ALLIANCE RESOURCE PARTNERS LP
Form 10-Q
November 06, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2009

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)

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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ¨ Yes ¨ No

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

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

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

As of November 6, 2009, 36,661,029 Common Units are outstanding.

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PART I

FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(In thousands, except unit data)

(Unaudited)

	September 30, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 91,634	$ 244,875
Trade receivables	93,532	87,922
Other receivables	3,662	6,018
Due from affiliates	86	
Marketable securities	4,952	
Inventories	49,239	26,510
Advance royalties	3,200	3,200
Prepaid expenses and other assets	802	10,070
Total current assets	247,107	378,595
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment, at cost	1,317,098	1,085,214
Less accumulated depreciation, depletion and amortization	(532,741)	(468,784)
Total property, plant and equipment, net	784,357	616,430
OTHER ASSETS:		
Advance royalties	26,628	23,828
Other long-term assets	12,346	11,787
Total other assets	38,974	35,615
TOTAL ASSETS	$ 1,070,438	$ 1,030,640
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 65,534	$ 63,236
Due to affiliates	487	706
Accrued taxes other than income taxes	11,837	11,195
Accrued payroll and related expenses	23,709	20,555
Accrued interest	6,703	3,454
Workers compensation and pneumoconiosis benefits	9,254	9,377

Current capital lease obligation	331	351
Other current liabilities	12,424	11,911
Current maturities, long-term debt	18,000	18,000
Total current liabilities	148,279	138,785
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities	422,000	440,000
Pneumoconiosis benefits	33,559	31,436
Accrued pension benefit	20,881	19,952
Workers compensation	59,663	47,828
Asset retirement obligations	57,949	56,204
Due to affiliates	867	420
Long-term capital lease obligation	543	784
Other liabilities	6,140	5,039
Total long-term liabilities	601,602	601,663
Total liabilities	749,881	740,448
COMMITMENTS AND CONTINGENCIES		
PARTNERS CAPITAL:		
Alliance Resource Partners, L.P. (ARLP) Partners Capital:		
Limited Partners - Common Unitholders 36,661,029 and 36,613,458 units outstanding, respectively	631,458	604,998
General Partners deficit	(293,652)	(295,834)
Accumulated other comprehensive income (loss)	(18,408)	(19,899)
Total ARLP Partners Capital	319,398	289,265
Noncontrolling interest	1,159	927
Total Partners Capital	320,557	290,192
TOTAL LIABILITIES AND PARTNERS CAPITAL	$ 1,070,438	$ 1,030,640

See notes to condensed consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(In thousands, except unit and per unit data)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
SALES AND OPERATING REVENUES:				
Coal sales	$ 281,628	$ 269,318	$ 881,508	$ 800,043
Transportation revenues	11,663	11,721	35,347	33,348
Other sales and operating revenues	6,353	4,751	15,993	12,211
Total revenues	299,644	285,790	932,848	845,602
EXPENSES:				
Operating expenses (excluding depreciation, depletion and amortization)	204,840	199,321	605,693	583,302
Transportation expenses	11,663	11,721	35,347	33,348
Outside coal purchases	517	6,995	5,709	14,450
General and administrative	9,959	7,184	29,000	28,134
Depreciation, depletion and amortization	28,145	25,403	83,767	74,297
Gain from sale of coal reserves				(5,159)
Net gain from insurance settlement and other				(2,790)
Total operating expenses	255,124	250,624	759,516	725,582
INCOME FROM OPERATIONS	44,520	35,166	173,332	120,020
Interest expense (net of interest capitalized for the three and nine months ended September 30, 2009 and 2008 of $310, $182, $857 and $484, respectively)	(7,675)	(8,134)	(23,464)	(14,372)
Interest income	112	2,118	1,036	2,413
Other income	126	231	554	698
INCOME BEFORE INCOME TAXES	37,083	29,381	151,458	108,759
INCOME TAX EXPENSE (BENEFIT)	586	92	811	(633)
NET INCOME	36,497	29,289	150,647	109,392
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	(53)	(153)	(232)	(396)
NET INCOME ATTRIBUTABLE TO ALLIANCE RESOURCE PARTNERS, L.P. (NET INCOME OF ARLP)	$ 36,444	$ 29,136	$ 150,415	$ 108,996
GENERAL PARTNERS INTEREST IN NET INCOME OF ARLP	$ 15,192	$ 11,512	$ 44,813	$ 32,331

LIMITED PARTNERS INTEREST IN NET INCOME OF ARLP	$ 21,252	$ 17,624	$ 105,602	$ 76,665
BASIC AND DILUTED NET INCOME OF ARLP PER LIMITED PARTNER UNIT (Note 7)	$ 0.57	$ 0.47	$ 2.85	$ 2.08
DISTRIBUTIONS PAID PER LIMITED PARTNER UNIT	$ 0 .745	$ 0.66	$ 2.19	$ 1.83
BASIC AND DILUTED WEIGHTED AVERAGE NUMBER OF UNITS OUTSTANDING	36,661,029	36,613,458	36,653,710	36,601,769

See notes to condensed consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Nine Months Ended September 30,	
	2009	**2008**
CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 238,349	$ 192,720
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(251,453)	(122,887)
Changes in accounts payable and accrued liabilities	5,084	11,339
Proceeds from sale of property, plant and equipment	1	2,487
Proceeds from sale of coal reserves		7,159
Purchase of marketable securities	(4,527)	
Payment for acquisition of coal reserves and other assets		(29,800)
Receipts of prior advances on Gibson rail project	1,828	1,645
Net cash used in investing activities	(249,067)	(130,057)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from issuance of long-term debt		350,000
Borrowings under revolving credit facilities		88,850
Payments under revolving credit facilities		(116,850)
Payment on long-term debt	(18,000)	(18,000)
Payments on capital lease obligation	(261)	(281)
Payment of debt issuance costs		(1,721)
Net settlement of employee withholding taxes on vesting of Long-Term Incentive Plan	(791)	
Cash contributions by General Partners	31	866
Distributions paid to Partners	(123,689)	(96,912)
Net cash (used in) provided by financing activities	(142,710)	205,952
EFFECT OF CURRENCY TRANSLATION ON CASH	187	
NET CHANGE IN CASH AND CASH EQUIVALENTS	(153,241)	268,615
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	244,875	1,118
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 91,634	$ 269,733
SUPPLEMENTAL CASH FLOW INFORMATION:		
Cash paid for interest	$ 20,734	$ 11,538

Cash paid for income taxes	$ 225	$
NON-CASH INVESTING AND FINANCING ACTIVITY:		
Accounts payable for purchase of property, plant and equipment	$ 20,176	$ 16,385
Non-cash contribution by general partner	$	$ 620
Market value of common units vested in Long-Term Incentive Plan before minimum statutory tax withholding requirements	$ 2,333	$ 3,658

See notes to condensed consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND PRESENTATION

Significant Relationships Referenced in Notes to Condensed Consolidated Financial Statements

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

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

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

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

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

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

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

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

Organization

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

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

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

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Basis of Presentation

The accompanying condensed consolidated financial statements include the accounts and operations of the ARLP Partnership and present our financial position as of September 30, 2009 and December 31, 2008, results of our operations for the three and nine months ended September 30, 2009 and 2008 and our cash flows for the nine months ended September 30, 2009 and 2008. All of our intercompany transactions and accounts have been eliminated. Net income attributable to Alliance Resource Partners, L.P. from our accompanied condensed consolidated financial statements will be described as Net Income of ARLP.

These condensed consolidated financial statements and notes are unaudited. However, in the opinion of management, these financial statements reflect all adjustments (which include only normal recurring adjustments) necessary for a fair presentation of the results for the periods presented. Results for interim periods are not necessarily indicative of results for a full year.

These condensed consolidated financial statements and notes are prepared pursuant to the rules and regulations of the Securities and Exchange Commission (the SEC) for interim reporting and should be read in conjunction with the consolidated financial statements and notes included in our Annual Report on Form 10-K for the year ended December 31, 2008.

2. NEW ACCOUNTING STANDARDS

New Accounting Standards Issued and Adopted

In June 2009, we adopted amendments to Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 105, *Generally Accepted Accounting Principles* (Statement of Financial Accounting Standards (SFAS) No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles-A Replacement of FASB Statement No. 162*), effective for interim periods ending after September 15, 2009. FASB ASC 105-10-05-1 establishes the FASB Accounting Standards Codification as the only source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with Generally Accepted Accounting Principles (GAAP). Rules and interpretive releases of the SEC under federal securities laws are also sources of authoritative GAAP for SEC registrants. FASB ASC 105 is not intended to change GAAP. All references to GAAP standards below include both FASB ASC reference in addition to the previously disclosed GAAP standard references as appropriate. The adoption of FASB ASC 105 had no impact on our financial position or results of operations.

In September 2009, the FASB issued Accounting Standards Update (ASU) 2009-06, *Implementation Guidance on Accounting for Uncertainty in Income Taxes and Disclosure Amendments for Nonpublic Entities.* ASU 2009-06 amended guidance on certain aspects of FASB ASC 740, *Income Taxes,* including application to nonpublic entities, as well as application guidance on the accounting for income tax uncertainties for all entities. The amendments are applicable to all entities that apply FASB ASC 740 as well as those that historically had not, such as pass-through and tax-exempt not-for-profit entities. The amendments clarify that an entity s tax status as a pass-through or tax-exempt not-for-profit entity is a tax position subject to the recognition requirements of FASB ASC 740 and therefore these entities must use the recognition and measurement guidance in FASB ASC 740 when assessing their tax positions. The ASU 2009-06 amendments are effective for interim and annual periods ending after September 15, 2009. The adoption of the ASU 2009-06 amendments is for the quarterly period ending September 30, 2009 did not have a material impact on our consolidated financial statements.

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On January 1, 2009, we adopted amendments to FASB ASC 805, *Business Combinations* (SFAS No. 141R, *Business Combinations*), issued by the FASB in December 2007. The FASB ASC 805 amendments apply to all business combinations and establish guidance for recognizing and measuring identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree and goodwill. Most of these items are recognized at their full fair value on the acquisition date, including acquisitions where the acquirer obtains control but less than 100% ownership in the acquiree. The FASB ASC 805 amendments also require expensing restructuring and acquisition-related costs as incurred and establish disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. Per FASB ASC 805-10-65-1, these amendments to FASB ASC 805 are effective for business combinations with an acquisition date in fiscal years beginning after December 15, 2008. We did not complete any business acquisitions during the nine months ended September 30, 2009.

On January 1, 2009, we adopted FASB ASC 810-10-65 and 810-10-45-16 (SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements*) (Note 13), FASB ASC 260-10-55-102 through 55-110, *Master Limited Partnerships* (Emerging Issues Task Force (EITF) No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128, Earnings Per Share, to Master Limited Partnerships),* and FASB ASC 260-10-55-25 (Financial Staff Position (FSP) No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities*) (Note 7).

Beginning with the quarterly period ended June 30, 2009, we adopted FASB ASC 825-10-50-2A (FSP SFAS No. 107-1 and Accounting Principles Board (APB) Opinion No. 28-1, *Interim Disclosures about Fair Value of Financial Instruments*). FASB ASC 825-10-50-2A requires disclosures about fair value of financial instruments in interim financial statements as well as in annual financial statements (Note 5).

Beginning with the quarterly period ended June 30, 2009, we adopted amendments to FASB ASC 855, *Subsequent Events* (SFAS No. 165, *Subsequent Events*), issued by the FASB in May 2009. The amendments to FASB ASC 855 establish the accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The amendments to FASB ASC 855 also require disclosure of the date through which an entity has evaluated subsequent events and the basis for that date, that is, whether that date represents the date the financial statements were issued or were available to be issued (Note 14).

New Accounting Standards Issued and Not Yet Adopted

In August 2009, the FASB issued ASU 2009-05, *Measuring Liabilities at Fair Value*. The ASU 2009-05 amendments provide additional guidance on measuring the fair value of liabilities, as well as outline alternative valuation methods and a hierarchy for their use. The amendments also clarify that restrictions preventing the transfer of a liability should not be considered as a separate input or adjustment in the measurement of its fair value. The ASU 2006-05 amendments are effective as of the beginning of interim and annual reporting periods that begin after August 26, 2009. We do not anticipate these requirements will have a material impact on our consolidated financial statements.

In June 2009, the FASB issued amendments to FASB ASC 810, *Consolidation* (SFAS No. 167, *Amendments to FASB Interpretation No. 46(R)),* which change the consolidation guidance applicable to a variable interest entity (VIE). These amendments also update the guidance governing the determination of whether an enterprise is the primary beneficiary of a VIE, and is, therefore, required to consolidate an entity, by requiring a qualitative analysis rather than a quantitative analysis. The qualitative analysis will include, among other things, consideration of who has the power to direct the activities of the entity that most significantly impact the entity s economic performance and who has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. This standard also requires continuous reassessments of whether an

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enterprise is the primary beneficiary of a VIE. Previously, FASB ASC 810 required reconsideration of whether an enterprise was the primary beneficiary of a VIE only when specific events had occurred. Qualifying special purpose entities, which were previously exempt from the application of this standard, will be subject to the provisions of this standard when it becomes effective. These amendments also require enhanced disclosures about an enterprise s involvement with a VIE. The provisions of these amendments are effective as of the beginning of interim and annual reporting periods that begin after November 15, 2009. We are currently evaluating the requirements of these amendments.

In December 2008, FASB ASC 715, *Compensation-Retirement Benefits*, was amended (FSP SFAS No. 132(R)-1, *Employers Disclosures about Postretirement Benefit Plan Assets*) to require more detailed annual disclosures about employers plan assets, concentrations of risk within plan assets and valuation techniques used to measure the fair value of plan assets. These amendments are effective for fiscal years ending after December 15, 2009. We are currently evaluating these requirements. However, we do not anticipate these requirements will have a material impact on our consolidated financial statements.

3. CONTINGENCIES

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

The matters referenced in the previous paragraph include, but are not limited to, the *Rector* lawsuit, which is a royalty dispute involving certain coal leases that had been previously terminated. Plaintiffs have alleged damages of over $33 million and have also asserted a claim for punitive damages. We believe plaintiffs claims are without merit, have accrued no loss and are vigorously defending the litigation. This legal matter is also discussed in Part II, Item 1. Legal Proceedings.

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.

4. ACQUISITIONS

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

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existing cash on hand and borrowings under our revolving credit facility. Since this transaction was a related-party transaction, it was 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 Board of Directors and its Conflicts Committee approved the SGP Land transaction as fair and reasonable to us and our limited partners. Because the SGP Land acquisition was between entities under common control, it was accounted for at historical cost.

5. FAIR VALUE MEASUREMENTS

Effective January 1, 2008, we adopted FASB ASC 820, *Fair Value Measurements and Disclosures* (SFAS No. 157, *Fair Value Measurements*) which, among other things, defines fair value, requires enhanced disclosures about assets and liabilities carried at fair value and establishes a hierarchal disclosure framework based upon the quality of inputs used to measure fair value. We elected to defer the application of FASB ASC 820 to nonfinancial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis until our fiscal year beginning January 1, 2009, as permitted by FASB ASC 820-10-15-1A (FSP No. SFAS 157-2). The application of FASB ASC 820 to nonfinancial assets and liabilities on January 1, 2009 did not have an impact on our condensed consolidated financial statements as of September 30, 2009.

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

Level 1 Quoted prices for identical instruments in active markets.

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

Level 3 Instruments whose significant value drivers are unobservable.

Our investment in marketable securities at September 30, 2009 that are classified as available for sale comprise a United Kingdom treasury bill with a six month maturity, which was valued using quoted prices in active markets that are considered Level 1 inputs. The fair value of our marketable securities at September 30, 2009 was $5.0 million and had a cumulative unrealized gain reflected in partners capital of $0.4 million at September 30, 2009.

The carrying amounts for accounts receivable and accounts payable approximate fair value because of the short maturity of those instruments. At September 30, 2009 and December 31, 2008, the estimated fair value of our fixed rate term debt, including current maturities, was approximately $454.3 million and $362.8 million, respectively, based on interest rates that we believe are currently available to us for issuance of debt with similar terms and remaining maturities (see Note 6).

6. LONG-TERM DEBT

On September 30, 2009, our Intermediate Partnership entered into Amendment No. 2 (the Credit Amendment) to its Second Amended and Restated Credit Agreement (the ARLP Credit Facility) dated September 25, 2007.

The Credit Amendment increases the annual capital expenditure limits under the ARLP Credit Facility. The new limits are $425.0 million for 2009, $375.0 million for 2010, $350.0 million for 2011 and $250.0 million for 2012. The amount of any annual limit in excess of actual capital expenditures for that year carries forward and is added to the annual limit of the subsequent year.

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Pursuant to the Credit Amendment, the applicable margin for London Interbank Offered Rate borrowings under the ARLP Credit Facility is increased from a range of 0.625% to 1.150% (depending on the Intermediate Partnership s leverage margin) to a range of 1.115% to 2.000%, and the annual commitment fee is increased from a range of 0.15% to 0.35% (also depending on the Intermediate Partnership s leverage margin) to a range of 0.25% to 0.50%. In addition, the Credit Amendment includes certain changes relating to a defaulting lender , including changes which clarify that the overall ARLP Credit Facility commitment would be reduced by the commitment share of a defaulting lender but also provide our Intermediate Partnership with more flexibility in replacing a defaulting lender.

At September 30, 2009, we had no borrowings and $13.9 million of letters of credit outstanding under the ARLP Credit Facility.

In addition to limitations on our maximum annual capital expenditures, the ARLP Credit Facility, Senior Notes and 2008 Senior Notes require our Intermediate Partnership to maintain (i) a minimum debt to cash flow ratio of not more than 3.0 to 1.0 and (ii) a ratio of cash flow to interest expense of not less than 4.0 to 1.0, in each case during the four most recently ended fiscal quarters. The Credit Amendment did not change these requirements. We were in compliance with all covenants as of September 30, 2009.

7. NET INCOME OF ARLP PER LIMITED PARTNER UNIT

On January 1, 2009, we adopted FASB ASC 260-10-55-102 through 55-110 (EITF No. 07-4), which considers whether the IDR of a master limited partnership represents a participating security when considered in the calculation of earnings per unit under the two-class method. FASB ASC 260-10-55-102 through 55-110 also considers whether the partnership agreement contains any contractual limitations concerning distributions to IDR holders that would impact the amount of earnings to allocate to the IDR holders for each reporting period. If distributions are contractually limited to the IDR holders share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the IDR holders. Our partnership agreement contractually limits our distributions to available cash and therefore, undistributed earnings are no longer allocated to the IDR holder. Accordingly, the adoption impacts our presentation of earnings per unit in periods when Net Income of ARLP exceeds the aggregate distributions because undistributed earnings are no longer allocated to the IDR holder.

Also, on January 1, 2009, we adopted the provisions of FASB ASC 260-10-55-25 (FASB FSP No. EITF No. 03-6-1), which affects entities that accrue cash dividends on share-based payment awards during the awards service period when the dividends are not required to be returned if the employees forfeit the award. Outstanding unvested share-based payment awards that contain rights to nonforfeitable dividends participate in undistributed earnings with common shareholders and are considered participating securities. Because the awards are considered participating securities, the issuing entity is required to apply the two-class method of computing basic and diluted earnings per share. We now include an allocation of undistributed and distributed earnings to outstanding unvested awards under our Long-Term Incentive Plan (LTIP) (Note 9) in the calculation of our basic earnings per unit.

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The following is a reconciliation of Net Income of ARLP and net income used for calculating basic earnings per unit and the weighted average units used in computing basic and diluted earnings per unit with retrospective application for the three and nine months ended September 30, 2009 and 2008, respectively, (in thousands, except per unit data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net Income of ARLP	$ 36,444	$ 29,136	$ 150,415	$ 108,996
Adjustments:				
General partner s priority distributions	(14,758)	(12,587)	(42,658)	(32,201)
General partners 2% equity ownership	(434)	(360)	(2,155)	(1,565)
General partners special allocation of certain general and administrative expenses		1,435		1,435
Limited partners interest in Net Income of ARLP	21,252	17,624	105,602	76,665
Less:				
Distributions on LTIP awards outstanding	(253)	(271)	(744)	(585)
Undistributed earnings attributable to LTIP awards			(212)	(35)
Net Income of ARLP available to limited partners	$ 20,999	$ 17,353	$ 104,646	$ 76,045
Weighted average limited partner units outstanding	36,661	36,613	36,654	36,602
Basic Net Income of ARLP per limited partner unit	$ 0.57	$ 0.47	$ 2.85	$ 2.08
Weighted average limited partner units basic	36,661	36,613	36,654	36,602
Dilutive units:				
Directors compensation phantom units				4
Supplemental Executive Retirement Plan phantom units				9
Weighted average limited partner units, assuming dilutive effect of contingently issuable units (1)	36,661	36,613	36,654	36,615
Diluted Net Income of ARLP per limited partner unit	$ 0.57	$ 0.47	$ 2.85	$ 2.08

(1) Diluted earnings per unit give effect to all dilutive potential common units outstanding during the period using the treasury stock method. Dilutive earnings per unit exclude all dilutive potential units calculated under the treasury stock method if their effect is anti-dilutive. For the three and nine months ended September 30, 2009 and 2008, LTIP units of 184,115, 147,834, 157,829 and 136,720, respectively, were considered anti-dilutive.

Net Income of ARLP is allocated to the general partners and limited partners in accordance with their respective partnership percentages, after giving effect to any special income allocations, including incentive distributions to our managing general partner, the holder of the IDR, which are declared and paid following the close of each quarter. Under the quarterly IDR provisions of our partnership agreement, our managing general partner is entitled to receive 15% of the amount we distribute in excess of $0.275 per unit, 25% of the amount we distribute in excess of $0.3125 per unit, and 50% of the amount we distribute in excess of $0.375 per unit.

On January 29, 2008 the compensation committee of the Board of Directors (Compensation Committee) approved amendments to the Deferred Compensation Plan for Directors and Supplemental Executive Retirement Plan to eliminate the option of settling awards in common units of ARLP and require that vested benefits be paid to participants in cash only. As a result, the

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phantom units associated with these plans are no longer considered in the calculation of diluted units effective January 29, 2008. The non-vested LTIP grants associated with the LTIP Plan continue to entitle the LTIP participants to receive ARLP common units and accordingly are included in the calculation of basic and diluted units (to the extent of dilution).

FASB ASC 260-10-65-1 and 65-2 requires retrospective application of FASB ASC 260-10-55-102 through 55-110 and 260-10-55-25. The following is a reconciliation of basic and diluted Net Income of ARLP per limited partner unit as presented in the prior period for the three and nine months ended September 30, 2008:

	Basic		Dilutive	
	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2008	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2008
Basic and diluted Net Income of ARLP per limited partners unit as previously reported	$ 0.48	$ 2.04	$ 0.48	$ 2.03
Effect of the adoption of FASB ASC 260-10-55-102 through 55-110 (EITF No. 07-4) on basic and diluted Net Income of ARLP per limited partner unit		0.05		0.06
Effect of the adoption of FASB ASC 260-10-55-25 (FSP No. EITF No. 03-6-1) on basic and diluted Net Income of ARLP per limited partner unit	(0.01)	(0.01)	(0.01)	(0.01)
Basic and diluted Net Income of ARLP per limited partner unit as presented	$ 0.47	$ 2.08	$ 0.47	$ 2.08

8. WORKERS COMPENSATION

The changes in the workers compensation liability (including current and long-term liability balances) for each of the periods presented were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Beginning balance	$ 63,082	$ 54,243	$ 56,671	$ 51,619
Accruals increase/decrease	4,703	4,116	13,850	12,316
Payments	(3,459)	(3,015)	(9,412)	(8,944)
Interest accretion	864	765	2,592	2,295
Valuation changes (gain)/loss	3,193	(2,132)	4,682	(3,309)
Ending balance	$ 68,383	$ 53,977	$ 68,383	$ 53,977

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9. COMPENSATION PLANS

We have the LTIP for certain employees and officers of our managing general partner and its affiliates who perform services for us. The LTIP awards are grants of non-vested notional units, which upon satisfaction of vesting requirements entitle the LTIP participant to receive ARLP common units. On January 27, 2009, the Compensation Committee determined that the vesting requirements for the 2006 grants of 71,975 units (which is net of 18,725 forfeitures) had been satisfied as of January 1, 2009. As a result of this vesting, on February 12, 2009, we issued 47,571 unrestricted common units to LTIP participants. The remaining units were settled in cash to satisfy the individual tax withholding obligations for the LTIP participants. On January 29, 2008 and October 28, 2008, the Compensation Committee authorized additional grants up to 100,000 and 152,445 units, respectively of which 93,600 and 141,145 units had been granted as of December 31, 2008 and will vest January 1, 2011 and 2012, respectively subject to satisfaction of certain financial tests. During the nine months ended September 30, 2009, LTIP grants were made of 9,625 units, all of which will vest on January 1, 2012 subject to satisfaction of certain financial tests. The fair value of these 2009 grants is equal to the intrinsic value at the date of grant, which was $25.60 per unit on a weighted average basis. LTIP expense was $0.9 million, $0.7 million, $2.7 million and $2.2 million, for the three and nine months ended September 30, 2009 and 2008, respectively. As of September 30, 2009, the outstanding unvested LTIP grants exceeded the units available for issuance under the LTIP by 1,705 units. However, reloading of units available for awards as a result of settlement of a portion of outstanding awards in cash to satisfy tax withholding obligations, as provided in the LTIP, will provide sufficient units to fulfill all outstanding awards. In addition, on October 23, 2009, our unitholders approved the Third Amendment (Third Amendment) to the Amended and Restated Alliance Coal, LLC Long-Term Incentive Plan (See Note 14). The Third Amendment was previously authorized by the Board of Directors, subject to unitholder approval. The Third Amendment increased the number of units available for issuance under the LTIP from 1.2 million to 3.6 million, providing 2.4 million units for satisfaction of future awards.

As of September 30, 2009, there was $4.5 million in total unrecognized compensation expense related to the non-vested LTIP grants that are expected to vest. That expense is expected to be recognized over a weighted-average period of 1.4 years. As of September 30, 2009, the intrinsic value of the non-vested LTIP grants was $12.1 million. As of September 30, 2009, the total obligation associated with the LTIP was $5.9 million and is included in the partners capital-limited partners line item in our condensed consolidated balance sheets.

As provided under the distribution equivalent rights provisions of the LTIP, all non-vested grants include contingent rights to receive quarterly cash distributions in an amount equal to the cash distributions we make to unitholders during the vesting period.

10. COMPONENTS OF PENSION PLAN NET PERIODIC BENEFIT COSTS

Employees at certain of our mining operations participate in a defined benefit plan (the Pension Plan) that we sponsor. The benefit formula for the Pension Plan is a fixed dollar unit based on years of service. Effective during 2008, new employees of these participating operations are no longer eligible to participate in the Pension Plan, but are eligible to participate in a defined contribution profit sharing and savings plan (PSSP) that we sponsor. Additionally, certain employees participating in the Pension Plan, for some of those participating operations, had the one-time option during 2008 to remain in the Pension Plan or participate in enhanced benefit provisions under the PSSP. Components of the net periodic benefit cost for each of the periods presented are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Service cost	$ 667	$ 655	$ 2,001	$ 2,062
Interest cost	755	682	2,264	1,987
Expected return on plan assets	(608)	(842)	(1,824)	(2,601)
Amortization of actuarial loss	355		1,066	
Net periodic benefit cost	$ 1,169	$ 495	$ 3,507	$ 1,448

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We previously disclosed in our financial statements for the year ended December 31, 2008 that we expected to contribute $10.6 million to the Pension Plan in 2009 for the 2008 plan year. Based upon guidance recently issued by the Internal Revenue Service regarding determination of pension plan liabilities, we have elected to not contribute to the Pension Plan in 2009 for the 2008 plan year. During the nine months ended September 30, 2009, we made contribution payments of $1.5 million for the 2009 plan year.

11. COMPREHENSIVE INCOME

Total comprehensive income for the three and nine months ended September 30, 2009 and 2008, respectively (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income	$ 36,497	$ 29,289	$ 150,647	$ 109,392
Other comprehensive income:				
Unrealized (loss) gain on marketable securities	(142)		425	
Pension (Note 10)	355		1,066	
Total other comprehensive income	213		1,491	
Total comprehensive income	36,710	29,289	152,138	109,392
Less comprehensive income attributable to noncontrolling interest	(53)	(153)	(232)	(396)
Comprehensive income attributable to ARLP	$ 36,657	$ 29,136	$ 151,906	$ 108,996

Comprehensive income differs from net income due to an unrealized gain on our available for sale marketable securities resulting from valuation changes and amortization of actuarial loss associated with adoption of amendments to FASB ASC 715, *Compensation Retirement Benefits* (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))*, issued by the FASB in September 2006.

12. SEGMENT INFORMATION

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

The Illinois Basin segment is comprised of Webster County Coal s Dotiki mining complex, Gibson County Coal, LLC s Gibson North mining complex, Hopkins County Coal s Elk Creek mining complex, White County Coal, LLC s (White County Coal) Pattiki mining complex, Warrior s mining complex, River View Coal, LLC s newly constructed mining complex, which recently initiated operations, the Gibson County Coal (South), LLC (Gibson South) property and certain properties of Alliance Resource Properties. We are in the process of permitting the Gibson South property for future mine development.

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

The Northern Appalachian segment is comprised of Mettiki Coal, LLC s mining complex, Mettiki Coal (WV) LLC s Mountain View mining complex, two small third-party mining operations (one of which was idled in May 2009), a mining complex currently under construction at Tunnel Ridge, LLC and the Penn Ridge Coal, LLC (Penn Ridge) property. We are in the process of permitting the Penn Ridge property for future mine development.

Other and Corporate includes marketing and administrative expenses, Matrix Design Group, LLC (Matrix Design), Alliance Design Group, LLC (Alliance Design), the Mt. Vernon Transfer Terminal, LLC (Mt. Vernon) dock activities, coal brokerage activity, Mid-America Carbonates, LLC (MAC) and certain properties of Alliance Resource Properties.

Segment results for the three and nine months ended September 30, 2009 and 2008 are presented below:

	Illinois Basin	Central Appalachia	Northern Appalachia	Other and Corporate	Elimination (1)	Consolidated
			(in thousands)			
Operating segment results for the three months ended September 30, 2009:						
Total revenues (2)	$ 217,128	$ 41,401	$ 36,041	$ 9,489	$ (4,415)	$ 299,644
Segment Adjusted EBITDA Expense (3)	137,579	34,839	30,650	6,298	(4,135)	205,231
Segment Adjusted EBITDA (4)	70,090	6,517	3,234	3,189	(280)	82,750
Capital expenditures	54,274	3,845	17,589	1,060		76,768
Operating segment results for the three months ended September 30, 2008:						
Total revenues (2)	$ 181,276	$ 49,836	$ 51,262	$ 5,508	$ (2,092)	$ 285,790
Segment Adjusted EBITDA Expense (3)	128,186	38,846	37,284	3,843	(2,074)	206,085
Segment Adjusted EBITDA (4)	45,068	10,998	10,270	1,666	(18)	67,984
Capital expenditures (5)	39,232	5,086	6,162	1,457		51,937
Operating segment results for the nine months ended September 30, 2009:						
Total revenues (2)	$ 675,441	$ 137,739	$ 106,898	$ 27,430	$ (14,660)	$ 932,848
Segment Adjusted EBITDA Expense (3)	410,103	106,784	88,934	19,325	(14,298)	610,848
Segment Adjusted EBITDA (4)	237,860	29,486	11,571	8,098	(362)	286,653
Total assets	684,823	90,141	178,259	117,334	(119)	1,070,438
Capital expenditures	186,678	11,555	49,910	3,310		251,453
Operating segment results for the nine months ended September 30, 2008:						
Total revenues (2)	$ 549,831	$ 151,898	$ 136,015	$ 14,628	$ (6,770)	$ 845,602
Segment Adjusted EBITDA Expense (3)	376,707	115,594	99,133	12,390	(6,770)	597,054
Segment Adjusted EBITDA (4)	149,824	39,047	26,881	7,397		223,149
Total assets	531,487	96,761	133,056	285,731	(122)	1,046,913
Capital expenditures (5)	99,223	9,004	11,826	2,834		122,887

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

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(2) Revenues included in the Other and Corporate column are primarily attributable to Matrix Design revenues, Alliance Design revenues, Mt. Vernon transloading revenues, administrative service revenues from affiliates, MAC rock dust revenues and brokerage sales (nine months ended September 30, 2009 only).

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Segment Adjusted EBITDA Expense	$ 205,231	$ 206,085	$ 610,848	$ 597,054
Outside coal purchases	(517)	(6,995)	(5,709)	(14,450)
Other income	126	231	554	698
Operating expenses (excluding depreciation, depletion and amortization)	$ 204,840	$ 199,321	$ 605,693	$ 583,302

(4) Segment Adjusted EBITDA is defined as net income before net interest expense, income taxes, depreciation, depletion and amortization, net income attributable to noncontrolling interest and general and administrative expenses. Consolidated Segment Adjusted EBITDA is reconciled to net income and Net Income of ARLP below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Segment Adjusted EBITDA	$ 82,750	$ 67,984	$ 286,653	$ 223,149
General and administrative	(9,959)	(7,184)	(29,000)	(28,134)
Depreciation, depletion and amortization	(28,145)	(25,403)	(83,767)	(74,297)
Interest expense, net	(7,563)	(6,016)	(22,428)	(11,959)
Income tax (expense) benefit	(586)	(92)	(811)	633
Net income	36,497	29,289	150,647	109,392
Net income attributable to noncontrolling interest	(53)	(153)	(232)	(396)
Net Income of ARLP	$ 36,444	$ 29,136	$ 150,415	$ 108,996

(5) Capital expenditures for the three and nine months ended September 30, 2008 do not include acquisition of coal reserves and other assets in the Illinois Basin of $16.5 million and $29.8 million, respectively, separately reported in our condensed consolidated statements of cash flows.

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13. NONCONTROLLING INTEREST

On January 1, 2009, we adopted FASB ASC 810-10-65 and FASB ASC 810-10-45-16 (SFAS No. 160), which establishes accounting and reporting standards for noncontrolling ownership interests in subsidiaries. Noncontrolling ownership interest in consolidated subsidiaries is presented in the consolidated balance sheet within partners capital as a separate component from the parent s equity. Consolidated net income now includes earnings attributable to both the parent and the noncontrolling interests. Earnings per unit is based on earnings attributable to only the parent company and did not change upon adoption. In addition, FASB ASC 810-10-65 provides guidance on accounting for changes in the parent s ownership interest in a subsidiary, including transactions where control is retained and where control is relinquished and requires additional disclosure of information related to amounts attributable to the parent for income from continuing operations, discontinued operations, extraordinary items and reconciliations of the parent and noncontrolling interests equity of a subsidiary. The provisions are applied prospectively to transactions involving noncontrolling interests, including noncontrolling interests that arose prior to the effective date, as of the beginning of 2009, the year of adoption. However, the presentation of noncontrolling interests within partners capital and the inclusion of earnings attributable to the noncontrolling interests in consolidated net income requires retrospective application to all periods presented.

The noncontrolling interest designated as MAC represents a 50% third-party interest in MAC. White County Coal entered into a limited liability company agreement with a third-party in 2006 to form MAC, which manufactures and sells rock dust. We consolidate MAC s financial results in accordance with FASB ASC 810, *Consolidation* (FIN No. 46R, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51)*. Based on the guidance in FASB ASC 810, we concluded that MAC is a VIE and we are the primary beneficiary. Effective January 1, 2010, we will adopt the amendments to FASB ASC 810*, Consolidation* (SFAS No. 167), issued in June 2009, and we are currently evaluating the amendments impact, if any, on MAC (Note 2).

The following tables present the change in partners capital with retrospective application due to the adoption of FASB ASC 810-10-65 for the nine months ended September 30, 2009 and 2008 (in thousands):

	Alliance Resource Partners, L.P.				
	Limited Partners Capital	General Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Partners Capital
January 1, 2009	$ 604,998	$ (295,834)	$ (19,899)	$ 927	$ 290,192
Net income	105,602	44,813		232	150,647
Other comprehensive income			1,491		1,491
Vesting of Long-Term Incentive Plan	(791)				(791)
Common unit-based compensation under Long-Term Incentive Plan	2,676				2,676
General Partners contribution		31			31
Distributions on common unit-based compensation	(773)				(773)
Distributions paid to Partners	(80,254)	(42,662)			(122,916)
Balance at September 30, 2009	$ 631,458	$ (293,652)	$ (18,408)	$ 1,159	$ 320,557

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	Alliance Resource Partners, L.P.				
	Limited Partners Capital	General Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Partners Capital
January 1, 2008	$ 607,777	$ (290,669)	$ 109	$ 507	$ 317,724
Net income	76,665	32,331		396	109,392
Vesting of Long-Term Incentive Plan	(1,181)				(1,181)
Common unit-based compensation under Long-Term Incentive Plan	2,234				2,234
Common control acquisitions		(9,809)			(9,809)
General Partners contribution		1,486			1,486
Distributions on common unit-based compensation	(517)				(517)
Distributions paid to Partners	(66,966)	(29,429)			(96,395)
Balance at September 30, 2008	$ 618,012	$ (296,090)	$ 109	$ 903	$ 322,934

14. SUBSEQUENT EVENTS

On October 28, 2009, we declared a quarterly distribution for the quarter ended September 30, 2009, of $0.76 per unit, on all common units outstanding, totaling approximately $43.2 million (which includes our managing general partner s incentive distributions), payable on November 13, 2009 to all unitholders of record as of November 6, 2009.

On October 23, 2009, our unitholders approved the Third Amendment. This Amendment was previously authorized by the Board of Directors, subject to unitholder approval, and increased the number of units available for issuance under the LTIP from 1.2 million to 3.6 million, providing 2.4 million units for satisfaction of future awards.

Subsequent events have been evaluated through November 6, 2009, the issuance date of the financial statements.

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ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Significant relationships referenced in this management s discussion and analysis of financial condition and results of operations include the following:

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

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

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

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

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

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

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

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

Summary

We are a diversified producer and marketer of coal primarily to major U.S. utilities and industrial users. We began mining operations in 1971 and, since then, have grown through acquisitions and internal development to become what we believe to be the fifth largest coal producer in the eastern U.S. We operate eight mining complexes in Illinois, Indiana, Kentucky, Maryland and West Virginia. We recently initiated operations at a newly constructed mining complex in Kentucky which is now our ninth mining complex and are constructing a new mining complex in West Virginia. We also operate a coal loading terminal on the Ohio River at Mt. Vernon, Indiana. As is customary in the coal industry, we have entered into long-term coal supply agreements with many of our customers.

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

Illinois Basin segment is comprised of Webster County Coal, LLC s Dotiki mining complex, Gibson County Coal, LLC s Gibson North mining complex, Hopkins County Coal LLC s Elk Creek mining complex, White County Coal LLC s (White County Coal) Pattiki mine and Warrior Coal, LLC s (Warrior) mining complex, River View Coal, LLC s (River View) newly constructed mining complex which recently initiated operations, the Gibson County Coal (South), LLC (Gibson South) property and certain properties of Alliance Resource Properties, LLC (Alliance Resource Properties). We are in the process of permitting the Gibson South property for future mine development.

Central Appalachian segment is comprised of Pontiki Coal, LLC s and MC Mining, LLC s mining complexes.

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Northern Appalachian segment is comprised of Mettiki Coal, LLC s mining complex, Mettiki Coal (WV) LLC s Mountain View mining complex, two small third-party mining operations (one of which was idled in May 2009), a mining complex currently under construction at Tunnel Ridge, LLC (Tunnel Ridge) and the Penn Ridge Coal, LLC (Penn Ridge) property. We are in the process of permitting the Penn Ridge property for future mine development.

Other and Corporate segment includes marketing and administrative expenses, Matrix Design Group, LLC (Matrix Design), Alliance Design Group, LLC (Alliance Design), the Mt. Vernon Transfer Terminal LLC (Mt. Vernon) dock activities, coal brokerage activity, Mid-America Carbonates, LLC (MAC) and certain properties of Alliance Resource Properties.

Overview

On a macro level, although some segments of the U.S. economy are beginning to show signs of stability, growth in general remains elusive and electric power generation continues to be constrained. This weakness is evident in the following statistics reported in October 2009 by the Energy Information Administration (EIA) for the twelve months ended July 2009:

Net electricity generation in the U.S. dropped 7.6 percent.

Industrial production fell 13.1 percent.

Low prices continued to benefit natural gas-fired generation, which showed the largest absolute fuel specific increase.

In contrast, the drop in coal-fired generation was the largest absolute fuel specific decline falling 15 percent during this period. Reflecting these factors, utility coal stock piles have continued to climb, with current levels well above historical averages and representing an estimated 70 days of consumption and we believe the overhang in customer inventories is likely to continue into the first half of 2010.

Despite near-term challenges, we strengthened our long-term contract position and have secured commitments and pricing for substantially all of ARLP s remaining 2009 production, approximately 90% to 95% of currently estimated 2010 production and approximately 80% to 85% of currently estimated production for 2011. We also continue to see encouraging long-term indicators and remain positive on the future of coal. For 2010, industrial and power demand is likely to increase with improved economic activity and the EIA is forecasting coal demand will likely climb 2% as power demand recovers and natural gas prices edge up from 2009 lows.

Longer term, coal remains the fastest growing fuel source worldwide and the International Energy Agency expects global demand for coal to outpace the combined growth in demand for natural gas, nuclear, hydro, wind and solar through 2025. In the U.S., power generators continue to install scrubber technology on existing facilities and approximately 19 gigawatts of new coal-fired electricity generation capacity is progressing toward commercial operation. We believe anticipated higher coal demand, coupled with significant reductions in coal production from economic, regulatory and legislative pressures, are setting the stage for potential coal supply shortages over the next few years.

Results of Operations

Comparison of our operating results for the nine months ended September 30, 2009 (2009 Period) and September 30, 2008 (2008 Period) is affected by the following significant items:

Gain on sale of non-core coal reserves of $5.2 million in the 2008 Period;

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Gain of $2.8 million on settlement of claims against the third-party that provided security services at the time of the December 2004 MC Mining mine fire (MC Mining Fire Incident) was recognized in the 2008 Period; and

Gain of $1.9 million on settlement of claims relating to the 2005 failure of the vertical belt system (the Vertical Belt Incident) at our Pattiki mine in the 2008 Period recorded as a reduction to operating expenses. The 2008 Period gain resulted from a settlement reached with the third-party installer of the vertical belt system and represents a partial recovery of expenses incurred in 2005.

Three Months Ended September 30, 2009 Compared to Three Months Ended September 30, 2008

We reported Net Income of ARLP of $36.4 million for the three months ended September 30, 2009 (2009 Quarter) compared to $29.1 million for the three months ended September 30, 2008 (2008 Quarter). This increase of $7.3 million was principally due to improved contract pricing resulting in an average coal sales price of $45.58 per ton sold, as compared to $40.79 per ton sold for the 2008 Quarter. We sold 6.2 million tons and produced 6.3 million tons in the 2009 Quarter, compared to 6.6 million tons sold and produced in the 2008 Quarter. Unplanned customer outages, contractual deferrals and weak spot market demand continued to impact coal sales and production volumes in the 2009 Quarter as compared to the 2008 Quarter. Increased operating expenses (excluding outside coal purchases) during the 2009 Quarter primarily reflect the increase in labor and labor-related expenses, as well as higher sales-related expenses, and other factors described below.

	Three Months Ended September 30,			
	2009	2008	2009	2008
	(in thousands)		(per ton sold)	
Tons sold	6,179	6,603	N/A	N/A
Tons produced	6,304	6,561	N/A	N/A
Coal sales	$ 281,628	$ 269,318	$ 45.58	$ 40.79
Operating expenses and outside coal purchases	$ 205,357	$ 206,316	$ 33.23	$ 31.25

Coal sales. Coal sales for the 2009 Quarter increased 4.6% to $281.6 million from $269.3 million for the 2008 Quarter. The increase of $12.3 million in coal sales reflected the benefit of higher average coal sales prices (contributing $29.6 million in additional coal sales) partially offset by lower sales volumes due to unplanned customer outages, contractual deferrals and weak spot market demand (reducing coal sales by $17.3 million). Average coal sales prices increased $4.79 per ton sold to $45.58 per ton in the 2009 Quarter compared to the 2008 Quarter, primarily as a result of improved contract pricing in the Illinois Basin and Central Appalachian regions.

Operating expenses. Operating expenses increased 2.8% to $204.8 million for the 2009 Quarter from $199.3 million for the 2008 Quarter. Higher operating expenses of $5.5 million resulted from the specific factors listed below:

Labor and benefit expenses per ton produced, excluding workers compensation, increased 14.6% to $11.04 per ton in the 2009 Quarter from $9.63 per ton in the 2008 Quarter. This increase of $1.41 per ton represents pay rate increases and higher benefit expenses, primarily increased health care costs and retirement expenses, and the impact of increased headcount as we continue to hire and train new employees for the River View and Tunnel Ridge mine development projects;

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Workers compensation expenses per ton produced increased to $1.64 per ton in the 2009 Quarter from $0.56 per ton in the 2008 Quarter. The increase of $1.08 per ton produced primarily reflected a non-cash charge during the 2009 Quarter and a non-cash benefit during the 2008 Quarter that both resulted from discount rate changes, which increased and decreased, respectively, the accrued liabilities for the present value of estimated future claim payments;

Material and supplies per ton produced decreased 8.3% to $9.59 per ton in the 2009 Quarter from $10.46 per ton in the 2008 Quarter. The decrease of $0.87 per ton produced resulted from decreased costs for certain products and services, primarily roof support (decrease of $0.64 per ton), seals (decrease of $0.16 per ton), fuel used in the mining process (decrease of $0.14 per ton) and outside services (decrease of $0.10 per ton), offset partially by increased costs per ton in various other categories;

Maintenance expenses per ton produced increased 2.0% to $3.55 per ton in the 2009 Quarter from $3.48 per ton in the 2008 Quarter. The increase of $0.07 per ton produced resulted primarily from higher repair costs related to longwall equipment;

Mine administration expenses decreased $1.9 million for the 2009 Quarter compared to the 2008 Quarter, primarily as a result of lower estimated regulatory costs;

Contract mining expenses decreased $2.9 million for the 2009 Quarter compared to the 2008 Quarter. The decrease reflects a curtailment of third-party mining operations in our Northern Appalachian segment in response to weak demand in export and spot coal markets;

Production taxes and royalties expenses (which were incurred as a percentage of coal sales and coal volumes) increased $0.39 per produced tons sold in the 2009 Quarter compared to the 2008 Quarter primarily as a result of increased average coal sales prices;

Operating expenses increased due to higher beginning coal inventory cost per ton of $35.76 for 915,000 tons in the 2009 Quarter compared to $33.45 per ton for 341,000 tons in the 2008 Quarter;

Operating expenses decreased due to a 281,000 ton reduction in produced tons sold reflecting unplanned customer outages, contractual deferrals and lower export and spot market demand; and

Operating expenses incurred during the 2009 Quarter related to our River View and Tunnel Ridge mine development projects increased $2.3 million over the 2008 Quarter. These expenses are generally included in the variances discussed above.

General and administrative. General and administrative expenses for the 2009 Quarter increased to $10.0 million compared to $7.2 million in the 2008 Quarter. The increase of $2.8 million was primarily due to higher unit-based incentive compensation expense.

Other sales and operating revenues. Other sales and operating revenues are principally comprised of Mt. Vernon transloading revenues, products and services provided by MAC and Matrix Design, and other outside services and administrative services revenue from affiliates. Other sales and operating revenues increased to $6.4 million for the 2009 Quarter from $4.8 million for the 2008 Quarter. The increase of $1.6 million was primarily attributable to increased Matrix Design product sales and Mt. Vernon transloading revenues partially offset by decreases in other outside services and MAC product sales.

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Outside coal purchases. Outside coal purchases decreased to $0.5 million for the 2009 Quarter compared to $7.0 million in the 2008 Quarter. The decrease of $6.5 million was primarily attributable to a decrease in outside coal purchases at our Central and Northern Appalachian regions due to reduced demand in the spot and export coal markets.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased to $28.1 million for the 2009 Quarter from $25.4 million for the 2008 Quarter. The increase of $2.7 million was primarily attributable to additional depreciation expense associated with continuing capital expenditures related to infrastructure improvements, efficiency projects and expansion of production capacity.

Interest expense. Interest expense, net of capitalized interest decreased to $7.7 million for the 2009 Quarter from $8.1 million for the 2008 Quarter. The decrease of $0.4 million was principally attributable to reduced interest expense resulting from our August 2009 principal repayment of $18.0 million on our original senior notes issued in 1999.

Interest income. Interest income decreased to $0.1 million for the 2009 Quarter compared to $2.1 million for the 2008 Quarter. The decrease of $2.0 million resulted from a decrease in short-term investments, which were originally purchased with proceeds from the $350 million private placement of senior notes received in June 2008 discussed in more detail below under -Debt Obligations. Short-term investments are lower in the 2009 Quarter due to increased capital expenditures for the 2009 Period discussed in more detail below under -Capital Expenditures.

Transportation revenues and expenses. Transportation revenues and expenses were $11.7 million each for the 2009 and 2008 Quarters. The cost of transportation services are passed through to our customers. Consequently, we do not realize any gain or loss on transportation revenues.

Income tax expense (benefit). Income tax expense increased to $0.6 million for the 2009 Quarter compared to $0.1 million for the 2008 Quarter, primarily due to increased operating income of Matrix Design, which is owned by our subsidiary, Alliance Services, Inc. (ASI).

Net income attributable to noncontrolling interest. The noncontrolling interest represents a 50% third-party interest in MAC. The third-party s portion of MAC s net income was $0.1 million and $0.2 million for the 2009 and 2008 Quarters, respectively**.** For more information about MAC, please read Item 1. Financial Statements (Unaudited) Note 13. Noncontrolling Interest of this Quarterly Report on Form 10-Q.

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Segment Adjusted EBITDA. Our 2009 Quarter Segment Adjusted EBITDA increased $14.8 million, or 21.7%, to $82.8 million from the 2008 Quarter Segment Adjusted EBITDA of $68.0 million. Segment Adjusted EBITDA, tons sold, coal sales, other sales and operating revenues and Segment Adjusted EBITDA Expense by segment are (in thousands):

	Three Months Ended September 30,			
	2009	2008	Increase/(Decrease)	
Segment Adjusted EBITDA				
Illinois Basin	$ 70,090	$ 45,068	$ 25,022	55.5%
Central Appalachia	6,517	10,998	(4,481)	(40.7)%
Northern Appalachia	3,234	10,270	(7,036)	(68.5)%
Other and Corporate	3,189	1,666	1,523	91.4%
Elimination	(280)	(18)	(262)	(1)
Total Segment Adjusted EBITDA (2)	$ 82,750	$ 67,984	$ 14,766	21.7%
Tons sold				
Illinois Basin	4,925	4,934	(9)	(0.2)%
Central Appalachia	604	810	(206)	(25.4)%
Northern Appalachia	650	859	(209)	(24.3)%
Other and Corporate				
Elimination				
Total tons sold	6,179	6,603	(424)	(6.4)%
Coal sales				
Illinois Basin	$ 207,410	$ 173,096	$ 34,314	19.8%
Central Appalachia	41,357	49,829	(8,472)	(17.0)%
Northern Appalachia	32,861	46,393	(13,532)	(29.2)%
Other and Corporate				
Elimination				
Total coal sales	$ 281,628	$ 269,318	$ 12,310	4.6%
Other sales and operating revenues				
Illinois Basin	$ 257	$ 158	$ 99	62.7%
Central Appalachia		15	(15)	(1)
Northern Appalachia	1,024	1,161	(137)	(11.8)%
Other and Corporate	9,487	5,508	3,979	72.2%
Elimination	(4,415)	(2,091)	(2,324)	(1)
Total other sales and operating revenues	$ 6,353	$ 4,751	$ 1,602	33.7%
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 137,579	$ 128,186	$ 9,393	7.3%
Central Appalachia	34,839	38,846	(4,007)	(10.3)%
Northern Appalachia	30,650	37,284	(6,634)	(17.8)%
Other and Corporate	6,298	3,843	2,455	63.9%
Elimination	(4,135)	(2,074)	(2,061)	(99.4)%
Total Segment Adjusted EBITDA Expense (3)	$ 205,231	$ 206,085	$ (854)	(0.4)%

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

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

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

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

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

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

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

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

	Three Months Ended September 30,	
	2009	2008
Segment Adjusted EBITDA	$ 82,750	$ 67,984
General and administrative	(9,959)	(7,184)
Depreciation, depletion and amortization	(28,145)	(25,403)
Interest expense, net	(7,563)	(6,016)
Income tax expense	(586)	(92)
Net income	$ 36,497	$ 29,289
Net income attributable to noncontrolling interest	(53)	(153)
Net Income of ARLP	$ 36,444	$ 29,136

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

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

	Three Months Ended September 30,	
	2009	2008
Segment Adjusted EBITDA Expense	$ 205,231	$ 206,085
Outside coal purchases	(517)	(6,995)
Other income	126	231
Operating expense (excluding depreciation, depletion and amortization)	$ 204,840	$ 199,321

Illinois Basin Segment Adjusted EBITDA increased 55.5% to $70.1 million in the 2009 Quarter from $45.1 million in the 2008 Quarter. The increase of $25.0 million was primarily attributable to improved contract pricing reflecting a higher average coal sales price of $42.11 per ton during the 2009 Quarter compared to $35.08 per ton for the 2008 Quarter. Coal sales increased 19.8% to $207.4 million in the 2009 Quarter compared to $173.1 million in the 2008 Quarter. The increase of $34.3 million was partially offset by higher Segment Adjusted EBITDA Expense in the 2009 Quarter. Total Segment Adjusted EBITDA Expense for the 2009 Quarter increased 7.3% to $137.6 million from $128.2 million in the 2008 Quarter, primarily as a result of certain cost increases described above under consolidated operating expenses. On a per ton sold basis, Segment Adjusted EBITDA Expense for the 2009 Quarter increased $1.95 to $27.93 per ton compared to the 2008 Quarter Segment Adjusted EBITDA Expense of $25.98 per ton.

Central Appalachia Segment Adjusted EBITDA decreased 40.7% to $6.5 million for the 2009 Quarter compared to $11.0 million in the 2008 Quarter. The decrease of $4.5 million was primarily the result of lower sales volumes due to unplanned customer outages, weak coal demand in the spot market and higher expenses per ton during the 2009 Quarter, partially offset by improved contract pricing that resulted in an increase in the average coal sales price of $6.91 per ton to $68.43 per ton in the 2009 Quarter, compared to $61.52 per ton in the 2008 Quarter. Although Segment Adjusted EBITDA Expense for the 2009 Quarter decreased 10.3% to $34.8 million from $38.8 million in the 2008 Quarter primarily as a result of lower coal sales volumes, Segment Adjusted EBITDA Expense per ton sold during the 2009 Quarter increased $9.68 per ton sold to $57.64 as compared to $47.96 per ton sold in the 2008 Quarter. The increase in Segment Adjusted EBITDA Expense per ton resulted in part from decreased coal production primarily due to reduced clean coal recovery, unplanned customer outages and lower spot market demand, in addition to certain cost per ton increases described above under consolidated operating expenses. Lower clean coal recovery resulted partly from Pontiki s transition from the depleted Pond Creek coal seam into the thinner Van Lear coal seam during the second quarter of 2009.

Northern Appalachia Segment Adjusted EBITDA decreased 68.5% to $3.2 million for the 2009 Quarter as compared to $10.3 million in the 2008 Quarter. This decrease of $7.1 million was primarily the result of lower sales volumes due to weakness in the spot and export coal markets and higher Segment Adjusted EBITDA expense per ton sold in the 2009 Quarter of $47.18 per ton, an increase of $3.78 per ton compared to $43.40 per ton in the 2008 Quarter. Increased Segment Adjusted EBITDA Expense per ton in the 2009 Quarter resulted primarily from lower production during the 2009 Quarter, as well as the other cost increases described above under consolidated operating expenses, including expenses incurred related to our Tunnel Ridge organic growth project, partially offset by curtailment of third-party mining operations (which began in the second quarter of 2009). Lower production was primarily in response to weak demand in export and spot coal markets in addition to lower clean coal recovery resulting from

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difficult mining conditions partially offset by higher longwall production days in the 2009 Quarter. Although Segment Adjusted EBITDA Expense per ton sold increased in the 2009 Quarter, Segment Adjusted EBITDA Expense for the 2009 Quarter decreased 17.8% to $30.7 million from $37.3 million in the 2008 Quarter, primarily as a result of lower coal sales volumes offset in part by higher expenses per ton as described above. Reduced coal sales also reflect a lower average coal sales price of $50.58 per ton for the 2009 Quarter as compared to $54.00 per ton for the 2008 Quarter due to weakness in the spot market mentioned above.

Other and Corporate Segment Adjusted EBITDA increased to $3.2 million in the 2009 Quarter from $1.7 million in the 2008 Quarter, primarily due to increased Matrix Design and Alliance Design product sales and service revenues and Mt. Vernon transloading revenues, partially offset by decreased MAC product sales. The increase in Segment Adjusted EBITDA Expense, as defined in reference (3) to the above table, primarily reflects increased expenses associated with higher outside services revenue and product sales.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

We reported record Net Income of ARLP of $150.4 million for the 2009 Period compared to $109.0 million for the 2008 Period. This increase of $41.4 million was principally due to improved contract pricing resulting in an average coal sales price of $46.76 per ton sold, as compared to $39.57 per ton sold for the 2008 Period. We had tons sold of 18.9 million and tons produced of 19.5 million for the 2009 Period compared to 20.2 million tons sold and 19.9 million tons produced for the 2008 Period. Unplanned customer outages, contractual deferrals and weak spot market demand continued to impact coal sales and production volumes in the 2009 Period as compared to the 2008 Period. The 2008 Period also included significant gains of $9.9 million discussed above under Results of Operations. Increased operating expenses (excluding outside coal purchases) during the 2009 Period primarily reflect the increase in labor and labor-related expenses, as well as higher sale-related expenses, maintenance costs and other factors described below.

	Nine Months Ended September 30,			
	2009	2008	2009	2008
	(in thousands)		(per ton sold)	
Tons sold	18,853	20,219	N/A	N/A
Tons produced	19,500	19,893	N/A	N/A
Coal sales	$ 881,508	$ 800,043	$ 46.76	$ 39.57
Operating expenses and outside coal purchases	$ 611,402	$ 597,752	$ 32.43	$ 29.56

Coal sales. Coal sales for the 2009 Period increased 10.2% to $881.5 million from $800.0 million for the 2008 Period. The increase of $81.5 million in coal sales reflected the benefit of higher average coal sales prices (contributing $135.5 million of the increase) partially offset by lower sales volume (reducing coal sales by $54.0 million). Average coal sales prices increased $7.19 per ton sold to $46.76 per ton in the 2009 Period as compared to the 2008 Period, primarily as a result of improved contract pricing across all operations.

Operating expenses. Operating expenses increased 3.8% to $605.7 million for the 2009 Period from $583.3 million for the 2008 Period. Higher operating expenses of $22.4 million resulted from the specific factors listed below:

- Labor and benefit expenses per ton produced, excluding workers compensation, increased 18.9% to $10.90 per ton in the 2009 Period from $9.17 per ton in the 2008 Period. The increase of $1.73 per ton produced represents pay rate increases and higher benefit expenses, particularly increased health care costs and retirement expenses, and the impact of increased headcount as we continue to hire and train new employees for the River View and Tunnel Ridge mine development projects;

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Workers compensation expenses per ton produced increased 81.9% to $1.31 per ton in the 2009 Period from $0.72 per ton in the 2008 Period. The increase of $0.59 per ton produced primarily reflected a non-cash charge during the 2009 Period that resulted from discount rate changes, which increased the accrued liabilities for the present value of estimated future claim payments;

Material and supplies per ton produced decreased 3.3% to $9.47 per ton in the 2009 Period from $9.79 per ton in the 2008 Period. This decrease of $0.32 per ton produced resulted from decreased costs for certain products and services, primarily roof support (decrease of $0.23 per ton), outside services (decrease of $0.15 per ton), seals (decrease of $0.14 per ton) and fuel used in the mining process (decrease of $0.15 per ton). These decreases were offset in part by increased costs in bits and cutter bars (increase of $0.06 per ton), higher power costs (increase of $0.09 per ton), preparation plant costs (increase of $0.11 per ton), and additional supplies associated with disruptions related to an ice storm during the 2009 first quarter in the Illinois Basin region, among other factors;

Maintenance expenses per ton produced increased 13.7% to $3.66 per ton in the 2009 Period from $3.22 per ton in the 2008 Period. The increase of $0.44 per ton produced resulted from higher repair costs related to continuous miners, belt conveyor equipment and other equipment categories;

Mine administration expenses decreased $1.8 million for the 2009 Period compared to the 2008 Period, primarily as a result of lower estimated regulatory costs;

Contract mining expenses decreased $2.1 million for the 2009 Period as compared to the 2008 Period. The decrease reflects a curtailment of third-party mining operations in our Northern Appalachian segment in response to weak demand in export and spot coal markets;

Operating expenses decreased due to a 1.2 million ton reduction in produced tons sold due to the previously mentioned 2009 first quarter weather disruptions in western Kentucky, particularly at the Dotiki, Warrior and Elk Creek mines, as well as unplanned customer outages, contractual deferrals and lower export and spot demand throughout the 2009 Period;

Production taxes and royalties expenses (which were incurred as a percentage of coal sales and coal volumes) increased $0.51 per produced tons sold in the 2009 Period compared to the 2008 Period primarily as a result of increased average coal sales prices;

Operating expenses incurred during the 2009 Period relating to our River View and Tunnel Ridge mine development projects increased $6.0 million over the 2008 Period. These expenses are generally included in the variances discussed above; and

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

General and administrative. General and administrative expenses for the 2009 Period increased to $29.0 million compared to $28.1 million in the 2008 Period. The increase was primarily due to higher unit-based incentive compensation expense and increased salary and benefit costs primarily related to higher staffing levels.

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Other sales and operating revenues. Other sales and operating revenues are principally comprised of Mt. Vernon transloading revenues, products and services provided by MAC and Matrix Design, and other outside services and administrative services revenue from affiliates. Other sales and operating revenues increased to $16.0 million for the 2009 Period from $12.2 million for the 2008 Period. The increase of $3.8 million was primarily attributable to increased revenues from Mt. Vernon transloading revenues and Matrix Design product sales partially offset by decreases in other outside services and MAC product sales.

Outside coal purchases. Outside coal purchases decreased to $5.7 million for the 2009 Period from $14.5 million in the 2008 Period. The decrease of $8.8 million was primarily attributable to a decrease in outside coal purchases at our Central and Northern Appalachian regions in response to a weak demand in export and spot coal markets.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased to $83.8 million for the 2009 Period from $74.3 million for the 2008 Period. The increase of $9.5 million was primarily attributable to additional depreciation expense associated with continuing capital expenditures related to infrastructure improvements, efficiency projects and expansion of production capacity.

Interest expense. Interest expense, net of capitalized interest increased to $23.5 million for the 2009 Period from $14.4 million for the 2008 Period. The increase of $9.1 million was principally attributable to the increased interest expense resulting from the $350 million private placement during late June of the 2008 Period, partially offset by reduced interest expense from our August 2009 principal payment of $18.0 million on our original senior notes issued in 1999. The 2008 financing activities are discussed in more detail below under Debt Obligations.

Interest income. Interest income decreased to $1.0 million for the 2009 Period from $2.4 million for the 2008 Period. The decrease of $1.4 million resulted from fewer short-term investments, which were originally purchased with proceeds from the $350 million private placement of senior notes during the 2008 Period discussed in more detail below under Debt Obligations.

Transportation revenues and expenses. Transportation revenues and expenses each increased to $35.3 million for the 2009 Period compared to $33.3 million for the 2008 Period. The increase of $2.0 million was primarily attributable to an increase in coal sales volumes in the 2009 Period for which we arrange transportation compared to the 2008 Period, partially offset by a decrease in average transportation rates of $0.36 on a per ton basis in the 2009 Period compared to the 2008 Period primarily due to lower fuel costs. The cost of transportation services are passed through to our customers. Consequently, we do not realize any gain or loss on transportation revenues.

Income tax expense (benefit). Income tax expense for the 2009 Period was $0.8 million compared to income tax benefit of $0.6 million for the 2008 Period. The income tax expense for the 2009 Period was primarily due to operating income of Matrix Design, while the income tax benefit for the 2008 Period was primarily due to operating losses of Matrix Design.

Net income attributable to noncontrolling interest. The noncontrolling interest represents a 50% third-party interest in MAC. The third-party s portion of MAC s net income was $0.2 million for the 2009 Period and $0.4 million for the 2008 Period. For more information about MAC, please read Item 1. Financial Statements (Unaudited) Note 13. Noncontrolling Interest of this Quarterly Report on Form 10-Q.

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Segment Adjusted EBITDA. Our 2009 Period Segment Adjusted EBITDA increased $63.5 million to a record $286.6 million from the 2008 Period Segment Adjusted EBITDA of $223.1 million. Segment Adjusted EBITDA, tons sold, coal sales, other sales and operating revenues and Segment Adjusted EBITDA Expense by segment are (in thousands):

	Nine Months Ended September 30,		Increase/(Decrease)	
	2009	2008		
Segment Adjusted EBITDA				
Illinois Basin	$ 237,860	$ 149,824	$ 88,036	58.8%
Central Appalachia	29,486	39,047	(9,561)	(24.5)%
Northern Appalachia	11,571	26,881	(15,310)	(57.0)%
Other and Corporate	8,098	7,397	701	9.5%
Elimination	(362)		(362)	(1)
Total Segment Adjusted EBITDA (2)	$ 286,653	$ 223,149	$ 63,504	28.5%
Tons sold				
Illinois Basin	14,950	15,258	(308)	(2.0)%
Central Appalachia	1,983	2,522	(539)	(21.4)%
Northern Appalachia	1,920	2,439	(519)	(21.3)%
Other and Corporate				
Elimination				
Total tons sold	18,853	20,219	(1,366)	(6.8)%
Coal sales				
Illinois Basin	$ 646,901	$ 525,655	$ 121,246	23.1%
Central Appalachia	136,143	151,675	(15,532)	(10.2)%
Northern Appalachia	98,007	122,713	(24,706)	(20.1)%
Other and Corporate	457		457	(1)
Elimination				
Total coal sales	$ 881,508	$ 800,043	$ 81,465	10.2%
Other sales and operating revenues				
Illinois Basin	$ 1,061	$ 876	$ 185	21.1%
Central Appalachia	128	176	(48)	(27.3)%
Northern Appalachia	2,499	3,301	(802)	(24.3)%
Other and Corporate	26,965	14,628	12,337	84.3%
Elimination	(14,660)	(6,770)	(7,890)	(1)
Total other sales and operating revenues	$ 15,993	$ 12,211	$ 3,782	31.0%
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 410,103	$ 376,707	$ 33,396	8.9%
Central Appalachia	106,784	115,594	(8,810)	(7.6)%
Northern Appalachia	88,934	99,133	(10,199)	(10.3)%
Other and Corporate	19,325	12,390	6,935	56.0%
Elimination	(14,298)	(6,770)	(7,528)	(1)
Total Segment Adjusted EBITDA Expense (3)	$ 610,848	$ 597,054	$ 13,794	2.3%

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

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

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

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

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

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

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

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

	Nine Months Ended September 30,	
	2009	2008
Segment Adjusted EBITDA	$ 286,653	$ 223,149
General and administrative	(29,000)	(28,134)
Depreciation, depletion and amortization	(83,767)	(74,297)
Interest expense, net	(22,428)	(11,959)
Income tax (expense) benefit	(811)	633
Net income	150,647	109,392
Net income attributable to noncontrolling interest	(232)	(396)
Net income of ARLP	$ 150,415	$ 108,996

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

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

	Nine Months Ended September 30,	
	2009	2008
Segment Adjusted EBITDA Expense	$ 610,848	$ 597,054
Outside coal purchases	(5,709)	(14,450)
Other income	554	698
Operating expense (excluding depreciation, depletion and amortization)	$ 605,693	$ 583,302

Illinois Basin Segment Adjusted EBITDA increased 58.8% to $237.9 million for the 2009 Period from $149.8 million for the 2008 Period. The increase of $88.1 million was primarily attributable to improved contract pricing resulting in a higher average coal sales price of $43.27 per ton during the 2009 Period compared to $34.45 per ton for the 2008 Period. The benefit of higher average coal sales price was partially offset by reduced tons sold due to weather disruptions in western Kentucky, particularly at the Dotiki, Warrior and Elk Creek mines, as well as unplanned customer outages, weakness in the spot market during the 2009 Period. Total Segment Adjusted EBITDA Expense for the 2009 Period increased 8.9% to $410.1 million from $376.7 million in the 2008 Period. The increase in the 2009 Period Segment Adjusted EBITDA Expense compared to the 2008 Period was primarily the result of cost increases described above under consolidated operating expenses and the impact of weather disruptions in the first quarter of 2009, partially offset by the $1.9 million gain on settlement of claims relating to the Pattiki Vertical Belt Incident during the 2008 Period, as discussed above under Results of Operations. On a per ton basis, Segment Adjusted EBITDA Expense for the 2009 Period increased $2.74 per ton to $27.43 per ton as compared to the 2008 Period Segment Adjusted EBITDA Expense of $24.69 per ton.

Central Appalachia Segment Adjusted EBITDA decreased $9.5 million, or 24.5%, to $29.5 million for the 2009 Period, compared to $39.0 million for the 2008 Period. The decrease was primarily the result of lower sales volumes due to unplanned customer outages, contract deferrals and weak coal demand in the spot market during the 2009 Period, partially offset by improved contract pricing that resulted in an increase in the average coal sales price of $8.50 per ton to $68.65 per ton in the 2009 Period, as compared to $60.15 per ton in the 2008 Period. Although Segment Adjusted EBITDA Expense for the 2009 Period decreased 7.6% to $106.8 million from $115.6 million in the 2008 Period primarily as a result of lower coal sales volumes, Segment Adjusted EBITDA Expense per ton sold during the 2009 Period increased $8.01 per ton to $53.85 per ton, or 17.5% over the 2008 Period Segment Adjusted EBITDA Expense per ton of $45.84. The increase in the Segment Adjusted EBITDA Expense per ton resulted in part from decreased coal production primarily due to unplanned customer outages, contractual deferrals, lower spot market demand and reduced clean coal recovery resulting partly from Pontiki s transition from the depleted Pond Creek coal seam into the thinner Van Lear coal seam during the 2009 Period in addition to cost per ton increases described above under consolidated operating expenses. Segment Adjusted EBITDA in the 2008 Period benefited from the $2.8 million gain recognized on settlement of claims from the third-party that provided security services at the time of the MC Mining Fire Incident as discussed above under Results of Operations.

Northern Appalachia Segment Adjusted EBITDA decreased 57.0%, to $11.6 million for the 2009 Period, compared to $26.9 million for the 2008 Period. The decrease of $15.3 million was primarily the result of lower sales volumes during the 2009 Period reflecting unplanned customer outages, contractual deferrals and reduced spot market sales resulting in lower tons sold, and

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higher Segment Adjusted EBITDA Expense per ton sold during the 2009 Period of $46.32 per ton, an increase of $5.68 per ton, or 14.0%, as compared to $40.64 per ton in the 2008 Period. Increased Segment Adjusted EBITDA Expense per ton in the 2009 Period resulted primarily from lower production which was impacted by a reduction in longwall run-days for the 2009 Period, in addition to a curtailment of third-party mining operations during the 2009 Period, as well as the other cost increases described above under consolidated operating expenses, including higher expenses incurred related to our Tunnel Ridge organic growth project and higher longwall maintenance expense per ton. Although Segment Adjusted EBITDA Expense per ton sold increased in the 2009 Period, Segment EBITDA Expense for the 2009 Period decreased 10.3% to $88.9 million from $99.1 million in the 2008 Period, primarily as a result of lower coal sales volumes offset in part by higher expenses per ton as described above. Coal sales benefited from a higher average coal sales price of $51.05 per ton for the 2009 Period as compared to $50.30 per ton for the 2008 Period reflecting improved contract sales prices partially offset by lower spot market prices.

Other and Corporate Segment Adjusted EBITDA increased to $8.1 million in the 2009 Period from $7.4 million in the 2008 Period, primarily due to increased Matrix Design and Alliance Design product sales and service revenues and Mt. Vernon transloading revenue in the 2009 Period partially offset by decreased MAC product sales in the 2009 Period and a $5.2 million gain on sale of non-core coal reserves in the 2008 Period. The increase in Segment Adjusted EBITDA Expense primarily reflects increased cost associated with higher outside services revenue and product sales.

Liquidity and Capital Resources

Liquidity

We have historically satisfied our working capital requirements and funded our capital expenditures and debt service obligations from cash generated from operations, cash provided by the issuance of debt or equity and borrowings under revolving credit facilities. We believe that the current cash on hand along with cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated capital expenditures (other than major capital improvements or acquisitions), scheduled debt payments and distribution payments. Our ability to satisfy our obligations and planned expenditures will depend upon our future operating performance and access to and cost of capital sources, which will be affected by prevailing economic conditions generally and in the coal industry specifically, which are beyond our control. Based on our recent operating results, current cash position, anticipated future cash flows and sources of capital that we expect to have available, we do not anticipate any significant liquidity constraints in the foreseeable future. However, to the extent operating cash flow or access to and cost of capital sources are materially different than expected, future liquidity may be adversely affected. Please see Item 1A. Risk Factors in the Annual Report on Form 10-K for the year ended December 31, 2008.

Cash Flows

Cash provided by operating activities was $238.3 million for the 2009 Period compared to $192.7 million for the 2008 Period. The increase in cash provided by operating activities was principally attributable to higher net income and a reduction in the change in accounts receivable during the 2009 Period compared to the 2008 Period, partially offset by reduced cash flow related to increases in certain operating assets such as inventory.

Net cash used in investing activities was $249.1 million for the 2009 Period compared to $130.1 million for the 2008 Period. The increase in cash used for investing activities was primarily attributable to increased capital expenditures related to the continuing mine development at the River View and Tunnel Ridge organic growth projects, as well as the purchase of $4.5 million in marketable

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securities. There were no significant acquisitions or sales of coal reserves and other assets in the 2009 Period compared to net cash used of $22.6 million on such transactions in the 2008 Period. Additionally, timing of materials and services receipts, vendor invoices and related payments of accounts payable and accrued liabilities for capital expenditures during the 2009 Period reduced cash used for capital expenditures in the 2009 Period to a lesser extent than the 2008 Period.

Net cash used in financing activities was $142.7 million for the 2009 Period compared to net cash provided by financing activities of $206.0 million for the 2008 Period. The difference was primarily attributable to proceeds from borrowings in the 2008 Period from the issuance of the $350 million of senior notes in a private placement (see Debt Obligations below) in addition to increased distributions paid to partners in the 2009 Period.

Capital Expenditures

Capital expenditures increased to $251.5 million in the 2009 Period from $122.9 million in the 2008 Period. See Cash Flows above concerning this increase in capital expenditures. Our anticipated total capital expenditures for the year ending December 31, 2009 are estimated in a range of $350 to $400 million. Management anticipates funding remaining 2009 capital requirements with cash and cash equivalents ($91.6 million as of September 30, 2009), cash flows provided by operations and borrowing available under our revolving credit facility as discussed below. 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 and cost 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.

Debt Obligations

ARLP Credit Facility. Our Intermediate Partnership has a $150.0 million revolving credit facility (ARLP Credit Facility) dated September 25, 2007, which matures in 2012. On September 30, 2009, our Intermediate Partnership entered into Amendment No. 2 (the Credit Amendment) to the ARLP Credit Facility. The Credit Amendment increased the annual capital expenditure limits under the ARLP Credit Facility. The new limits are $425.0 million for 2009, $375.0 million for 2010, $350.0 million for 2011 and $250.0 million for 2012. The amount of any annual limit in excess of actual capital expenditures for that year carries forward and is added to the annual limit of the subsequent year.

Pursuant to the Credit Amendment, the applicable margin for London Interbank Offered Rate borrowings under the ARLP Credit Facility was increased from a range of 0.625% to 1.150% (depending on the Intermediate Partnership s leverage margin) to a range of 1.115% to 2.000%, and the annual commitment fee was increased from a range of 0.15% to 0.35% (also depending on the Intermediate Partnership s leverage margin) to a range of 0.25% to 0.50%. In addition, the Credit Amendment includes certain changes relating to a defaulting lender, including changes which clarify that the overall ARLP Credit Facility commitment would be reduced by the commitment share of a defaulting lender but also provides our Intermediate Partnership with more flexibility in replacing a defaulting lender.

At September 30, 2009, we had $13.9 million of letters of credit outstanding with $136.1 million available for borrowing under the ARLP Credit Facility. We had no borrowings outstanding under the ARLP Credit Facility as of September 30, 2009. We incur an annual commitment fee of 0.25% on the undrawn portion of the ARLP Credit Facility.

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

Senior Notes. Our Intermediate Partnership has $90.0 million principal amount of 8.31% senior notes due August 20, 2014, payable in five remaining equal annual installments of $18.0 million with interest payable semi-annually (Senior Notes).

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

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

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

The ARLP Credit Facility, Senior Notes and 2008 Senior Notes (collectively, ARLP Debt Arrangements) are guaranteed by all of the direct and indirect subsidiaries of our Intermediate Partnership. The ARLP Debt Arrangements contain various covenants affecting our Intermediate Partnership and its subsidiaries restricting, among other things, the amount of distributions by our Intermediate Partnership, the incurrence of additional indebtedness and liens, the sale of assets, the making of investments, the entry into mergers and consolidations and the entry into transactions with affiliates, in each case subject to various exceptions. The ARLP Debt Arrangements also require the Intermediate Partnership to remain in control of a certain amount of mineable coal reserves relative to its annual production. In addition, the ARLP Debt Arrangements require our Intermediate Partnership to maintain (i) a minimum debt to cash flow ratio of not more than 3.0 to 1.0, (ii) a ratio of cash flow to interest expense of not less than 4.0 to 1.0 and (iii) maximum annual capital expenditures, excluding acquisitions, of $425.0 million for the year ending December 31, 2009, in each case, during the four most recently ended fiscal quarters. The Credit Amendment did not change the required minimum debt to cash flow or cash flow to interest expense ratios. The debt to cash flow ratio, cash flow to interest expense ratio and actual capital expenditures were 1.34 to 1.0, 10.1 to 1.0 and $305.0 million, respectively, for the trailing twelve months ended September 30, 2009. Regarding the 2009 maximum annual capital expenditures requirement, see Capital Expenditures above. We were in compliance with the covenants of the ARLP Debt Arrangements as of September 30, 2009.

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Other. In addition to the letters of credit available under the ARLP Credit Facility discussed above, we also have agreements with two banks to provide additional letters of credit in an aggregate amount of $31.1 million to maintain surety bonds to secure certain asset retirement obligations and our obligations for workers compensation benefits. At September 30, 2009, we had $31.1 million in letters of credit outstanding under agreements with these two banks. Our special general partner guarantees $5.0 million of these outstanding letters of credit.

Related-Party Transactions

We have continuing related-party transactions with our managing general partner, AHGP and our special general partner and its affiliates. These related-party transactions relate principally to the provision of administrative services to AHGP and Alliance Resource Holdings II, Inc. and their respective affiliates, a time sharing agreement concerning use of aircraft and mineral and equipment leases with our special general partner and its affiliates, and guarantees from our special general partner for letters of credit.

Please read our Annual Report on Form 10-K for the year ended December 31, 2008, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Related-Party Transactions for additional information concerning the related-party transactions described above.

New Accounting Standards

New Accounting Standards Issued and Adopted

In June 2009, we adopted amendments to Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 105, *Generally Accepted Accounting Principles* (Statement of Financial Accounting Standards (SFAS) No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles-A Replacement of FASB Statement No. 162*), effective for interim periods ending after September 15, 2009. FASB ASC 105-10-05-1 establishes the FASB Accounting Standards Codification as the only source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with Generally Accepted Accounting Principles (GAAP). Rules and interpretive releases of the SEC under federal securities laws are also sources of authoritative GAAP for SEC registrants. FASB ASC 105 is not intended to change GAAP. All references to GAAP standards below include both FASB ASC reference in addition to the previously disclosed GAAP standard references as appropriate. The adoption of FASB ASC 105 had no impact on our financial position or results of operations.

In September 2009, the FASB issued Accounting Standards Update (ASU) 2009-06, *Implementation Guidance on Accounting for Uncertainty in Income Taxes and Disclosure Amendments for Nonpublic Entities.* ASU 2009-06 amended guidance on certain aspects of FASB ASC 740, *Income Taxes,* including application to nonpublic entities, as well as application guidance on the accounting for income tax uncertainties for all entities. The amendments are applicable to all entities that apply FASB ASC 740 as well as those that historically had not, such as pass-through and tax-exempt not-for-profit entities. The amendments clarify that an entity s tax status as a pass-through or tax-exempt not-for-profit entity is a tax position subject to the recognition requirements of FASB ASC 740 and therefore these entities must use the recognition and measurement guidance in FASB ASC 740 when assessing their tax positions. The ASU 2009-06 amendments are effective for interim and annual periods ending after September 15, 2009. The adoption of the ASU 2009-06 amendments for the 2009 Quarter did not have a material impact on our consolidated financial statements.

On January 1, 2009, we adopted amendments to FASB ASC 805, *Business Combinations* (SFAS No. 141R, *Business Combinations*), issued by the FASB in December 2007. The FASB ASC 805 amendments apply to all business combinations and establish guidance for recognizing and measuring identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree and goodwill.

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Most of these items are recognized at their full fair value on the acquisition date, including acquisitions where the acquirer obtains control but less than 100% ownership in the acquiree. The FASB ASC 805 amendments also require expensing restructuring and acquisition-related costs as incurred and establish disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. Per FASB ASC 805-10-65-1, these amendments to FASB ASC 805 are effective for business combinations with an acquisition date in fiscal years beginning after December 15, 2008. We did not complete any business acquisitions during the 2009 Period.

On January 1, 2009, we adopted FASB ASC 810-10-65 and 810-10-45-16 (SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements*), which establishes accounting and reporting standards for noncontrolling ownership interests in subsidiaries. Noncontrolling ownership interests in consolidated subsidiaries is presented in the consolidated balance sheet within total partners capital as a separate component from the parent s equity. Consolidated net income now includes earnings attributable to both the parent and the noncontrolling interests. Earnings per unit is based on earnings attributable to only the parent company and did not change upon adoption. In addition, FASB ASC 810-10-65 provides guidance on accounting for changes in the parent s ownership interest in a subsidiary, including transactions where control is retained and where control is relinquished and also requires additional disclosure of information related to amounts attributable to the parent for income from continuing operations, discontinued operations, extraordinary items and reconciliations of the parent and noncontrolling interests equity of a subsidiary. The provisions are applied prospectively to transactions involving noncontrolling interests, including noncontrolling interests that arose prior to the effective date, as of the beginning of 2009, the year of adoption. However, the presentation of noncontrolling interests within partners capital and the inclusion of earnings attributable to the noncontrolling interests in consolidated net income requires retrospective application to all periods presented. For more information, please read Item 1. Financial Statements (Unaudited) Note 13. Noncontrolling Interest of this Quarterly Report on Form 10-Q.

On January 1, 2009, we adopted FASB ASC 260-10-55-102 through 55-110, *Master Limited Partnerships* (Emerging Issues Task Force (EITF) No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128, Earnings Per Share, to Master Limited Partnerships*), which considers whether the IDR of a master limited partnership represents a participating security when considered in the calculation of earnings per unit under the two-class method. FASB ASC 260-10-55-102 through 55-110 also considers whether the partnership agreement contains any contractual limitations concerning distributions to IDR holders that would impact the amount of earnings to allocate to the IDR holders for each reporting period. If distributions are contractually limited to the IDR holders share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the IDR holders. We believe our partnership agreement contractually limits our distributions to available cash and therefore, undistributed earnings are no longer allocated to the IDR holder. Accordingly, the adoption impacts our presentation of earnings per unit in periods when Net Income of ARLP exceeds the aggregate distributions because undistributed earnings are no longer allocated to the IDR holder. For more information, please read Item 1. Financial Statements (Unaudited) Note 7. Net Income of ARLP per Limited Partner Unit of this Quarterly Report on Form 10-Q.

On January 1, 2009, we adopted the provisions of FASB ASC 260-10-55-25 (FASB Staff Position (FSP) No. EITF No. 03-6-1 *Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities*), which affects entities that accrue cash dividends on share-based payment awards during the awards service period when the dividends are not required to be returned if the employees forfeit the award. Outstanding unvested share-based payment awards that contain rights to nonforfeitable dividends participate in undistributed earnings with common shareholders and are considered participating securities. Because the awards are considered participating securities, the issuing entity is required to apply the two-class method of computing basic and diluted earnings per share. We now include an allocation of undistributed and distributed earnings to outstanding unvested awards

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under our Long-Term Incentive Plan in the calculation of our basic earnings per unit. For more information, please read Item 1. Financial Statements (Unaudited) Note 7. Net Income of ARLP per Limited Partner Unit of this Quarterly Report on Form 10-Q.

Beginning with the quarterly period ended June 30, 2009, we adopted FASB ASC 825-10-50-2A (FSP SFAS No. 107-1 and Accounting Principles Board (APB) Opinion No. 28-1, *Interim Disclosures about Fair Value of Financial Instruments).* FASB ASC 825-10-50-2A requires disclosures about fair value of financial instruments in interim financial statements as well as in annual financial statements. For more information, please read Item 1. Financial Statements (Unaudited) Note 5. Fair Value Measurements of this Quarterly Report on Form 10-Q.

Beginning with the quarterly period ended June 30, 2009, we adopted amendments to FASB ASC 855, *Subsequent Events* (SFAS No. 165, *Subsequent Events*), issued by the FASB in May 2009. The amendments to FASB ASC 855 establish the accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The amendments to FASB ASC 855 also require disclosure of the date through which an entity has evaluated subsequent events and the basis for that date, that is, whether that date represents the date the financial statements were issued or were available to be issued. For more information, please read Item 1. Financial Statements (Unaudited) Note 14. Subsequent Events of this Quarterly Report on Form 10-Q.

New Accounting Standards Issued and Not Yet Adopted

In August 2009, the FASB issued ASU 2009-05, *Measuring Liabilities at Fair Value*. The ASU 2009-05 amendments provide additional guidance on measuring the fair value of liabilities, as well as outline alternative valuation methods and a hierarchy for their use. The amendments also clarify that restrictions preventing the transfer of a liability should not be considered as a separate input or adjustment in the measurement of its fair value. The ASU 2006-05 amendments are effective as of the beginning of interim and annual reporting periods that begin after August 26, 2009. We do not anticipate these requirements will have a material impact on our consolidated financial statements.

In June 2009, the FASB issued amendments to FASB ASC 810, *Consolidation* (SFAS No. 167, *Amendments to FASB Interpretation No. 46(R),* which change the consolidation guidance applicable to a variable interest entity (VIE). These amendments also update the guidance governing the determination of whether an enterprise is the primary beneficiary of a VIE, and is, therefore, required to consolidate an entity, by requiring a qualitative analysis rather than a quantitative analysis. The qualitative analysis will include, among other things, consideration of who has the power to direct the activities of the entity that most significantly impact the entity s economic performance and who has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. This standard also requires continuous reassessments of whether an enterprise is the primary beneficiary of a VIE. Previously, FASB ASC 810 required reconsideration of whether an enterprise was the primary beneficiary of a VIE only when specific events had occurred. Qualifying special purpose entities, which were previously exempt from the application of this standard, will be subject to the provisions of this standard when it becomes effective. These amendments also require enhanced disclosures about an enterprise s involvement with a VIE. The provisions of these amendments are effective as of the beginning of interim and annual reporting periods that begin after November 15, 2009. We are currently evaluating the requirements of these amendments.

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In December 2008, FASB ASC 715, *Compensation-Retirement Benefits* was amended (FSP SFAS No. 132(R)-1, *Employers Disclosures about Postretirement Benefit Plan Assets*) to require more detailed annual disclosures about employers plan assets, concentrations of risk within plan assets and valuation techniques used to measure the fair value of plan assets. These amendments are effective for fiscal years ending after December 15, 2009. We are currently evaluating these requirements. However, we do not anticipate these requirements will have a material impact on our consolidated financial statements.

Other

Insurance

During September 2009, we completed our annual property and casualty insurance renewal with various insurance coverages effective October 1, 2009. As in past years, we have elected to retain a participating interest in our commercial property insurance program at an average rate of approximately 14.7% in the overall $75.0 million of coverage, representing 22% of the primary $50.0 million layer. We do not participate in the second layer of $25.0 million in excess of $50.0 million.

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

ITEM 3. 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 resulting from regulatory changes.

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. We do not have any interest rate or commodity price-hedging transactions outstanding.

Borrowings under the ARLP Credit Facility are at variable rates and, as a result, we have interest rate exposure. Historically, our earnings have not been materially affected by changes in interest rates. We had no borrowings outstanding under the ARLP Credit Facility as of September 30, 2009.

As of September 30, 2009, the estimated fair value of the Senior Notes and the 2008 Senior Notes was approximately $454.3 million. 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 September 30, 2009. There were no other significant changes in our quantitative and qualitative disclosures about market risk as set forth in our Annual Report on Form 10-K for the year ended December 31, 2008.

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ITEM 4. CONTROLS AND PROCEDURES

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports we file with the U.S. Securities and Exchange Commission (SEC) is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure. 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 September 30, 2009. This evaluation was performed by our management, with the participation of our Chief Executive Officer and Chief Financial Officer. Based on this evaluation, 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 it is required to disclose in the reports it files with the SEC within the required time periods, and during the quarterly period ended September 30, 2009, there have not been any changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) identified in connection with this evaluation that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 that are intended to come within the safe harbor protection provided by those sections. These statements are based on our beliefs as well as assumptions made by, and information currently available to, us. When used in this document, the words anticipate, believe, continue, estimate, expect, forecast, may, project, will, and similar expressions identify statements. Without limiting the foregoing, all statements relating to our future outlook, anticipated capital expenditures, future cash flows and borrowings and sources of funding are forward-looking statements. These statements reflect our current views with respect to future events and are subject to numerous assumptions that we believe are reasonable, but are open to a wide range of uncertainties and business risks, and actual results may differ materially from those discussed in these statements. Among the factors that could cause actual results to differ from those in the forward-looking statements are:

- increased competition in coal markets and our ability to respond to the competition;
- sustained decreases in coal prices, which could adversely affect our operating results and cash flows;
- decreases in spot market prices for coal;
- risks associated with the expansion of our operations and properties;
- deregulation of the electric utility industry or the effects of any adverse change in the coal industry, electric utility industry, or general economic conditions;
- dependence on significant customer contracts, including renewing customer contracts upon expiration of existing contracts;
- the impact and duration of the current worldwide economic downturn;
- liquidity constraints, including those resulting from the cost or unavailability of financing due to current credit market conditions;
- customer bankruptcies, cancellations or breaches to existing contracts, or other failures to perform;
- customer delays or defaults in making payments;
- adjustments made in price, volume or terms to existing coal supply agreements;
- fluctuations in coal demand, prices and availability due to labor and transportation costs and disruptions, equipment availability, governmental regulations, including those related to carbon emissions, and other factors;

legislation, regulatory and court decisions and interpretations thereof, including issues related to climate change and miner health and safety;

our productivity levels and margins earned 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;

difficulty in making accurate assumptions and projections regarding pension and other post-retirement benefit liabilities;

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coal market s share of electricity generation, including as a result of environmental concerns related to coal mining and combustion and the cost and perceived benefits of alternative sources of energy, such as natural gas and nuclear energy;

prices of fuel that compete with or impact coal usage, such as oil or natural gas;

replacement of coal reserves;

our assumptions and projections concerning economically recoverable coal reserve estimates;

a loss or reduction of benefits from certain 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 Part II. Item 1A. Risk Factors and Item 1. 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 or considering any forward-looking statements contained in:

this Quarterly Report on Form 10-Q;

other reports filed by us with the SEC;

our press releases; and

written or oral statements made by us or any of our officers or other authorized persons acting on our behalf.

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PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The information in Note 3. Contingencies to the Unaudited Condensed Consolidated Financial Statements included in Item 1. Financial Statements (Unaudited) of this Quarterly Report on Form 10-Q herein is hereby incorporated by reference. See also Item 3. Legal Proceedings in the Annual Report on Form 10-K for the year ended December 31, 2008.

On November 2, 2006 George W. Rector et al. (the Plaintiffs) filed a complaint in the Circuit Court of the Second Judicial Circuit of Illinois, in White County, Illinois, against our subsidiaries White County Coal, LLC, Alliance Properties, LLC and Alliance Coal, LLC (collectively Alliance) asserting claims for breach of contract, breach of fiduciary duty and unjust enrichment. The case is scheduled for trial before the Circuit Court beginning November 16, 2009. The Plaintiffs claims are based on their assertion that, as a result of assignments in 1977, 1978 and 1979 from the Plaintiffs or their predecessors to Alliance s predecessors, MAPCO Coal, Inc. and MAPCO Land & Development Corporation (collectively MAPCO), of certain coal leases, they are entitled to receive royalty payments on all coal mined previously or in the future from the property once affected by those leases as well as from other property in the area. Plaintiffs have alleged damages of over $33 million, and have also asserted a claim for punitive damages. The subject assignments were made in accordance with an agreement between Plaintiffs and MAPCO pursuant to which Plaintiffs reserved the right to receive an overriding royalty on coal mined under the assigned leases. Several years after MAPCO terminated a number of the assigned leases, we entered into new leases of some of the property previously covered by the assigned leases, and subsequently began mining in the area. We believe that Plaintiffs overriding royalty interest did not extend to any renewal of the subject leases or to any new lease covering the same property, and that Plaintiffs claims are without merit. We also believe that an adverse decision in this litigation, if any, would not have a material adverse effect on our business, financial position or results of operations.

On April 24, 2006, we were served with a complaint from Mr. Ned Comer, et al. (the Plaintiffs) alleging that approximately 40 oil and coal companies, including us, (the Defendants) are liable to the Plaintiffs for tortuously causing damage to Plaintiffs property in Mississippi. The Plaintiffs allege that the Defendants greenhouse gas emissions caused global warming and resulted in the increase in the destructive capacity of Hurricane Katrina. On August 30, 2007, the trial court dismissed the Plaintiffs complaint. On September 17, 2007, Plaintiffs filed a notice of appeal of that dismissal to the U.S. Court of Appeals for the Fifth Circuit. On October 16, 2009, the Fifth Circuit overturned the trial court s dismissal of the Plaintiffs private nuisance, trespass and negligence claims, finding Article III constitutional standing and no political question. The Fifth Circuit remanded these claims to the trial court for further proceedings. We believe this complaint is without merit and we do not believe that an adverse decision in this litigation matter, if any, will have a material adverse effect on our business, financial position or results of operations.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this Quarterly Report on Form 10-Q, you should carefully consider the factors discussed in Part I, Item 1A Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2008 which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K and this Quarterly Report on Form 10-Q are not our only risks. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial based on current knowledge and factual circumstances, if such knowledge or facts change, also may materially adversely affect our business, financial condition and/or operating results in the future.

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ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

The Partnership filed a Consent Solicitation Statement dated September 25, 2009 with the Securities and Exchange Commission on Schedule 14A in connection with the solicitation of consents of the holders of common units to approve The Third Amendment (Third Amendment) to the 2000 Long-Term Incentive Plan, as amended (The Plan). A summary of the Third Amendment was set forth in the Partnership s Consent Solicitation Statement under the caption The Plan and Proposed Amendment. Such description is incorporated herein by reference and is qualified in its entirety by reference to the full text of the Amended and Restated Plan, as amended. On October 23, 2009, the unitholders of the Partnership approved the Third Amendment to the Plan. The Third Amendment had previously been authorized by the Board of Directors of Alliance Resource Management GP, LLC, the Partnership s managing general partner. The Third Amendment increased the number of common units available for issuance under the Plan from 1.2 million to 3.6 million.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

10.1	Amendment No. 2, dated as of September 30, 2009, to the Second Amended and Restated Credit Agreement, dated as of September 25, 2007, among Alliance Resource Operating Partners, L.P. as Borrower, the Initial Lenders, Initial Issuing Banks and Swing Line Bank, in each case as named therein, JPMorgan Chase Bank, N.A. as Paying Agent, Citicorp USA, Inc. and JPMorgan Chase Bank, N.A. as Co-Administrative Agents, and Citigroup Global Markets Inc. and J.P. Morgan Securities, Inc. as Joint Lend Arrangers and Joint Bookrunners. (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed with the Commission on October 6, 2009, File No. 000-26823).
10.2*[(1)]	Agreement for the Supply of Coal, dated August 20, 2009 between Tennessee Valley Authority and Alliance Coal, LLC.
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 November 6, 2009, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated November 6, 2009, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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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 November 6, 2009, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated November 6, 2009, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith (or furnished, in the case of Exhibits 32.1 and 32.2).

(1) Application has been made to the Commission for confidential treatment of certain provisions of this exhibit. Omitted material for which confidential treatment has been requested has been filed separately with the Commission.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, in Tulsa, Oklahoma, on November 6, 2009.

ALLIANCE RESOURCE PARTNERS, L.P.

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

/s/ Joseph W. Craft, III
Joseph W. Craft, III
President, Chief Executive Officer and Director, duly authorized to sign on behalf of the registrant.

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