $4,611,000 for the years ended December 31, 2006, 2005, and 2004, respectively. As of December 31, 2006, Webster County Coal has recouped, against earned royalties otherwise due, all but $2,629,000 of the advance minimum royalty payments made under the lease.

Warrior has a mineral lease and sublease with SGP Land. Under the terms of the lease, Warrior paid in arrears an annual minimum royalty of $2,270,000 until $15,890,000 of cumulative annual minimum and/or earned royalty payments were paid. The annual minimum royalty periods extend from October 1st through the end of the following September 30, expiring September 30, 2007. In 2006, Warrior's cumulative total of annual minimum royalties and/or earned royalty payments exceeded $15,890,000, therefore the annual minimum royalty payment of $2,270,000 is no longer required. Warrior paid royalties of $5,061,000, $3,627,000, and $2,561,000 for the years ended December 31, 2006, 2005, and 2004, respectively. As of December 31, 2006, Warrior has recouped, against earned royalties otherwise due, all advance minimum royalty payments made in accordance with these lease terms.

Hopkins County Coal has 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 $684,000 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, are fully recoupable against future earned royalty payments. Hopkins County Coal paid advance minimum royalties and/or option fees of $684,000 during each of the years ended December 31, 2006 and 2005, respectively. As of December 31, 2006, $4,369,000 of advance minimum royalties and/or option fees paid under the Coal Lease Agreements is available for recoupment, and management expects that it will be recouped against future production.

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 $5,038,000, $6,379,000 and $5,428,000 for the years ended December 31, 2006, 2005, and 2004, respectively, for the base lease obligations. As of December 31, 2006, Webster County Coal, Warrior, and Hopkins County Coal have 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 $323,000.

In 2001, SGP Land, as successor in interest to an unaffiliated third-party, entered into an amended mineral lease with MC Mining. Under the terms of the lease, MC Mining has paid and will continue to pay an annual minimum royalty of $300,000 until $6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. MC Mining paid royalties of $300,000 and $600,000 during the years ended December 31, 2006 and 2005, respectively (the 2004 annual minimum royalty obligation of $300,000 was paid in January 2005 rather than in December 2004). As of December 31, 2006, $900,000 of advance minimum royalties paid under the lease is available for recoupment, and management expects that it will be recouped against future production.

*SGP*

As noted above, 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 obligation of $3.0 million until the earlier of January 1, 2033 or the exhaustion of the mineable and merchantable leased coal. We paid advance minimum royalties of $3.0 million during each of 2006 and 2005, which management expects 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 $240,000. 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 $240,000 for the year ended December 31, 2006.

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 $216,000 through January 2011. Lease expense incurred for each of the three years in the period ended December 31, 2006 was $2,595,000.

We previously entered into and have maintained agreements with two banks to provide letters of credit in an aggregate amount of $31.0 million. At December 31, 2006, we had $26.6 million in outstanding letters of credit under these agreements. The SGP guarantees $5.0 million of these outstanding letters of credit. Historically, we have compensated the SGP for a guarantee fee equal to 0.30% per annum of the face amount of the letters of credit outstanding. During 2003, the SGP agreed to waive the guarantee fee in exchange for a parent guarantee from the Intermediate Partnership and Alliance Coal on the mineral leases and subleases with Webster County Coal and Warrior described above. Since the guarantee is made on behalf of entities within the consolidated partnership, the guarantee has no fair value under FIN No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, including Indirect Guarantees of Indebtedness of Other*s, and does not impact our consolidated financial statements.

**Omnibus Agreement**

Concurrent with the closing of our initial public offering, we entered into an omnibus agreement with Alliance Resource Holdings, Inc. and our general partners, which govern potential competition among us and the other parties to this agreement. The omnibus agreement was amended in May 2002. Pursuant to the terms of the amended omnibus agreement, Alliance Resource Holdings agreed, and caused its controlled affiliates to agree, for so long as management controls our managing general partner, not to engage in the business of mining, marketing or transporting coal in the U.S., unless it first offers us the opportunity to engage in a potential activity or acquire a potential business, and the Board of Directors of our managing general partner, with the concurrence of its Conflicts Committee, elects to cause us not to pursue such opportunity or acquisition. In addition, Alliance Resource Holdings has the ability to purchase businesses, the majority value of which is not mining, marketing or transporting coal, provided Alliance Resource Holdings offers us the opportunity to purchase the coal assets following their acquisition. The restriction does not apply to the assets retained and business conducted by Alliance Resource Holdings at the closing of our initial public offering. Except as provided above, Alliance Resource Holdings and its controlled affiliates are prohibited from engaging in activities wherein they compete directly with us. In addition to its non-competition provisions, this agreement contains provisions which indemnify us against liabilities associated with certain assets and businesses of Alliance Resource Holdings which were disposed of or liquidated prior to consummating our initial public offering. 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 2006, 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, Neafsey and Robinson—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."

## ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

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

> Audit Services. Fees for audit services provided during the years ended December 31, 2006 and 2005, were $655,000 and $784,000, respectively. Audit services consist primarily of the audit and quarterly reviews of the consolidated financial statements, but can also be related to statutory audits of subsidiaries required by governmental or regulatory bodies, attestation services required by statute or regulation, comfort letters, consents, assistance with and review of documents filed with the SEC, work performed by tax professionals in connection with the audit and quarterly reviews, and accounting and financial reporting consultations and research work necessary to comply with generally accepted accounting principles.
>
> Audit-Related Services. Fees for audit-related services provided during the years ended December 31, 2006 and 2005, were $95,000 and $44,000, respectively. Audit-related services consist primarily of audits of employee benefit plans, consultations concerning financial accounting and reporting standards, and attestation services associated with third-party compliance.
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> Tax Services. Fees for tax services provided during the years ended December 31, 2006 and 2005, were $275,000 and $134,000, respectively. Tax services relate primarily to the preparation of federal and state tax returns but can also be related to tax advice, exclusive of tax services rendered in conjunction with the audit.
>
> All Other Fees. There were no other fees for the years ended December 31, 2006 and 2005, 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.

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, 2006, 2005 and 2004, 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 Form 8-K filed with the Commission on October 27, 2005, File No. 000-26823).

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

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

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

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

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

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

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

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 Form 8-K filed with the Commission on August 1, 2006, File No. 000-26823).

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

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

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

10.3 Letter of Credit Facility Agreement dated as of 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).

10.4 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).

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

10.6 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).

10.7 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).

10.8 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).

10.9 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).

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

10.11 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).

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| 10.12 | 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). |
| 10.13[(1)] | Amended and Restated Alliance Resource Management GP, LLC 2000 Long-Term Incentive Plan. (Incorporated by reference to Exhibit 10.17 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 000-26823). |
| 10.14[(1)] | First Amendment to the Alliance Resource Management GP, LLC 2000 Long-Term Incentive Plan. (Incorporated by reference to Exhibit 10.18 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 000-26823). |
| 10.15[(1)] | Alliance Resource Management GP, LLC Short-Term Incentive Plan. (Incorporated by reference to Exhibit 10.12 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 000-26823). |
| 10.16[(1)] | Alliance Resource Management GP, LLC Supplemental Executive Retirement Plan. (Incorporated by reference to Exhibit 99.2 of the Registrant's Registration Statement on Form S-8 filed with the Commission on April 1, 2002 (Reg. No. 333-85258)). |
| 10.17 | 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)). |
| 10.18 | 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)). |
| 10.19 | 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). |
| 10.20 | Amendment No. 3 to the Restated and Amended Coal Supply Agreement effective January 1, 2003 between Webster County Coal, LLC, White County Coal, LLC, Alliance Coal, LLC, and Seminole Electric Cooperative, Inc. (Incorporated by reference to Exhibit 10.39 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003, File No. 000-26823). |
| 10.21 | 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 Form 8-K filed with the Commission on October 26, 2005, File No. 000-26823). |
| 10.22 | 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). |
| 10.23 | Financial Covenants Agreement dated October 25, 2005 by and between Seminole Electric Corporation, Inc. and Alliance Coal, LLC. (Portions of this agreement have been omitted based upon a request for confidential treatment. Those omitted portions have been filed with the SEC). (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). |

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| 10.24 | 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). |
| 10.25 | 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 Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823). |
| 10.26 | 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 Form 8-K filed with the Commission on February 20, 2007, File No. 000-26823). |
| 10.27 | Ancillary Services Agreement, dated June 22, 2005, between Virginia Electric and Power Company and Alliance Coal, LLC. (Incorporated by reference to Exhibit 10.2 of the Registrant's Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823). |
| 10.28 | Amended and Restated Lease Agreement, dated June 22, 2005, between Virginia Electric and Power Company and Mettiki Coal, LLC. (Incorporated by reference to Exhibit 10.3 of the Registrant's Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823). |
| 10.29 | Amended and Restated Equipment Lease Agreement (Existing Truck Unloading Facility), dated June 22, 2005, between Virginia Electric and Power Company and Mettiki Coal, LLC. (Incorporated by reference to Exhibit 10.4 of the Registrant's Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823). |
| 10.30 | Amended and Restated Memorandum of Understanding dated as of June 22, 2005, among Virginia Electric and Power Company, Alliance Coal, LLC and Mettiki Coal, LLC. (Incorporated by reference to Exhibit 10.5 of the Registrant's Form 8-K filed with the Commission on June 27, 2005, File No. 000-26823). |
| 10.31 | Feedstock Agreement No. 2, dated as of July 1, 2005, between Alliance Coal, LLC and Mount Storm Coal Supply, LLC. (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K filed with the Commission on August 5, 2005, File No. 000-26823). |
| 10.32 | Memorandum of Understanding dated January 17, 2005 between VEPCO and Mettiki. (Incorporated by reference to Exhibit 10.2 of the Registrants Form 8-K filed with the Commission on January 19, 2005, File No. 000-26823). |
| *10.33[(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. |
| 10.34 | Amendment No. 1 dated January 17, 2005 between VEPCO and Mettiki to the Coal Supply Agreement. (Incorporated by reference to Exhibit 10.2 of the Registrants Form 8-K filed with the Commission on January 19, 2005, File No. 000-26823). |
| 10.35 | 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). |
| 10.36 | 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). |

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| 10.37 | 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). |
| 10.38 | 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). |
| 10.39 | Letter Agreement dated January 31, 2003 between ARH Warrior Holdings, Inc. and Alliance Resource Partners, L.P. (Incorporated by reference to Exhibit 10.34 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 File No. 000-26823). |
| 10.40[(1)] | Consulting Agreement for Mr. Sachse dated January 1, 2001. (Incorporated by reference to Exhibit 10.18 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2000, File No. 000-26823). |
| 10.41[(1)] | Extension of Consulting Agreement with Mr. Sachse, dated September 30, 2003. (Incorporated by reference to Exhibit 10.42 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, File No. 000-26823). |
| 10.42 | Amended and Restated Charter for the Audit Committee of the Board of Directors dated March 10, 2005. (Incorporated by reference to Exhibit 10.41 of the Registrant's Annual Report on Form 10-K filed with the Commission on March 15, 2005). |
| 10.43 | Amended and Restated Credit Agreement, dated as of April 13, 2006, among Alliance Resource Operating Partners, L.P. as Borrower and the Initial Lenders, Initial Issuing Banks and Swing Line Bank and JPMorgan 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 Form 8-K filed with the Commission on April 18, 2006, File No. 000-26823) |
| 10.44 | 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 Form 8-K filed with the Commission on May 16, 2006, File No. 000-26823). |
| 10.45 | The termination of Guarantee Agreement, dated as of April 24, 2006, between Alliance Resource GP, LLC and Fifth Third Bank (Incorporated by reference to Exhibit 10.2 of the Registrant's Form 8-K filed with the Commission on May 16, 2006, File No. 000-26823). |
| 10.46 | 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) |
| 10.47 | 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) |

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| 10.48 | 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 Form 8-K filed with the Commission on July 13, 2006, File No. 000-26823) |
| * 10.49 | Charter for the Compensation Committee of the Board of Directors dated February 28, 2007. |
| * 10.50(1) | First Amendment to the Amended and Restated Alliance Resource Management GP, LLC Supplemental Executive Retirement Plan |
| * 10.51(1) | Second Amendment to the Amended and Restated Alliance Resource Management GP, LLC Long-Term Incentive Plan |
| * 10.52(1) | First Amendment to the Alliance Resource Management GP, LLC Short-Term Incentive Plan |
| * 10.53 | First 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-3 and Form S-8, Registration Statements No. 333-85282 and 333-85258, respectively. |
| * 31.1 | Certification of Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated March 1, 2007, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 furnished herewith. |
| * 31.2 | Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated March 1, 2007, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 furnished herewith. |
| * 32.1 | Certification of Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated March 1, 2007, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 furnished herewith. |
| * 32.2 | Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated March 1, 2007, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 furnished herewith. |

* Filed herewith.

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(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.

## 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 1, 2007.

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<br>Joseph W. Craft III | President, Chief Executive Officer,<br>and Director (Principal Executive Officer) | March 1, 2007 |
| /s/ Brian L. Cantrell<br>Brian L. Cantrell | Senior Vice President and<br>Chief Financial Officer | March 1, 2007 |
| /s/Merribel S. Ayres<br>Merribel S. Ayres | Director | March 1, 2007 |
| /s/ Michael J. Hall<br>Michael J. Hall | Director | March 1, 2007 |
| /s/ John P. Neafsey<br>John P. Neafsey | Director | March 1, 2007 |
| /s/ John H. Robinson<br>John H. Robinson | Director | March 1, 2007 |
| /s/ Wilson M. Torrence<br>Wilson M. Torrence | Director | March 1, 2007 |

# Unitholder Information.

Alliance Resource Partners, L.P. is a publicly traded master limited partnership. Alliance Resource Partners, L.P. common units began trading on the NASDAQ Global Select Market under the symbol "ARLP" in August 1999. As of December 31, 2006, there were 36,419,847 common units outstanding.

**CASH DISTRIBUTIONS**

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

**PARTNERSHIP TAX DETAILS**

• Unitholders are partners in the Partnership and receive cash distributions. The cash distributions are generally not taxable as long as the unitholder's tax basis remains above zero.

• A partnership is generally not subject to federal or state income tax. The annual income, gains, losses, deductions or credits of the Partnership flow through to the unitholders, who are required to report their allocated share of these amounts on their individual tax returns, as though the unitholder had incurred these items directly.

• Unitholders of record will receive Schedule K-1 packages that summarize their allocated share of the Partnership's reportable tax items for the fiscal year. It is important to note that cash distributions received should not be reported as taxable income. Only the amounts provided on the Schedule K-1 should be entered on each unitholder's tax return.

• Should you have questions regarding the Schedule K-1 contact:

Alliance Resource Partners, L.P.
K-1 Support
P.O. Box 799060
Dallas, TX 75379-9060
(800) 485-6875
Fax: (972) 428-5395

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**TRANSFER AGENT AND REGISTRAR**

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

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

**ADDITIONAL INVESTOR INFORMATION**

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

**PARTNERSHIP OFFICES**

Alliance Resource Partners, L.P.
1717 South Boulder Avenue, Suite 400
Tulsa, OK 74119
(918) 295-7600

**PARTNERSHIP MAILING ADDRESS**

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

**INDEPENDENT AUDITORS**

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

**CONTACT**

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

**OFFICERS AND DIRECTORS**

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

**Robert G. Sachse**
Executive Vice President and Marketing

**Brian L. Cantrell**
Senior Vice President
and Chief Financial Officer

**R. Eberley Davis**
Senior Vice President,
General Counsel and Secretary

**Charles R. Wesley**
Senior Vice President and Operations

**Merribel S. Ayres**
Director

**Michael J. Hall**
Director

**John P. Neafsey**
Chairman of the Board

**John H. Robinson**
Director

**Wilson M. (Mack) Torrence**
Director

NASDAQ LISTED

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

ALLIANCE RESOURCE
PARTNERS, L.P.

P.O. Box 22027 | Tulsa, Oklahoma 74121-2027 | *www.arlp.com*