

ALLIANCE RESOURCE PARTNERS LP

Form 10-K

February 26, 2016

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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2015

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)

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DELAWARE
(STATE OR OTHER JURISDICTION OF
INCORPORATION OR ORGANIZATION)

73-1564280
(IRS EMPLOYER IDENTIFICATION NO.)

1717 SOUTH BOULDER AVENUE, SUITE 400, TULSA, OKLAHOMA 74119

(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES AND ZIP CODE)

(918) 295-7600

(REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE)

Securities registered pursuant to Section 12(b) of the Act:

<u>Title of Each Class</u>	<u>Name of Each Exchange On Which Registered</u>
Common Units representing limited partner interests	The NASDAQ Stock Market LLC

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

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

Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. 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

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

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

Large Accelerated Filer

Accelerated Filer

Non-Accelerated Filer

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 No

The aggregate value of the common units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately \$1,049,721,404 as of June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter, based on the reported closing price of the common units as reported on The NASDAQ Stock Market LLC on such date.

As of February 26, 2016, 74,375,025 common units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: None

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PART IV

Item 15.

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FORWARD-LOOKING STATEMENTS

Certain statements and information in this Annual Report on Form 10-K may constitute forward-looking statements. These statements are based on our beliefs as well as assumptions made by, and information currently available to, us. When used in this document, the words anticipate, believe, continue, estimate, expect, forecast, may, project, will, and similar expressions identify forward-looking statements. With 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:

- changes in coal prices, which could affect our operating results and cash flows;
- changes in competition in coal markets and our ability to respond to such changes;
- legislation, regulations, and court decisions and interpretations thereof, including those relating to the environment and the release of greenhouse gasses, mining, miner health and safety and health care;
- deregulation of the electric utility industry or the effects of any adverse change in the coal industry, electric utility industry, or general economic conditions;
- risks associated with the expansion of our operations and properties;
- dependence on significant customer contracts, including renewing existing contracts upon expiration;
- adjustments made in price, volume or terms to existing coal supply agreements;
- changing global economic conditions or in industries in which our customers operate;
- liquidity constraints, including those resulting from any future unavailability of financing;
- customer bankruptcies, cancellations or breaches to existing contracts, or other failures to perform;
- customer delays, failure to take coal under contracts or defaults in making payments;
- fluctuations in coal demand, prices and availability;
- we have made investments in oil and gas mineral interests through Cavalier Minerals and the value of those investments and related cash flows may be materially adversely affected by a continuation or worsening of depressed oil and gas prices
- our productivity levels and margins earned on our coal sales;

- the coal industry'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 other sources of electricity, such as natural gas, nuclear energy and renewable fuels;
- changes in raw material costs;
- changes in the availability of skilled labor;
- our ability to maintain satisfactory relations with our employees;
- increases in labor costs including costs of health insurance and taxes resulting from the Affordable Care Act, adverse changes in work rules, or cash payments or projections associated with post-mine reclamation and workers compensation claims;
- increases in transportation costs and risk of transportation delays or interruptions;
- operational interruptions due to geologic, permitting, labor, weather-related or other 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, black lung benefits and other post-retirement benefit liabilities;
- uncertainties in estimating and replacing our coal reserves;
- a loss or reduction of benefits from certain tax deductions and credits;
- difficulty obtaining commercial property insurance, and risks associated with our participation (excluding any applicable deductible) in the commercial insurance property program;
- difficulty in making accurate assumptions and projections regarding future revenues and costs associated with equity investments in companies we do not control; and
- other factors, including those discussed in Item 1A. Risk Factors and Item 3. Legal Proceedings.

If one or more of these or other risks or uncertainties materialize, or should underlying assumptions prove incorrect, our actual results may differ materially from those described in any forward-looking statement. When considering forward-looking statements, you should also keep in mind the risk factors described in Item 1A. Risk Factors below. The risk factors could also cause our actual results to differ materially from those contained in any forward-looking

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statement. We disclaim any obligation to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

You should consider the information above when reading any forward-looking statements contained in this Annual Report on Form 10-K; other reports filed by us with the U.S. Securities and Exchange Commission (SEC); our press releases; our website <http://www.arlp.com>; and written or oral statements made by us or any of our officers or other authorized persons acting on our behalf.

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Significant Relationships Referenced in this Annual Report

- References to we, us, our or ARLP Partnership mean the business and operations of Alliance Resource Partners, L.P., the parent company, as well as its consolidated subsidiaries.
- References to ARLP mean Alliance Resource Partners, L.P., individually as the parent company, and not on a consolidated basis.
- References to MGP mean Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., also referred to as our managing general partner.
- References to SGP mean Alliance Resource GP, LLC, the special general partner of Alliance Resource Partners, L.P., also referred to as our special general partner.
- References to Intermediate Partnership mean Alliance Resource Operating Partners, L.P., the intermediate partnership of Alliance Resource Partners, L.P., also referred to as our intermediate partnership.
- References to Alliance Resource Properties mean Alliance Resource Properties, LLC, the land-holding company for the mining operations of Alliance Resource Operating Partners, L.P.
- References to Alliance Coal mean Alliance Coal, LLC, the holding company for the mining operations of Alliance Resource Operating Partners, L.P., also referred to as our operating subsidiary.
- References to AHGP mean Alliance Holdings GP, L.P., individually as the parent company, and not on a consolidated basis.
- References to AGP mean Alliance GP, LLC, the general partner of Alliance Holdings GP, L.P.

PART I

ITEM 1. BUSINESS

General

We are a diversified producer and marketer of coal primarily to major United States (U.S.) utilities and industrial users. We began mining operations in 1971 and, since then, have grown through acquisitions and internal development to become the second-largest coal producer in the eastern U.S. At December 31, 2015, we had approximately 1.8 billion tons of coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. In 2015, we sold a record 40.2 million tons of coal and produced a record 41.2 million tons of coal, of which

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3.6% was low-sulfur coal, 17.3% was medium-sulfur coal and 79.1% was high-sulfur coal. In 2015, we sold 96.1% of our total tons to electric utilities, of which 99.7% was sold to utility plants with installed pollution control devices. These devices, also known as scrubbers, eliminate substantially all emissions of sulfur dioxide. We classify low-sulfur coal as coal with a sulfur content of less than 1%, medium-sulfur coal as coal with a sulfur content of 1% to 2%, and high-sulfur coal as coal with a sulfur content of greater than 2%.

We operate ten underground mining complexes in Illinois, Indiana, Kentucky, Maryland and West Virginia. We also operate a coal loading terminal on the Ohio River at Mt. Vernon, Indiana. Our mining activities are conducted in two geographic regions commonly referred to in the coal industry as the Illinois Basin and Appalachian regions. We have grown historically primarily through expansion of our operations by adding and developing mines and coal reserves in these regions.

ARLP, a Delaware limited partnership, completed its initial public offering on August 19, 1999 and is listed on the NASDAQ Global Select Market under the ticker symbol ARLP. We are managed by our managing general partner, MGP, a Delaware limited liability company, which holds a 0.99% and 1.0001% managing general partner interest in ARLP and the Intermediate Partnership, respectively. AHGP is a Delaware limited partnership that owns and is the controlling member of MGP. AHGP completed its initial public offering (AHGP IPO) on May 15, 2006 and is listed on the NASDAQ Global Select Market under the ticker symbol AHGP. AHGP owns, directly and indirectly, 100% of the members interest of MGP, a 0.001% managing interest in Alliance Coal, the incentive distribution rights (IDR) in ARLP and 31,088,338 common units of ARLP. Our special general partner is owned by Alliance Resource Holdings, Inc., a Delaware corporation (ARH), which is owned by Joseph W. Craft III, the President and Chief Executive Officer and a Director of our managing general partner, and Kathleen S. Craft.

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The following diagram depicts our organization and ownership as of December 31, 2015:

(1) The units held by SGP and most of the units held by the Management Group (some of whom are current or former members of management) are subject to a transfer restrictions agreement that, subject to a number of exceptions (including certain transfers by Mr. Craft in which the other parties to the agreement are entitled or required to participate), prohibits the transfer of such units unless approved by a majority of the disinterested members of the board of directors of AGP pursuant to certain procedures set forth in the agreement or as otherwise provided in the agreement. Certain provisions of the transfer restrictions agreement may cause the parties to it to comprise a group under Rule 13d-5(b) of the Securities Exchange Act of 1934, as amended (the Exchange Act).

Our internet address is <http://www.arlp.com>, and we make available free of charge on our website our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K, Forms 3, 4 and 5 for our Section 16 filers and other documents (and amendments and exhibits, such as press releases, to such filings) as soon as reasonably practicable after we electronically file with or furnish such material to the SEC. Information on our website or any other website is not incorporated by reference into this report and does not constitute a part of this report.

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The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any documents that we file with the SEC at <http://www.sec.gov>.

Mining Operations

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

<u>Regions</u>	2015	2014	Year Ended December 31,		2011
			2013	2012	
			(tons in millions)		
Illinois Basin (1)	32.0	30.9	30.7	28.4	25.5
Appalachia	9.2	9.8	7.4	5.8	4.3
Other (2)	-	-	0.7	0.6	1.0
Total	41.2	40.7	38.8	34.8	30.8

(1) As a result of acquiring the remaining equity interests in White Oak Resources LLC (White Oak), we include White Oak Mine No. 1 (now known as Hamilton Mine No. 1) as part of our Illinois Basin production starting on July 31, 2015. Please see Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions for a discussion on this acquisition.

(2) Other includes production from our former Pontiki Coal, LLC (Pontiki) mine, which is located in Martin County, Kentucky. The Pontiki mine ceased operations in November 2013. As a result of the cessation we evaluated the ongoing management of our mining operations and coal sales efforts to ensure that resources were appropriately allocated to maximize our overall results. Based on this evaluation, we have realigned the management of our operating and marketing teams and changed our reportable segment presentation to reflect this realignment.

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The following map shows the location of our mining complexes and projects:

Illinois Basin Operations

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. As of February 11, 2016, we had 2,955 employees, and we operate seven mining complexes in the Illinois Basin.

Dotiki Complex. Our subsidiary, Webster County Coal, LLC (Webster County Coal), operates Dotiki, which is an underground mining complex located near the city of Providence in Webster County, Kentucky. The complex was

opened in 1966, and we purchased the mine in 1971. The Dotiki complex utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. In connection with the transition of mining operations from the No. 9 and the No. 11 seams, where it has historically operated, to the No. 13 seam, Dotiki constructed a new preparation plant that became operational in early 2012 and has throughput capacity of 1,800 tons of raw coal per hour. Coal from the Dotiki complex is shipped via the CSX Transportation, Inc. (CSX) and Paducah & Louisville Railway, Inc. (PAL) railroads and by truck on U.S. and state highways directly to customers or to various transloading facilities, including our Mt. Vernon Transfer Terminal, LLC (Mt. Vernon) transloading facility, for barge deliveries.

Warrior Complex. Our subsidiary, Warrior Coal, LLC (Warrior), operates an underground mining complex located near the city of Madisonville in Hopkins County, Kentucky. The Warrior complex was opened in 1985, and we acquired it in February 2003. Warrior utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. Warrior completed construction of a new preparation plant in 2009, which has throughput capacity of 1,200 tons of raw coal per hour. Warrior's production is shipped via the CSX and PAL railroads and by truck on U.S. and state highways directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries. Warrior is currently in the process of transitioning from the No. 11 seam to the No. 9 seam, which is expected to continue over the next one to two years.

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Pattiki Complex. Our subsidiary, White County Coal, LLC (White County Coal), operates Pattiki, an underground mining complex located near the city of Carmi in White County, Illinois. We began construction of the complex in 1980 and have operated it since its inception. The Pattiki complex utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. The preparation plant has throughput capacity of 1,000 tons of raw coal per hour. Coal from the Pattiki complex is shipped via the Evansville Western Railway, Inc. (EVW) railroad directly, or via connection with the CSX railroad, to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries.

Hopkins Complex. The Hopkins complex, which we acquired in January 1998, is located near the city of Madisonville in Hopkins County, Kentucky. Our subsidiary, Hopkins County Coal, LLC (Hopkins County Coal) operates the Elk Creek underground mine using continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. Coal produced from the Elk Creek mine is processed and shipped through Hopkins County Coal 's preparation plant, which has throughput capacity of 1,200 tons of raw coal per hour. Elk Creek 's production is shipped via the CSX and PAL railroads and by truck on U.S. and state highways directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries. The Elk Creek mine is currently expected to cease production in early 2016. Hopkins County Coal also controls the Fies property for potential future development.

Gibson Complex. Our subsidiary, Gibson County Coal, LLC (Gibson County Coal), operates the Gibson North mine, an underground mine located near the city of Princeton in Gibson County, Indiana. The Gibson North mine began production in November 2000 and utilizes continuous mining units employing room-and-pillar mining techniques to produce medium-sulfur coal. The Gibson North mine was idled on December 18, 2015. The Gibson North mine 's preparation plant, which is leased from an affiliate, has throughput capacity of 700 tons of raw coal per hour. Production from the Gibson North mine is either shipped by truck on U.S. and state highways or transported by rail on the CSX and Norfolk Southern Railway Company (NS) railroads directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries.

Gibson County Coal operates the Gibson South mine, also located near the city of Princeton in Gibson County, Indiana. The Gibson South mine is an underground mine and utilizes continuous mining units employing room-and-pillar mining techniques to produce medium-sulfur coal. The Gibson South mine 's preparation plant has throughput capacity of 1,800 tons of raw coal per hour. Production from the Gibson South mine is shipped by truck on U.S. and state highways or transported by rail from the Gibson North rail loadout facility directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge delivery. Production from the mine began in April 2014.

River View Complex. Our subsidiary, River View Coal, LLC (River View), operates the River View mine, which is located in Union County, Kentucky and is currently the largest room-and-pillar underground coal mine in the U.S. The River View mine began production in 2009, and utilizes continuous mining units to produce high-sulfur coal. River View 's preparation plant has throughput capacity of 2,700 tons of raw coal per hour. Coal produced from the River View mine is transported by overland belt to a barge loading facility on the Ohio River.

Sebree Mining Complex. On April 2, 2012, we acquired substantially all of Green River Collieries, LLC's (Green River) assets related to its coal mining business and operations located in Webster and Hopkins Counties, Kentucky, including the Onton No. 9 mining complex (Onton mine). The Onton mine is operated by our subsidiary, Sebree Mining, LLC (Sebree Mining). Sebree Mining utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. The Onton mine's preparation plant, which is leased from a third party, has throughput capacity of 750 tons of raw coal per hour. Coal from Sebree Mining's mining complex is transported by overland belt to a barge loading facility on the Green River for shipment to customers, or is shipped via truck on U.S. and state highways directly to customers. The Onton mine was idled on November 6, 2015.

Hamilton Mining Complex. In July 2015, we acquired the remaining equity interest in White Oak, thereby gaining complete ownership and control of the Mine No. 1 mine (Mine No. 1), located near the city of McLeansboro, Illinois. Our subsidiary, Hamilton County Coal, LLC (Hamilton), formerly known as Alliance WOR Processing, LLC, operates Mine No. 1, which is an underground longwall mining operation producing high-sulfur coal from the Herrin No. 6 seam.

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Initial development production from the continuous miner units began in 2013, and longwall mining began in October 2014. As part of our initial transaction with White Oak in 2011, Hamilton acquired a preferred equity interest in White Oak and constructed, owned, and operated the coal handling and processing facilities associated with Mine No. 1, which has throughput capacity of 2,000 tons of raw coal per hour. Hamilton has the ability to ship production from Mine No. 1 via the CSX and EVW rail directly to customers or to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries. For more information about the White Oak transactions, please read Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions

Alliance WOR Properties, LLC. Alliance Resource Properties owns or controls coal reserves that it leases to certain of our subsidiaries that operate our mining complexes. In September 2011, and in subsequent follow-on transactions, Alliance Resource Properties subsidiary, Alliance WOR Properties, LLC (WOR Properties), acquired from and leased back to White Oak the rights to approximately 309.6 million tons of proven and probable high-sulfur coal reserves. Prior to our July 31, 2015 acquisition of White Oak, White Oak paid WOR Properties earned royalties during the period beginning January 1, 2015 and ending July 31, 2015 in the amount of \$11.4 million. Earned royalties from coal production in 2014 and 2013 in the amount of \$0.2 million and \$15.0 thousand were paid to WOR Properties by White Oak. Following the acquisition, royalty activities under leases between Hamilton and Alliance Resource Properties are accounted for as intercompany transactions and are eliminated upon consolidation.

Appalachian Operations

Our Appalachian mining operations are located in eastern Kentucky, Maryland and West Virginia. As of February 11, 2016, we had 916 employees, and we operate three mining complexes in Appalachia.

MC Mining Complex. The MC Mining Complex is located near the city of Pikeville in Pike County, Kentucky. We acquired the mine in 1989. Our subsidiary, MC Mining, LLC (MC Mining), owns the mining complex and controls the reserves, and our subsidiary, Excel Mining, LLC (Excel) conducts all mining operations. The underground operation utilizes continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal. The preparation plant has throughput capacity of 1,000 tons of raw coal per hour. Substantially all of the coal produced at MC Mining in 2015 met or exceeded the compliance requirements of Phase II of the Federal Clean Air Act (CAA) (see Regulation and Laws *Air Emissions* below). Coal produced from the mine is shipped via the CSX railroad directly to customers or to various transloading facilities on the Ohio River for barge deliveries, or by truck via U.S. and state highways directly to customers or to various docks on the Big Sandy River for barge deliveries.

Mettiki Complex. The Mettiki Complex comprises the Mountain View mine located in Tucker County, West Virginia operated by our subsidiary Mettiki Coal (WV), LLC (Mettiki (WV)) and a preparation plant located near the city of Oakland in Garrett County, Maryland operated by our subsidiary Mettiki Coal, LLC (Mettiki (MD)). In addition, production from the Mountain View mine can be supplemented with production from a temporarily sealed smaller-scale mine in Maryland controlled by another of our subsidiaries, Backbone Mountain, LLC. Mettiki (WV) began continuous miner development of the Mountain View mine in July 2005 and began longwall mining in November 2006. The Mountain View mine produces medium-sulfur coal, which is transported by truck either to the

Mettiki (MD) preparation plant for processing or directly to the coal blending facility at the Virginia Electric and Power Company Mt. Storm Power Station. The Mettiki (MD) preparation plant has throughput capacity of 1,350 tons of raw coal per hour. Coal processed at the preparation plant can be trucked to the blending facility at Mt. Storm or shipped via the CSX railroad, which provides the opportunity to ship into the domestic and international thermal and metallurgical coal markets.

Tunnel Ridge Complex. Our subsidiary, Tunnel Ridge, LLC (Tunnel Ridge), operates the Tunnel Ridge mine, an underground longwall mine in the Pittsburgh No. 8 coal seam, located near Wheeling, West Virginia. Tunnel Ridge began construction of the mine and related facilities in 2008. Development mining began in 2010, and longwall mining operations began at Tunnel Ridge in May 2012. Coal produced from the Tunnel Ridge mine is transported by conveyor belt to a barge loading facility on the Ohio River. Through an agreement with a third party, Tunnel Ridge has the ability to transload coal from barges for rail shipment on the Wheeling and Lake Erie Railway.

Other Operations

Mt. Vernon Transfer Terminal, LLC

Our subsidiary, Mt. Vernon, leases land and operates a coal loading terminal on the Ohio River at Mt. Vernon, Indiana. Coal is delivered to Mt. Vernon by both rail and truck. The terminal has a capacity of 8.0 million tons per year

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with existing ground storage of approximately 60,000 to 70,000 tons. During 2015, the terminal loaded approximately 3.4 million tons for customers of Gibson County Coal, Hamilton County Coal, Hopkins County Coal and White County Coal.

Coal Brokerage

As markets allow, we buy coal from non-affiliated producers principally throughout the eastern U.S., which we then resell. We have a policy of matching our outside coal purchases and sales to minimize market risks associated with buying and reselling coal. In 2015, we did not make outside coal purchases for brokerage activity.

Matrix Group

Our subsidiaries, Matrix Design Group, LLC (Matrix Design) and its subsidiaries Matrix Design International, LLC and Matrix Design Africa (PTY) LTD, and Alliance Design Group, LLC (Alliance Design) (collectively the Matrix Design entities and Alliance Design are referred to as the Matrix Group), provide a variety of mine products and services for our mining operations and certain products and services to unrelated parties. We acquired this business in September 2006. Matrix Group s products and services include design of systems for automating and controlling various aspects of industrial and mining environments; and design and sale of mine safety equipment, including its miner and equipment tracking and proximity detection systems.

Alliance Minerals

On November 10, 2014 (the Cavalier Formation Date), our subsidiary, Alliance Minerals, LLC (Alliance Minerals) purchased a 96% ownership interest in Cavalier Minerals JV, LLC (Cavalier Minerals). Cavalier Minerals acquired a 71.7% limited partner interest in AllDale Minerals L.P. (AllDale I) and subsequently acquired a 72.8% limited partner interest in AllDale Minerals II, L.P. (AllDale II , collectively with AllDale I, AllDale Minerals), entities created to purchase oil and gas mineral interests in various geographic locations within producing basins in the continental U.S. Between the Cavalier Formation Date and December 31, 2015, Cavalier Minerals contributed \$65.9 million to AllDale Minerals, of which \$63.1 million was funded by Alliance Minerals. For more information about Cavalier Minerals, please read Item 8. Financial Statements and Supplementary Data Note 11. Variable Interest Entities. For more information about AllDale Minerals, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments.

Additional Services

We develop and market additional services in order to establish ourselves as the supplier of choice for our customers. Historically, and in 2015, revenues from these services were immaterial. In addition, our affiliate, Mid-America Carbonates, LLC (MAC), which was a joint venture of White County Coal, manufactures and sells rock dust to us and to unrelated parties. Effective January 1, 2015, White County Coal acquired the remainder of the interest in MAC, which is now a wholly owned subsidiary of Alliance Coal.

Reportable Segments

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

Coal Marketing and Sales

As is customary in the coal industry, we have entered into long-term coal supply agreements with many of our customers. These arrangements are mutually beneficial to us and our customers in that they provide greater predictability of sales volumes and sales prices. Although many utility customers recently have appeared to favor a shorter-term contracting strategy, in 2015 approximately 92.2% and 93.1% of our sales tonnage and total coal sales, respectively, were sold under long-term contracts (contracts having a term of one year or greater) with committed term expirations ranging from 2016 to 2021. As of February 22, 2016, our nominal commitment under long-term contracts was approximately 34.3 million tons in 2016, 19.1 million tons in 2017, 14.5 million tons in 2018 and 7.1 million tons in 2019. The commitment of coal under contract is an approximate number because a limited number of our contracts contain provisions that could cause the nominal commitment to increase or decrease; however, the overall variance to

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total committed sales is minimal. The contractual time commitments for customers to nominate future purchase volumes under these contracts are typically sufficient to allow us to balance our sales commitments with prospective production capacity. In addition, the nominal commitment can otherwise change because of reopener provisions contained in certain of these long-term contracts.

The provisions of long-term contracts are the results of both bidding procedures and extensive negotiations with each customer. As a result, the provisions of these contracts vary significantly in many respects, including, among other factors, price adjustment features, price and contract reopener terms, permitted sources of supply, force majeure provisions, and coal qualities and quantities. Virtually all of our long-term contracts are subject to price adjustment provisions, which periodically permit an increase or decrease in the contract price, typically to reflect changes in specified indices or changes in production costs resulting from regulatory changes, or both. These provisions, however, may not assure that the contract price will reflect every change in production or other costs. Failure of the parties to agree on a price pursuant to an adjustment or a reopener provision can, in some instances, lead to early termination of a contract. Some of the long-term contracts also permit the contract to be reopened for renegotiation of terms and conditions other than pricing terms, and where a mutually acceptable agreement on terms and conditions cannot be concluded, either party may have the option to terminate the contract. The long-term contracts typically stipulate procedures for transportation of coal, quality control, sampling and weighing. Most contain provisions requiring us to deliver coal within stated ranges for specific coal characteristics such as heat, sulfur, ash, moisture, grindability, volatility and other qualities. Failure to meet these specifications can result in economic penalties, rejection or suspension of shipments or termination of the contracts. While most of the contracts specify the approved seams and/or approved locations from which the coal is to be mined, some contracts allow the coal to be sourced from more than one mine or location. Although the volume to be delivered pursuant to a long-term contract is stipulated, the buyers often have the option to vary the volume within specified limits.

Reliance on Major Customers

Our two largest customers in 2015 were Louisville Gas and Electric Company and Tennessee Valley Authority. During 2015, we derived approximately 28.5% of our total revenues from these two customers and at least 10.0% of our total revenues from each of the two. For more information about these customers, please read Item 8. Financial Statements and Supplementary Data Note 21. Concentration of Credit Risk and Major Customers.

Competition

The coal industry is intensely competitive. The most important factors on which we compete are coal price, coal quality (including sulfur and heat content), transportation costs from the mine to the customer and the reliability of supply. Our principal competitors include Alpha Natural Resources, Inc., Arch Coal, Inc., CNX Coal Resources LP, CONSOL Energy, Inc. (CONSOL), Foresight Energy LP, Murray Energy, Inc., and Peabody Energy Corporation. While a number of our competitors are experiencing significant financial distress as a result of deteriorating market conditions, and some are involved in reorganization in bankruptcy, we believe these events will not result in a material diminution in available coal supply and that they or their reorganized successors will remain significant competition for ongoing coal sales. We also compete directly with a number of smaller producers in the Illinois Basin and Appalachian regions. The prices we are able to obtain for our coal are primarily linked to coal consumption patterns of domestic electricity generating utilities, which in turn are influenced by economic activity, government regulations, weather and technological developments. At times, we have exported a portion of our coal into the international coal markets and historically the prices we obtain for our export coal have been influenced by a number of factors, such as global economic conditions, weather patterns and political instability, among others. Further, coal competes with other fuels such as petroleum, natural gas, nuclear energy and renewable energy sources for electrical power generation. Over time, costs and other factors, such as safety and environmental considerations, may affect the overall demand for coal as a fuel. For additional information, please see Item 1A. Risk Factors. At times, we may also compete with companies that produce coal from one or more foreign countries.

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Transportation

Our coal is transported to our customers by rail, barge and truck. Depending on the proximity of the customer to the mine and the transportation available for delivering coal to that customer, transportation costs can be a substantial part of the total delivered cost of a customer's coal. As a consequence, the availability and cost of transportation constitute important factors in the marketability of coal. We believe our mines are located in favorable geographic locations that minimize transportation costs for our customers, and in many cases we are able to accommodate multiple transportation options. Our customers typically pay the transportation costs from the mining complex to the destination, which is the standard practice in the industry. Approximately 42.1% of our 2015 sales volume was initially shipped from the mines by rail, 40.8% was shipped from the mines by barge and 17.1% was shipped from the mines by truck. In 2015, the largest volume transporter of our coal shipments was the CSX railroad, which moved approximately 14.9% of our tonnage over its rail system. The practices of, rates set by and capacity availability of, the transportation company serving a particular mine or customer may affect, either adversely or favorably, our marketing efforts with respect to coal produced from the relevant mine.

Regulation and Laws

The coal mining industry is subject to extensive regulation by federal, state and local authorities on matters such as:

- employee health and safety;
- mine permits and other licensing requirements;
- air quality standards;
- water quality standards;
- storage of petroleum products and substances that are regarded as hazardous under applicable laws or that, if spilled, could reach waterways or wetlands;
- plant and wildlife protection;
- reclamation and restoration of mining properties after mining is completed;
- discharge of materials;
- storage and handling of explosives;
- wetlands protection;
- surface subsidence from underground mining; and
- the effects, if any, that mining has on groundwater quality and availability.

In addition, the utility industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which has adversely affected demand for coal. It is possible that new legislation or regulations may be adopted, or that existing laws or regulations may be differently interpreted or more stringently enforced, any of which could have a significant impact on our mining operations or our customers ability to use coal. For more information, please see risk factors described in Item 1A. Risk Factors below.

We are committed to conducting mining operations in compliance with applicable federal, state and local laws and regulations. However, because of the extensive and detailed nature of these regulatory requirements, particularly the regulatory system of the Mine Safety and Health Administration (MSHA) where citations can be issued without regard to fault and many of the standards include subjective elements, it is not reasonable to expect any coal mining company to be free of citations. When we receive a citation, we attempt to remediate any identified condition immediately. While we have not quantified all of the costs of compliance with applicable federal and state laws and associated regulations, those costs have been and are expected to continue to be significant. Compliance with these laws and regulations has substantially increased the cost of coal mining for domestic coal producers.

Capital expenditures for environmental matters have not been material in recent years. We have accrued for the present value of the estimated cost of asset retirement obligations and mine closings, including the cost of treating mine water discharge, when necessary. The accruals for asset retirement obligations and mine closing costs are based upon permit requirements and the costs and timing of asset retirement obligations and mine closing procedures. Although management believes it has made adequate provisions for all expected reclamation and other costs associated with mine closures, future operating results would be adversely affected if these accruals were insufficient.

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Mining Permits and Approvals

Numerous governmental permits or approvals are required for mining operations. Applications for permits require extensive engineering and data analysis and presentation, and must address a variety of environmental, health and safety matters associated with a proposed mining operation. These matters include the manner and sequencing of coal extraction, the storage, use and disposal of waste and other substances and impacts on the environment, the construction of water containment areas, and reclamation of the area after coal extraction. Meeting all requirements imposed by any of these authorities may be costly and time consuming, and may delay or prevent commencement or continuation of mining operations.

The permitting process for certain mining operations can extend over several years and can be subject to administrative and judicial challenge, including by the public. Some required mining permits are becoming increasingly difficult to obtain in a timely manner, or at all. We cannot assure you that we will not experience difficulty or delays in obtaining mining permits in the future or that a current permit will not be revoked.

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

Mine Health and Safety Laws

Stringent safety and health standards have been imposed by federal legislation since the Federal Coal Mine Health and Safety Act of 1969 (CMHSA) was adopted. The Federal Mine Safety and Health Act of 1977 (FMSHA), and regulations adopted pursuant thereto, significantly expanded the enforcement of health and safety standards of the CMHSA, and imposed extensive and detailed safety and health standards on numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations, and numerous other matters. MSHA monitors and rigorously enforces compliance with these federal laws and regulations. In addition, most of the states where we operate have state programs for mine safety and health regulation and enforcement. Federal and state safety and health regulations affecting the coal mining industry are perhaps the most comprehensive and rigorous system in the U.S. for protection of employee safety and have a significant effect on our operating costs. Although many of the requirements primarily impact underground mining, our competitors in all of the areas in which we operate are subject to the same laws and regulations.

The FMSHA has been construed as authorizing MSHA to issue citations and orders pursuant to the legal doctrine of strict liability, or liability without fault, and FMSHA requires imposition of a civil penalty for each cited violation. Negligence and gravity assessments, and other factors can result in the issuance of various types of orders, including orders requiring withdrawal from the mine or the affected area, and some orders can also result in the imposition of civil penalties. The FMSHA also contains criminal liability provisions. For example, criminal liability may be imposed upon corporate operators who knowingly and willfully authorize, order or carry out violations of the FMSHA, or its mandatory health and safety standards.

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

- sealing off abandoned areas of underground coal mines;
- mine safety equipment, training and emergency reporting requirements;
- substantially increased civil penalties for regulatory violations;
- training and availability of mine rescue teams;
- underground refuge alternatives capable of sustaining trapped miners in the event of an emergency;
- flame-resistant conveyor belts, fire prevention and detection, and use of air from the belt entry; and

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

MSHA continues to interpret and implement various provisions of the MINER Act, along with introducing new proposed regulations and standards.

In 2014, MSHA began implementation of a finalized new regulation titled Lowering Miner's Exposure to Respirable Coal Mine Dust, Including Continuous Personal Dust Monitors. The final rule implements a reduction in the allowable respirable coal mine dust exposure limits, requires the use of sampling data taken from a single sample rather than an average of samples, and increases oversight by MSHA regarding coal mine dust and ventilation issues at each mine, including the approval process for ventilation plans at each mine, all of which is expected to increase mining costs. Legal challenges to the final rule have been unsuccessful, thus far, and presently MSHA is expected to require mine operators to implement all aspects of the final rule by the end of 2016.

Additionally, in July 2014, MSHA proposed a rule addressing the criteria and procedures for assessment of civil penalties. Public commenters have expressed concern that the proposed rule exceeds MSHA's rulemaking authority and would result in substantially increased civil penalties for regulatory violations cited by MSHA. MSHA last revised the process for proposing civil penalties in 2006 and, as discussed above, civil penalties increased significantly. The notice-and-comment period for this proposed rule has closed, and it is uncertain when MSHA will present a final rule addressing these civil penalties.

In January 2015, MSHA published a final rule requiring mine operators to install proximity detection systems on continuous mining machines, over a staggered time frame ranging from November 2015 through March 2018. The proximity detection systems initiate a warning or shutdown the continuous mining machine depending on the proximity of the machine to a miner.

Subsequent to passage of the MINER Act, Illinois, Kentucky, Pennsylvania and West Virginia have enacted legislation addressing issues such as mine safety and accident reporting, increased civil and criminal penalties, and increased inspections and oversight; and since January 2012, West Virginia has continued to consider additional mine safety legislation. Additionally, state administrative agencies can promulgate administrative rules and regulations affecting our operations. Other states may pass similar legislation or administrative regulations in the future.

Some of the costs of complying with existing regulations and implementing new safety and health regulations may be passed on to our customers. Although we have not quantified the full impact, implementing and complying with these new state and federal safety laws and regulations have had, and are expected to continue to have, an adverse impact on our results of operations and financial position.

Black Lung Benefits Act

The Black Lung Benefits Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981 (BLBA) requires businesses that conduct current mining operations to make payments of black lung benefits to current and former coal miners with black lung disease and to some survivors of a miner who dies from this disease. The BLBA levies a tax on production of \$1.10 per ton for underground-mined coal and \$0.55 per ton for surface-mined coal, but not to exceed 4.4% of the applicable sales price, in order to compensate miners who are totally disabled

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due to black lung disease and some survivors of miners who died from this disease, and who were last employed as miners prior to 1970 or subsequently where no responsible coal mine operator has been identified for claims. In addition, the BLBA provides that some claims for which coal operators had previously been responsible are or will become obligations of the government trust funded by the tax. The Revenue Act of 1987 extended the termination date of this tax from January 1, 1996, to the earlier of January 1, 2014, or the date on which the government trust becomes solvent. For miners last employed as miners after 1969 and who are determined to have contracted black lung, we self-insure the potential cost of compensating such miners using our actuary estimates of the cost of present and future claims. We are also liable under state statutes for black lung claims. Congress and state legislatures regularly consider various items of black lung legislation, which, if enacted, could adversely affect our business, results of operations and financial position.

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

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The Patient Protection and Affordable Care Act enacted in 2010, includes significant changes to the federal black lung program, retroactive to 2005, including an automatic survivor benefit paid upon the death of a miner with an awarded black lung claim and establishes a rebuttable presumption with regard to pneumoconiosis among miners with 15 or more years of coal mine employment that are totally disabled by a respiratory condition. These changes could have a material impact on our costs expended in association with the federal black lung program.

Workers Compensation

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. Workers compensation laws also compensate survivors of workers who suffer employment related deaths. Several states in which we operate consider changes in workers compensation laws from time to time. We generally self-insure this potential expense using our actuary estimates of the cost of present and future claims. For more information concerning our requirement to maintain bonds to secure our workers compensation obligations, see the discussion of surety bonds below under *Bonding Requirements*.

Coal Industry Retiree Health Benefits Act

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

Surface Mining Control and Reclamation Act

The Federal Surface Mining Control and Reclamation Act of 1977 (SMCRA) and similar state statutes establish operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of deep mining. Although we have minimal surface mining activity and no mountaintop removal mining activity, SMCRA nevertheless requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of our mining activities.

SMCRA and similar state statutes require, among other things, that mined property be restored in accordance with specified standards and approved reclamation plans. SMCRA requires us to restore the surface to approximate the original contours as contemporaneously as practicable with the completion of surface mining operations. Federal law and some states impose on mine operators the responsibility for replacing certain water supplies damaged by mining operations and repairing or compensating for damage to certain structures occurring on the surface as a result of mine subsidence, a consequence of longwall mining and possibly other mining operations. We believe we are in compliance in all material respects with applicable regulations relating to reclamation.

In addition, the Abandoned Mine Lands Program, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The tax for surface-mined and underground-mined coal is \$0.28 per ton and \$0.12 per ton, respectively. We have accrued the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. Please read Item 8. Financial Statements and Supplementary Data Note 17. Asset Retirement Obligations. In addition, states from time to time have increased and may continue to increase their fees and taxes to fund reclamation or orphaned mine sites and acid mine drainage control on a statewide basis. The President's Budget for Fiscal Year 2017 proposes to restore fees on coal production to pre-2006 levels in order to fund the reclamation of abandoned mines. If enacted into law, this proposal would increase the fees on surface mining to \$0.35 per ton and \$0.15 for underground mines.

Under SMCRA, responsibility for unabated violations, unpaid civil penalties and unpaid reclamation fees of independent contract mine operators and other third parties can be imputed to other companies that are deemed, according to the regulations, to have owned or controlled the third-party violator. Sanctions against the owner or controller are quite severe and can include being blocked from receiving new permits and having any permits revoked

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that were issued after the time of the violations or after the time civil penalties or reclamation fees became due. We are not aware of any currently pending or asserted claims against us relating to the ownership or control theories discussed above. However, we cannot assure you that such claims will not be asserted in the future.

The U.S. Office of Surface Mining Reclamation (OSM) published in November 2009 an Advance Notice of Proposed Rulemaking, announcing its intent to revise the Stream Buffer Zone (SBZ) rule published in December 2008. The SBZ rule prohibits mining disturbances within 100 feet of streams if there would be a negative effect on water quality. Environmental groups brought lawsuits challenging the rule, and in a March 2010 settlement, the OSM agreed to rewrite the SBZ rule. In January 2013, the environmental groups reopened the litigation against OSM for failure to abide by the terms of the settlement. Oral arguments were heard on January 31, 2014. OSM published a notice on December 22, 2014 to vacate the 2008 SBZ rule to comply with an order issued by the U.S. District Court for the District of Columbia. OSM reimplemented the 1983 SBZ rule.

OSM has proposed a Stream Protection Rule (SPR) to replace the vacated SBZ rule. This draft rule was published on July 17, 2015. Among the 475 changes or modifications to existing rules within the SMCRA program are; 1) significant new groundwater monitoring requirements, 2) redefinitions of key SMCRA terms including a federal definition of material damage to the hydrologic balance which overlaps and conflicts with existing requirements under the Clean Water Act, 3) new requirements related to both listed and proposed threatened and endangered species under the Endangered Species Act, 4) increased bonding requirements for stream restoration and restrictions on the use of certain types of bonds, 5) expanded application to ephemeral streams while importing the U.S. Environmental Protection Agency (EPA) definition of Waters of the United States (WOTUS), and 6) enhanced requirements to restore streams to their original ecological function. We anticipate that the SPR will be published as a final rule prior to the end of 2016. These actions by the OSM potentially could result in additional delays and costs associated with obtaining permits, prohibitions or restrictions relating to mining activities near streams, and additional enforcement actions. The requirements of the SPR rule, if adopted, will likely be stricter than the prior SBZ rule and may adversely affect our business and operations.

Following the spill of coal combustion residues (CCRs) in the Tennessee Valley Authority impoundment in Kingston, Tennessee, in December 2009, the EPA issued proposed rules on CCRs in 2010. This final rule was published on December 19, 2014. The EPA's final rule does not address the placement of CCRs in minefills or non-minefill uses of CCRs at coal mine sites. OSM has announced their intention to release a proposed rule to regulate placement and use of CCRs at coal mine sites in August 2015. These actions by OSM, potentially could result in additional delays and costs associated with obtaining permits, prohibitions or restrictions relating to mining activities, and additional enforcement actions.

Bonding Requirements

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, to pay federal and state workers compensation, to pay certain black lung claims, and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. It has become increasingly difficult for us and for our competitors to secure new surety bonds without posting collateral. In addition, surety bond costs have increased while the market terms of surety bonds have generally become less favorable to us. It is possible that surety bond issuers may refuse to renew bonds or may demand additional collateral upon those renewals. Our failure to maintain, or inability to acquire, surety bonds that are required by state and federal laws would have a material adverse effect on our ability to produce coal, which could affect our profitability and cash flow. For additional information, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources *Off-Balance Sheet Arrangements*.

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Air Emissions

The CAA and similar state and local laws and regulations regulate emissions into the air and affect coal mining operations. The CAA directly impacts our coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, achieve certain emissions standards, or implement certain work practices on sources that emit various air pollutants. The CAA also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants and other coal-burning facilities. There have been a series of federal rulemakings focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technology and any additional measures required under applicable state and federal laws and regulations related to air emissions will make it more costly to operate coal-fired power plants and possibly other facilities that consume coal and, depending on the requirements of individual state implementation plans (SIPs), could make coal a less attractive fuel alternative in the planning and building of power plants in the future. A significant reduction in coal's share of power generating capacity could have a material adverse effect on our business, financial condition and results of operations. Since 2010, utilities have formally announced the retirement or conversion of 499 coal-fired electric generating units through 2030.

In addition to the greenhouse gas (GHG) issues discussed below, the air emissions programs that may affect our operations, directly or indirectly, include, but are not limited to, the following:

- The EPA's Acid Rain Program, provided in Title IV of the CAA, regulates emissions of sulfur dioxide from electric generating facilities. Sulfur dioxide is a by-product of coal combustion. Affected facilities purchase or are otherwise allocated sulfur dioxide emissions allowances, which must be surrendered annually in an amount equal to a facility's sulfur dioxide emissions in that year. Affected facilities may sell or trade excess allowances to other facilities that require additional allowances to offset their sulfur dioxide emissions. In addition to purchasing or trading for additional sulfur dioxide allowances, affected power facilities can satisfy the requirements of the EPA's Acid Rain Program by switching to lower-sulfur fuels, installing pollution control devices such as flue gas desulfurization systems, or scrubbers, or by reducing electricity generating levels. In 2015, we sold 96.1% of our total tons to electric utilities, of which 99.7% was sold to utility plants with installed pollution control devices. These requirements would not be supplanted by a replacement rule for the Clean Air Interstate Rule (CAIR), discussed below.
- The CAIR calls for power plants in 28 states and Washington, D.C. to reduce emission levels of sulfur dioxide and nitrogen oxide pursuant to a cap-and-trade program similar to the system in effect for acid rain. In June 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR), a replacement rule for CAIR, which would have required 28 states in the Midwest and eastern seaboard to reduce power plant emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. Under CSAPR, the first phase of the nitrogen oxide and sulfur dioxide emissions reductions would have commenced in 2012 with further reductions effective in 2014. However, in August 2012, the D.C. Circuit Court of Appeals vacated CSAPR, finding the EPA exceeded its statutory authority under the CAA and striking down the EPA's decision to require federal implementation plans (FIPs), rather than SIPs, to implement mandated reductions. In its ruling, the D.C. Circuit Court of Appeals ordered the EPA to continue administering CAIR but proceed expeditiously to promulgate a replacement rule for CAIR. The U.S. Supreme Court granted the EPA's certiorari petition appealing the D.C. Circuit Court of Appeals' decision and heard oral arguments on December 10, 2013. In April 2014, the U.S. Supreme Court reversed and remanded the D.C. Circuit Court of Appeals' decision, concluding that the EPA's approach is lawful. CSAPR has been reinstated and the

EPA began implementation of Phase 1 requirements on January 1, 2015; Phase 2 will begin January 1, 2017. Some issues that remain will be litigated further in D.C. Circuit Court of Appeals. The impacts of CSAPR are unknown at the present time due to the implementation of Mercury and Air Toxic Standards (MATS), discussed below, and the significant number of coal retirements that have resulted and that potentially will result from MATS.

- In February 2012, the EPA adopted the MATS, which regulates the emission of mercury and other metals, fine particulates, and acid gases such as hydrogen chloride from coal and oil-fired power plants. In March 2013, the EPA finalized a reconsideration of the MATS rule as it pertains to new power plants, principally adjusting emissions limits to levels attainable by existing control technologies. Appeals were filed and oral arguments were heard by the D.C. Circuit Court of Appeals in December 2013. On April 15, 2014 the D.C. Circuit Court of Appeals upheld MATS. On June 29, 2015 the Supreme Court remanded the final rule back to the D.C. Circuit holding that the agency must consider cost before deciding whether regulation is

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necessary and appropriate. On December 1, 2015, the EPA issued, for comment, the proposed Supplemental Finding. The agency has indicated that the Supplemental Finding will be issued by April 15, 2016. Many electric generators have already announced retirements due to the MATS rule. If upheld by the D.C. Circuit Court of Appeals, MATS will force generators to make capital investments to retrofit power plants and could lead to additional premature retirements of older coal-fired generating units. The announced and possible additional retirements are likely to reduce the demand for coal. Apart from MATS, several states have enacted or proposed regulations requiring reductions in mercury emissions from coal-fired power plants, and federal legislation to reduce mercury emissions from power plants has been proposed. Regulation of mercury emissions by the EPA, states, or Congress may decrease the future demand for coal. We continue to evaluate the possible scenarios associated with CSAPR and MATS and the effects they may have on our business and our results of operations, financial condition or cash flows.

- In January 2013, the EPA issued final Maximum Achievable Control Technology (MACT) standards for several classes of boilers and process heaters, including large coal-fired boilers and process heaters (Boiler MACT), which require owners of industrial, commercial, and institutional boilers to comply with standards for air pollutants, including mercury and other metals, fine particulates, and acid gases such as hydrogen chloride. Businesses and environmental groups have filed legal challenges to Boiler MACT in the D.C. Circuit Court of Appeals and petitioned the EPA to reconsider the rule. On December 1, 2014, the EPA announced reconsideration of the standard and will accept public comment on five issues for its standards on area sources, will review three issues related to its major-source boiler standards, and four issues relating to commercial and solid waste incinerator units. Before reconsideration, the EPA estimated the rule will affect 1,700 existing major source facilities with an estimated 14,316 boilers and process heaters. While some owners would make capital expenditures to retrofit boilers and process heaters, a number of boilers and process heaters could be prematurely retired. Retirements are likely to reduce the demand for coal. The impact of the regulations will depend on the EPA's reconsideration and the outcome of subsequent legal challenges.

- The EPA is required by the CAA to periodically re-evaluate the available health effects information to determine whether the national ambient air quality standards (NAAQS) should be revised. Pursuant to this process, the EPA has adopted more stringent NAAQS for fine particulate matter (PM), ozone, nitrogen oxide and sulfur dioxide. As a result, some states will be required to amend their existing SIPs to attain and maintain compliance with the new air quality standards and other states will be required to develop new SIPs for areas that were previously in attainment but do not attain the new standards. In addition, under the revised ozone NAAQS, significant additional emissions control expenditures may be required at coal-fired power plants. Initial non-attainment determinations related to the revised sulfur dioxide standard became effective in October 2013. In addition, in January 2013, the EPA updated the NAAQS for fine particulate matter emitted by a wide variety of sources including power plants, industrial facilities, and gasoline and diesel engines, tightening the annual PM 2.5 standard to 12 micrograms per cubic meter. The revised standard became effective in March 2013. In November 2013, the EPA proposed a rule to clarify PM 2.5 implementation requirements to the states for current 1997 and 2006 non-attainment areas. On October 26, 2015, the EPA published a final rule that reduced the ozone NAAQS from 75 to 70 ppb. Murray Energy filed a challenge to the final rule in the D.C. Circuit. Since that time, other industry and state petitioners have filed challenges as have several environmental groups. Attainment dates for the new standards range between 2013 and 2030, depending on the severity of the non-attainment. In July 2009, the D.C. Circuit Court of Appeals vacated part of a rule implementing the ozone NAAQS and remanded certain other aspects of the rule to the EPA for further consideration. In June 2013, the EPA proposed a rule for implementing the 2008 ozone NAAQS. In November 2014, the EPA proposed to increase the stringency of the 2008 ozone standard from 75 parts per billion (ppb) to between 65 ppb and 70 ppb. A new standard may impose additional emissions control requirements on new and expanded coal-fired power plants and industrial boilers. Because coal mining operations and coal-fired electric generating facilities emit particulate matter

and sulfur dioxide, our mining operations and our customers could be affected when the new standards are implemented by the applicable states, and developments might indirectly reduce the demand for coal.

- The EPA's regional haze program is designed to protect and improve visibility at and around national parks, national wilderness areas and international parks. Under the program, states are required to develop SIPs to improve visibility. Typically, these plans call for reductions in sulfur dioxide and nitrogen oxide emissions from coal-fueled electric plants. In recent cases, the EPA has decided to negate the SIPs and impose

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stringent requirements through FIPs. The regional haze program, including particularly the EPA's FIPs, and any future regulations may restrict the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas and may require some existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions. These requirements could limit the demand for coal in some locations.

- The EPA's new source review (NSR) program under the CAA in certain circumstances requires existing coal-fired power plants, when modifications to those plants significantly increase emissions, to install more stringent air emissions control equipment. The Department of Justice, on behalf of the EPA, has filed lawsuits against a number of coal-fired electric generating facilities alleging violations of the NSR program. The EPA has alleged that certain modifications have been made to these facilities without first obtaining certain permits issued under the program. Several of these lawsuits have settled, but others remain pending. Depending on the ultimate resolution of these cases, demand for coal could be affected.

Carbon Dioxide Emissions

Combustion of fossil fuels, such as the coal we produce, results in the emission of carbon dioxide, which is considered a GHG. Combustion of fuel for mining equipment used in coal production also emits GHGs. Future regulation of GHG emissions in the U.S. could occur pursuant to future U.S. treaty commitments, new domestic legislation or regulation by the EPA. President Obama has expressed support for a mandatory cap and trade program to restrict or regulate emissions of GHGs and Congress has considered various proposals to reduce GHG emissions, and it is possible federal legislation could be adopted in the future. Internationally, the Kyoto Protocol set binding emission targets for developed countries that ratified it (the U.S. did not ratify, and Canada officially withdrew from its Kyoto commitment in 2012) to reduce their global GHG emissions. The Kyoto Protocol was nominally extended past its expiration date of December 2012, with a requirement for a new legal construct to be put into place by 2015. Most recently, the United Nations Framework Convention on Climate Change met in Paris, France in December 2015 and agreed to an international climate agreement. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions. These commitments could further reduce demand and prices for our coal. Also, many states, regions and governmental bodies have adopted GHG initiatives and have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities, including coal-fired electric generating facilities. Depending on the particular regulatory program that may be enacted, at either the federal or state level, the demand for coal could be negatively impacted, which would have an adverse effect on our operations.

Even in the absence of new federal legislation, the EPA has begun to regulate GHG emissions under the CAA based on the U.S. Supreme Court's 2007 decision in *Massachusetts v. Environmental Protection Agency* that the EPA has authority to regulate GHG emissions. In 2009, the EPA issued a final rule, known as the (Endangerment Finding), declaring that GHG emissions, including carbon dioxide and methane, endanger public health and welfare and that six GHGs, including carbon dioxide and methane, emitted by motor vehicles endanger both the public health and welfare.

In May 2010, the EPA issued its final tailoring rule for GHG emissions, a policy aimed at shielding small emission sources from CAA permitting requirements. The EPA's rule phases in various GHG-related permitting requirements beginning in January 2011. Beginning July 1, 2011, the EPA requires facilities that must already obtain NSR permits (new or modified stationary sources) for other pollutants to include GHGs in their permits for new construction projects that emit at least 100,000 tons per year of GHGs and existing facilities that increase their emissions by at least 75,000 tons per year. These permits require that the permittee adopt the Best Available Control Technology (BACT). In June 2012, the D.C. Circuit Court of Appeals upheld these permitting regulations. In June 2014, the U.S. Supreme Court invalidated the EPA's

position that power plants and other sources can be subject to permitting requirements based on their GHG emissions alone. For CO₂ BACT to apply, CAA permitting must be triggered by another regulated pollutant (e.g., SO₂). Currently the impacts are uncertain. Industry and the EPA filed motions with the D.C. Circuit Court of Appeals. On April 10, 2015, the D.C. Circuit ordered the EPA regulations under review to be vacated, with certain limitations. On August 19, 2015, the EPA issued a final rule amending its PSD and Title V regulations to remove portions of those regulations that were vacated by the D.C. Circuit.

As a result of revisions to its preconstruction permitting rules that became fully effective in 2011, the EPA is now requiring new sources, including coal-fired power plants, to undergo control technology reviews for GHGs (predominantly carbon dioxide) as a condition of permit issuance. These reviews may impose limits on GHG emissions,

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or otherwise be used to compel consideration of alternative fuels and generation systems, as well as increase litigation risk for and so discourage development of coal-fired power plants.

In March 2012, the EPA proposed New Source Performance Standards (NSPS) for carbon dioxide emissions from new fossil fuel-fired power plants. The proposal requires new coal units to meet a carbon dioxide emissions standard of 1,000 lbs. CO₂/MWh, which is equivalent to the carbon dioxide emitted by a natural gas combined cycle unit. In January 2014, the EPA formally published its re-proposed NSPS for carbon dioxide emissions from new power plants. The re-proposed rule requires an emissions standard of 1,100 lbs. CO₂/MWh for new coal-fired power plants. To meet such a standard, new coal plants would be required to install carbon capture and storage (CCS) technology.

In June 2014, the EPA proposed CO₂ emission guidelines for modified and existing fossil fuel-fired power plants under Section 111(d) of the CAA. The EPA finalized the Clean Power Plan (CPP) in August 2015, which established carbon pollution standards for power plants, called CO₂ emission performance rates. The EPA expects each state to develop implementation plans for power plants in its state to meet the individual state targets established in the CPP. The EPA has given states the option to develop compliance plans for annual rate-based reductions (pounds per megawatt hour) or mass-based tonnage limits for CO₂. The state plans are due in September 2016, subject to potential extensions of up to two years for final plan submission. The compliance period begins in 2022, and emission reductions will be phased in up to 2030. The EPA also proposed a federal compliance plan to implement the CPP in the event that an approvable state plan is not submitted to the EPA. Although each state can determine its own method of compliance, the requirements rely on decreased use of coal and increased use of natural gas and renewables for electricity generation, as well as reductions in the amount of electricity used by consumers. Judicial challenges have been filed. On February 9, 2016, the U.S. Supreme Court issued a stay, halting implementation of the regulations. The stay will be in place until the D.C. Circuit Court of Appeals rules on the merits of the legal challenges and, if following a ruling by the D.C. Circuit Court of Appeals, a writ of certiorari from the Supreme Court is sought and granted, the stay will remain in place until the Supreme Court issues its decision on the merits. If, despite the legal challenges, the rules were implemented in their current form, demand for coal will likely be further decreased, potentially significantly, and adversely impact our business.

In August 2015, the EPA released final rules requiring newly constructed coal-fired steam electric generating units (EGUs) to emit no more than 1,400 lbs CO₂/MWh (gross) and be constructed with CCS to capture 16% of CO₂ produced by an electric generating unit burning bituminous coal. At the same time, the EPA finalized GHG emissions regulations for modified and existing power plants. The rule for modified sources required reducing GHG emissions from any modified or reconstructed source and could limit the ability of generators to upgrade coal-fired power plants thereby reducing the demand for coal. The rule for existing sources proposes to establish different target emission rates (lbs per megawatt hour) for each state and has an overall goal to achieve a 32% reduction of carbon dioxide emissions from 2005 levels by 2030. The compliance period begins in 2022 and in 2030 CO₂ emissions goals must be met.

Collectively, these requirements have led to premature retirements and could lead to additional premature retirements of coal-fired generating units and reduce the demand for coal. Congress has rejected legislation to restrict carbon dioxide emissions from existing power plants and it is unclear whether the EPA has the legal authority to regulate carbon dioxide emissions for existing and modified power plants without additional

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Congressional authority. Challenges to the rule by a number of states and industry groups are pending before the D.C. Circuit Court of Appeals.

On June 28, 2010, the EPA issued the Final Mandatory Reporting of Greenhouse Gases Rule requiring all stationary sources that emit more than 25,000 tons of GHGs per year to collect and report annually to the EPA data regarding such emissions occurring after January 1, 2010. This suite of GHG rules affects many of our customers, as well as additional source categories, including all underground mines subject to quarterly methane sampling by MSHA. Underground mines subject to these rules, including ours, were required to begin monitoring GHG emissions on January 1, 2011 and began reporting to the EPA in 2012.

In October 2013, the U.S. Supreme Court granted a number of petitions for certiorari seeking review of the EPA's approach to GHG regulation. The Supreme Court heard oral arguments in February 2014. On June 23, 2014, the Supreme Court issued an opinion affirming the D.C. Circuit decision in part and reversing the decision in part. The Court struck down the EPA's tailoring rule, making permanent a temporary exclusion that the EPA had provided for small sources. However, the Court's holding affirmed the EPA's authority to regulate GHG emissions from the vast majority of sources subject to the CAA's permitting provisions, and did not affect the EPA's ability to regulate GHG emissions from new and existing sources. Future legislation or new regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs.

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associated with our operations. Substantial limitations on GHG emissions could adversely affect demand for the coal we produce.

There have been numerous protests of and challenges to the permitting of new coal-fired power plants by environmental organizations and state regulators for concerns related to GHG emissions. For instance, various state regulatory authorities have rejected the construction of new coal-fueled power plants based on the uncertainty surrounding the potential costs associated with GHG emissions from these plants under future laws limiting the emissions of carbon dioxide. In addition, several permits issued to new coal-fueled power plants without limits on GHG emissions have been appealed to the EPA's Environmental Appeals Board. In addition, over thirty states have currently adopted renewable energy standards or renewable portfolio standards, which encourage or require electric utilities to obtain a certain percentage of their electric generation portfolio from renewable resources by a certain date. These standards range generally from 10% to 30%, over time periods that generally extend from the present until between 2020 and 2030. Other states may adopt similar requirements, and federal legislation is a possibility in this area. To the extent these requirements affect our current and prospective customers, they may reduce the demand for coal-fired power, and may affect long-term demand for our coal. Finally, a federal appeals court allowed a lawsuit pursuing federal common law claims to proceed against certain utilities on the basis that they may have created a public nuisance due to their emissions of carbon dioxide, while a second federal appeals court dismissed a similar case on procedural grounds. The U.S. Supreme Court overturned that decision in June 2011, holding that federal common law provides no basis for public nuisance claims against utilities due to their carbon dioxide emissions. The Supreme Court did not, however, decide whether similar claims can be brought under state common law. As a result, despite this favorable ruling, tort-type liabilities remain a concern.

In addition, environmental advocacy groups have filed a variety of judicial challenges claiming that the environmental analyses conducted by federal agencies before granting permits and other approvals necessary for certain coal activities do not satisfy the requirements of the National Environmental Policy Act (NEPA). These groups assert that the environmental analyses in question do not adequately consider the climate change impacts of these particular projects. In December 2014 the Council on Environmental Quality (CEQ) released updated draft guidance discussing how federal agencies should consider the effects of GHG emissions and climate change in their NEPA evaluations. The guidance encourages agencies to provide more detailed discussion of the direct, indirect, and cumulative impacts of a proposed action's reasonably foreseeable emissions and effects. This guidance could create additional delays and costs in the NEPA review process or in our operations, or even an inability to obtain necessary federal approvals for our future operations, including due to the increased risk of legal challenges from environmental groups seeking additional analysis of climate impacts.

Many states and regions have adopted GHG initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of GHG by certain facilities, including coal-fired electric generating facilities. For example, in 2005, ten Northeastern states entered into the Regional Greenhouse Gas Initiative agreement (RGGI), calling for implementation of a cap and trade program aimed at reducing carbon dioxide emissions from power plants in the participating states. The members of RGGI have established in statutes and/or regulations a carbon dioxide trading program. Auctions for carbon dioxide allowances under the program began in September 2008. Though New Jersey withdrew from RGGI in 2011, since its inception, several additional northeastern states and Canadian provinces have joined as participants or observers.

Following the RGGI model, five Western states launched the Western Regional Climate Action Initiative to identify, evaluate, and implement collective and cooperative methods of reducing GHG in the region to 15% below 2005 levels by 2020. These states were joined by two additional states and four Canadian provinces and became collectively known as the Western Climate Initiative Partners. However, in November 2011, six states withdrew, leaving California and the four Canadian provinces as members. At a January 2012 stakeholder meeting, this group confirmed a commitment and timetable to create the largest carbon market in North America and provide a model to guide future efforts to establish national approaches in both Canada and the U.S. to reduce GHG emissions. It is likely that these regional efforts will continue.

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It is possible that future international, federal and state initiatives to control GHG emissions could result in increased costs associated with coal production and consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, or otherwise adversely affect our operations and demand for our products, which could have a material adverse effect on our business, financial condition and results of operations.

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Water Discharge

The Federal Clean Water Act (CWA) and similar state and local laws and regulations affect coal mining operations by imposing restrictions on effluent discharge into waters and the discharge of dredged or fill material into the waters of the U.S. Regular monitoring, as well as compliance with reporting requirements and performance standards, is a precondition for the issuance and renewal of permits governing the discharge of pollutants into water. Section 404 of the CWA imposes permitting and mitigation requirements associated with the dredging and filling of wetlands and streams. The CWA and equivalent state legislation, where such equivalent state legislation exists, affect coal mining operations that impact wetlands and streams. Although permitting requirements have been tightened in recent years, we believe we have obtained all necessary permits required under CWA Section 404 as it has traditionally been interpreted by the responsible agencies. However, mitigation requirements under existing and possible future fill permits may vary considerably. For that reason, the setting of post-mine asset retirement obligation accruals for such mitigation projects is difficult to ascertain with certainty and may increase in the future. For more information about asset retirement obligations, please read Item 8. Financial Statements and Supplementary Data Note 17. Asset Retirement Obligations. Although more stringent permitting requirements may be imposed in the future, we are not able to accurately predict the impact, if any, of such permitting requirements.

The U.S. Army Corps of Engineers (Corps of Engineers) maintains two permitting programs under CWA Section 404 for the discharge of dredged or fill material: one for individual permits and a more streamlined program for general permits. In June 2010, the Corps of Engineers suspended the use of general permits under Nationwide Permit 21 (NWP 21) in the Appalachian states. In February 2012, the Corps of Engineers reissued the final 2012 NWP 21. The Center for Biological Diversity later filed a notice of intent to sue the Corps of Engineers based on allegations the 2012 NWP 21 program violated the Endangered Species Act (ESA). The Corps of Engineers and National Marine Fisheries Service (NMFS) have completed their programmatic ESA Section 7 consultation process on the Corps of Engineers 2012 NWP 21 package, and NMFS has issued a revised biological opinion finding that the NWP 21 program does not jeopardize the continued existence of threatened and endangered species and will not result in the destruction or adverse modification of designated critical habitat. However, the opinion contains 12 additional protective measures the Corps of Engineers will implement in certain districts to enhance the protection of listed species and critical habitat. While these measures will not affect previously verified permit activities where construction has not yet been completed, several Corps of Engineers districts with mining operations will be impacted by the additional protective measures going forward. These measures include additional reporting and notification requirements, potential imposition of new regional conditions and additional actions concerning cumulative effects analyses and mitigation. Our coal mining operations typically require Section 404 permits to authorize activities such as the creation of slurry ponds and stream impoundments. The CWA authorizes the EPA to review Section 404 permits issued by the Corps of Engineers, and in 2009, the EPA began reviewing Section 404 permits issued by the Corps of Engineers for coal mining in Appalachia. Currently, significant uncertainty exists regarding the obtaining of permits under the CWA for coal mining operations in Appalachia due to various initiatives launched by the EPA regarding these permits.

For instance, even though the State of West Virginia has been delegated the authority to issue permits for coal mines in that state, the EPA is taking a more active role in its review of National Pollutant Discharge Elimination System (NPDES) permit applications for coal mining operations in Appalachia. The EPA has stated that it plans to review all applications for NPDES permits. Indeed, final guidance issued by the EPA in July 2011, encouraged the EPA Regions 3, 4 and 5 to object to the issuance of state program NPDES permits where the Region does not believe that the proposed permit satisfies the requirements of the CWA, and with regard to state issued general Section 404 permits, support the previously drafted Enhanced Coordination Procedures (ECP). In October 2011, the U.S. District Court for the District of Columbia rejected the ECP on several different legal grounds and later, this same court enjoined the EPA from any further usage of its final guidance. The U.S. Supreme Court denied a request to review this decision. Any future

application of procedures similar to ECP, such as may be enacted following notice and comment rulemaking, would have the potential to delay issuance of permits for surface coal mines, or to change the conditions or restrictions imposed in those permits.

The EPA also has statutory veto power over a Section 404 permit if the EPA determines, after notice and an opportunity for a public hearing, that the permit will have an unacceptable adverse effect. In January 2011, the EPA exercised its veto power to withdraw or restrict the use of a previously issued permit for Spruce No. 1 Surface Mine in West Virginia, which is one of the largest surface mining operations ever authorized in Appalachia. This action was the first time that such power was exercised with regard to a previously permitted coal mining project. A challenge to the EPA's exercise of this authority was made in the U.S. District Court for the District of Columbia and in March 2012, that

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court ruled that the EPA lacked the statutory authority to invalidate an already issued Section 404 permit retroactively. In April 2013, the D.C. Circuit Court of Appeals reversed this decision and authorized the EPA to retroactively veto portions of a Section 404 permit. The U.S. Supreme Court denied a request to review this decision. Any future use of the EPA's Section 404 veto power could create uncertainty with regard to our continued use of current permits, as well as impose additional time and cost burdens on future operations, potentially adversely affecting our coal revenues. In addition, the EPA initiated a preemptive veto prior to the filing of any actual permit application for a copper and gold mine based on fictitious mine scenario. The implications of this decision could allow the EPA to bypass the state permitting process and engage in watershed and land use planning.

Total Maximum Daily Load (TMDL) regulations under the CWA establish a process to calculate the maximum amount of a pollutant that an impaired water body can receive and still meet state water quality standards, and to allocate pollutant loads among the point and non-point pollutant sources discharging into that water body. Likewise, when water quality in a receiving stream is better than required, states are required to conduct an antidegradation review before approving discharge permits. The adoption of new TMDL-related allocations or any changes to antidegradation policies for streams near our coal mines could require more costly water treatment and could adversely affect our coal production.

In June 2014, the EPA issued a new rule providing a definition of the WOTUS. This rule is broadly written and expands the EPA and Corps of Engineers jurisdiction. WOTUS creates new federal authority over lands, ditches, and potentially on-site mining waters. Of critical concern to our industry is the possibility that many water features commonly found on mine sites which are currently not considered jurisdictional could nevertheless fall within the definition of WOTUS under the proposed rule. Ditches, closed loop systems, on-site ponds, impoundments, and other water management features are integral to mining operations, and are used to manage on-site waters in an environmentally sound and frequently statutorily mandated manner. The rule could lead to substantially increased permitting requirements with more costs, delays, and increased risk of litigation. Industry Groups have challenged the final rule. Multiple suits were filed across the country by states, industry, and outside parties. The Coal Industry is currently active in suits in the Texas District Court and 6th Circuit Court of Appeals, though the coalition has moved to intervene in several suits (to both defend certain provisions in the rule important to industry and contest overly-broad provisions). The 6th Circuit ordered a nationwide stay of the rule that will remain in effect at least until it issues its jurisdictional determination (expected in the near future). At present, it is not clear whether an appellate court or multiple district courts will exercise jurisdiction over the claims. Both the 6th Circuit and 11th Circuit are expected to rule in the coming months on the threshold question of whether jurisdiction to hear the case lies with the district courts or the circuit courts.

Hazardous Substances and Wastes

The Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), otherwise known as the Superfund law, and analogous state laws, impose liability, without regard to fault or the legality of the original conduct on certain classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for the release of hazardous substances may be subject to joint and several liability under CERCLA for the costs of cleaning up releases of hazardous substances and natural resource damages. Some products used in coal mining operations generate waste containing hazardous substances. We are currently unaware of any material liability associated with the release or disposal of hazardous substances from our past or present mine sites.

The Federal Resource Conservation and Recovery Act (RCRA) and corresponding state laws regulating hazardous waste affect coal mining operations by imposing requirements for the generation, transportation, treatment, storage, disposal, and cleanup of hazardous wastes. Many

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mining wastes are excluded from the regulatory definition of hazardous wastes, and coal mining operations covered by SMCRA permits are by statute exempted from RCRA permitting. RCRA also allows the EPA to require corrective action at sites where there is a release of hazardous substances. In addition, each state has its own laws regarding the proper management and disposal of waste material. While these laws impose ongoing compliance obligations, such costs are not believed to have a material impact on our operations.

In June 2010, the EPA released a proposed rule to regulate the disposal of certain coal combustion by-products (CCB). The proposed rule set forth two very different options for regulating CCB under RCRA. The first option called for regulation of CCB as a hazardous waste under Subtitle C, which creates a comprehensive program of federally enforceable requirements for waste management and disposal. The second option utilized Subtitle D, which would give

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the EPA authority to set performance standards for waste management facilities and would be enforced primarily through citizen suits. The proposal leaves intact the Bevill exemption for beneficial uses of CCB. In April 2012, several environmental organizations filed suit against the EPA to compel the EPA to take action on the proposed rule. Several companies and industry groups intervened. A consent decree was entered on January 29, 2014.

The EPA finalized the CCB rule on December 19, 2014, setting nationwide solid nonhazardous waste standards for CCB disposal. On April 17, 2015, the EPA finalized regulations under the solid waste provisions (Subtitle D) of RCRA and not the hazardous waste provisions (Subtitle C) which became effective on October 19, 2015. EPA affirms in the preamble to the final rule that this rule does not apply to CCR placed in active or abandoned underground or surface mines. Instead, the U.S. Department of Interior (DOI) and EPA will address the management of CCR in mine fills in a separate regulatory action(s). While classification of CCB as a hazardous waste would have led to more stringent restrictions and higher costs, this regulation may still increase our customers' operating costs and potentially reduce their ability to purchase coal.

On November 3, 2015, EPA published the final rule Effluent Limitations Guidelines and Standards (ELG), revising the regulations for the Steam Electric Power Generating category which became effective on January 4, 2016. The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades. The combined effect of the CCR and ELG regulations has forced power generating companies to close existing ash ponds and will likely force the closure of certain older existing coal burning power plants that cannot comply with the new standards. These regulations add costs to the operation of coal burning power plants on top of other regulations like the 2014 regulations issued under Section 316(b) of the CWA that affects the cooling water intake structures at power plants in order to reduce fish impingement and entrainment. Individually and collectively, these regulations could, in turn, impact the market for our products.

Endangered Species Act

The federal Endangered Species Act (ESA) and counterpart state legislation protect species threatened with possible extinction. The U.S. Fish and Wildlife Service (the USFWS) works closely with the OSM and state regulatory agencies to ensure that species subject to the ESA are protected from mining-related impacts. If the USFWS were to designate species indigenous to the areas in which we operate as threatened or endangered, we could be subject to additional regulatory and permitting requirements.

Other Environmental, Health and Safety Regulations

In addition to the laws and regulations described above, we are subject to regulations regarding underground and above ground storage tanks in which we may store petroleum or other substances. Some monitoring equipment that we use is subject to licensing under the Federal Atomic Energy Act. Water supply wells located on our properties are subject to federal, state, and local regulation. In addition, our use of explosives is subject to the Federal Safe Explosives Act. We are also required to comply with the Federal Safe Drinking Water Act, the Toxic Substance Control Act, and the Emergency Planning and Community Right-to-Know Act. The costs of compliance with these regulations should not have a material adverse effect on our business, financial condition or results of operations.

Employees

To conduct our operations, as of February 11, 2016, we employed 4,243 full-time employees, including 3,864 employees involved in active mining operations, 182 employees in other operations, and 190 corporate employees. Our work force is entirely union-free. On February 5, 2016, due to market conditions, we provided temporary layoff notices to 182 employees, terminated 65 employees and provided The Worker Adjustment and Retraining Notification Act (WARN) notices to 723 employees. It is currently anticipated that a majority of the employees receiving WARN notices will be moved to other operations or remain employees at the affected facilities. While final full-time employee numbers may change as a result of market conditions, it is currently anticipated that our total workforce reduction will be less than 10%.

Administrative Services

On April 1, 2010, effective January 1, 2010, ARLP entered into an amended and restated administrative services agreement (Administrative Services Agreement) with our managing general partner, the Intermediate Partnership,

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AGP, AHGP and Alliance Resource Holdings II, Inc. (ARH II). The Administrative Services Agreement superseded the administrative services agreement signed in connection with the AHGP IPO in 2006. Under the Administrative Services Agreement, certain employees, including some executive officers, provide administrative services for AHGP, AGP and ARH II and their respective affiliates. We are reimbursed for services rendered by our employees on behalf of these entities as provided under the Administrative Services Agreement. We billed and recognized administrative service revenue under this agreement for the year ended December 31, 2015 of \$0.4 million from AHGP and \$0.1 million from ARH II. Please read Item 13 Certain Relationships and Related Transactions, and Director Independence *Administrative Services*.

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ITEM 1A. RISK FACTORS

Risks Inherent in an Investment in Us

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

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

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

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

- the level of our capital expenditures;

- the cost of acquisitions, if any;
- our debt service requirements and restrictions on distributions contained in our current or future debt agreements;
- fluctuations in our working capital needs;
- unavailability of financing resulting in unanticipated liquidity constraints;
- our ability to borrow under our credit agreement to make distributions to our unitholders; and
- the amount, if any, of cash reserves established by our managing general partner, in its discretion, for the proper conduct of our business.

Because of these and other factors, we may not have sufficient available cash to pay a specific level of cash distributions to our unitholders. Furthermore, the amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from financial reserves and working capital borrowing, and is not solely a function of profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record net losses and may be unable to make cash distributions during periods when we record net income. Please read [Risks Related to our Business](#) for a discussion of further risks affecting our ability to generate available cash and [Item 8. Financial Statements and Supplementary Data Note 11 Variable Interest Entities](#) for further discussion of restrictions on the cash available for distribution.

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

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

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

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

As of December 31, 2015, AHGP owned 31,088,338 of our common units. AHGP also owns our managing general partner. In the future, AHGP may sell some or all of these units or it may distribute our common units to the holders of its equity interests and those holders may dispose of some or all of these units. The sale or disposition of a substantial number of our common units in the public markets could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. We do not know whether any such sales would be made in the public market or in private placements, nor do we know what impact such potential or actual sales would have on our unit price in the future.

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

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

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

The credit and risk profile of our managing general partner or its owners may be factors in credit evaluations of us as a master limited partnership. This is because our managing general partner can exercise significant influence or control over our business activities, including our cash distribution policy, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of AHGP, including the degree of its financial leverage and its dependence on cash flow from us to service its indebtedness.

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

Our unitholders do not elect our managing general partner or vote on our managing general partner's officers or directors. As of December 31, 2015, AHGP owned 41.9% of our outstanding units, a sufficient number to block any attempt to remove our managing general partner.

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

In addition, if our unitholders are dissatisfied with the performance of our managing general partner, they will have little ability to remove our general partner. Our managing general partner may not be removed except upon the vote of the holders of at least 66.7% of our outstanding units. As of December 31, 2015, AHGP held approximately 41.9% of our outstanding units. Consequently, it is not currently possible for our managing general partner to be removed without the consent of AHGP. As a result, the price at which our units trade may be lower because of the absence or reduction of a takeover premium in the trading price.

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

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

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

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

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

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

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

We depend on the leadership and involvement of Joseph W. Craft III and other key personnel for the success of our business.

We depend on the leadership and involvement of Mr. Craft, a Director and President and Chief Executive Officer of our managing general partner. Mr. Craft has been integral to our success, due in part to his ability to identify and develop internal growth projects and accretive acquisitions, make strategic decisions and attract and retain key personnel. The loss of his leadership and involvement or the services of any members of our senior management team could have a material adverse effect on our business, financial condition and results of operations.

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

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

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

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

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

- permits our managing general partner to make a number of decisions in its sole discretion. This entitles our managing general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;
- provides that our managing general partner is entitled to make other decisions in its reasonable discretion ;
- generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be fair and reasonable to us and that, in determining whether a transaction or resolution is fair and reasonable, our managing general partner may consider the interests of all parties involved, including its own. Unless our managing general partner has acted in bad faith, the action taken by our managing general partner shall not constitute a breach of its fiduciary duty; and
- provides that our general partners and our officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our general partners and those other persons acted in good faith.

In becoming a limited partner of our partnership, a common unitholder is bound by the provisions in the partnership agreement, including the provisions discussed above.

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

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

Our managing general partner's discretion in determining the level of cash reserves may adversely affect our ability to

make cash distributions to our unitholders.

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

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

Conflicts of interest could arise in the future as a result of relationships between our general partners and their affiliates, on the one hand, and us, on the other hand. As a result of these conflicts our general partners may favor their own interests and those of their affiliates over the interests of our unitholders. The nature of these conflicts includes the following considerations:

- Remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty are limited. Unitholders are deemed to have consented to some actions and conflicts of interest that might otherwise be deemed a breach of fiduciary or other duties under applicable state law.
- Our managing general partner is allowed to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its fiduciary duties to our unitholders.
- Our general partners' affiliates are not prohibited from engaging in other businesses or activities, including those in direct competition with us, except as provided in the omnibus agreement (please see Item 13. Certain Relationships and Related Transactions, and Director Independence Omnibus Agreement).

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- Our managing general partner determines the amount and timing of our asset purchases and sales, capital expenditures, borrowings and reserves, each of which can affect the amount of cash that is distributed to unitholders.
- Our managing general partner determines whether to issue additional units or other equity securities in us.
- Our managing general partner determines which costs are reimbursable by us.
- Our managing general partner controls the enforcement of obligations owed to us by it.
- Our managing general partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our managing general partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or from entering into additional contractual arrangements with any of these entities on our behalf.
- In some instances our managing general partner may borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions.

Risks Related to our Business

Global economic conditions or economic conditions in any of the industries in which our customers operate as well as sustained uncertainty in financial markets may have material adverse impacts on our business and financial condition that we currently cannot predict.

Weakness in global economic conditions or economic conditions in any of the industries we serve or in the financial markets could materially adversely affect our business and financial condition. For example:

- the demand for electricity in the U.S. may decline if economic conditions deteriorate, which may negatively impact the revenues, margins and profitability of our business;
- any inability of our customers to raise capital could adversely affect their ability to honor their obligations to us; and
- our future ability to access the capital markets may be restricted as a result of future economic conditions, which could materially impact our ability to grow our business, including development of our coal reserves.

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

Our results of operations are primarily dependent upon the prices we receive for our coal, as well as our ability to improve productivity and control costs. The prices we receive for our production depends upon factors beyond our control, including:

- the supply of and demand for domestic and foreign coal;
- weather conditions and patterns;
- the proximity to and capacity of transportation facilities;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- the effect of worldwide energy consumption; and
- prevailing economic conditions.

Any adverse change in these factors could result in weaker demand and lower prices for our products. A substantial or extended decline in coal prices could materially and adversely affect us by decreasing our revenues to the extent we are not protected by the terms of existing coal supply agreements.

Fluctuations in the oil and natural gas industry could affect our profitability.

Through our affiliate, Cavalier Minerals, we have investments in oil and gas mineral interests in the continental U.S. Consequently, the value of the investment as well as any resulting cash flows, may fluctuate with changes in the market and prices for oil and natural gas. During 2015, the oil and natural gas industry experienced a significant decrease in commodity prices driven by a global supply/demand imbalance for oil and an oversupply of natural gas in the U.S. The decline in commodity prices and the global economic conditions contributing to the decline have continued into 2016, and low commodity prices may exist for an extended period. If commodity prices continue to decline or remain depressed, we could see a decrease in the value of these investments or in the cash flows they generate. For more information on our involvement with AllDale Minerals, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments of this Annual Report on Form 10-K.

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

We compete with other coal producers in various regions of the U.S. for domestic coal sales. The most important factors on which we compete are delivered price (*i.e.*, the cost of coal delivered to the customer, including transportation costs, which are generally paid by our customers either directly or indirectly), coal quality characteristics, contract flexibility (*e.g.*, volume optionality and multiple supply sources) and reliability of supply. Some competitors may have, among other things, larger financial and operating resources, lower per ton cost of production, or relationships with specific transportation providers. The competition among coal producers may impact our ability to retain or attract

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customers and could adversely impact our revenues and cash available for distribution. In addition, declining prices from an oversupply of coal in the market could reduce our revenues and cash available for distribution.

Changes in consumption patterns by utilities regarding the use of coal have affected our ability to sell the coal we produce. Since 2000, coal's share of U.S. electricity production has fallen from 53% to 31%, while natural gas share has increased from 16% to 35%.

The domestic electric utility industry accounts for over 93.0% of domestic coal consumption. The amount of coal consumed by the domestic electric utility industry is affected primarily by the overall demand for electricity, environmental and other governmental regulations, and the price and availability of competing fuels for power plants such as nuclear, natural gas and fuel oil as well as alternative sources of energy. Gas-fueled generation has the potential to displace coal-fueled generation, particularly from older, less efficient coal-powered generators. We expect that many of the new power plants needed in the U.S. to meet increasing demand for electricity generation will be fueled by natural gas because gas-fired plants are cheaper to construct and permits to construct these plants are easier to obtain.

In addition, future environmental regulation of GHG emissions could accelerate the use by utilities of fuels other than coal. In addition, state and federal mandates for increased use of electricity derived from renewable energy sources could affect demand for coal. For example, the EPA's CPP will likely incentivize additional electric generation from natural gas and renewable sources, and Congress has extended tax credits for renewables. In addition, a number of states have enacted mandates that require electricity suppliers to rely on renewable energy sources in generating a certain percentage of power. Such mandates, combined with other incentives to use renewable energy sources, such as tax credits, could make alternative fuel sources more competitive with coal. A decrease in coal consumption by the domestic electric utility industry could adversely affect the price of coal, which could negatively impact our results of operations and reduce our cash available for distribution.

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

Federal, state and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from coal-fired electric power plants, which are the ultimate consumers of much of our coal. These laws and regulations can require significant emission control expenditures for many coal-fired power plants, and various new and proposed laws and regulations may require further emission reductions and associated emission control expenditures. These laws and regulations may affect demand and prices for coal. There is also continuing pressure on state and federal regulators to impose limits on carbon dioxide emissions from electric power plants, particularly coal-fired power plants. Further, far-reaching federal regulations promulgated by the EPA in the last five years, such as CSAPR and MATS, have led to the premature retirement of coal-fired generating units and a significant reduction in the amount of coal-fired generating capacity in the U.S. At the President's direction the EPA proposed CO₂ emissions requirements, known as the CPP, for existing and modified power plants and published such rules on October 23, 2015. As a result of these current and proposed laws, regulations and regulatory initiatives, electricity generators may elect to switch to other fuels that generate less of these emissions or by-products, further reducing demand for coal. Please read Item 1. Business Regulation and Laws *Air Emissions, Carbon Dioxide Emissions and Hazardous Substances and Wastes.*

Increased regulation of GHG emissions could result in increased operating costs and reduced demand for coal as a fuel source, which could reduce demand for our products, decrease our revenues and reduce our profitability.

Combustion of fossil fuels, such as the coal we produce, results in the emission of carbon dioxide into the atmosphere. On December 15, 2009, the EPA published the Endangerment Finding asserting that emissions of carbon dioxide and other GHGs present an endangerment to public health and the environment, and the EPA has begun to regulate GHG emissions pursuant to the CAA. The EPA has finalized a rule to regulate GHG emissions from new power plants. The finalized standard requires CCS, a technology that is not yet commercially feasible without government subsidies and that has not been demonstrated in the marketplace. This requirement effectively prevents construction of new coal fired power plants. In August 2015, the EPA finalized GHG emissions regulations for modified and existing power plants. The rule for modified sources requires reducing GHG emissions from any modified or reconstructed source and could limit the ability of generators to upgrade coal-fired power plants thereby reducing the demand for coal. The rule for existing sources proposes to establish different target emission rates (lbs per megawatt hour) for each state and has an overall goal to achieve a 32% reduction of carbon dioxide emissions from 2005 levels by 2030. If upheld by courts, the regulation could lead to premature retirements of coal-fired electric generating units and

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significantly reduce the demand for coal. In addition, many states and regions have adopted GHG initiatives. Also, there have been numerous protests of, and challenges to, the permitting of new coal-fired power plants by environmental organizations and state regulators due to concerns related to GHG emissions. Please read Item 1. Business Regulation and Laws *Air Emissions* and *Carbon Dioxide Emissions*.

Numerous political and regulatory authorities and governmental bodies, as well as environmental activist groups, are devoting substantial resources to anti-coal activities to minimize or eliminate the use of coal as a source of electricity generation, domestically and internationally, thereby further reducing the demand and pricing for coal and potentially materially and adversely impacting our future financial results, liquidity and growth prospects.

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate issues, are resulting in increased regulation of coal combustion in many jurisdictions, unfavorable lending policies by lending institutions and divestment efforts affecting the investment community, which could significantly affect demand for our products or our securities. Global climate issues continue to attract public and scientific attention. Some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. Numerous reports, such as the Fourth and Fifth Assessment Report of the Intergovernmental Panel on Climate Change, have also engendered concern about the impacts of human activity, especially fossil fuel combustion, on global climate issues. In turn, increasing government attention is being paid to global climate issues and to emissions of GHGs, including emissions of carbon dioxide from coal combustion by power plants.

Federal, state and local governments may pass laws mandating the use of alternative energy sources, such as wind power and solar energy, which may decrease demand for our coal products. The CPP is one of a number of recent developments aimed at limiting GHG emissions which could limit the market for some of our products by encouraging electric generation from sources that do not generate the same amount of GHG emissions. Enactment of laws or passage of regulations regarding emissions from the combustion of coal by the U.S., states, or other countries, could also result in electricity generators further switching from coal to other fuel sources or additional coal-fueled power plant closures. For example, the agreement resulting from the 2015 United Nations Framework Convention on Climate Change contains voluntary commitments by numerous countries to reduce their GHG emissions, and could result in additional firm commitments by various nations with respect to future GHG emissions. These commitments could further disfavor coal-fired generation, particularly in the medium- to long-term.

Congress has extended certain tax credits for renewable sources of electric generation, which will increase the ability of these sources to compete with our coal products in the market. In addition, the U.S. Department of Interior recently announced a moratorium on issuing certain new coal leases on federal land while the Bureau of Land Management undertakes a programmatic review of the federal coal program. While none of our operations are located on federal lands impacted by this moratorium, it does signal increased attention at the federal level to coal mining practices and the GHG emissions resulting from coal combustion.

There have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, promoting the divestment of fossil fuel equities and also pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. In California, for example, legislation was signed into law in October 2015 that requires California's state pension funds to divest investments in companies that generate 50% or more of their revenue from coal mining by July 2017. Other activist campaigns have urged banks to cease financing coal-driven businesses. As a result, at least ten major banks have enacted such policies in 2015. The impact of such efforts may adversely affect the demand for and price of securities issued by us, and impact our access to the capital and financial markets.

In addition, several well-funded non-governmental organizations have explicitly undertaken campaigns to minimize or eliminate the use of coal as a source of electricity generation. Collectively, these actions and campaigns could adversely impact our future financial results, liquidity and growth prospects.

Government regulations have resulted and could continue to result in significant retirements of coal-fired electric generating units. Retirements of coal-fired electric generating units decrease the overall capacity to burn coal and negatively impact coal demand.

Since 2010, utilities have formally announced the retirement or conversion of 499 coal-fired electric generating units through 2030. These retirements and conversions amount to over 81,000 megawatts (MW) or approximately 25% of

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the 2010 total coal electric generating capacity. At the end of 2015 retirement and conversions affecting 47,000 MW, or approximately 15% of the 2010 total coal electric generating capacity, are estimated to have occurred. Most of these announced and completed retirements and conversions have been attributed to the EPA regulations, although other factors such as an aging coal fleet and low natural gas prices have also played a role. The reduction in coal electric capacity negatively impacts overall coal demand. Additional regulations, such as the EPA's CPP approved early this year, and other factors could lead to additional retirements and conversions and, thereby, additional reductions in the demand for coal.

Plaintiffs in federal court litigation have attempted to pursue tort claims based on the alleged effects of climate change.

In 2004, eight states and New York City sued five electric utility companies in *Connecticut v. American Electric Power Co.* Invoking the federal and state common law of public nuisance, plaintiffs sought an injunction requiring defendants to abate their contribution to the nuisance of climate change by capping carbon dioxide emissions and then reducing them. In June 2011, the U.S. Supreme Court issued a unanimous decision holding that the plaintiffs' federal common law claims were displaced by federal legislation and regulations. The U.S. Supreme Court did not address the plaintiffs' state law tort claims and remanded the issue of preemption for the district court to consider. While the U.S. Supreme Court held that federal common law provides no basis for public nuisance claims against utilities due to their carbon dioxide emissions, tort-type liabilities remain a possibility and a source of concern. Proliferation of successful climate change litigation could adversely impact demand for coal and ultimately have a material adverse effect on our business, financial condition and results of operations.

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

In 2015, we sold approximately 92.2% of our sales tonnage under contracts having a term greater than one year, which we refer to as long-term contracts. Long-term sales contracts have historically provided a relatively secure market for the amount of production committed under the terms of the contracts. From time to time industry conditions may make it more difficult for us to enter into long-term contracts with our electric utility customers, and if supply exceeds demand in the coal industry, electric utilities may become less willing to lock in price or quantity commitments for an extended period of time. Accordingly, we may not be able to continue to obtain long-term sales contracts with reliable customers as existing contracts expire, which could subject a portion of our revenue stream to the increased volatility of the spot market.

Our business can be negatively impacted by customers refusing to honor existing contracts. For example, we initiated litigation on January 15, 2015 alleging that a customer anticipatorily breached a coal supply contract when it notified us that it would not accept coal shipments under the contract after April 15, 2015. See Item 3. Legal Proceedings.

Some of our long-term coal sales contracts contain provisions allowing for the renegotiation of prices and, in some instances, the termination of the contract or the suspension of purchases by customers.

Some of our long-term contracts contain provisions that allow for the purchase price to be renegotiated at periodic intervals. These price reopener provisions may automatically set a new price based on the prevailing market price or, in some instances, require the parties to the

contract to agree on a new price. Any adjustment or renegotiation leading to a significantly lower contract price could adversely affect our operating profit margins. Accordingly, long-term contracts may provide only limited protection during adverse market conditions. In some circumstances, failure of the parties to agree on a price under a reopen provision can also lead to early termination of a contract.

Several of our long-term contracts also contain provisions that allow the customer to suspend or terminate performance under the contract upon the occurrence or continuation of certain events that are beyond the customer's reasonable control. Such events may include labor disputes, mechanical malfunctions and changes in government regulations, including changes in environmental regulations rendering use of our coal inconsistent with the customer's environmental compliance strategies. Additionally, most of our long-term contracts contain provisions requiring us to deliver coal within stated ranges for specific coal characteristics. Failure to meet these specifications can result in economic penalties, rejection or suspension of shipments or termination of the contracts. In the event of early termination of any of our long-term contracts, if we are unable to enter into new contracts on similar terms, our business, financial condition and results of operations could be adversely affected.

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

During 2015, we derived approximately 28.5% of our total revenues from two customers and at least 10.0% of our 2015 total revenues from each of the two. If we were to lose either of these customers without finding replacement customers willing to purchase an equivalent amount of coal on similar terms, or if these customers were to decrease the amounts of coal purchased or the terms, including pricing terms, on which they buy coal from us, it could have a material adverse effect on our business, financial condition and results of operations.

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

From time to time we have disputes with our customers over the provisions of long-term coal supply contracts relating to, among other things, coal pricing, quality, quantity and the existence of specified conditions beyond our or our customers' control that suspend performance obligations under the particular contract. Disputes may occur in the future and we may not be able to resolve those disputes in a satisfactory manner, which could have a material adverse effect on our business, financial condition and results of operations. See Item 3. Legal Proceedings.

Our ability to collect payments from our customers could be impaired if their creditworthiness declines or if they fail to honor their contracts with us.

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

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

Our mining operations are influenced by changing conditions or events that can affect production levels and costs at particular mines for varying lengths of time and, as a result, can diminish our profitability. These conditions and events include, among others:

- mining and processing equipment failures and unexpected maintenance problems;
- unavailability of required equipment;
- prices for fuel, steel, explosives and other supplies;

- fines and penalties incurred as a result of alleged violations of environmental and safety laws and regulations;
- variations in thickness of the layer, or seam, of coal;
- amounts of overburden, partings, rock and other natural materials;
- weather conditions, such as heavy rains, flooding, ice and other natural events affecting operations, transportation or customers;
- accidental mine water discharges and other geological conditions;
- fires;
- employee injuries or fatalities;
- labor-related interruptions;
- increased reclamation costs;
- inability to acquire, maintain or renew mining rights or permits in a timely manner, if at all;
- fluctuations in transportation costs and the availability or reliability of transportation; and
- unexpected operational interruptions due to other factors.

These conditions have the potential to significantly impact our operating results. Prolonged disruption of production at any of our mines would result in a decrease in our revenues and profitability, which could materially adversely impact our quarterly or annual results.

Effective October 1, 2015, we renewed our annual property and casualty insurance program. Our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance, LLC (Wildcat Insurance).

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Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased reinsurance for the program in the standard market at a reduced cost. The maximum limit in the commercial property program is \$100.0 million per occurrence excluding a \$1.5 million deductible for property damage, a 75, 90 or 120-day waiting period for underground business interruption depending on the mining complex and a \$10.0 million overall aggregate deductible. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future.

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

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

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

We are subject to numerous federal, state and local laws and regulations affecting the coal mining industry, including laws and regulations pertaining to employee health and safety, permitting and licensing requirements, air and water quality standards, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge or release of materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Certain of these laws and regulations may impose strict liability without regard to fault or legality of the original conduct. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial liabilities, and the issuance of injunctions limiting or prohibiting the performance of operations. Complying with these laws and regulations may be costly and time consuming and may delay commencement or continuation of exploration or production operations. The possibility exists that new laws or regulations may be adopted, or that judicial interpretations or more stringent enforcement of existing laws and regulations may occur, which could materially affect our mining operations, cash flow, and profitability, either through direct impacts on our mining operations, or indirect impacts that discourage or limit our customers' use of coal. Please read Item 1. Business Regulations and Laws.

State and federal laws addressing mine safety practices impose stringent reporting requirements and civil and criminal penalties for violations. Federal and state regulatory agencies continue to interpret and implement these laws and propose new regulations and standards. Implementing and complying with these laws and regulations has increased and will continue to increase our operational expense and to have an adverse effect on our results of operation and financial position. For more information, please read Item 1. Business Regulation and Laws *Mine Health and Safety Laws*.

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

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Mining companies must obtain numerous governmental permits or approvals that impose strict conditions and obligations relating to various environmental and safety matters in connection with coal mining. The permitting rules are complex and can change over time. Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. The public has the right to comment on permit applications and otherwise participate in the permitting process, including through court intervention. Accordingly, permits required to conduct our operations may not be issued, maintained or renewed, or may not be issued or renewed in a timely fashion, or may involve requirements that restrict our ability to economically conduct our mining operations. Limitations on our ability to conduct our mining operations due to the inability to obtain or renew necessary permits or similar approvals could reduce our production, cash flow and profitability. Please read Item 1. Business Regulations and Laws *Mining Permits and Approvals*.

The EPA has begun reviewing permits required for the discharge of overburden from mining operations under Section 404 of the CWA. Various initiatives by the EPA regarding these permits have increased the time required to obtain and the costs of complying with such permits. In addition, the EPA previously exercised its veto power to withdraw or restrict the use of previously issued permits in connection with one of the largest surface mining operations

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in Appalachia. The EPA's action was ultimately upheld by a federal court. As a result of these developments, we may be unable to obtain or experience delays in securing, utilizing or renewing Section 404 permits required for our operations, which could have an adverse effect on our results of operation and financial position. Please read Item 1. Business Regulations and Laws *Water Discharge*.

In addition, some of our permits could be subject to challenges from the public, which could result in additional costs or delays in the permitting process, or even an inability to obtain permits, permit modifications, or permit renewals necessary for our operations.

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

Transportation costs represent a significant portion of the total cost of coal for our customers and, as a result, the cost of transportation is a critical factor in a customer's purchasing decision. Increases in transportation costs could make coal a less competitive source of energy or could make our coal production less competitive than coal produced from other sources. Disruption of transportation services due to weather-related problems, flooding, drought, accidents, mechanical difficulties, strikes, lockouts, bottlenecks or other events could temporarily impair our ability to supply coal to our customers. Our transportation providers may face difficulties in the future that may impair our ability to supply coal to our customers, resulting in decreased revenues. If there are disruptions of the transportation services provided by our primary rail or barge carriers that transport our coal and we are unable to find alternative transportation providers to ship our coal, our business could be adversely affected.

Conversely, significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country. For instance, difficulty in coordinating the many eastern coal loading facilities, the large number of small shipments, the steeper average grades of the terrain and a more unionized workforce are all issues that combine to make coal shipments originating in the eastern U.S. inherently more expensive on a per-mile basis than coal shipments originating in the western U.S. Historically, high coal transportation rates from the western coal producing areas into certain eastern markets limited the use of western coal in those markets. Lower rail rates from the western coal producing areas to markets served by eastern U.S. coal producers have created major competitive challenges for eastern coal producers. In the event of further reductions in transportation costs from western coal producing areas, the increased competition with certain eastern coal markets could have a material adverse effect on our business, financial condition and results of operations.

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

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

Since our formation and the acquisition of our predecessor in August 1999, we have expanded our operations by adding and developing mines and coal reserves in existing, adjacent and neighboring properties. We continually seek to expand our operations and coal reserves. Our future growth could be limited if we are unable to continue to make acquisitions, or if we are unable to successfully integrate the companies, businesses or properties we acquire. We may not be successful in consummating any acquisitions and the consequences of undertaking these acquisitions are unknown. Moreover, any acquisition could be dilutive to earnings and distributions to unitholders and any additional debt incurred to finance an acquisition could affect our ability to make distributions to unitholders. Our ability to make acquisitions in the future could require

significant amounts of financing that may not be available to us under acceptable terms and may be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties or the lack of suitable acquisition candidates.

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

If we are unable to successfully integrate the companies, businesses or properties we acquire, our profitability may decline and we could experience a material adverse effect on our business, financial condition, or results of operations. Expansion and acquisition transactions involve various inherent risks, including:

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

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

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

We plan to fund capital expenditures for our current growth projects with existing cash balances, future cash flows from operations, borrowings under revolving credit and securitization facilities and cash provided from the issuance of debt or equity. Weakness in the energy sector in general and coal in particular has significantly impacted access to the debt and equity capital markets. Accordingly, our funding plans may be negatively impacted by this constrained environment as well as numerous other factors, including higher than anticipated capital expenditures or lower than expected cash flow from operations. In addition, we may be unable to refinance our current revolving credit and securitization facilities when they expire or obtain adequate funding prior to expiry because our lending counterparties may be unwilling or unable to meet their funding obligations. Furthermore, additional growth projects and expansion opportunities may develop in the future that could also require significant amounts of financing that may not be available to us on acceptable terms or in the amounts we expect, or at all.

Various factors could adversely impact the debt and equity capital markets as well as our credit ratings or our ability to remain in compliance with the financial covenants under our then current debt agreements, which in turn could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance our growth and future expansions as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our plans.

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

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

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The estimates of our coal reserves may prove inaccurate and could result in decreased profitability.

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

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

For these reasons, estimates of the recoverable quantities of coal attributable to any particular group of properties, classifications of reserves based on risk of recovery and estimates of future net cash flows expected from these properties as prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and these variations may be material. Any inaccuracy in the estimates of our reserves could result in higher than expected costs and decreased profitability.

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

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

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

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

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

Our coal mining operations are affected by commodity prices. We use significant amounts of steel, petroleum products and other raw materials in various pieces of mining equipment, supplies and materials, including the roof bolts required by the room-and-pillar method of mining. Steel prices and the prices of scrap steel, natural gas and coking coal consumed in the production of iron and steel fluctuate significantly and may change unexpectedly. There may be acts of nature or terrorist attacks or threats that could also impact the future costs of raw materials. Future volatility in the price of steel, petroleum products or other raw materials will impact our operational expenses and could result in significant fluctuations in our profitability.

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

We have long-term indebtedness, consisting of our outstanding senior unsecured notes, revolving credit facility and term loan agreement. At December 31, 2015, our total long-term indebtedness outstanding was \$819.3 million. Our leverage may:

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

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

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

- during an event of default under any of our indebtedness; or
- if either before or after such distribution, we fail to meet a coverage test based on the ratio of our consolidated debt to our consolidated cash flow.

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

Federal and state laws require bonds to secure our obligations related to statutory reclamation requirements and workers' compensation and black lung benefits. Our inability to acquire or failure to maintain surety bonds that are required by state and federal law would have a material adverse effect on us.

Federal and state laws require us to place and maintain bonds to secure our obligations to repair and return property to its approximate original state after it has been mined (often referred to as "reclaim" or "reclamation"), to pay federal and state workers' compensation and

pneumoconiosis, or black lung, benefits and to satisfy other miscellaneous obligations. These bonds provide assurance that we will perform our statutorily required obligations and are referred to as surety bonds. These bonds are typically renewable on a yearly basis. The failure to maintain or the inability to acquire sufficient surety bonds, as required by state and federal laws, could subject us to fines and penalties and result in the loss of our mining permits. Such failure could result from a variety of factors, including:

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

We have outstanding surety bonds with governmental agencies for reclamation, federal and state workers compensation and other obligations. At December 31, 2015, our total of such obligations was \$234.0 million. We may have difficulty maintaining our surety bonds for mine reclamation as well as workers compensation and black lung benefits. In addition, those governmental agencies may increase the amount of bonding required. Our inability to acquire or failure to maintain these bonds, or a substantial increase in the bonding requirements, would have a material adverse effect on us.

We and our subsidiaries are subject to various legal proceedings, which may have a material effect on our business.

We are party to a number of legal proceedings incident to our normal business activities. There is the potential that an individual matter or the aggregation of multiple matters could have an adverse effect on our cash flows, results of operations or financial position. Please see Item 8. Financial Statements and Supplementary Data Note 20. Commitments and Contingencies for further discussion.

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Tax Risks to Our Common Unitholders

Our tax treatment depends on our status as a partnership for federal tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (IRS) treats us as a corporation for federal income tax purposes, or we become subject to entity-level taxation for state tax purposes, our cash available for distribution to you would be substantially reduced.

The anticipated after-tax benefit of an investment in our units depends largely on our being treated as a partnership for U.S. federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a qualifying income requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. However, we have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

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

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal, state or local income tax purposes, the minimum quarterly distribution (MQD) amount and the target distribution amounts may be adjusted to reflect the impact of that law on us. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced and the value of our common units could be negatively impacted.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Obama administration's budget proposal for fiscal year 2017 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2022. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration's proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly-traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, the IRS, on May 5, 2015, issued proposed regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. We do not believe the proposed regulations affect our ability to qualify as a publicly traded partnership. However, finalized regulations could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the amount of our common unit distributions and the value of an investment in our common units.

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If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce cash available for distribution to our unitholders. Recently enacted legislation alters the procedures for assessing and collecting taxes due for taxable years beginning after December 31, 2017, in a manner that could substantially reduce cash available for distribution to you.

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

Recently enacted legislation applicable to us for taxable years beginning after December 31, 2017 alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting taxes due (including applicable penalties and interest) as a result of an audit. Unless we are eligible to (and choose to) elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed under the new rules. If we are required to pay taxes, penalties and interest as the result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

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

You will be required to pay federal income taxes and, in some cases, state and local income taxes, on your share of our taxable income, whether or not you receive cash distributions from us. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, you may be allocated taxable income and gain resulting from the sale and our cash available for distribution would not increase. Similarly, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in cancellation of indebtedness income being allocated to our unitholders as taxable income without any increase in our cash available for distribution. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability which results from your share of our taxable income.

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

If you sell your units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in those units. Because distributions in excess of your allocable share of our net taxable income result in a decrease in your tax basis in your units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis therein, even if the price you receive is less than your original cost. In addition, because the amount realized includes a unitholder's share of our non-recourse liabilities, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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A substantial portion of the amount realized from the sale of your units, whether or not representing gain, may be taxed as ordinary income to you due to potential recapture items, including depreciation recapture. Thus, you may recognize both ordinary income and capital loss from the sale of your units if the amount realized on a sale of your units is less than your adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to \$3,000 of ordinary income per year. In the taxable period in which you sell your units, you may recognize ordinary income from our allocations of income and gain to you prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

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

Investment in our units by tax-exempt entities, such as employee benefit plans, individual retirement accounts (IRAs) and non-U.S. persons, raises issues unique to them. For example, virtually all of our income allocated to

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organizations exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Allocations and/or distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

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

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

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

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Department of Treasury recently adopted final Treasury Regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such regulations do not specifically authorize the use of the proration method we have adopted for our 2015 taxable year and may not specifically authorize all aspects of our proration method thereafter. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

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

We have adopted certain valuation methodologies in determining unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our respective assets. The IRS may challenge these valuation methods and the resulting allocations or character of income, gain, loss and deduction.

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

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Certain federal income tax deductions currently available with respect to coal mining and production may be eliminated as a result of future legislation.

The Obama administration has indicated a desire to eliminate certain key U.S. federal income tax provisions currently applicable to coal companies, including the percentage depletion allowance with respect to coal properties. No legislation with that effect has been proposed and elimination of those provisions would not impact our financial statements or results of operations. However, elimination of the provisions could result in unfavorable tax consequences for our unitholders and, as a result, could negatively impact our unit price.

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

We will be considered to have terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in our filing two tax returns for one calendar year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in taxable income for the unitholder's taxable year that includes our termination. Our termination would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for U.S. federal income tax purposes following the termination. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred. The IRS has implemented relief procedures whereby if a publicly traded partnership that has technically terminated, requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the two short tax periods included in the year in which the termination occurs.

You will likely be subject to state and local taxes and income tax return filing requirements in jurisdictions where you do not live as a result of investing in our units.

In addition to U.S. federal income taxes, you will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements.

We currently own assets and conduct business in a variety of states which currently impose a personal income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is your responsibility to file all U.S. federal, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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We must obtain permits from applicable regulatory authorities before beginning to mine particular reserves. For more information on this permitting process, and matters that could hinder or delay the process, please read Item 1. Business Regulation and Laws *Mining Permits and Approvals*.

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

At December 31, 2015, we had approximately 1.8 billion tons of coal reserves. All of the estimates of reserves which are presented in this Annual Report on Form 10-K are of proven and probable reserves (as defined below) and closely adhere to the standards described in U.S. Geological Survey (USGS) Circular 831 and USGS Bulletin 1450-B. For information on the locations of our mines, please read *Mining Operations* under Item 1. Business.

The following table sets forth reserve information at December 31, 2015 about our mining operations:

Operations	Mine Type (1)	Heat Content (BTUs per pound)	Pounds S02 per MMBTU			Total	Classification		Reserve Assignment		Reserve Control	
			<1.2	1.2-2.5	>2.5		Proven	Probable	Assigned	Unassigned	Owned	Leased
Illinois Basin Operations												
Dotiki (KY)	U	12,200	-	-	87.9	87.9	61.5	26.4	38.6	49.3	28.9	59.0
Warrior (KY)	U	12,500	-	-	100.4	100.4	76.9	23.5	78.2	22.2	25.7	74.7
Hopkins (KY)	U	12,000	-	-	19.8	19.8	15.4	4.4	5.9	13.9	4.5	15.3
	S	11,500	-	-	7.8	7.8	7.8	-	7.8	-	7.8	-
River View (KY)	U	11,500	-	-	162.0	162.0	100.9	61.1	162.0	-	35.8	126.2
Henderson/Union (KY)	U	11,400	-	5.7	497.6	503.3	170.5	332.8	-	503.3	91.3	412.0
Onton (KY)	U	11,750	-	-	40.3	40.3	22.6	17.7	40.3	-	0.2	40.1
Sebree (KY)	U	11,400	-	-	13.6	13.6	5.8	7.8	-	13.6	3.9	9.7
Hamilton County (IL)	U	11,650	-	-	557.0	557.0	203.1	353.9	150.7	406.3	54.3	502.7
Pattiki (IL)	U	11,500	-	-	54.6	54.6	45.4	9.2	12.1	42.5	0.1	54.5
Gibson (North) (IN)	U	11,500	0.1	10.0	15.7	25.8	19.0	6.8	25.8	-	0.7	25.1

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Gibson (South) (IN)	U	11,500	1.2	25.5	47.6	74.3	62.0	12.3	74.3	-	20.0	54.3
Region Total			1.3	41.2	1,604.3	1,646.8	790.9	855.9	595.7	1,051.1	273.2	1,373.6
<i>Appalachia Operations</i>												
MC Mining (KY)	U	12,600	6.0	0.5	1.6	8.1	7.0	1.1	6.0	2.1	0.7	7.4
Mettiki (MD)	U	13,200	-	1.7	3.8	5.5	5.3	0.2	5.5	-	-	5.5
Mountain View (WV)	U	13,200	-	12.4	8.2	20.6	15.3	5.3	14.7	5.9	5.3	15.3
Tunnel Ridge (WV)	U	12,600	-	-	77.4	77.4	34.9	42.5	77.4	-	-	77.4
Region Total			6.0	14.6	91.0	111.6	62.5	49.1	103.6	8.0	6.0	105.6
Total			7.3	55.8	1,695.3	1,758.4	853.4	905.0	699.3	1,059.1	279.2	1,479.2
% of Total			0.4%	3.2%	96.4%	100%	48.5%	51.5%	39.8%	60.2%	15.9%	84.1%

(1) U = Underground and S = Surface

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

Reserve estimates will change from time to time to reflect mining activities, additional analysis, new engineering and geological data, acquisition or divestment of reserve holdings, modification of mining plans or mining methods, and other factors. Weir International Mining Consultants performed an audit of our reserves and calculation methods in July 2015.

Reserves represent that part of a mineral deposit that can be economically and legally extracted or produced, and reflect estimated losses involved in producing a saleable product. All of our reserves are steam coal, except for reserves at Mettiki that can be delivered to the steam or metallurgical markets. The 6.0 million tons of reserves listed at MC Mining as <1.2 pounds of SO₂ per million British thermal units (MMBTU) are marketable as compliance coal under Phase II of CAA.

Assigned reserves are those reserves that have been designated for mining by a specific operation. Unassigned reserves are those reserves that have not yet been designated for mining by a specific operation. British thermal units (BTU) values are reported on an as shipped, fully washed basis. Shipments that are either fully or partially raw will have a lower BTU value.

We own or control certain leases for coal deposits that do not currently meet the criteria to be reflected as reserves but may be reclassified as reserves in the future. These tons are classified as non-reserve coal deposits and are not included in our reported reserves. These non-reserve coal deposits include the following: Mettiki 3.8 million tons, Tunnel Ridge 3.6 million tons, Hamilton County 36.5 million tons, Warrior 8.2 million tons, Dotiki 2.3 million tons, Onton 4.6 million tons, River View 0.1 million tons, Gibson (North) 0.1 million tons, Gibson (South) 1.3 million tons and Pattiki 15.5 million tons. The Henderson/Union County Undeveloped Reserves account for the majority of our non-reserve coal deposits with 206.1 million tons. In addition, there are 47.8 million tons located near our Dotiki complex for total non-reserve coal deposits of 329.9 million tons. For more information on reserve acquisitions see Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions.

We lease most of our reserves and generally have the right to maintain leases in force until the exhaustion of mineable and merchantable coal located within the leased premises or a larger coal reserve area. These leases provide for royalties to be paid to the lessor at a fixed amount per ton or as a percentage of the sales price. Many leases require payment of minimum royalties, payable either at the time of the execution of the lease or in periodic installments, even if no mining activities have begun. These minimum royalties are normally credited against the production royalties owed to a lessor once coal production has commenced.

Table of Contents**Mining Operations**

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

Operations	Location	Tons Produced			Transportation	Equipment
		2015	2014 (in millions)	2013		
<i>Illinois Basin Operations</i>						
Dotiki	Kentucky	4.0	3.9	3.5	CSX, PAL, truck, barge	CM
Warrior	Kentucky	4.0	5.1	5.9	CSX, PAL, truck, barge	CM
Hopkins	Kentucky	2.9	3.0	3.1	CSX, PAL, truck, barge	CM, TS
River View	Kentucky	9.1	9.3	9.3	Barge	CM
Onton	Kentucky	1.8	2.4	2.4	Barge, truck	CM
Hamilton	Illinois	2.7	-	-	CSX, EVWR, truck, barge	LW, CM
Pattiki	Illinois	2.4	2.6	2.6	CSX, EVWR, barge	CM
Gibson (North)	Indiana	2.2	3.8	3.9	CSX, NS, truck, barge	CM
Gibson (South)	Indiana	2.9	0.8	-	CSX, NS, truck, barge	CM
Region Total		32.0	30.9	30.7		
<i>Appalachia Operations</i>						
MC Mining	Kentucky	1.5	1.6	1.3	CSX, truck, barge	CM
Mettki	Maryland	-	-	0.1	Truck, CSX	CM
Mountain View	West Virginia	2.1	1.9	2.3	Truck, CSX	LW, CM
Tunnel Ridge	West Virginia	5.6	6.3	3.7	Barge, WLE	LW, CM
Region Total		9.2	9.8	7.4		
<i>Other Operations</i>						
Pontiki	Kentucky	-	-	0.7	NS, truck, barge	CM
Region Total		-	-	0.7		
TOTAL		41.2	40.7	38.8		

CSX	- CSX Railroad
NS	- Norfolk Southern Railroad
PAL	- Paducah & Louisville Railroad
CM	- Continuous Miner
LW	- Longwall
EVWR	- Evansville Western Railroad
WLE	- Wheeling & Lake Erie Railroad
TS	- Truck, Shovel, Front End Loader or Dozer

ITEM 3. LEGAL PROCEEDINGS

From time to time we are party to litigation matters incidental to the conduct of our business. We initiated litigation on January 15, 2015 alleging that a customer anticipatorily breached a coal supply contract when it notified us that it would not accept coal shipments under the contract after April 15, 2015. The contract obligates the customer to purchase more than 5.0 million tons during the period between April 16, 2015 and the end of the contract term on December 31, 2021. We are seeking to recover damages resulting from the customer's alleged breach of contract.

It is the opinion of management that the ultimate resolution of our pending litigation matters will not have a material adverse effect on our financial condition, results of operation or liquidity. However, we cannot assure you that disputes or litigation will not arise or that we will be able to resolve any such future disputes or litigation in a satisfactory manner. The information under General Litigation and Other in Item 8, Financial Statements and Supplementary Data Note 20, Commitments and Contingencies is incorporated herein by this reference.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 to this Annual Report on Form 10-K.

Table of Contents**PART II****ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES**

The common units representing limited partners' interests are listed on the NASDAQ Global Select Market under the symbol ARLP. The common units began trading on August 20, 1999. On February 11, 2016, the closing market price for the common units was \$10.31 per unit and there were 74,375,025 common units outstanding. There were approximately 35,012 record holders of common units at December 31, 2015.

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

	High (1)	Low (1)	Distributions Per Unit
1st Quarter 2014	\$43.38	\$37.51	\$0.61125 (paid May 15, 2014)
2nd Quarter 2014	\$48.02	\$41.08	\$0.625 (paid August 14, 2014)
3rd Quarter 2014	\$53.84	\$41.56	\$0.6375 (paid November 14, 2014)
4th Quarter 2014	\$50.02	\$37.08	\$0.65 (paid February 13, 2015)
1st Quarter 2015	\$43.65	\$31.13	\$0.6625 (paid May 15, 2015)
2nd Quarter 2015	\$34.70	\$23.67	\$0.675 (paid August 14, 2015)
3rd Quarter 2015	\$26.18	\$19.95	\$0.675 (paid November 13, 2015)
4th Quarter 2015	\$24.37	\$11.93	\$0.675 (paid February 12, 2016)

(1) We completed a two-for-one unit split on June 16, 2014. Trading prices and distributions per unit for periods prior to the completion of the unit split have been adjusted to give effect to the unit split.

We distribute to our partners, on a quarterly basis, all of our available cash. Available cash, as defined in our partnership agreement, generally means, with respect to any quarter, all cash on hand at the end of each quarter, plus working capital borrowings after the end of the quarter, less cash reserves in the amount necessary or appropriate in the reasonable discretion of our managing general partner to (a) provide for the proper conduct of our business, (b) comply with applicable law or any debt instrument or other agreement of ours or any of our affiliates, and (c) provide funds for distributions to unitholders and the general partners for any one or more of the next four quarters. If quarterly distributions of available cash exceed certain target distribution levels as established in our partnership agreement, our managing general partner will receive distributions based on specified increasing percentages of the available cash that exceed the target distribution levels. The target distribution levels are based on the amounts of available cash from our operating surplus distributed for a given quarter that exceed the MQD and common unit arrearages, if any. Our partnership agreement defines the MQD as \$0.125 per unit for each full fiscal quarter (\$0.50 per unit on an annual basis).

Under the quarterly incentive distribution provisions of the partnership agreement, our managing general partner is entitled to receive 15% of the amount we distribute in excess of \$0.1375 per unit, 25% of the amount we distribute in excess of \$0.15625 per unit, and 50% of the amount we

distribute in excess of \$0.1875 per unit.

Equity Compensation Plans

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

Table of Contents**ITEM 6. SELECTED FINANCIAL DATA**

Our historical financial data below were derived from our audited consolidated financial statements as of and for the years ended December 31, 2015, 2014, 2013, 2012 and 2011.

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

	Year Ended December 31,				
	2015	2014	2013	2012	2011
Statements of Income					
Sales and operating revenues:					
Coal sales	\$ 2,158.0	\$ 2,208.6	\$ 2,137.4	\$ 1,979.4	\$ 1,786.1
Transportation revenues	33.6	26.0	32.6	22.0	31.9
Other sales and operating revenues	82.1	66.1	35.5	32.9	25.6
Total revenues	2,273.7	2,300.7	2,205.5	2,034.3	1,843.6
Expenses:					
Operating expenses (excluding depreciation, depletion and amortization)	1,377.1	1,383.4	1,398.8	1,303.3	1,131.8
Transportation expenses	33.6	26.0	32.6	22.0	31.9
Outside coal purchases	0.3	-	2.0	38.6	54.3
General and administrative	67.5	72.5	63.7	58.8	52.3
Depreciation, depletion and amortization	333.7	274.6	264.9	218.1	160.3
Asset impairment	100.1	-	-	19.0	-
Total operating expenses	1,912.3	1,756.5	1,762.0	1,659.8	1,430.6
Income from operations	361.4	544.2	443.5	374.5	413.0
Interest expense (net of interest capitalized)	(31.2)	(33.6)	(27.0)	(28.7)	(22.0)
Interest income	1.5	1.7	1.0	0.2	0.4
Equity in loss of affiliates, net	(49.0)	(16.7)	(24.4)	(14.7)	(3.4)
Acquisition gain, net	22.5	-	-	-	-
Other income	1.0	1.6	1.8	3.2	1.0
Income before income taxes	306.2	497.2	394.9	334.5	389.0
Income tax expense (benefit)	-	-	1.4	(1.1)	(0.4)
Net income	306.2	497.2	393.5	335.6	389.4
Less: Net loss attributable to noncontrolling interest	-	-	-	-	-
Net income attributable to Alliance Resource Partners, L.P. (Net Income of ARLP)	\$ 306.2	\$ 497.2	\$ 393.5	\$ 335.6	\$ 389.4
General Partners' interest in Net Income of ARLP	\$ 146.3	\$ 138.3	\$ 121.4	\$ 106.8	\$ 86.3
Limited Partners' interest in Net Income of ARLP	\$ 159.9	\$ 358.9	\$ 272.1	\$ 228.8	\$ 303.1
Basic and diluted net income of ARLP per limited partner unit (1)	\$ 2.11	\$ 4.77	\$ 3.63	\$ 3.06	\$ 4.06
Distributions paid per limited partner unit	\$ 2.6625	\$ 2.4725	\$ 2.2825	\$ 2.08125	\$ 1.81375
Weighted-average number of units outstanding-basic and diluted	74,174,389	74,044,417	73,904,384	73,726,044	73,538,252
Balance Sheet Data:					
Working capital (2)	\$ (108.5)	\$ (80.0)	\$ 109.4	\$ 73.0	\$ 269.3

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Total assets	2,363.1	2,285.1	2,121.9	1,956.0	1,731.5
Long-term obligations (3)	660.2	606.9	848.4	791.6	688.5
Total liabilities	1,373.8	1,270.0	1,270.7	1,250.5	1,107.8
Partners capital	\$ 989.3	\$ 1,015.1	\$ 851.2	\$ 705.5	\$ 623.7
Other Operating Data:					
Tons sold	40.2	39.7	38.8	35.2	31.9
Tons produced	41.2	40.7	38.8	34.8	30.8
Coal sales per ton sold (4)	\$ 53.62	\$ 55.59	\$ 55.04	\$ 56.28	\$ 55.95
Cost per ton sold (5)	\$ 34.22	\$ 34.82	\$ 36.07	\$ 38.15	\$ 37.15
Other Financial Data:					
Net cash provided by operating activities	\$ 716.3	\$ 739.2	\$ 704.7	\$ 555.9	\$ 574.0
Net cash used in investing activities	(355.9)	(441.2)	(426.0)	(623.4)	(401.1)
Net cash used in financing activities	(351.6)	(367.0)	(213.3)	(177.7)	(238.9)
EBITDA (6)	669.6	803.7	685.9	581.1	570.8
Adjusted EBITDA (6)	747.2	803.7	685.9	600.1	570.8
Maintenance capital expenditures (7)	236.3	236.3	222.4	282.6	192.7

(1) Diluted earnings per unit (EPU) gives effect to all dilutive potential common units outstanding during the period using the treasury stock method. Diluted EPU excludes all dilutive units calculated under the treasury stock method if their effect is anti-dilutive. For the years ended December 31, 2015, 2014, 2013, 2012 and 2011, long-term incentive plan (LTIP), Supplemental Executive Retirement Plan (SERP) and Directors compensation units of 734,171, 798,701, 682,746, 689,912 and 819,938, respectively, were considered anti-dilutive.

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(2) Working capital is impacted by current maturities of long-term debt. For information regarding long-term debt, please read Item 8. Financial Statements and Supplementary Data Note 7. Long-Term Debt of this Annual Report on Form 10-K.

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

(4) Coal sales per ton sold are based on total coal sales divided by tons sold.

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

(6) EBITDA and Adjusted EBITDA are financial measures not calculated in accordance with generally accepted accounting principles (GAAP). EBITDA is defined as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes and depreciation, depletion and amortization and Adjusted EBITDA is EBITDA modified for certain items that may not reflect the trend of future results, such as non-cash impairments and gains and losses on acquisition related accounting. EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on investment 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.

We believe Adjusted EBITDA is a useful measure for investors because it further demonstrates the performance of our assets without regard to items that may not reflect the trend of future results.

EBITDA and Adjusted EBITDA should not be considered as alternatives to net income, income from operations, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. EBITDA and Adjusted EBITDA are not intended

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to represent cash flow and do not represent the measure of cash available for distribution. Our method of computing EBITDA and Adjusted EBITDA may not be the same method used to compute similar measures reported by other companies, or EBITDA and Adjusted EBITDA may be computed differently by us in different contexts (*e.g.*, public reporting versus computation under financing agreements).

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

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands)				
Cash flows provided by operating activities	\$ 716,342	\$ 739,201	\$ 704,652	\$ 555,856	\$ 573,983
Non-cash compensation expense	(12,631)	(11,250)	(8,896)	(7,428)	(6,235)
Asset retirement obligations	(3,192)	(2,730)	(3,004)	(2,853)	(2,546)
Coal inventory adjustment to market	(1,952)	(377)	(2,811)	(2,978)	(386)
Equity in loss of affiliates, net	(49,046)	(16,648)	(24,441)	(14,650)	(3,404)
Net gain (loss) on sale of property, plant and equipment	1	4,409	(3,475)	(147)	634
Valuation allowance of deferred tax assets	(1,557)	(1,636)	(3,483)	-	-
Other	(6,388)	5,151	6,251	3,815	(1,488)
Net effect of working capital changes	75,889	55,659	(6,392)	41,109	(10,870)
Interest expense, net	29,694	31,913	26,082	28,455	21,579
Income tax expense (benefit)	21	-	1,396	(1,082)	(431)
Adjusted EBITDA	747,181	803,692	685,879	600,097	570,836
Asset impairment	(100,130)	-	-	(19,031)	-
Acquisition gain, net	22,548	-	-	-	-
EBITDA	669,599	803,692	685,879	581,066	570,836
Depreciation, depletion and amortization	(333,713)	(274,566)	(264,911)	(218,122)	(160,335)
Interest expense, net	(29,694)	(31,913)	(26,082)	(28,455)	(21,579)
Income tax (expense) benefit	(21)	-	(1,396)	1,082	431
Net income	\$ 306,171	\$ 497,213	\$ 393,490	\$ 335,571	\$ 389,353

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

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

General

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

Executive Overview

We are a diversified producer and marketer of coal primarily to major U.S. utilities and industrial users and were the first such producer and marketer in the nation to be a publicly traded master limited partnership. We are currently the second-largest coal producer in the eastern U.S. In 2015, we produced and sold a record 41.2 million and 40.2 million tons of coal, respectively. The coal we produced in 2015 was approximately 3.6% low-sulfur coal, 17.3% medium-sulfur coal and 79.1% high-sulfur coal. We classify low-sulfur coal as coal with a sulfur content of less than 1%, medium-sulfur coal as coal with a sulfur content of 1% to 2%, and high-sulfur coal as coal with a sulfur content of greater than 2%.

We operate ten underground mining complexes, including the White Oak Mine No. 1 (now known as the Hamilton Mine No. 1), of which we assumed control in July 2015. Prior to assuming control, we owned a preferred equity interest in White Oak and purchased and funded development of coal reserves, and operated surface facilities at White Oak's mining complex in southern Illinois. We also operate a coal-loading terminal on the Ohio River at Mt. Vernon, Indiana. In addition, we own through our consolidated affiliate, Cavalier Minerals, an equity interest and plan to make additional equity investments in AllDale Minerals for the purchase of oil and gas mineral interests in various geographic locations within producing basins in the continental U.S. At December 31, 2015, we had approximately 1.8 billion tons of proven and probable coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia compared to 1.5 billion tons at December 31, 2014. We believe we control adequate reserves to implement our currently contemplated mining plans. Please see Item 1. Business Mining Operations for further discussion of our mines. For more information regarding control of White Oak and our increase in reserves, please read Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions.

In 2015, approximately 96.1% of our sales tonnage was purchased by electric utilities, with the balance sold to third-party resellers and industrial consumers. Although many utility customers recently have appeared to favor a shorter-term contracting strategy, in 2015, approximately 92.2% of our sales tonnage was sold under long-term contracts. Our long-term contracts contribute to our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2015, approximately 98.6% of our medium- and high-sulfur coal was sold to utility plants with installed pollution control devices. These devices, also known as scrubbers, eliminate substantially all emissions of sulfur dioxide.

As discussed in more detail in Item 1A. Risk Factors, our results of operations could be impacted by prices for items that are used in coal production such as steel, electricity and other supplies, unforeseen geologic conditions or mining and processing equipment failures and

unexpected maintenance problems, and by the availability or reliability of transportation for coal shipments. Additionally, our results of operations could be impacted by our ability to obtain and renew permits necessary for our operations, secure or acquire coal reserves, or find replacement buyers for coal under contracts with comparable terms to existing contracts. Moreover, the regulatory environment has grown increasingly stringent in recent years. As outlined in Item 1. Business Regulation and Laws, a variety of measures taken by regulatory agencies in the U.S. and abroad in response to the perceived threat from climate change attributed to GHG emissions could substantially increase compliance costs for us and our customers and reduce demand for coal, which could materially and adversely impact our results of operations. For additional information regarding some of the risks and uncertainties that affect our business and the industry in which we operate, see Item 1A. Risk Factors.

Our principal expenses related to the production of coal are labor and benefits, equipment, materials and supplies, maintenance, royalties and excise taxes. We employ a totally union-free workforce. Many of the benefits of our union-free workforce are related to higher productivity and are not necessarily reflected in our direct costs. In addition, transportation costs may be substantial and are often the determining factor in a coal consumer's contracting decision.

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Our mining operations are located near many of the major eastern utility generating plants and on major coal hauling railroads in the eastern U.S. Our River View and Tunnel Ridge mines and Mt. Vernon transloading facility are located on the Ohio River and our Onton mine is located on the Green River in western Kentucky. Onton was idled in November 2015.

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

- expanding our operations by adding and developing mines and coal reserves in existing, adjacent or neighboring properties;
- extending the lives of our current mining operations through acquisition and development of coal reserves using our existing infrastructure;
- continuing to make productivity improvements to remain a low-cost producer in each region in which we operate;
- strengthening our position with existing and future customers by offering a broad range of coal qualities, transportation alternatives and customized services;
- developing strategic relationships to take advantage of opportunities within the coal industry and MLP sector; and
- making equity investments for the purchase of oil and gas mineral interests in various geographic locations within producing basins in the continental U.S.

We have two reportable segments: Illinois Basin and Appalachia and an all other category referred to as Other and Corporate. Our reportable segments correspond to major coal producing regions in the eastern U.S. Factors similarly affecting financial performance of our operating segments within each of these two reportable segments generally include coal quality, geology, coal marketing opportunities, mining and transportation methods and regulatory issues.

As a result of the previously discussed acquisition of the remaining equity interests in White Oak, we restructured our reportable segments to include Hamilton as part of our Illinois Basin segment due to the similarities in product, management, location, and operation with other mines included in the segment. This new organization reflects how our chief operating decision maker manages and allocates resources to our various operations. Prior periods have been recast to include White Oak in our Illinois Basin segment. For more information on our acquisition of White Oak, please read Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions.

- *Illinois Basin* reportable segment is comprised of multiple operating segments, including Webster County Coal's Dotiki mining complex, Gibson County Coal's mining complex, which includes the Gibson North mine and Gibson South mine, Hopkins County Coal's mining complex, which includes the Elk Creek mine and the Fies property, White County Coal's Pattiki mining complex, Warrior's mining complex, Sebree Mining's mining complex, which includes the Onton mine, Steamport and certain Sebree Reserves, River View's mining complex, Hamilton's mining complex discussed above, CR Services, LLC, certain properties and equipment of Alliance Resource Properties, ARP Sebree,

LLC (ARP Sebree), ARP Sebree South, LLC, UC Coal, LLC, UC Mining, LLC, and UC Processing, LLC. In April 2014, initial production began at the Gibson South mine. In the fourth quarter of 2014 and February 2015, Alliance Resource Properties acquired reserves that will significantly extend the life of the Dotiki mine, allow increased production from our River View mine and add three new potential development projects for our organic growth strategy. During the fourth quarter of 2015, we idled our Onton and Gibson North mines in response to market conditions and continued increases in coal inventories at our mines and customer locations. The Elk Creek mine is currently expected to cease production in early 2016. The Sebree Mining and Fies properties are held by us for future mine development. For information regarding the permitting process and matters that could hinder or delay the process, please read Item 1. Business Regulation and Laws *Mining Permits and Approvals* . For information regarding the acquisition of reserves in December 2014 and February 2015 and the assumption of control at the Hamilton Mine No. 1 in July 2015, please read Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions of this Annual Report on Form 10-K.

- *Appalachia* reportable segment is comprised of multiple operating segments, including the Mettiki mining complex, the Tunnel Ridge mining complex and the MC Mining mining complex. The Mettiki mining complex includes Mettiki Coal (WV) s Mountain View mine and Mettiki Coal s preparation plant. During the fourth quarter 2015, we surrendered the Penn Ridge leases as they were no longer a core part of our foreseeable development plans. Please read Item 8. Financial Statements and Supplementary Data

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Note 4. Long-Lived Asset Impairment for further discussion of this surrender. In June 2013, Alliance Resource Properties acquired reserves that extended the life of the Mettiki (WV) Mountain View mine. For information regarding the reserves acquired, please read Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions of this Annual Report on Form 10-K.

- *Other and Corporate* includes marketing and administrative expenses, Alliance Service, Inc. (ASI) and its subsidiary, Matrix Design Group, LLC and its subsidiaries Matrix Design International, LLC and Matrix Design Africa (PTY) LTD, Alliance Design Group, LLC (collectively the Matrix entities and Alliance Design, are referred to as Matrix Design Group), ASI s ownership of aircraft, Mt. Vernon s dock activities; coal brokerage activity, MAC s manufacturing and sales (primarily to our mines) of rock dust, certain activities of Alliance Resource Properties, the Pontiki Coal mining complex, which ceased operations in November 2013 and sold most of its assets in May 2014, Wildcat Insurance, which was established in September 2014 to assist the ARLP Partnership with its insurance requirements, Alliance Minerals and its affiliate, Cavalier Minerals, which holds equity investments in AllDale Minerals and AROP Funding, LLC (AROP Funding). Please read Item 8. Financial Statements and Supplementary Data Note 7. Long-Term Debt , Note 11. Variable Interest Entities and Note 12. Equity Investments of this Annual Report on Form 10-K for more information on AROP Funding, Alliance Minerals, Cavalier Minerals and AllDale Minerals.

How We Evaluate Our Performance

Our management uses a variety of financial and operational measurements to analyze our performance. Primary measurements include the following: (1) raw and saleable tons produced per unit shift; (2) coal sales price per ton; (3) Segment Adjusted EBITDA Expense per ton; (4) EBITDA; and (5) Segment Adjusted EBITDA.

Raw and Saleable Tons Produced per Unit Shift. We review raw and saleable tons produced per unit shift as part of our operational analysis to measure the productivity of our operating segments, which is significantly influenced by mining conditions and the efficiency of our preparation plants. Our discussion of mining conditions and preparation plant costs are found below under *Analysis of Historical Results of Operations* and therefore provides implicit analysis of raw and saleable tons produced per unit shift.

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

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

EBITDA. We define EBITDA (a non-GAAP financial measure) as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes and depreciation, depletion and amortization. EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on investment 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. We define Segment Adjusted EBITDA (a non-GAAP financial measure) as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes, depreciation, depletion and amortization, asset impairment charge, acquisition gain, net and general and administrative expenses. Management therefore is able 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.

Table of Contents**Analysis of Historical Results of Operations***2015 Compared with 2014*

We reported net income of \$306.2 million for 2015 compared to \$497.2 million for 2014. The decrease of \$191.0 million was principally due to non-cash asset impairments of \$100.1 million, lower average coal sales prices particularly at our Appalachian segment mines, increased depreciation, depletion and amortization and higher equity in loss of affiliates, partially offset by record coal sales volumes, increased coal volumes at lower cost per ton operations, a net gain of \$22.5 million related to the final business combination accounting for the acquisition of White Oak's remaining equity on July 31, 2015 (the Hamilton Acquisition) and increased other sales and operating revenues primarily reflecting higher surface facility services and coal royalties from White Oak prior to the Hamilton Acquisition. For more information on the Hamilton Acquisition, please read Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions. For more information on the non-cash asset impairments, please read Item 8. Financial Statements and Supplementary Data Note 4. Long-Lived Asset Impairments.

	December 31,		December 31,	
	2015	2014	2015	2014
	(in thousands)		(per ton sold)	
Tons sold	40,247	39,731	N/A	N/A
Tons produced	41,178	40,749	N/A	N/A
Coal sales	\$ 2,158,006	\$ 2,208,611	\$ 53.62	\$ 55.59
Operating expenses and outside coal purchases	\$ 1,377,380	\$ 1,383,374	\$ 34.22	\$ 34.82

Coal sales. Coal sales decreased 2.3% to \$2.16 billion for 2015 from \$2.21 billion for 2014. The decrease of \$50.6 million in coal sales reflected lower average coal sales prices, which reduced coal sales by \$79.3 million, partially offset by the benefit of record tons sold, which contributed \$28.7 million in additional coal sales. Average coal sales prices decreased by \$1.97 to \$53.62 per ton sold in 2015 compared to \$55.59 per ton sold in 2014, primarily as a result of current market conditions impacted by reduced coal demand at utilities due to low natural gas prices, regulatory pressures that caused coal to gas switching or plant closures and high inventories. The decline in average sales prices was particularly noticeable for our Appalachian segment, decreasing \$4.51 per ton to \$60.75. In addition, average coal sales prices were impacted by lower-priced legacy contracts inherited in the Hamilton Acquisition. Sales and production volumes rose to 40.2 million tons sold and 41.2 million tons produced in 2015 compared to 39.7 million tons sold and 40.7 million tons produced in 2014, primarily due to the addition of Hamilton production beginning August 1, 2015, the ramp up of coal production at our Gibson South mine following the commencement of operations in April 2014 and increased sales at our Tunnel Ridge and Mettiki mines. Volume increases were partially offset by lower sales at our Warrior, Gibson North, River View and Onton mines due to shift reductions, the shutdown of operations at our Gibson North and Onton mines in the fourth quarter of 2015 and scaled back production at our Tunnel Ridge mine during the second half of 2015, all in response to weak coal demand, as well as an inventory build at several locations. In addition to shift reductions, reduced production from Warrior resulted from its continuing transition to a new mining area.

Operating expenses and outside coal purchases. Operating expenses and outside coal purchases decreased 0.4% to \$1.38 billion in 2015 remaining comparable to 2014. Decreases primarily resulted from a production scale-back at various mines discussed above, lower compensation expense and reduced selling expense resulting from lower coal sales prices and a favorable sales mix. These decreases were partially offset by increased operating expenses resulting from the assumption of operations at the Hamilton Mine No. 1 and a full year of production operations at our Gibson South mine. On a per ton basis, operating expenses and outside coal purchases decreased by 1.7% to \$34.22 per ton sold in 2015 from \$34.82 per ton sold in 2014, primarily as a result of lower operating expenses discussed above and increased coal volumes at lower cost per ton mines, partially offset by the impact of scaled back production at our Tunnel Ridge mine. Operating expenses were impacted by various other factors, the most significant of which are discussed below:

- Labor and benefit expenses per ton produced, excluding workers' compensation, decreased 1.5% to \$11.55 per ton in 2015 from \$11.72 per ton in 2014. This decrease of \$0.17 per ton was primarily attributable to a favorable production mix in 2015 discussed above, lower production-related bonus compensation and reduced overtime hours as a result of reduced unit shifts at certain mines, offset partially by higher medical expenses in 2015;

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- Material and supplies expenses per ton produced decreased 3.0% to \$11.25 per ton in 2015 from \$11.60 per ton in 2014. The decrease of \$0.35 per ton produced resulted primarily from the benefits of increased production and a favorable production mix in 2015 discussed above and related decreases of \$0.31 per ton for roof support supplies and \$0.13 per ton for certain ventilation related materials and supplies expenses, partially offset by an increase of \$0.10 per ton in longwall subsidence expense;
- Production taxes and royalties expenses incurred as a percentage of coal sales prices and volumes decreased \$0.45 per produced ton sold in 2015 compared to 2014 primarily as a result of lower average coal sales prices and a favorable sales mix as discussed above and increased brokerage coal sales which have minimal production taxes and royalty expenses if any; and
- Operating expenses also benefited from a \$4.4 million gain reflecting a reduction in the estimated value, due to lower coal sales prices, of contingent consideration potentially payable in the Hamilton Acquisition.

Operating expenses and outside coal purchases per ton decreases discussed above were partially offset by the following increases:

- Operating expenses for 2015 increased as a result of the benefit of \$7.0 million of insurance proceeds in 2014 related to claims from an adverse geological event at the Onton mine in 2013 and a gain of \$4.4 million recognized in 2014 on the sale of Pontiki's assets, both of which were absent in 2015. In May 2014, Pontiki completed the sale of most of its assets, including certain coal reserves, mining equipment and infrastructure and surface facilities.

Other sales and operating revenues. Other sales and operating revenues are principally comprised of Mt. Vernon transloading revenues, Matrix Design Group sales, surface facility services and coal royalty revenues received from White Oak prior to the Hamilton Acquisition and other outside services and administrative services revenue from affiliates. Other sales and operating revenues increased to \$82.1 million for 2015 from \$66.1 million for 2014. The increase of \$16.0 million was primarily attributable to White Oak's start-up of longwall production and resulting increased surface facility services and coal royalty revenues prior to the Hamilton Acquisition and increased revenues at our Mt. Vernon operations primarily due to increased transloading fees from White Oak prior to the Hamilton Acquisition, partially offset by decreased payments-in-lieu-of-shipments received from a customer related to an Appalachian coal supply agreement.

General and administrative. General and administrative expenses for 2015 decreased to \$67.5 million compared to \$72.6 million in 2014. The decrease of \$5.1 million was primarily due to lower incentive compensation expenses.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased to \$333.7 million for 2015 from \$274.6 million for 2014. The increase of \$59.1 million was attributable to the reduction of the economic mine life at our Elk Creek mine, which is expected to close near the end of the first quarter of 2016, increased production at the Gibson South mine, which commenced initial production in April 2014, amortization of coal supply agreements acquired in December 2014 and the addition of the Hamilton Mine No. 1 in late July 2015.

Interest expense. Interest expense, net of capitalized interest, decreased to \$31.2 million in 2015 from \$33.6 million in 2014. The decrease of \$2.4 million was principally attributable to the repayment of our Series A senior notes in June 2015 partially offset by interest incurred on debt assumed in the Hamilton Acquisition and an increase in the principal balance of our revolving credit facility. Our debt instruments are discussed in more detail below under Debt Obligations.

Equity in loss of affiliates, net. Equity in loss of affiliates, net for 2015 includes our equity investments in White Oak prior to the Hamilton Acquisition and AllDale Minerals. In 2014, our equity investments also include MAC. For 2015, we recognized equity in loss of affiliates of \$49.0 million compared to \$16.6 million for 2014. The increase in equity in loss of affiliates, net is primarily due to low coal sales price realizations and higher expenses related to White Oak's ramp up of longwall operations in 2015 prior to the Hamilton Acquisition and the impact of changes in allocations of equity income or losses resulting from reduced equity contributions during 2015 from another White Oak partner.

Acquisition gain, net. In 2015, we recognized a \$22.5 million non-cash net gain related to the final business combination accounting for the Hamilton Acquisition. For more information on the Hamilton Acquisition, please read Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions.

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Transportation revenues and expenses. Transportation revenues and expenses were \$33.6 million and \$26.0 million for 2015 and 2014, respectively. The increase of \$7.6 million was primarily attributable to increased tonnage for which we arrange transportation at certain mines, partially offset by a decrease in average transportation rates in 2015. The cost of transportation services are passed through to our customers. Consequently, we do not realize any gain or loss on transportation revenues.

Segment Information. Our 2015 Segment Adjusted EBITDA decreased 7.0% to \$814.7 million from 2014 Segment Adjusted EBITDA of \$876.2 million. Segment Adjusted EBITDA, tons sold, coal sales, other sales and operating revenues and Segment Adjusted EBITDA Expense by segment are as follows:

	Year Ended December 31,				Increase (Decrease)	
	2015	2014 (recast)	(in thousands)			
Segment Adjusted EBITDA						
Illinois Basin	\$ 617,148	\$ 616,727	\$	421	0.1%	
Appalachia	183,908	254,037		(70,129)	(27.6)%	
Other and Corporate	26,189	8,599		17,590	(1)	
Elimination	(12,580)	(3,119)		(9,461)	(1)	
Total Segment Adjusted EBITDA (2)	\$ 814,665	\$ 876,244	\$	(61,579)	(7.0)%	
Tons sold						
Illinois Basin	30,801	30,549		252	0.8%	
Appalachia	9,439	9,182		257	2.8%	
Other and Corporate	2,813	-		2,813	(1)	
Elimination	(2,806)	-		(2,806)	(1)	
Total tons sold	40,247	39,731		516	1.3%	
Coal sales						
Illinois Basin	\$ 1,571,014	\$ 1,609,094	\$	(38,080)	(2.4)%	
Appalachia	573,453	599,262		(25,809)	(4.3)%	
Other and Corporate	133,498	255		133,243	(1)	
Elimination	(119,959)	-		(119,959)	(1)	
Total coal sales	\$ 2,158,006	\$ 2,208,611	\$	(50,605)	(2.3)%	
Other sales and operating revenues						
Illinois Basin	\$ 43,856	\$ 24,306	\$	19,550	80.4%	
Appalachia	11,136	19,464		(8,328)	(42.8)%	
Other and Corporate	47,007	33,834		13,173	38.9%	
Elimination	(19,869)	(11,515)		(8,354)	(72.5)%	
Total other sales and operating revenues	\$ 82,130	\$ 66,089	\$	16,041	24.3%	
Segment Adjusted EBITDA Expense						
Illinois Basin	\$ 949,271	\$ 1,000,028	\$	(50,757)	(5.1)%	
Appalachia	400,681	364,689		35,992	9.9%	
Other and Corporate	153,720	25,487		128,233	(1)	
Elimination	(127,247)	(8,396)		(118,851)	(1)	
Total Segment Adjusted EBITDA Expense (2)	\$ 1,376,425	\$ 1,381,808	\$	(5,383)	(0.4)%	

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

(2) For a definition of Segment Adjusted EBITDA and Segment Adjusted EBITDA Expense and related reconciliations to comparable GAAP financial measures, please see below under Reconciliation of non-GAAP Segment Adjusted EBITDA to GAAP net income and reconciliation of non-GAAP Segment Adjusted EBITDA Expense to GAAP Operating Expenses.

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Illinois Basin Segment Adjusted EBITDA increased slightly by 0.1% to \$617.1 million in 2015 from \$616.7 million in 2014. The increase was primarily attributable to increased surface facility services and coal royalty revenues received from White Oak prior to the Hamilton Acquisition as well as decreased expenses per ton resulting from a favorable production mix, partially offset by lower coal sales, which decreased 2.4% to \$1.57 billion in 2015 from \$1.61 billion in 2014, and higher equity in loss of affiliates from White Oak prior to the Hamilton Acquisition as discussed above. The decrease of \$38.1 million in coal sales primarily reflects lower average coal sales prices of \$51.01 in 2015 compared to \$52.67 in 2014 resulting from current market conditions discussed above and the assumption of lower-priced legacy contracts inherited in the Hamilton Acquisition, partially offset by increased tons sold, which increased 0.8% to 30.8 million tons in 2015 compared to 30.5 million tons in 2014. Higher coal sales volumes resulted from our Gibson South mine and the assumption of operations at the Hamilton Mine No. 1, partially offset by lower recoveries and shift reductions at our River View, Warrior and Gibson North mines, shift reductions at our Onton mine, as well as the shutdown of operations at our Gibson North and Onton mines in the fourth quarter of 2015, all in response to weak coal demand. Segment Adjusted EBITDA Expense decreased 5.1% to \$949.3 million in 2015 from \$1.00 billion in 2014 and decreased \$1.92 per ton sold to \$30.82 from \$32.74 per ton sold in 2014, primarily due to the favorable production mix in 2015, partially offset by insurance proceeds received in 2014 related to the Onton mine discussed above, as well as the impact of certain other cost increases and decreases described above under **Operating expenses and outside coal purchases**.

Appalachia Segment Adjusted EBITDA decreased to \$183.9 million for 2015 as compared to \$254.0 million for 2014. The decrease of \$70.1 million was primarily attributable to lower average coal sales prices as a result of current market conditions, lower production recoveries across the region and decreased payments in lieu of shipments received from a customer related to a Tunnel Ridge coal supply agreement. Coal sales decreased 4.3% to \$573.5 million in 2015 compared to \$599.3 million in 2014. The decrease of \$25.8 million was primarily attributable to lower average coal sales prices of \$60.75 per ton sold during 2015 compared to \$65.26 per ton sold in 2014 reflecting the impact of market conditions on sales from our Tunnel Ridge and MC Mining mines, partially offset by increased tons sold, which increased 2.8% to 9.4 million tons in 2015 compared to 9.2 million tons sold in 2014 as a result of increased sales volumes at our Tunnel Ridge and Mettiki mines. Segment Adjusted EBITDA Expense increased 9.9% to \$400.7 million in 2015 from \$364.7 million in 2014 and increased \$2.73 per ton sold to \$42.45 from \$39.72 per ton sold in 2014, primarily due to lower recoveries and reduced production at our Tunnel Ridge mine as a result of lower coal demand and the need to manage coal inventories, partially offset by the benefit of fewer longwall move days in 2015, as well as the impact of certain other cost increases and decreases discussed above under **Operating expenses and outside coal purchases**.

Other and Corporate Segment Adjusted EBITDA increased \$17.6 million to \$26.2 million in 2015 from \$8.6 million in 2014 and Segment Adjusted EBITDA Expense increased to \$153.7 million for 2015 from \$25.5 million in 2014. These increases were primarily as a result of increased Mt. Vernon transloading services and intercompany related activity such as increased coal brokerage activity, MAC sales and revenues and expenses of AROP Funding and Wildcat Insurance, which are eliminated upon consolidation. Segment Adjusted EBITDA Expense also increased in 2015 due to the absence of the benefit of a gain of \$4.4 million recognized in the 2014 Period on the sale of Pontiki's assets.

Elimination Segment Adjusted EBITDA Expense and coal sales eliminations significantly increased in 2015 to \$127.2 million and \$120.0 million, respectively, reflecting additional intercompany coal sales to Alliance Coal to support increased coal brokerage activity resulting from coal supply agreements acquired from Patriot Coal Corporation (Patriot) on December 31, 2014. For more information on the Patriot acquisition, please read **Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions**.

2014 Compared with 2013

We reported record net income of \$497.2 million for 2014 compared to \$393.5 million for 2013. The increase of \$103.7 million was principally due to increased sales from low-cost production at our Tunnel Ridge mine in addition to increased coal sales and production volumes, which

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rose to 39.7 million tons sold and 40.7 million tons produced in 2014 compared to 38.8 million tons sold and produced in 2013. The increase in tons sold and produced resulted primarily from increased production as a result of improved mining conditions at our Tunnel Ridge, MC Mining and Dotiki mines and the start-up of coal production at our Gibson South mine in April 2014. Record net income also benefited from throughput fees received from surface facility services and coal royalties related to operations at the White Oak Mine No. 1 (now known as the Hamilton Mine No. 1) prior to the Hamilton Acquisition in July 2015 discussed in Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions. Lower operating expenses during 2014 resulted primarily from a coal inventory build during the year; improved productivity at our Tunnel Ridge,

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MC Mining and Dotiki mines; a significant increase in sales of lower-cost production from Tunnel Ridge; insurance proceeds received in 2014 related to an adverse geological event at our Onton mine that also increased operating expenses in 2013; the idling of a higher-cost third-party mining operation at our Mettiki mine; and the absence of higher-cost production at our Pontiki mine, which was closed in late 2013.

	December 31, 2014		December 31, 2013	
	(in thousands)		(per ton sold)	
Tons sold	39,731		38,835	
Tons produced	40,749		38,782	
Coal sales	\$	2,208,611	\$	2,137,449
Operating expenses and outside coal purchases	\$	1,383,374	\$	1,400,793
			\$	55.59
			\$	55.04
			\$	34.82
			\$	36.07

Coal sales. Coal sales increased 3.3% to \$2.2 billion in 2014 from \$2.1 billion in 2013. The increase of \$71.2 million reflected the benefit of increased tons sold (contributing \$49.3 million in additional coal sales) and higher average coal sales prices (contributing \$21.9 million in additional coal sales). Average coal sales prices increased \$0.55 per ton sold in 2014 to \$55.59 per ton compared to \$55.04 per ton sold in 2013, primarily as a result of increased contract pricing at our Mettiki mine, an increase of higher-priced coal sales at our Tunnel Ridge mine and the addition of higher-priced coal sales at our Gibson South mine, partially offset by the absence of higher-priced Pontiki sales in 2014.

Operating expenses and outside coal purchases. Operating expenses and outside coal purchases decreased 1.2% to \$1.4 billion in 2014. On a per ton basis, operating expenses and outside coal purchases decreased 3.5% to \$34.82 per ton from \$36.07 per ton sold in 2013, primarily due to increased lower-cost production at our Tunnel Ridge mine, strong production performance at our MC Mining and Dotiki mines, improved production and operating conditions at our Onton mine and the absence of higher-cost production at our Pontiki mine. Operating expenses were impacted by various other factors, the most significant of which are discussed below:

- Labor and benefit expenses per ton produced, excluding workers' compensation, decreased 2.7% to \$11.72 per ton in 2014 from \$12.04 per ton in 2013. The decrease of \$0.32 per ton was primarily attributable to lower labor cost per ton resulting from increased production discussed above, lower medical expenses at the Mettiki mine and the absence of higher-cost per ton labor and benefits at our Pontiki mine;
- Materials and supplies expenses per ton produced decreased slightly to \$11.60 per ton in 2014 from \$11.63 per ton in 2013. The decrease of \$0.03 per ton produced resulted primarily from increased production discussed above and a decrease in cost for certain products and services, primarily safety related materials and supplies (decrease of \$0.09 per ton), lower longwall subsidence expense (decrease of \$0.04 per ton) offset partially by increased roof supports (increase of \$0.06 per ton) and ventilation-related materials and supplies (increase of \$0.05 per ton);

- Maintenance expenses per ton produced decreased 2.5% to \$3.90 per ton in 2014 from \$4.00 per ton in 2013. The decrease of \$0.10 per ton produced was primarily from the benefits of increased production at certain locations, as discussed above, and the absence of higher-cost per ton maintenance expenses at our Pontiki mine;
- Contract mining expenses decreased \$4.8 million in 2014 compared to 2013. The decrease primarily reflects lower production resulting from the idling of a third-party mining operation at our Mettiki mine complex in 2013 due to reduced metallurgical coal export market opportunities;
- Operating expenses benefited from insurance proceeds of \$7.0 million received in 2014 related to claims from an adverse geological event at the Onton mine in 2013 and the absence of \$3.8 million of asset retirements that occurred in 2013 resulting from the Onton mine's previously mentioned adverse geological event.

Operating expenses and outside coal purchases per ton decreases discussed above were partially offset by the following increase:

- Workers' compensation and black lung expenses per ton produced increased to \$0.30 per ton in 2014 from \$0.17 per ton in 2013. The increase of \$0.13 per ton resulted primarily from a decrease in the discount rate used

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to calculate the estimated present value of future obligations and reduced favorable claim trends and disability incident rate assumptions in 2014 compared to 2013.

Other sales and operating revenues. Other sales and operating revenues are principally comprised of Mt. Vernon transloading revenues, Matrix Design sales, throughput fees received from White Oak prior to the Hamilton Acquisition and other outside services and administrative services revenue from affiliates. Other sales and operating revenues increased to \$66.1 million in 2014 from \$35.5 million in 2013. The increase of \$30.6 million was primarily attributable to White Oak throughput fees and payments in lieu of shipments received from a customer in 2014 related to an Appalachian coal sales contract.

General and administrative. General and administrative expenses for 2014 increased to \$72.6 million compared to \$63.7 million in 2013. The increase of \$8.9 million was primarily due to increased compensation-related expenses.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased to \$274.6 million in 2014 compared to \$264.9 million in 2013. The increase of \$9.7 million was primarily attributable to increased production volumes mentioned above, as well as capital expenditures related to production expansion and infrastructure investments at various operations.

Interest expense. Interest expense, net of capitalized interest, increased to \$33.6 million in 2014 from \$27.0 million in 2013. The increase of \$6.6 million was principally attributable to decreased capitalized interest on the equity investment in White Oak, partially offset by decreased interest resulting from principal repayments made during 2014 of \$18.8 million and \$18.0 million on our term loan and original senior notes issued in 1999, respectively. The term loan and senior notes are discussed in more detail below under Debt Obligations.

Equity in loss of affiliates, net. Equity in loss of affiliates, net includes our share of the results of operations of our equity investments in White Oak prior to the Hamilton Acquisition, AllDale Minerals and MAC prior to its acquisition in January 2015. Equity in loss of affiliates, net was \$16.6 million in 2014 compared to \$24.4 million in 2013. The decrease in net equity in loss of affiliates is primarily related to our equity investment in White Oak prior to the Hamilton Acquisition and the impact of changes in allocations of equity income or losses resulting from equity contributions during 2014 by another White Oak owner, partially offset by increased losses incurred by White Oak during 2014. Prior to the Hamilton Acquisition, equity contributions impacted the future preferred distributions allocable to each owner and the ongoing allocation of income and losses for GAAP purposes.

Transportation revenues and expenses. Transportation revenues and expenses decreased to \$26.0 million in 2014 from \$32.6 million in 2013. The decrease of \$6.6 million was primarily attributable to a decrease in average transportation rates reflecting the absence of export sales to a certain customer from our Warrior mine in 2014 compared to 2013, as well

as decreased tonnage for which we arranged transportation at certain other mines in 2014. 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. Income tax expense decreased \$1.4 million in 2014. Income taxes are primarily due to the operations of Matrix Design. The decrease in income tax expense was primarily due to a large valuation allowance of ASI s deferred tax assets in 2013.

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Segment Information. Our 2014 Segment Adjusted EBITDA increased 16.9% to \$876.2 million from 2013 Segment Adjusted EBITDA of \$749.6 million. Segment Adjusted EBITDA, tons sold, coal sales, other sales and operating revenues and Segment Adjusted EBITDA Expense by segment are as follows:

	Year Ended December 31,				Increase (Decrease)
	2014 (recast)	2013 (recast)			
		(in thousands)			
Segment Adjusted EBITDA					
Illinois Basin	\$ 616,727	\$ 632,175	\$	(15,448)	(2.4)%
Appalachia	254,037	105,123		148,914	(1)
Other and Corporate	8,599	12,278		(3,679)	(30.0)%
Elimination	(3,119)	-		(3,119)	(1)
Total Segment Adjusted EBITDA (2)	\$ 876,244	\$ 749,576	\$	126,668	16.9%
Tons sold					
Illinois Basin	30,549	30,640		(91)	(0.3)%
Appalachia	9,182	7,493		1,689	22.5%
Other and Corporate	-	775		(775)	(1)
Elimination	-	(73)		73	(1)
Total tons sold	39,731	38,835		896	2.3%
Coal sales					
Illinois Basin	\$ 1,609,094	\$ 1,605,232	\$	3,862	0.2%
Appalachia	599,262	476,736		122,526	25.7%
Other and Corporate	255	60,073		(59,818)	(99.6)%
Elimination	-	(4,592)		4,592	(1)
Total coal sales	\$ 2,208,611	\$ 2,137,449	\$	71,162	3.3%
Other sales and operating revenues					
Illinois Basin	\$ 24,306	\$ 6,052	\$	18,254	(1)
Appalachia	19,464	4,310		15,154	(1)
Other and Corporate	33,834	38,199		(4,365)	(11.4)%
Elimination	(11,515)	(13,091)		1,576	12.0%
Total other sales and operating revenues	\$ 66,089	\$ 35,470	\$	30,619	86.3%
Segment Adjusted EBITDA Expense					
Illinois Basin	\$ 1,000,028	\$ 953,798	\$	46,230	4.8%
Appalachia	364,689	375,923		(11,234)	(3.0)%
Other and Corporate	25,487	86,864		(61,377)	(70.7)%
Elimination	(8,396)	(17,683)		9,287	52.5%
Total Segment Adjusted EBITDA Expense (2)	\$ 1,381,808	\$ 1,398,902	\$	(17,094)	(1.2)%

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

(2) For a definition of Segment Adjusted EBITDA and Segment Adjusted EBITDA Expense and related reconciliations to comparable GAAP financial measures, please see below under Reconciliation of non-GAAP Segment Adjusted EBITDA to GAAP net income and reconciliation of non-GAAP Segment Adjusted EBITDA Expense to GAAP Operating Expenses.

Illinois Basin Segment Adjusted EBITDA decreased 2.4% to \$616.7 million in 2014 from \$632.2 million in 2013. The decrease of \$15.5 million was primarily attributable to decreased coal recoveries at our Warrior mine as it continues to transition into a new mining area and increased expenses per ton at our Pattiki and Hopkins mines due to difficult mining conditions, partially offset by improved sales and production from our Dotiki mine, improved production and operating conditions at our Onton mine, increased throughput revenues for surface facility services and coal royalties from White Oak and reduced losses allocated to us as a result of equity contributions made by another White Oak owner

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as discussed above under -Equity in loss of affiliates, net. Also benefiting 2014 were higher average coal sales prices that increased slightly to \$52.67 per ton sold compared to \$52.39 per ton in 2013. Coal sales increased \$3.9 million to \$1.6 billion in 2014 primarily reflecting increased tons sold from our Dotiki mine and higher-priced coal sales from start-up production at our Gibson South mine, partially offset by reduced tons sold at our Warrior and Gibson North mines. Segment Adjusted EBITDA Expense increased 4.8% to \$1.0 billion in 2014 and increased \$1.61 per ton sold to \$32.74 from \$31.13 per ton sold in 2013, primarily as a result of difficult mining conditions and lower recoveries discussed above. The increase in Segment Adjusted EBITDA Expense was partially offset by insurance proceeds received in 2014 related to the impact of the adverse geological event at our Onton mine in 2013 mentioned above, as well as certain other cost decreases discussed above under -Operating expenses and outside coal purchases .

Appalachia Segment Adjusted EBITDA increased to \$254.0 million for 2014 compared to \$105.1 million for 2013. The increase of \$148.9 million was primarily attributable to increased tons sold, which rose 22.5% to 9.2 million tons sold, and higher average coal sales prices of \$65.26 per ton sold during 2014 compared to \$63.62 per ton sold during 2013. Coal sales increased 25.7% to \$599.3 million in 2014 compared to \$476.7 million in 2013. The increase of \$122.6 million was primarily due to increased production at our Tunnel Ridge and MC Mining operations and higher contract coal sales prices at our Mettiki mine. Segment Adjusted EBITDA also benefited from increased other sales and operating revenues due to payments in lieu of shipments received from a customer in 2014. Segment Adjusted EBITDA Expense decreased 3.0% to \$364.7 million in 2014 from \$375.9 million in 2013 and decreased \$10.45 per ton sold to \$39.72 from \$50.17 per ton sold in 2013, primarily due to improved productivity and geological conditions at our Tunnel Ridge mine and new Excel No. 4 mining area at the MC Mining operation, reduced contract mining expenses and lower employee benefit cost at our Mettiki mining complex, as well as certain other cost decreases discussed above under Operating expenses and outside coal purchases .

Other and Corporate Segment Adjusted EBITDA decreased \$3.7 million in 2014 from 2013 and Segment Adjusted EBITDA Expense decreased 70.7% to \$25.5 million for 2014. These decreases were primarily attributable to the absence of production and sales in 2014 from our former Pontiki mine discussed above.

Reconciliation of non-GAAP Segment Adjusted EBITDA to GAAP net income and reconciliation of non-GAAP Segment Adjusted EBITDA Expense to GAAP Operating Expenses

Segment Adjusted EBITDA (a non-GAAP financial measure) is defined as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes, depreciation, depletion and amortization, asset impairment charge, acquisition gain, net and general and administrative expenses. Segment Adjusted EBITDA is a key component of consolidated EBITDA, which is used as a supplemental financial measure by management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on investment 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 previous explanation of consolidated EBITDA. In addition, the exclusion of corporate general and administrative expenses, which are discussed above under Analysis of Historical Results of Operations, 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.

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The following is a reconciliation of consolidated Segment Adjusted EBITDA to net income, the most comparable GAAP financial measure:

	2015	Year Ended December 31, 2014	2013
		(in thousands)	
Consolidated Segment Adjusted EBITDA	\$ 814,665	\$ 876,244	\$ 749,576
General and administrative	(67,484)	(72,552)	(63,697)
Depreciation, depletion and amortization	(333,713)	(274,566)	(264,911)
Asset impairment charge	(100,130)	-	-
Interest expense, net	(29,694)	(31,913)	(26,082)
Acquisition gain, net	22,548	-	-
Income tax expense	(21)	-	(1,396)
Net income	\$ 306,171	\$ 497,213	\$ 393,490

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

The following is a reconciliation of consolidated Segment Adjusted EBITDA Expense to operating expense, the most comparable GAAP financial measure:

	2015	Year Ended December 31, 2014	2013
		(in thousands)	
Segment Adjusted EBITDA Expense	\$ 1,376,425	\$ 1,381,808	\$ 1,398,902
Outside coal purchases	(327)	(14)	(2,030)
Other income	955	1,566	1,891
Operating expenses (excluding depreciation, depletion and amortization)	\$ 1,377,053	\$ 1,383,360	\$ 1,398,763

Ongoing Acquisition Activities

Consistent with our business strategy, from time to time we engage in discussions with potential sellers regarding our possible acquisitions of certain assets and/or companies of the sellers. For more information on acquisitions, please read [Item 8. Financial Statements and Supplementary Data](#) [Note 3. Acquisitions](#) of this Annual Report on Form 10-K.

Liquidity and Capital Resources

Liquidity

We have historically satisfied our working capital requirements and funded our capital expenditures, equity investments and debt service obligations with cash generated from operations, cash provided by the issuance of debt or equity and borrowings under credit and securitization facilities. We believe that existing cash balances, future cash flows from operations, borrowings under credit facilities and cash provided from the issuance of debt or equity will be sufficient to meet our working capital requirements, capital expenditures and additional equity investments, debt payments, commitments and distribution payments. Nevertheless, our ability to satisfy our working capital

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requirements, to fund planned capital expenditures and equity investments, to service our debt obligations or to pay distributions will depend upon our future operating performance and access to and cost of financing sources, which will be affected by prevailing economic conditions generally and in the coal industry specifically, as well as other financial and business factors, some of which are beyond our control. Based on our recent operating results, current cash position, anticipated future cash flows and sources of financing that we expect to have available, we do not anticipate any significant liquidity constraints in the foreseeable future. However, to the extent operating cash flow or access to and cost of financing sources are materially different than expected, future liquidity may be adversely affected. Please see Item 1A. Risk Factors.

Our consolidated affiliate, Cavalier Minerals, owns equity interests and plans to make additional equity investments in the AllDale Minerals entities for the purchase of oil and gas mineral interests in various geographic locations within producing basins in the continental U.S. As of December 31, 2015, Cavalier Minerals had provided funding of \$65.9 million to AllDale Minerals and has a remaining commitment of \$83.1 million, which it expects to fund over the next two years. At Alliance Minerals' election, Cavalier Minerals will meet its remaining funding commitment to AllDale Minerals through contributions from Alliance Minerals and the other equity owner or from borrowings under the Cavalier Credit Facility (the Cavalier Credit Facility is discussed in more detail below under Debt Obligations). For more information on these transactions, please read Item 8. Financial Statements and Supplementary Data Note 11. Variable Interest Entities and Note 12. Equity Investments of this Annual Report on Form 10-K.

On September 22, 2011, we entered into a series of transactions with White Oak to support development of the White Oak longwall mining operation (now known as Hamilton Mine No. 1) including the purchase of preferred equity interests. On July 31, 2015 (Acquisition Date), we paid \$50.0 million to acquire the remaining equity interest in White Oak and assumed control of the mine. Prior to the Acquisition Date, we had funded \$422.6 million to White Oak under various agreements inclusive of the preferred equity interest purchases. In conjunction with the acquisition of White Oak, we assumed \$93.5 million of debt which was extinguished in the fourth quarter of 2015 and replaced with a \$100 million equipment sale-leaseback arrangement. For more information on this sale-leaseback arrangement, please read Item 8. Financial Statements and Supplementary Data Note 20. Commitments and Contingencies of this Annual Report on Form 10-K. In 2014 and 2015, we paid \$48.0 million to Patriot and \$11.6 million to CONSOL to acquire various assets, including certain mining equipment and reserves. We also paid \$5.5 million in 2015 to acquire MAC. For more information on our acquisitions, please read Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions of this Annual Report on Form 10-K.

Cash Flows

Cash provided by operating activities was \$716.3 million in 2015 compared to \$739.2 million in 2014. The decrease in cash provided by operating activities was primarily due to a decrease in net income adjusted for non-cash items, additional payments for accounts payable and other current liabilities in 2015 compared to 2014 related to beginning balances assumed in the Hamilton Acquisition, a decrease in payroll and related benefits accruals during 2015 compared to an increase during 2014 reflecting higher annual incentive compensation payments in 2015 and reduced incentive accruals as of December 31, 2015, an increase in advance royalties in 2015 compared to a decrease in 2014 primarily related to our first annual minimum royalties paid to WKY CoalPlay, LLC (WKY CoalPlay), offset by a favorable change in trade receivables during 2015 compared to 2014. For more information on royalties paid to WKY CoalPlay, please read Item 8. Financial Statements and Supplementary Data Note 19. Related-Party Transactions of this Annual Report on Form 10-K.

Net cash used in investing activities was \$355.9 million in 2015 compared to \$441.2 million in 2014. The decrease in cash used in investing activities was primarily attributable to the lower capital expenditures for mine infrastructure and equipment at various mines, partially as a result of utilization of mining equipment acquired in the Patriot acquisition, significantly lower capital expenditures at our Gibson South mine, and a decrease in funding of the White Oak equity investment in 2015, partially offset by cash and loans extended in connection with the Hamilton Acquisition in 2015. For more information regarding acquisitions, please read Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions of this Annual Report on Form 10-K.

Net cash used in financing activities was \$351.6 million in 2015 compared to \$367.0 million in 2014. The decrease in cash used in financing activities was primarily attributable to a decrease in payments and an increase in borrowings under our revolving credit facilities during 2015 as well as proceeds received from a sale-leaseback transaction in 2015, partially offset by a decrease in borrowings and an increase in payments under our securitization facility in 2015 and

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repayment of our Series A Senior Notes and a portion of our Term Loan as well as increased distributions paid to partners in 2015. For more information on our debt obligations, please read [Debt Obligations](#) below.

We have various commitments primarily related to long-term debt, including capital leases, operating lease commitments related to buildings and equipment, obligations for estimated future asset retirement obligations costs, workers' compensation and pneumoconiosis, capital projects and pension funding. We expect to fund these commitments with existing cash balances, future cash flows from operations, borrowings under revolving credit and securitization facilities and cash provided from the issuance of debt or equity.

The following table provides details regarding our contractual cash obligations as of December 31, 2015:

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(in thousands)		
Long-term debt	\$ 819,350	\$ 239,350	\$ 580,000	\$ -	\$ -
Future interest obligations(1)	40,146	21,985	18,161	-	-
Operating leases	42,663	15,347	20,706	6,610	-
Capital leases(2)	111,637	24,138	47,093	40,406	-
Purchase obligations for capital projects	28,722	28,722	-	-	-
Reclamation obligations(3)	228,485	1,251	5,655	9,925	211,654
Workers' compensation and pneumoconiosis benefit(3)	269,166	11,857	20,876	15,908	220,525
	\$ 1,540,169	\$ 342,650	\$ 692,491	\$ 72,849	\$ 432,179

(1) Interest on variable-rate, long-term debt was calculated using rates elected by us at December 31, 2015 for the remaining term of outstanding borrowings.

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

(3) Future commitments for reclamation obligations, workers' compensation and pneumoconiosis are shown at undiscounted amounts. These obligations are primarily statutory, not contractual.

We expect to contribute \$2.6 million to our defined benefit pension plan during 2016.

In addition to the above described capital expenditures related to our operating activities, we currently anticipate funding to AllDale Minerals during the next two years approximately \$83.1 million for the acquisition of oil and gas mineral interests in various geographic locations within producing basins in the continental U.S.

Off-Balance Sheet Arrangements

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

We use a combination of surety bonds and letters of credit to secure our financial obligations for reclamation, workers compensation and other obligations as follows as of December 31, 2015:

	Reclamation Obligation	Workers Compensation Obligation	Other	Total
		(in millions)		
Surety bonds	\$ 153.5	\$ 67.3	\$ 13.2	\$ 234.0
Letters of credit	-	22.7	13.9	36.6

Our involvement in our equity investment in AllDale Minerals consists of our support for AllDale Minerals acquisition of oil and gas mineral interests in various geographic locations within producing basins in the continental

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U.S. We incurred allocated losses related to Cavalier Minerals' equity investment in AllDale Minerals of \$0.5 million for the year ended December 31, 2015. For more information on our involvement with AllDale Minerals, please read Item 8. Financial Statements and Supplementary Data Note 12. Equity Investments of this Annual Report on Form 10-K.

Capital Expenditures

Capital expenditures decreased to \$212.8 million in 2015 compared to \$307.4 million in 2014. See our discussion of Cash Flows above concerning this decrease in capital expenditures.

We currently project average estimated annual maintenance capital expenditures over the next five years of approximately \$4.75 per ton produced. Our anticipated total capital expenditures, including maintenance capital expenditures, for 2016 are estimated in a range of \$134.0 to \$142.0 million. Management anticipates funding 2016 capital requirements with our December 31, 2015 cash and cash equivalents of \$33.4 million, future cash flows from operations, borrowings under revolving credit and securitization facilities and cash provided from the issuance of debt or equity. 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.

Insurance

Effective October 1, 2015, we renewed our annual property and casualty insurance program. In an effort to reduce cost, our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance. Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased reinsurance for the program in the standard market. The maximum limit in the commercial property program is \$100.0 million per occurrence, excluding a \$1.5 million deductible for property damage, a 75, 90 or 120 day waiting period for underground business interruption depending on the mining complex and an additional \$10.0 million overall aggregate deductible. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future.

Debt Obligations

Credit Facility and Senior Notes

Credit Facility. On May 23, 2012, our Intermediate Partnership entered into a credit agreement (the *Credit Agreement*) with various financial institutions for a revolving credit facility (the *Revolving Credit Facility*) of \$700.0 million and a term loan (the *Term Loan*) in the aggregate principal amount of \$250.0 million (collectively, the *Revolving Credit Facility* and *Term Loan* are referred to as the *Credit Facility*). Borrowings under the *Credit Agreement* bear interest at a Base Rate or Eurodollar Rate, at our election, plus an applicable margin that fluctuates depending upon the ratio of

Consolidated Debt to Consolidated Cash Flow (each as defined in the Credit Agreement). We have elected a Eurodollar Rate, which, with applicable margin, was 2.06% on borrowings outstanding as of December 31, 2015. The Credit Facility matures May 23, 2017, at which time all amounts then outstanding are required to be repaid. Interest is payable quarterly, with principal of the Term Loan due as follows: for each quarter commencing June 30, 2014 and ending March 31, 2016, quarterly principal payments in an amount per quarter equal to 2.50% of the aggregate amount of the Term Loan advances outstanding; for each quarter beginning June 30, 2016 through December 31, 2016, 20% of the aggregate amount of the Term Loan advances outstanding; and the remaining balance of the Term Loan advances at maturity. In June 2014, we began making quarterly principal payments on the Term Loan, leaving a balance of \$206.3 million at December 31, 2015. We have the option to prepay the Term Loan at any time in whole or in part subject to terms and conditions described in the Credit Agreement. Upon a change of control (as defined in the Credit Agreement), the unpaid principal amount of the Credit Facility, all interest thereon and all other amounts payable under the Credit Agreement would become due and payable. On October 16, 2015, the Revolving Credit Facility was amended to increase the baskets for capital lease obligations from \$10.0 million to 100.0 million and sale-leaseback arrangements from \$10.0 million to \$100.0 million per annum.

At December 31, 2015, we had borrowings of \$385.0 million and \$5.9 million of letters of credit outstanding with \$309.1 million available for borrowing under the Revolving Credit Facility. We utilize the Revolving Credit Facility, as

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appropriate, for working capital requirements, capital expenditures and investments in affiliates, scheduled debt payments and distribution payments. We incur an annual commitment fee of 0.25% on the undrawn portion of the Revolving Credit Facility.

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

The Series B Senior Notes and the Credit Facility described above (collectively, ARLP Debt Arrangements) are guaranteed by all of the material 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, incurrence of additional indebtedness and liens, sale of assets, investments, mergers and consolidations and 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 (a) debt to cash flow ratio of not more than 3.0 to 1.0 and (b) cash flow to interest expense ratio of not less than 3.0 to 1.0, in each case, during the four most recently ended fiscal quarters. The debt to cash flow ratio and cash flow to interest expense ratio were 1.19 to 1.0 and 24.2 to 1.0, respectively, for the trailing twelve months ended December 31, 2015. We were in compliance with the covenants of the ARLP Debt Arrangements as of December 31, 2015.

Accounts Receivable Securitization. On December 5, 2014, certain direct and indirect wholly owned subsidiaries of our Intermediate Partnership entered into a \$100.0 million accounts receivable securitization facility (Securitization Facility) providing additional liquidity and funding. Under the Securitization Facility, certain subsidiaries sell trade receivables on an ongoing basis to our Intermediate Partnership, which then sells the trade receivables to AROP Funding, a wholly owned bankruptcy-remote special purpose subsidiary of our Intermediate Partnership, which in turn borrows on a revolving basis up to \$100.0 million secured by the trade receivables. After the sale, Alliance Coal, as servicer of the assets, collects the receivables on behalf of AROP Funding. The Securitization Facility bears interest based on a Eurodollar Rate. It was renewed in December 2015 and matures in December 2016. At December 31, 2015, we had \$83.1 million outstanding under the Securitization Facility.

Cavalier Credit Agreement. On October 6, 2015, Cavalier Minerals entered into a credit agreement (the Cavalier Credit Agreement) with Mineral Lending, LLC (Mineral Lending) for a \$100.0 million line of credit (the Cavalier Credit Facility). Mineral Lending is an entity owned by a) ARH II, the parent of ARH), b) an entity owned by an officer of ARH who is also a director of ARH II (ARH Officer) and c) foundations established by the President and Chief Executive Officer of MGP and Kathleen S. Craft. There is no commitment fee under the facility. Borrowings under the Cavalier Credit Facility bear interest at a one month LIBOR rate plus 6% with interest payable quarterly. Repayment of the principal balance will begin following the first fiscal quarter after the earlier of the date on which the aggregate amount borrowed exceeds \$90.0 million or December 31, 2017, in quarterly payments of an amount equal to the greater of \$1.3 million initially, escalated to \$2.5 million after two years, or 50% of Cavalier Minerals excess cash flow. The Cavalier Credit Facility matures September 30, 2024, at which time all amounts then outstanding are required to be repaid. To secure payment of the facility, Cavalier Minerals pledged all of its partnership interests, then owned or later acquired, in AllDale Minerals, L.P. and AllDale Minerals II, L.P. Cavalier Minerals may prepay the Cavalier Credit Facility at any time in whole or in part subject to terms and conditions

described in the Cavalier Credit Agreement. As of December 31, 2015, Cavalier Minerals had not drawn on the Cavalier Credit Facility.

Other. In addition to the letters of credit available under the 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 December 31, 2015, we had \$30.7 million in letters of credit outstanding under agreements with these two banks.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the U.S. The preparation of our consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts and disclosures in the consolidated financial statements. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances. We discuss these estimates and judgments with the audit committee of the MGP Board of Directors

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(Audit Committee) periodically. Actual results may differ from these estimates. We have provided a description of all significant accounting policies in the notes to our consolidated financial statements. The following critical accounting policies are materially impacted by judgments, assumptions and estimates used in the preparation of our consolidated financial statements:

Business Combinations and Goodwill

We account for business acquisitions using the purchase method of accounting. See Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions of this Annual Report on Form 10-K for more information on our acquisitions. Assets acquired and liabilities assumed are recorded at their estimated fair values at the acquisition date. The excess of purchase price over fair value of net assets acquired is recorded as goodwill. Given the time it takes to obtain pertinent information to finalize the acquired company's balance sheet, it may be several quarters before we are able to finalize those initial fair value estimates. Accordingly, it is not uncommon for the initial estimates to be subsequently revised. The results of operations of acquired businesses are included in the consolidated financial statements from the acquisition date.

In the White Oak and MAC acquisitions, we were required to value the previously held equity interests just prior to acquisition and record a gain or loss if fair value was determined to be different from our carrying value. We re-measured our equity investment immediately prior to the White Oak acquisition using a discounted cash flow model which resulted in a loss of \$52.2 million. The assumptions used in the determination of the fair value include projected financial information, forward coal price curves and a risk adjusted discount rate. When valuing the previously held equity investment in MAC, a market approach was used to determine that the carrying value of the investment was equal to the fair value resulting in no gain or loss being recorded.

An additional part of the White Oak acquisition was valuing the pre-existing relationships that the Partnership had with White Oak. If pre-existing relationships are settled as part of a business combination the acquirer must evaluate the terms of the relationships compared to current market terms and record a gain or loss to the extent that the relationships are considered above or below market. We developed a discounted cash flow model to determine the fair value of each of these agreements at market rates and compared the valuations to similar models using the contractual rates of the agreements to determine our gains or losses. The assumptions used in these valuation models include processing rates, royalty rates, transportation rates, marketing rates, forward coal price curves, current interest rates, projected financial information and risk-adjusted discount rates. After completing our analysis, we recorded a \$74.8 million gain as a result of net above-market terms associated with the pre-existing relationships.

The only indefinite-lived intangible that the Partnership has is goodwill. At December 31, 2015, the Partnership had \$136.4 million in goodwill. Goodwill is not amortized, but subject to annual reviews on November 30th for impairment at a reporting unit level. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed or operated. A reporting unit is an operating segment or a component that is one level below an operating segment. We have assessed the reporting unit definitions and determined that at December 31, 2015, the Hamilton reporting unit and the MAC reporting unit are the appropriate reporting units for testing goodwill impairment related to the White Oak and MAC acquisitions.

The Partnership computes the fair value of the reporting units primarily using the income approach (discounted cash flow analysis). The computations require management to make significant estimates. Critical estimates are used as part of these evaluations include, among other things, the discount rate applied to future earnings reflecting a weighted average cost of capital rate, and projected coal price assumptions. Our

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estimate of the coal forward sales price curve and future sales volumes are critical assumptions used in our discounted cash flow analysis. In future periods, it is reasonably possible that a variety of circumstances could result in an impairment of our goodwill.

A discounted cash flow analysis requires us to make various judgmental assumptions about sales, operating margins, capital expenditures, working capital and coal sales prices. Assumptions about sales, operating margins, capital expenditures and coal sales prices are based on our budgets, business plans, economic projections, and anticipated future cash flows. In determining the fair value of our reporting units, we were required to make significant judgments and estimates regarding the impact of anticipated economic factors on our business. The forecast assumptions used in the period ended December 31, 2015 makes certain assumptions about future pricing, volumes and expected maintenance capital expenditures. Assumptions are also made for a normalized perpetual growth rate for periods beyond the long range financial forecast period.

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Our estimates of fair value are sensitive to changes in all of these variables, certain of which relate to broader macroeconomic conditions outside our control. As a result, actual performance in the near and longer-term could be different from these expectations and assumptions. This could be caused by events such as strategic decisions made in response to economic and competitive conditions and the impact of economic factors, such as continued over production in coal and continued low prices of natural gas. In addition, some of the inherent estimates and assumptions used in determining fair value of the reporting units are outside the control of management, including interest rates, cost of capital and our credit ratings. While we believe we have made reasonable estimates and assumptions to calculate the fair value of the reporting units and other intangible assets, it is possible a material change could occur.

Coal Reserve Values

All of the reserves presented in this Annual Report on Form 10-K constitute proven and probable reserves. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. Estimates of coal reserves necessarily depend upon a number of variables and assumptions, any one of which may vary considerably from actual results. These factors and assumptions relate to:

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

For these reasons, estimates of the recoverable quantities of coal attributable to any particular group of properties, classifications of reserves based on risk of recovery and estimates of future net cash flows expected from these properties as prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and these variations may be material. Certain account classifications within our financial statements such as depreciation, depletion, and amortization, impairment charges and certain liability calculations such as asset retirement obligations may depend upon estimates of coal reserve quantities and values. Accordingly, when actual coal reserve quantities and values vary significantly from estimates, certain accounting estimates and amounts within our consolidated financial statements may be materially impacted. Coal reserve values are reviewed annually, at a minimum, for consideration in our consolidated financial statements.

Workers Compensation and Pneumoconiosis (Black Lung) Benefits

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. We generally provide for these claims through self-insurance programs. Workers compensation laws also compensate survivors of workers who

suffer employment related deaths. The liability for traumatic injury claims is our estimate of the present value of current workers' compensation benefits, based on our actuary estimates. Our actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including claim development patterns, mortality, medical costs and interest rates. See Item 8. Financial Statements and Supplementary Data Note 18. Accrued Workers' Compensation and Pneumoconiosis Benefits for additional discussion. We had accrued liabilities of \$54.6 million and \$57.6 million for these costs at December 31, 2015 and 2014, respectively. A one-percentage-point reduction in the discount rate would have increased the liability and operating expense by approximately \$4.3 million at December 31, 2015.

Coal mining companies are subject to CMHSA, as amended, and various state statutes for the payment of medical and disability benefits to eligible recipients related to coal worker's pneumoconiosis, or black lung. We provide for these claims through self-insurance programs. Our black lung benefits liability is calculated using the service cost method based on the actuarial present value of the estimated black lung obligation. Our actuarial calculations are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and discount rates. We had accrued liabilities of \$61.7 million and \$56.4 million for these benefits at December 31, 2015 and 2014, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2015 by approximately \$2.5 million. Under the service cost method used to estimate our black lung benefits liability, actuarial gains or losses attributable to changes in actuarial assumptions, such as the discount rate, are amortized over the remaining service period of active miners.

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The discount rate for workers' compensation and black lung is derived by applying the Citigroup Pension Discount Curve to the projected liability payout. Other assumptions, such as claim development patterns, mortality, disability incidence and medical costs, are based upon standard actuarial tables adjusted for our actual historical experiences whenever possible. We review all actuarial assumptions periodically for reasonableness and consistency and update such factors when underlying assumptions, such as discount rates, change or when sustained changes in our historical experiences indicate a shift in our trend assumptions are warranted.

Defined Benefit Plan

Eligible employees at certain of our mining operations participate in the Alliance Coal, LLC and Affiliates Pension Plan for Coal Employees (the Pension Plan) that we sponsor. The benefit formula for the Pension Plan is a fixed dollar unit based on years of service. The calculation of our net periodic benefit cost (pension expense) and benefit obligation (pension liability) associated with our Pension Plan requires the use of a number of assumptions. Changes in these assumptions can result in materially different pension expense and pension liability amounts. In addition, actual experiences can differ materially from the assumptions. Significant assumptions used in calculating pension expense and pension liability are shown in Item 8. Financial Statements and Supplementary Data Note 14. Employee Benefit Plans of this Annual Report on Form 10-K and as follows:

- Our expected long-term rate of return assumption is based on broad equity and bond indices, the investment goals and objectives, the target investment allocation and on the long-term historical rates of return for each asset class. Our expected long-term rate of return used to determine our pension liability was 8.0% at December 31, 2015 and 2014. Our expected long-term rate of return used to determine our pension expense was 8.0% for the years ended December 31, 2015 and 2014. The expected long-term rate of return used to determine our pension liability is based on an asset allocation assumption of:

As of December 31, 2015

	Asset allocation assumption	Expected long- term rate of return
Domestic equity securities	70%	8.6%
Foreign equity securities	10%	5.3%
Fixed income securities/cash	20%	5.1%
	100%	

- Our expected long-term rate of return is based on a 20-year-average annual total return for each investment group. Additionally, we base our determination of pension expense on a smoothed market-related valuation of assets equal to the fair value of assets, which immediately recognizes all investment gains or losses. The actual return on plan assets was (2.0)% and 5.4% for the years ended December 31, 2015 and 2014, respectively. Lowering the expected long-term rate of return assumption by 1.0% (from 8.0% to 7.0%) at December 31, 2014 would have increased our pension expense for the year ended December 31, 2015 by approximately \$0.7 million; and

- Our weighted-average discount rate used to determine our pension liability was 4.27% and 3.92% at December 31, 2015 and 2014, respectively. Our weighted-average discount rate used to determine our pension expense was 3.92% and 4.89% at December 31, 2015 and 2014, respectively. The discount rate that we utilize for determining our future pension obligation is based on a review of currently available high-quality fixed-income investments that receive one of the two highest ratings given by a recognized rating agency. We have historically used the average monthly yield for December of an A-rated utility bond index as the primary benchmark for establishing the discount rate. Lowering the discount rate assumption by 0.5% (from 3.92% to 3.42%) at December 31, 2014 would have increased our pension expense for the year ended December 31, 2015 by approximately \$0.1 million.

Long-Lived Assets

We review the carrying value of long-lived assets and certain identifiable intangibles whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Long-lived assets and certain intangibles are

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not reviewed for impairment unless an impairment indicator is noted. Several examples of impairment indicators include:

- A significant decrease in the market price of a long-lived asset;
- A significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset; or
- A significant adverse change in the extent or manner in which a long-lived asset is being used or in its physical condition.

The above factors are not all inclusive, and management must continually evaluate whether other factors are present that would indicate a long-lived asset may be impaired. If there is an indication that carrying amount of an asset may not be recovered, the asset is monitored by management where changes to significant assumptions are reviewed. Individual assets are grouped for impairment review purposes based on the lowest level for which there is identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a by-mine basis. The amount of impairment is measured by the difference between the carrying value and the fair value of the asset. The fair value of impaired assets is typically determined based on various factors, including the present values of expected future cash flows using a risk adjusted discount rate, the marketability of coal properties and the estimated fair value of assets that could be sold or used at other operations. We recorded an asset impairment charge of \$100.1 million in 2015 (see Item 8. Financial Statements and Supplementary Data Note 4. Long-Lived Asset Impairments of this Annual Report on Form 10-K). No impairment charges were recorded in 2014.

Mine Development Costs

Mine development costs are capitalized until production, other than production incidental to the mine development process, commences and are amortized on a units of production method based on the estimated proven and probable reserves. Mine development costs represent costs incurred in establishing access to mineral reserves and include costs associated with sinking or driving shafts and underground drifts, permanent excavations, roads and tunnels. The end of the development phase and the beginning of the production phase takes place when construction of the mine for economic extraction is substantially complete. Our estimate of when construction of the mine for economic extraction is substantially complete is based upon a number of factors, such as expectations regarding the economic recoverability of reserves, the type of mine under development, and completion of certain mine requirements, such as ventilation. Coal extracted during the development phase is incidental to the mine's production capacity and is not considered to shift the mine into the production phase. At December 31, 2015 and 2014, capitalized mine development costs were \$5.9 million and \$7.0 million, respectively, representing the carrying value of development costs attributable to properties where we have not reached the production stage of mining operations, and therefore, the mine development costs are not currently being amortized. We believe that the carrying value of these development costs will be recovered.

Asset Retirement Obligations

SMCRA and similar state statutes require that mined property be restored in accordance with specified standards and an approved reclamation plan. A liability is recorded for the estimated cost of future mine asset retirement and closing procedures on a present value basis when incurred or acquired and a corresponding amount is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to permanently sealing portals at underground mines and to reclaiming the final pits and support acreage at surface mines. Examples of these types

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of costs, common to both types of mining, include, but are not limited to, removing or covering refuse piles and settling ponds, water treatment obligations, and dismantling preparation plants, other facilities and roadway infrastructure. Accrued liabilities of \$123.7 million and \$93.1 million for these costs are recorded at December 31, 2015 and 2014, respectively. See Item 8. Financial Statements and Supplementary Data Note 17. Asset Retirement Obligations for additional information. The liability for asset retirement and closing procedures is sensitive to changes in cost estimates and estimated mine lives.

Accounting for asset retirement obligations also requires depreciation of the capitalized asset retirement cost and accretion of the asset retirement obligation over time. Depreciation is generally determined on a units-of-production basis and accretion is generally recognized over the life of the producing assets.

On at least an annual basis, we review our entire asset retirement obligation liability and make necessary adjustments for permit changes approved by state authorities, changes in the timing of reclamation activities, and revisions to cost estimates and productivity assumptions, to reflect current experience. Adjustments to the liability

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associated with these assumptions resulted in a decrease of \$1.4 million and an increase of \$7.9 million for the years ended December 31, 2015 and 2014, respectively. The adjustments to the liability for the year ended December 31, 2015 were primarily attributable to decreased estimates of reclamation requirements at property acquired from CONSOL in 2014, offset by increased refuse site disturbed acreage and material required at the Pattiki operation, along with updated estimates at all other operations, the acquisition of additional property with certain existing reclamation liabilities, as well as the net impact of overall general changes in inflation and discount rates, current estimates of the costs and scope of remaining reclamation work, reclamation work completed and fluctuations in other projected mine life estimates.

While the precise amount of these future costs cannot be determined with certainty, we have estimated the costs and timing of future asset retirement obligations escalated for inflation, then discounted and recorded at the present value of those estimates. Discounting resulted in reducing the accrual for asset retirement obligations by \$104.8 million and \$88.8 million at December 31, 2015 and 2014. We estimate that the aggregate undiscounted cost of final mine closure is approximately \$228.5 million at December 31, 2015. If our assumptions differ from actual experiences, or if changes in the regulatory environment occur, our actual cash expenditures and costs that we incur could be materially different than currently estimated.

Contingencies

We are currently involved in certain legal proceedings. Our estimates of the probable costs and probability of resolution of these claims are based upon a number of assumptions, which we have developed in consultation with legal counsel involved in the defense of these matters and based upon an analysis of potential results, assuming a combination of litigation and settlement strategies. 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.

Universal Shelf

In February 2015, we filed with the SEC a universal shelf registration statement allowing us to issue from time to time an indeterminate amount of debt or equity securities (2015 Registration Statement). At February 26, 2016, we had not utilized any amounts available under the 2015 Registration Statement.

Related Party Transactions

The Board of Directors and the conflicts committee of the MGP Board of Directors review our related-party transactions that involve a potential conflict of interest between a general partner and ARLP or its subsidiaries or another partner to determine that such transactions reflect market-clearing terms and conditions customary in the coal industry. As a result of these reviews, the Board of Directors and the Conflicts Committee approved our related-party transactions described in Item 8. Financial Statements and Supplementary Data Note 19. Related-Party Transactions that had such potential conflict of interest as fair and reasonable to us and our limited partners.

Accruals of Other Liabilities

We had accruals for other liabilities, including current obligations, totaling \$279.2 million and \$228.5 million at December 31, 2015 and 2014, respectively. These accruals were chiefly comprised of workers' compensation benefits, black lung benefits, and costs associated with asset retirement obligations. These obligations are self-insured except for certain excess insurance coverage for workers' compensation. The accruals of these items were based on estimates of future expenditures based on current legislation, related regulations and other developments. Thus, from time to time, our results of operations may be significantly affected by changes to these liabilities. Please see Item 8. Financial Statements and Supplementary Data Note 17. Asset Retirement Obligations and Note 18. Accrued Workers' Compensation and Pneumoconiosis Benefits.

Inflation

Any future inflationary or deflationary pressures could adversely affect the results of our operations. For example, at times our results have been significantly impacted by price increases affecting many of the components of our operating expenses such as fuel, steel, maintenance expense and labor. Please see Item 1A. Risk Factors.

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New Accounting Standards

See Item 8. Financial Statements and Supplementary Data Note 2. Summary of Significant Accounting Policies for a discussion of new accounting standards.

Other Information

White Oak IRS Notice

We received notice that the Internal Revenue Service issued White Oak a Notice of Beginning of Administrative Proceeding in conjunction with an audit of the income tax return of White Oak for the tax year ended December 31, 2011.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

We have significant long-term coal supply agreements as evidenced by approximately 93.1% of our sales tonnage, including approximately 94.1% of our medium- and high-sulfur coal sales tonnage, being sold under long-term contracts in 2015. Most of the long-term coal supply agreements are subject to price adjustment provisions, which periodically permit an increase or decrease in the contract price, typically to reflect changes in specified indices or changes in production costs resulting from regulatory changes, or both. For additional discussion of coal supply agreements, please see Item 1. Business Coal Marketing and Sales and Item 8. Financial Statements and Supplementary Data Note 21. Concentration of Credit Risk and Major Customers. As of February 22, 2016, our nominal commitment under long-term contracts was approximately 34.3 million tons in 2016, 19.1 million tons in 2017, 14.5 million tons in 2018 and 7.1 million tons in 2019. Please read Item 3. Legal Proceedings.

We have exposure to price risk for supplies that are used directly or indirectly in the normal course of coal production such as steel, electricity and other supplies. We manage our risk for these items through strategic sourcing contracts for normal quantities required by our operations. We do not utilize any commodity price-hedges or other derivatives related to these risks.

Credit Risk

In 2015, approximately 96.1% of our sales tonnage was purchased by electric utilities. Therefore, our credit risk is primarily with domestic electric power generators. Our policy is to independently evaluate each customer's creditworthiness prior to entering into transactions and to constantly monitor outstanding accounts receivable against established credit limits. When deemed appropriate by our credit management department, we will take steps to reduce our credit exposure to customers that do not meet our credit standards or whose credit has deteriorated. These steps may include obtaining letters of credit or cash collateral, requiring prepayments for shipments or establishing customer trust accounts held for our benefit in the event of a failure to pay.

Exchange Rate Risk

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.

Interest Rate Risk

Borrowings under the Credit Facility and Securitization 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 do not utilize any interest rate derivative instruments related to

our outstanding debt. We had \$385.0 million in borrowings under the Revolving Credit Facility, \$206.3 million outstanding under the Term Loan and \$83.1 million in borrowings under the Securitization Facility at December 31, 2015. A one percentage point increase in the interest rates related to the Credit Facility and Securitization Facility would result in an annualized increase in interest expense of \$6.7 million, based on borrowing levels at December 31, 2015. With respect to our fixed-rate borrowings, we had \$145.0 million in borrowings under our Series Senior B notes at December 31, 2015. A one percentage point increase in interest rates would result in a decrease of approximately \$3.5 million in the estimated fair value of these borrowings.

The table below provides information about our market sensitive financial instruments and constitutes a forward-looking statement. The fair values of long-term debt are estimated using discounted cash flow analyses, based upon our current incremental borrowing rates for similar types of borrowing arrangements as of December 31, 2015 and 2014.

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The carrying amounts and fair values of financial instruments are as follows:

Expected Maturity Dates as of December 31, 2015	2016	2017	2018	2019	2020	Thereafter	Total	Fair Value
								December 31, 2015
				(in thousands)				
Fixed rate debt	\$ -	\$ -	\$ 145,000	\$ -	\$ -	\$ -	\$ 145,000	\$ 145,000
Weighted-average interest rate	6.72%	6.72%	6.72%	-	-	-		
Variable rate debt	\$ 239,350	\$ 435,000	\$ -	\$ -	\$ -	\$ -	\$ 674,350	\$ 674,483
Weighted-average interest rate (1)	1.96%	2.08%	-	-	-	-		

Expected Maturity Dates as of December 31, 2014	2015	2016	2017	2018	2019	Thereafter	Total	Fair Value
								December 31, 2014
				(in thousands)				
Fixed rate debt	\$ 205,000	\$ -	\$ -	\$ 145,000	\$ -	\$ -	\$ 350,000	\$ 364,221
Weighted-average interest rate	6.54%	6.72%	6.72%	6.72%	-	-		
Variable rate debt	\$ 25,000	\$ 256,250	\$ 190,000	\$ -	\$ -	\$ -	\$ 471,250	\$ 469,130
Weighted-average interest rate (1)	1.42%	1.41%	1.57%	-	-	-		

(1) Interest rate on variable rate debt equal to the rate elected by us as of December 31, 2015 and 2014, held constant for the remaining term of the outstanding borrowing.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

The Board of Directors of Alliance Resource Management GP, LLC

and the Partners of Alliance Resource Partners, L.P.

We have audited the accompanying consolidated balance sheets of Alliance Resource Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, cash flows, and partners' capital for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in the Index at Item 15(a)(2). These financial statements and schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Alliance Resource Partners, L.P. and subsidiaries at December 31, 2015 and 2014, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 26, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

February 26, 2016

Table of Contents**ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES****CONSOLIDATED BALANCE SHEETS****DECEMBER 31, 2015 AND 2014****(In thousands, except unit data)**

ASSETS	December 31,	
	2015	2014
CURRENT ASSETS:		
Cash and cash equivalents	\$ 33,431	\$ 24,601
Trade receivables	122,875	184,187
Other receivables	696	1,025
Due from affiliates	190	7,221
Inventories, net	121,081	83,155
Advance royalties, net	6,820	9,416
Prepaid expenses and other assets	29,812	31,283
Total current assets	314,905	340,888
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment, at cost	3,044,260	2,815,620
Less accumulated depreciation, depletion and amortization	(1,243,985)	(1,150,414)
Total property, plant and equipment, net	1,800,275	1,665,206
OTHER ASSETS:		
Advance royalties, net	21,295	15,895
Due from affiliate	-	11,047
Equity investments in affiliates	64,509	224,611
Goodwill (Note 3)	136,399	-
Other long-term assets	25,747	27,412
Total other assets	247,950	278,965
TOTAL ASSETS	\$ 2,363,130	\$ 2,285,059
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	\$ 83,597	\$ 85,843
Due to affiliates	129	370
Accrued taxes other than income taxes	15,621	19,426
Accrued payroll and related expenses	37,031	57,656
Accrued interest	306	318
Workers compensation and pneumoconiosis benefits	8,688	8,868
Current capital lease obligations	19,764	1,305
Other current liabilities	18,929	17,109
Current maturities, long-term debt	239,350	230,000
Total current liabilities	423,415	420,895
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities	580,000	591,250
Pneumoconiosis benefits	60,077	55,278
Accrued pension benefit	39,031	40,105
Workers compensation	47,486	49,797
Asset retirement obligations	122,434	91,085
Long-term capital lease obligations	80,150	15,624
Other liabilities	21,174	5,978
Total long-term liabilities	950,352	849,117
Total liabilities	1,373,767	1,270,012
COMMITMENTS AND CONTINGENCIES (Note 20)		

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PARTNERS' CAPITAL:

Alliance Resource Partners, L.P. (ARLP) Partners' Capital:			
Limited Partners - Common Unitholders 74,188,784 and 74,060,634 units outstanding, respectively	1,280,218		1,310,517
General Partners' deficit	(258,883)		(260,088)
Accumulated other comprehensive loss	(34,557)		(35,847)
Total ARLP Partners' Capital	986,778		1,014,582
Noncontrolling interest	2,585		465
Total Partners' Capital	989,363		1,015,047
TOTAL LIABILITIES AND PARTNERS' CAPITAL	\$ 2,363,130	\$	2,285,059

See notes to consolidated financial statements.

Table of Contents**ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES****CONSOLIDATED STATEMENTS OF INCOME****FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013****(In thousands, except unit and per unit data)**

	2015	Year Ended December 31, 2014	2013
SALES AND OPERATING REVENUES:			
Coal sales	\$ 2,158,006	\$ 2,208,611	\$ 2,137,449
Transportation revenues	33,597	26,021	32,642
Other sales and operating revenues	82,130	66,089	35,470
Total revenues	2,273,733	2,300,721	2,205,561
EXPENSES:			
Operating expenses (excluding depreciation, depletion and amortization)	1,377,053	1,383,360	1,398,763
Transportation expenses	33,597	26,021	32,642
Outside coal purchases	327	14	2,030
General and administrative	67,484	72,552	63,697
Depreciation, depletion and amortization	333,713	274,566	264,911
Asset impairment (Note 4)	100,130	-	-
Total operating expenses	1,912,304	1,756,513	1,762,043
INCOME FROM OPERATIONS	361,429	544,208	443,518
Interest expense (net of interest capitalized of \$695, \$833 and \$8,992, respectively)	(31,153)	(33,584)	(27,044)
Interest income	1,459	1,671	962
Equity in loss of affiliates, net	(49,046)	(16,648)	(24,441)
Acquisition gain, net (Note 3)	22,548	-	-
Other income	955	1,566	1,891
INCOME BEFORE INCOME TAXES	306,192	497,213	394,886
INCOME TAX EXPENSE	21	-	1,396
NET INCOME	306,171	497,213	393,490
LESS: NET LOSS ATTRIBUTABLE TO NONCONTROLLING INTEREST	27	16	-
NET INCOME ATTRIBUTABLE TO ALLIANCE RESOURCE PARTNERS, L.P. (NET INCOME OF ARLP)	\$ 306,198	\$ 497,229	\$ 393,490
GENERAL PARTNERS INTEREST IN NET INCOME OF ARLP	\$ 146,338	\$ 138,274	\$ 121,349
LIMITED PARTNERS INTEREST IN NET INCOME OF ARLP	\$ 159,860	\$ 358,955	\$ 272,141
BASIC AND DILUTED NET INCOME OF ARLP PER LIMITED PARTNER UNIT	\$ 2.11	\$ 4.77	\$ 3.63
DISTRIBUTIONS PAID PER LIMITED PARTNER UNIT	\$ 2.6625	\$ 2.4725	\$ 2.2825
WEIGHTED-AVERAGE NUMBER OF UNITS OUTSTANDING BASIC AND DILUTED	74,174,389	74,044,417	73,904,384

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013

(In thousands)

	2015	Year Ended December 31, 2014	2013
NET INCOME	\$ 306,171	\$ 497,213	\$ 393,490
OTHER COMPREHENSIVE INCOME (LOSS):			
Defined benefit pension plan			
Net actuarial (loss) gain	(863)	(23,821)	12,472
Amortization of actuarial loss (1)	3,354	773	2,653
Total defined benefit pension plan adjustments	2,491	(23,048)	15,125
Pneumoconiosis benefits			
Net actuarial (loss) gain	(750)	(2,029)	16,750
Amortization of actuarial (gain) loss (1)	(451)	(1,051)	670
Total pneumoconiosis benefits adjustments	(1,201)	(3,080)	17,420
OTHER COMPREHENSIVE (LOSS) INCOME	1,290	(26,128)	32,545
COMPREHENSIVE INCOME	307,461	471,085	426,035
Less: Comprehensive loss attributable to noncontrolling interest	27	16	-
COMPREHENSIVE INCOME ATTRIBUTABLE TO ARLP	\$ 307,488	\$ 471,101	\$ 426,035

(1) Amortization of actuarial gain or loss is included in the computation of net periodic benefit cost (see Notes 14 and 18 for additional details).

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013

(In thousands)

	2015	Year Ended December 31, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	\$ 306,171	\$ 497,213	\$ 393,490
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	333,713	274,566	264,911
Non-cash compensation expense	12,631	11,250	8,896
Asset retirement obligations	3,192	2,730	3,004
Coal inventory adjustment to market	1,952	377	2,811
Equity in loss of affiliates, net	49,046	16,648	24,441
Net (gain) loss on sale of property, plant and equipment	(1)	(4,409)	3,475
Asset impairment	100,130	-	-
Acquisition gain, net	(22,548)	-	-
Valuation allowance of deferred tax assets	1,557	1,636	3,483
Other	6,388	(5,151)	(6,251)
Changes in operating assets and liabilities:			
Trade receivables	64,412	(30,525)	19,062
Other receivables	422	16	243
Inventories	(31,628)	(39,103)	(795)
Prepaid expenses and other assets	(3,403)	856	4,290
Advance royalties	(6,915)	4,956	4,492
Accounts payable	(41,534)	8,742	(17,755)
Due to/from affiliates	(11,114)	(3,104)	(1,343)
Accrued taxes other than income taxes	(4,287)	365	(937)
Accrued payroll and related benefits	(24,527)	10,551	8,604
Pneumoconiosis benefits	2,808	3,743	5,944
Workers compensation	(2,491)	(5,349)	(14,092)
Other	(17,632)	(6,807)	(1,321)
Total net adjustments	410,171	241,988	311,162
Net cash provided by operating activities	716,342	739,201	704,652
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(212,797)	(307,387)	(329,151)
Changes in accounts payable and accrued liabilities	(3,021)	(2,270)	(3,048)
Proceeds from sale of property, plant and equipment	2,062	381	1,520
Proceeds from insurance settlement for property, plant and equipment	-	4,512	-
Purchases of equity investments in affiliates	(64,540)	(111,376)	(62,500)
Payments for acquisitions of businesses, net of cash acquired (Note 3)	(74,953)	-	-
Payments to affiliate for acquisition and development of coal reserves	-	(4,082)	(25,272)
Payment for acquisition of customer contracts	-	(11,687)	-
Advances/loans to affiliate	(7,300)	-	(7,500)
Other	4,634	(9,313)	-
Net cash used in investing activities	(355,915)	(441,222)	(425,951)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under securitization facility	6,500	100,000	-
Payments under securitization facility	(23,400)	-	-
Payments on term loans	(108,502)	(18,750)	-
Borrowings under revolving credit facilities	543,000	341,800	386,000
Payments under revolving credit facilities	(308,000)	(451,800)	(291,000)
Payments on long-term debt	(205,000)	(18,000)	(18,000)

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Proceeds on capital lease transaction	100,000	-	-
Payments on capital lease obligations	(4,312)	(1,494)	(1,190)
Payment of debt issuance costs	-	(263)	-
Contributions to consolidated company from affiliate noncontrolling interest	2,147	481	-
Net settlement of employee withholding taxes on vesting of Long-Term Incentive Plan	(2,719)	(2,991)	(3,015)
Cash contributions by General Partners	1,595	1,611	2,314
Distributions paid to Partners	(346,799)	(317,626)	(288,439)
Other	(6,107)	-	-
Net cash used in financing activities	(351,597)	(367,032)	(213,330)
NET CHANGE IN CASH AND CASH EQUIVALENTS	8,830	(69,053)	65,371
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	24,601	93,654	28,283
CASH AND CASH EQUIVALENTS AT END OF PERIOD	\$ 33,431	\$ 24,601	\$ 93,654

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013

(In thousands, except unit data)

	Number of Limited Partner Units	Limited Partners Capital	General Partners Capital (Deficit)	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Partners Capital
Balance at January 1, 2013	73,749,898	\$ 1,020,823	\$ (273,113)	\$ (42,264)	\$	\$ 705,446
Comprehensive income:						
Net income	-	272,141	121,349	-	-	393,490
Actuarially determined long-term liability adjustments	-	-	-	32,545	-	32,545
Total comprehensive income	-	-	-	-	-	426,035
Issuance of units to Long-Term Incentive Plan participants upon vesting	176,210	(3,015)	-	-	-	(3,015)
Common unit based compensation	-	8,896	-	-	-	8,896
Distributions on common unit-based compensation	-	(1,688)	-	-	-	(1,688)
General Partners contributions (Note 13)	-	-	2,314	-	-	2,314
Distributions to Partners	-	(168,638)	(118,113)	-	-	(286,751)
Balance at December 31, 2013	73,926,108	1,128,519	(267,563)	(9,719)	-	851,237
Comprehensive income:						
Net income (loss)	-	358,955	138,274	-	(16)	497,213
Actuarially determined long-term liability adjustments	-	-	-	(26,128)	-	(26,128)
Total comprehensive income	-	-	-	-	-	471,085
Issuance of units to Long-Term Incentive Plan participants upon vesting	134,526	(2,991)	-	-	-	(2,991)
Common unit-based compensation	-	11,250	-	-	-	11,250
Distributions on common unit-based compensation	-	(2,182)	-	-	-	(2,182)
General Partners contributions (Note 13)	-	-	1,611	-	-	1,611

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Contributions to consolidated company from affiliate noncontrolling interest (Note 11)	-	-	-	-	481	481
Distributions to Partners	-	(183,034)	(132,410)	-	-	(315,444)
Balance at December 31, 2014	74,060,634	1,310,517	(260,088)	(35,847)	465	1,015,047
Comprehensive income:						
Net income (loss)	-	159,860	146,338	-	(27)	306,171
Actuarially determined long-term liability adjustments	-	-	-	1,290	-	1,290
Total comprehensive income	-	-	-	-	-	307,461
Issuance of units to Long-Term Incentive Plan participants upon vesting	128,150	(2,719)	-	-	-	(2,719)
Common unit based compensation	-	12,631	-	-	-	12,631
Distributions on common unit-based compensation	-	(2,627)	-	-	-	(2,627)
General Partners contributions (Note 13)	-	-	1,595	-	-	1,595
Contributions to consolidated company from affiliate noncontrolling interest (Note 11)	-	-	-	-	2,147	2,147
Distributions to Partners	-	(197,444)	(146,728)	-	-	(344,172)
Balance at December 31, 2015	74,188,784 \$	1,280,218 \$	(258,883) \$	(34,557) \$	2,585 \$	989,363

See notes to consolidated financial statements.

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ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013

1. ORGANIZATION AND PRESENTATION

Significant Relationships Referenced in Notes to Consolidated Financial Statements

- References to we, us, our or ARLP Partnership mean the business and operations of Alliance Resource Partners, L.P., the parent company, as well as its consolidated subsidiaries.
- References to ARLP mean Alliance Resource Partners, L.P., individually as the parent company, and not on a consolidated basis.
- References to MGP mean Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., also referred to as our managing general partner.
- References to SGP mean Alliance Resource GP, LLC, the special general partner of Alliance Resource Partners, L.P., also referred to as our special general partner.
- References to Intermediate Partnership mean Alliance Resource Operating Partners, L.P., the intermediate partnership of Alliance Resource Partners, L.P.
- References to Alliance Resource Properties mean Alliance Resource Properties, LLC, the land-holding company for the mining operations of Alliance Resource Operating Partners, L.P.
- References to Alliance Coal mean Alliance Coal, LLC, the holding company for the mining operations of Alliance Resource Operating Partners, L.P., also referred to as our primary 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

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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 is owned by Joseph W. Craft III, the President and Chief Executive Officer and a Director of our managing general partner, and Kathleen S. Craft. SGP, a Delaware limited liability company, is owned by ARH and holds a 0.01% general partner interest in each of ARLP and the Intermediate Partnership.

We are managed by our managing general partner, MGP, a Delaware limited liability company, which holds a 0.99% and a 1.0001% managing general partner interest in ARLP and the Intermediate Partnership, respectively, and a 0.001% managing member interest in Alliance Coal. AHGP is a Delaware limited partnership that was formed to become the owner and controlling member of MGP. AHGP completed its initial public offering (AHGP IPO) on May 15, 2006. AHGP owns directly and indirectly 100% of the members' interest of MGP, the incentive distribution rights (IDR) in ARLP and 31,088,338 common units of ARLP.

The Delaware limited partnership, limited liability companies and corporation that comprise our subsidiaries are as follows: Intermediate Partnership; Alliance Coal; Alliance Design Group, LLC (Alliance Design); Alliance Land, LLC; Alliance Minerals, LLC (Alliance Minerals); Alliance Properties, LLC; Alliance Resource Properties; AROP Funding, LLC (AROP Funding); ARP Sebree, LLC (ARP Sebree); ARP Sebree South, LLC; Alliance WOR Properties, LLC (WOR Properties); Alliance Service, Inc. (ASI); Backbone Mountain, LLC; Cavalier Minerals JV, LLC (Cavalier Minerals); CR Services, LLC; Excel Mining, LLC; Gibson County Coal, LLC (Gibson County Coal); Hamilton County Coal, LLC (Hamilton previously known as Alliance WOR Processing, LLC); Hopkins County Coal, LLC (Hopkins County Coal); Matrix Design Group, LLC (Matrix Design); Matrix Design International, LLC; Matrix Design Africa (PTY) LTD; MC Mining, LLC (MC Mining); Mettiki Coal, LLC (Mettiki (MD)); Mettiki Coal (WV), LLC (Mettiki (WV)); Mid-America Carbonates, LLC (MAC); Mt. Vernon Transfer Terminal, LLC (Mt. Vernon); Penn Ridge Coal, LLC (Penn Ridge); Pontiki Coal, LLC (Pontiki); River View Coal, LLC (River View); Rough Creek Mining, LLC; Sebree Mining, LLC (Sebree Mining); Steamport, LLC; Tunnel Ridge, LLC (Tunnel Ridge); UC Coal, LLC; UC Mining, LLC; UC Processing, LLC; Warrior Coal, LLC (Warrior); Webster

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County Coal, LLC (Webster County Coal); White County Coal, LLC (White County Coal); WOR Land 6, LLC; White Oak Resources LLC (White Oak) and Wildcat Insurance, LLC (Wildcat Insurance).

Presentation

The accompanying consolidated financial statements include the accounts and operations of the ARLP Partnership and present our financial position as of December 31, 2015 and 2014, and results of our operations, comprehensive income, cash flows and changes in partners' capital for each of the three years in the period ended December 31, 2015. All of our intercompany transactions and accounts have been eliminated.

On July 31, 2015, we acquired the remaining equity interest in White Oak which resulted in the restructuring of our reportable segments. All prior periods have been recast to reflect this new segment presentation. See Note 3 Acquisitions for further discussion on the acquisition and Note 22 Segment Information for further discussion of our reportable segments.

On June 16, 2014, we completed a two-for-one split of our common units, whereby holders of record as of May 30, 2014 received a one unit distribution on each unit outstanding on that date. The unit split resulted in the issuance of 37,030,317 common units. All references to the number of units and per unit net income of ARLP and distribution amounts included in this report have been adjusted to give effect for this unit split for all periods presented. Also, ARLP's partnership agreement was amended effective June 16, 2014, to reduce by half the target thresholds for the incentive distribution rights per unit.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Estimates The preparation of consolidated financial statements in conformity with generally accepted accounting principles of the United States (GAAP) requires management to make estimates and assumptions that affect the reported amounts and disclosures in the consolidated financial statements. Actual results could differ from those estimates. Significant estimates and assumptions include:

- Impairment assessments of investments, property, plant and equipment, and goodwill;
- Asset retirement obligations;
- Pension valuation variables;
- Workers' compensation and pneumoconiosis valuation variables;
- Acquisition related purchase price allocations; and

- Life of mine assumptions.

These significant estimates and assumptions are discussed throughout these notes to the consolidated financial statements.

Consolidation The accompanying consolidated financial statements present the consolidated financial position, results of operations and cash flows of ARLP, its subsidiary the Intermediate Partnership (a variable interest entity of which ARLP is the primary beneficiary), Alliance Coal (a variable interest entity of which the Intermediate Partnership is the primary beneficiary) and other directly and indirectly wholly- and majority-owned subsidiaries of the Intermediate Partnership and Alliance Coal. The Intermediate Partnership, Alliance Coal and their wholly- and majority-owned subsidiaries represent virtually all the net assets of ARLP. MGP's interests in both Alliance Coal and the Intermediate Partnership and SGP's 0.01% interest in the Intermediate Partnership are reported as part of the overall two percent general partner interest in ARLP. MGP's incentive distribution rights in ARLP are also reported with the general partner interest in ARLP. All intercompany transactions have been eliminated. See Note 11 Variable Interest Entities for more information regarding ARLP's consolidation of the Intermediate Partnership and Alliance Coal. See Note 9 Distributions of Available Cash for more information regarding MGP's incentive distribution rights.

Fair Value Measurements We apply fair value measurements to certain assets and liabilities. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Fair value is based upon assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and risks inherent in valuation techniques and inputs to valuations. Fair value measurements assume that the transaction occurs in the principal market for the asset or liability or, in the absence of a principal market, the most advantageous market for the asset or liability

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(the market for which the reporting entity would be able to maximize the amount received or minimize the amount paid). Valuation techniques used in our fair value measurements are based upon observable and unobservable inputs. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect our own market assumptions.

We use the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad levels:

- **Level 1** Quoted prices for identical assets and liabilities in active markets that we have the ability to access at the measurement date.
- **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** Unobservable inputs for the asset or liability including situations where there is little, if any, market activity for the asset or liability.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall into different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement requires judgment, considering factors specific to the asset or liability. Significant fair value measurements are used in our significant estimates and are discussed throughout these notes. See Note 8 Fair Value Measurements for discussion of recurring fair value measurements not otherwise disclosed in these financial statements.

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

Cash Management The cash flows from operating activities section of our Consolidated Statements of Cash Flows reflects an adjustment for \$10.6 million and \$1.7 million representing book overdrafts at December 31, 2015 and 2014, respectively. We had no book overdrafts at December 31, 2013.

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

Business Combinations For acquisitions accounted for as a business combination, we record the assets acquired, including identified intangible assets and liabilities assumed at their fair value, which in many instances involves estimates

based on third-party valuations, such as appraisals, or internal valuations based on discounted cash flow analyses or other valuation techniques.

Goodwill Goodwill represents the excess of cost over the fair value of net assets of acquired businesses. Goodwill is not amortized, but instead is evaluated for impairment periodically. We evaluate goodwill for impairment annually on November 30th, or more often if events or circumstances indicate that goodwill might be impaired. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed or operated. A reporting unit is an operating segment or a component that is one level below an operating segment. There were no impairments of goodwill during 2015. In future periods it is reasonably possible that a variety of circumstances could result in an impairment of our goodwill.

Property, Plant and Equipment Expenditures which extend the useful lives of existing plant and equipment assets are capitalized. Interest costs associated with major asset additions are capitalized during the construction period. Maintenance and repairs that do not extend the useful life or increase productivity of the asset are charged to operating expense as incurred. Exploration expenditures are charged to operating expense as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves. Preparation plants and processing facilities are depreciated using the units-of-production method. Other plant and equipment assets are depreciated principally using the straight-line method over the estimated useful lives of the assets, ranging from 1 to 29 years, limited by the remaining estimated life of each mine. Depreciable lives for the mining equipment range from 1 to 22 years. Depreciable lives for buildings, office equipment and improvements range from 2 to 29 years. Gains or losses arising from retirements are included in operating expenses. Depletable lives for mineral rights, assuming current production expectations, range from 1 to 22 years. Depletion of mineral rights is provided on the basis of tonnage mined in relation

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to estimated recoverable tonnage, which equals estimated proven and probable reserves. Therefore, our mineral rights are depleted based on only proven and probable reserves derived in accordance with Industry Guide 7. At December 31, 2015 and 2014, land and mineral rights include \$30.7 million and \$53.2 million, respectively, representing the carrying value of coal reserves attributable to properties where we or a third party to which we lease reserves are not currently engaged in mining operations or leasing to third parties, and therefore, the coal reserves are not currently being depleted. We believe that the carrying value of these reserves will be recovered.

Mine Development Costs Mine development costs are capitalized until production, other than production incidental to the mine development process, commences and are amortized on a units of production method based on the estimated proven and probable reserves. Mine development costs represent costs incurred in establishing access to mineral reserves and include costs associated with sinking or driving shafts and underground drifts, permanent excavations, roads and tunnels. The end of the development phase and the beginning of the production phase takes place when construction of the mine for economic extraction is substantially complete. Coal extracted during the development phase is incidental to the mine's production capacity and is not considered to shift the mine into the production phase. At December 31, 2015 and 2014, capitalized mine development costs were \$5.9 million and \$7.0 million, respectively, representing the carrying value of development costs attributable to properties where we have not reached the production stage of mining operations, and therefore, the mine development costs are not currently being amortized. We believe that the carrying value of these development costs will be recovered.

Long-Lived Assets We review the carrying value of long-lived assets and certain identifiable intangibles whenever events or changes in circumstances indicate that the carrying amount may not be recoverable based upon estimated undiscounted future cash flows. To the extent the carrying amount is not recoverable based on undiscounted cash flows, the amount of impairment is measured by the difference between the carrying value and the fair value of the asset (See Note 4 Long-Lived Asset Impairments).

Intangibles Intangibles subject to amortization include contracts with covenants not to compete, customer contracts acquired from other parties and mining permits. Intangibles other than customer contracts are amortized on a straight-line basis over their useful life. Intangibles for customer contracts are amortized on a per unit basis over the terms of the contracts. Amortization expense attributable to intangibles was \$15.1 million, \$3.0 million and \$3.0 million for the years ending December 31, 2015, 2014 and 2013, respectively. Our intangibles are included in *Prepaid expenses and other assets*, *Other long-term assets*, *Other current liabilities* and *Other liabilities* on our consolidated balance sheets at December 31, 2015 and 2014. Our intangibles at December 31 are summarized as follows:

	December 31, 2015			December 31, 2014			Intangibles, Net
	Original Cost	Accumulated Amortization	Intangibles, Net (in thousands)	Original Cost	Accumulated Amortization		
Non-compete agreements	\$ 14,729	\$ (9,750)	\$ 4,979	\$ 15,152	\$ (8,545)	\$	6,607
Customer contracts and other	31,054	(16,959)	14,095	17,859	(3,599)		14,260

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Mining permits		1,500		(28)		1,472		3,843		(182)		3,661
Total	\$	47,283	\$	(26,737)	\$	20,546	\$	36,854	\$	(12,326)	\$	24,528

Amortization expense attributable to intangible assets is estimated as follows:

Year Ending December 31,		(in thousands)
2016	\$	15,300
2017		1,682
2018		1,021
2019		1,021
2020		385
Thereafter		1,137

Investments Investments and ownership interests are accounted for under the equity method of accounting if we have the ability to exercise significant influence, but not control, over the entity. Investments accounted for under the equity method are initially recorded at cost, and the difference between the basis of our investment and the underlying equity in the net assets of the joint venture at the investment date, if any, is amortized over the lives of the related assets

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that gave rise to the difference. In the event our ownership entitles us to a disproportionate sharing of income or loss, our equity in earnings or losses of affiliates is allocated based on the hypothetical liquidation at book value (HLBV) method of accounting.

Under the HLBV method, equity in earnings or losses of affiliates is allocated based on the difference between our claim on the net assets of the equity method investee at the end and beginning of the period with consideration of certain eliminating entries regarding differences of accounting for various related-party transactions, after taking into account contributions and distributions, if any. Our share of the net assets of the equity method investee is calculated as the amount we would receive if the equity method investee were to liquidate all of its assets at net book value and distribute the resulting cash to creditors, other investors and us according to the respective priorities.

Our equity method investments during 2015 included AllDale Minerals, L.P. (AllDale I) and AllDale Minerals II, L.P. (AllDale II) (collectively AllDale Minerals) and White Oak prior to our acquisition of its remaining equity interests on July 31, 2015. See Note 12 Equity Investments for further discussion of these equity method investments. In addition, during 2014, our equity method investments also included MAC prior to our acquisition of the remaining interest on January 1, 2015. For discussion of both acquisitions, see Note 3 Acquisitions. We review our investments and ownership interests accounted for under the equity method of accounting for impairment whenever events or changes in circumstances indicate a loss in the value of the investment may be other than temporary.

Advance Royalties, net Rights to coal mineral leases are often acquired and/or maintained through advance royalty payments. Where royalty payments represent prepayments recoupable against future production, they are recorded as an asset, with amounts expected to be recouped within one year classified as a current asset. As mining occurs on these leases, the royalty prepayments are charged to operating expenses. We assess the recoverability of royalty prepayments based on estimated future production. We have recorded a \$3.8 million and \$1.3 million allowance against these prepayments as of December 31, 2015 and 2014, respectively. Royalty prepayments estimated to be nonrecoverable are expensed. Our Advance royalties, net at December 31 are summarized as follows:

	2015		2014
	(in thousands)		
Advance royalties, affiliates (see Note 19 Related-Party Transactions)	\$	16,245	\$ 10,706
Advance royalties, third-parties		11,870	14,605
Total advance royalties, net	\$	28,115	\$ 25,311

Asset Retirement Obligations We record a liability for the estimated cost of future mine asset retirement and closing procedures on a present value basis when incurred or acquired and a corresponding amount is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to permanently sealing portals at underground mines and to reclaiming the final pits and support acreage at surface mines. Examples of these types of costs, common to both types of mining, include, but are not limited to, removing or covering refuse piles and settling ponds, water treatment obligations, and dismantling preparation plants, other facilities and roadway infrastructure. Accounting for asset retirement obligations also requires depreciation of the capitalized asset retirement cost and accretion of the asset retirement obligation over time. The depreciation is generally determined on a units-of-production basis and accretion is generally recognized over the life of the producing assets. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of

reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free interest rate. See Note 17 Asset Retirement Obligations for more information.

Pension Benefits The funded status of our pension benefit plan is recognized separately in our consolidated balance sheets as either an asset or liability. The funded status is the difference between the fair value of plan assets and the plan's benefit obligation. Pension obligations and net periodic benefit costs are actuarially determined and impacted by various assumptions and estimates including expected return on assets, discount rates, mortality assumptions, employee turnover rates and retirement dates. We evaluate our assumptions periodically and make adjustments to these assumptions and the recorded liability as necessary (See Note 14 Employee Benefit Plans).

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The discount rate is determined for our pension benefit plan based on an approach specific to our plan. The year-end discount rate is determined considering a yield curve comprised of high-quality corporate bonds and the timing of the expected benefit cash flows.

The expected long-term rate of return on plan assets is determined based on a broad equity and bond indices, the investment goals and objectives, the target investment allocation and on the 20-year average annual total return for each asset class.

Unrecognized actuarial gains and losses and unrecognized prior service costs and credits are deferred and recorded in accumulated other comprehensive income (AOCI) until amortized as a component of net periodic benefit cost. Unrecognized actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the market-related value of plan assets are amortized over the participants' average remaining future years of service.

Workers' Compensation and Pneumoconiosis (Black Lung) Benefits We are generally self-insured for workers' compensation benefits, including black lung benefits. We accrue a workers' compensation liability for the estimated present value of workers' compensation and black lung benefits based on our actuarially determined calculations (See Note 18 Accrued Workers' Compensation and Pneumoconiosis Benefits).

Revenue Recognition Revenues from coal sales are recognized when title passes to the customer as the coal is shipped. Some coal supply agreements provide for price adjustments based on variations in quality characteristics of the coal shipped. In certain cases, a customer's analysis of the coal quality is binding and the results of the analysis are received on a delayed basis. In these cases, we estimate the amount of the quality adjustment and adjust the estimate to actual when the information is provided by the customer. Historically, such adjustments have not been material. Non-coal sales revenues primarily consist of transloading fees, administrative service revenues from our affiliates, mine safety services and products, royalties and throughput fees earned from White Oak prior to July 31, 2015 as disclosed in Note 3 Acquisitions, other coal contract fees and other handling and service fees. Transportation revenues are recognized in connection with us incurring the corresponding costs of transporting coal to customers through third-party carriers for which we are directly reimbursed through customer billings.

Common Unit-Based Compensation The fair value of restricted common unit grants under the Long-Term Incentive Plan (LTIP), Supplemental Executive Retirement Plan (SERP) and the MGP Amended and Restated Deferred Compensation Plan for Directors (Deferred Compensation Plan) are determined on the grant date of the award and recognized as compensation expense on a pro rata basis for LTIP and SERP awards, as appropriate, over the requisite service period. Compensation expense is fully recognized on the grant date for quarterly distributions credited to SERP accounts and Deferred Compensation Plan awards. The corresponding liability is classified as equity and included in limited partners' capital in the consolidated financial statements (See Note 15 Compensation Plans).

Income Taxes We are not a taxable entity for federal or state income tax purposes; the tax effect of our activities accrues to the unitholders. Although publicly traded partnerships as a general rule will be taxed as corporations, we qualify for

an exemption because at least 90% of our income consists of qualifying income, as defined in Section 7704(c) of the Internal Revenue Code. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. Individual unitholders have different investment bases depending upon the timing and price of acquisition of their partnership units. Furthermore, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, differs from the accounting followed in our consolidated financial statements. Accordingly, the aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder's tax attributes in our partnership is not available to us. Our subsidiaries, ASI and Wildcat Insurance, are subject to federal and state income taxes. A valuation allowance is established if it is more likely than not that a deferred tax asset will not be realized.

Our tax counsel has provided an opinion that ARLP, the Intermediate Partnership and Alliance Coal will each be treated as a partnership. However, as is customary, no ruling has been or will be requested from the Internal Revenue Service (IRS) regarding our classification as a partnership for federal income tax purposes.

Variable Interest Entity (VIE) VIEs are primarily entities that lack sufficient equity to finance their activities without additional financial support from other parties or whose equity holders, as a group, lack one or more of the

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following characteristics: (a) direct or indirect ability to make decisions, (b) obligation to absorb expected losses or (c) right to receive expected residual returns. A VIE must be evaluated quantitatively and qualitatively to determine the primary beneficiary, which is the reporting entity that has (a) the power to direct activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. The primary beneficiary is required to consolidate the VIE for financial reporting purposes.

To determine a VIE's primary beneficiary, we perform a qualitative assessment to determine which party, if any, has the power to direct activities of the VIE and the obligation to absorb losses and/or receive its benefits. This assessment involves identifying the activities that most significantly impact the VIE's economic performance and determine whether it, or another party, has the power to direct those activities. When evaluating whether we are the primary beneficiary of a VIE, we perform a qualitative analysis that considers the design of the VIE, the nature of our involvement and the variable interests held by other parties. See Note 11 Variable Interest Entities for further information.

New Accounting Standards Issued and Adopted In September 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2015-16, *Simplifying the Accounting for Measurement-Period Adjustments* (ASU 2015-16). ASU 2015-16 requires that an acquirer within a business combination recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. ASU 2015-16 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015 with early adoption permitted and shall be applied prospectively after adoption. We elected to early adopt the standard in the third quarter of 2015. The adoption of ASU 2015-16 did not have a material impact on our consolidated financial statements as we did not have material measurement period adjustments in the third quarter of 2015. For more discussion of measurement period adjustments recorded in the fourth quarter of 2015, see Note 3 Acquisitions.

In April 2014, the FASB issued ASU 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* (ASU 2014-08). ASU 2014-08 changes the requirements for reporting discontinued operations in Accounting Standards Codification (ASC) 205, *Presentation of Financial Statements*, by updating the criteria for determining which disposals can be presented as discontinued operations and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of discontinued operations. ASU 2014-08 was effective for fiscal years, and interim periods within those years, beginning after December 15, 2014. The adoption of ASU 2014-08 did not have a material impact on our consolidated financial statements.

New Accounting Standards Issued and Not Yet Adopted In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 330): Simplifying the Measurement of Inventory* (ASU 2015-11). ASU 2015-11 simplifies the subsequent measurement of inventory. It replaces the current lower of cost or market test with the lower of cost or net realizable value test. Net realizable value is defined as the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The new standard should be applied prospectively and is effective for annual reporting periods beginning after December 15, 2016 and interim periods within those annual periods, with early adoption permitted. We are currently evaluating the effect of adopting ASU 2015-11, but do not expect it to have a material impact on our consolidated financial statements.

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In April 2015, the FASB issued ASU 2015-03, *Interest Imputation of Interest* (ASU 2015-03). ASU 2015-03 changes the classification and presentation of debt issuance costs by requiring debt issuance costs to be reported as a direct deduction from the face amount of the debt liability rather than an asset. Amortization of the costs is reported as interest expense. The amendment does not affect the current guidance on the recognition and measurement of debt issuance costs. ASU 2015-03 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015 and shall be applied retrospectively to each period presented. We do not anticipate the adoption of ASU 2015-03 will have a material impact on our consolidated financial statements.

In February 2015, the FASB issued ASU 2015-02, *Consolidation* (ASU 2015-02). ASU 2015-02 changes the requirements and analysis required when determining the reporting entity's need to consolidate an entity, including modifying the evaluation of limited partnership variable interest status, the presumption that a general partner should consolidate a limited partnership and the consolidation criterion applied by a reporting entity involved with variable interest entities. ASU 2015-02 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015 and shall be applied retrospectively to each period presented. We have evaluated the impact of the guidance and have reached an interpretation that the new guidance will not have a material impact on our consolidated financial statements.

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In August 2014, the FASB issued ASU 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* (ASU 2014-15). ASU 2014-15 provides guidance on management's responsibility in evaluating whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter with early adoption permitted. We do not anticipate the adoption of ASU 2014-15 will have a material impact on our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers* (ASU 2014-09). ASU 2014-09 is a new revenue recognition standard that provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the new standard is an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The standard will be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. ASU 2014-09 was originally effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. In August 2015, the FASB issued ASU 2015-14, *Revenue from Contracts with Customers: Deferral of the Effective Date* (ASU 2015-14), which defers the effective date by one year while providing the option to early adopt the standard on the original effective date. We have developed an assessment team to determine the effect of adopting ASU 2014-09. We are still determining whether there will be any material impact on our revenue recognition; however, we believe changes with respect to disclosures on revenue from contracts will be reflected in our consolidated financial statements. Our assessment team will continue working through the new guidance to finalize an evaluation later this year.

3. ACQUISITIONS

White Oak Resources

On July 31, 2015 (the Hamilton Acquisition Date) Hamilton acquired the remaining Series A and B Units, representing 60% of the voting interests of White Oak, from White Oak Finance Inc. and other parties (the Sellers) for total fair value consideration of \$310.3 million (the Hamilton Acquisition). The following table summarizes the preliminary and final total fair value of consideration transferred at the Hamilton Acquisition Date:

	Preliminary	Adjustments (in thousands)	Final
Cash on hand	\$ 50,000	-	\$ 50,000
Contingent consideration	14,300	500	14,800
Settlement of pre-existing relationships	119,663	4,716	124,379
Previously held equity-method investment	103,322	17,833	121,155
Total consideration transferred	\$ 287,285		\$ 310,334

Effective from the Hamilton Acquisition Date, the Partnership now owns 100% of the interests in White Oak and has assumed operating control of the White Oak Mine No. 1 (now known as Hamilton Mine No. 1), an underground longwall mining operation located in Hamilton County, Illinois. The Hamilton Acquisition is consistent with our general business strategy and a strategic complement to our current coal mining operations.

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The contingent consideration is payable to the Sellers to the extent Hamilton's quarterly average coal sales price exceeds a specified amount on future sales. Amounts payable under the contingent consideration arrangement are subject to a defined maximum of \$110.0 million reduced for any payments that we make under an overriding royalty agreement between White Oak and certain of the Sellers relating to undeveloped mineral interests controlled by White Oak. We estimated the fair value of the contingent consideration using a probability-weighted discounted cash flow model. The assumptions used in the model included a risk-adjusted discount rate, forward coal sales price curves, cost of debt, and probabilities of meeting certain threshold prices. The fair value measurement is based on significant inputs not observable in active markets and thus represents a Level 3 fair value measurement.

Prior to the Hamilton Acquisition Date, we accounted for our 40% interest in White Oak as an equity-method investment (See Note 12 - Equity Investments). The acquisition date fair value of the previous equity interest was \$121.2 million and is included in the measurement of the consideration transferred. We re-measured our equity

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investment immediately prior to the Hamilton Acquisition using a discounted cash flow model which resulted in a loss of \$52.2 million (Re-measurement Loss) which is recorded in the line item *Acquisition gain, net* in our consolidated statements of income. The assumptions used in the determination of the fair value include projected financial information, forward coal price curves, and a risk adjusted discount rate. The assumptions used in this fair value measurement are not observable in active markets and therefore represents a Level 3 fair value measurement.

In connection with the Hamilton Acquisition, we settled our pre-existing relationships with White Oak which included existing account balances of \$49.6 million. The settlement of pre-existing relationships also included, under business combination accounting, a \$74.8 million net gain for above-market terms associated with pre-existing contractual agreements which were comprised of coal leases, a coal handling and preparation agreement, a coal supply agreement, export marketing and transportation agreements and certain debt agreements. The net gain of \$74.8 million associated with the settlement of the net above-market terms is recorded in the line item *Acquisition gain, net* in our consolidated statements of income partially offset by the Re-measurement Loss of \$52.2 million discussed above which together, nets to \$22.5 million. These settlements of account balances and settlements of net above-market terms are included in the measurement of consideration transferred for the Hamilton Acquisition. As part of the settlement of these agreements, we considered the rates at which a market participant would enter into these agreements and recognized gains for the above-market rates and losses for the below-market rates contained in the various agreements. We developed a discounted cash flow model to determine the fair value of each of these agreements at market rates and compared the valuations to similar models using the contractual rates of the agreements to determine our gains or losses. The assumptions used in these valuation models include processing rates, royalty rates, transportation rates, marketing rates, forward coal price curves, interest rates, projected financial information and risk-adjusted discount rates. These fair value measurements were based on the previously discussed assumptions which are not observable in active markets and therefore represent Level 3 fair value measurements.

In the fourth quarter of 2015, we finalized our purchase price accounting which resulted in the following changes to the components of consideration transferred:

- An increase to the contingent consideration due to changes of various assumptions in the underlying valuation model such as the risk adjusted discount rate and the probabilities of meeting certain threshold coal sales prices.
- Adjustments in both the fair value of the settlement of pre-existing relationships and the re-measurement of our previously held equity investment in White Oak due to the finalization of depreciable lives and the identification of additional acquired assets and the finalization of value in property, plant and equipment (PP&E), which resulted in changes to projected depreciation included in the discounted cash flows used to determine fair values.
- As a result of these changes to our preliminary valuation, we recognized \$23.0 million in measurement period adjustments to the fair value of the consideration transferred increasing the fair value of net assets acquired from \$287.3 million to \$310.3 million in the fourth quarter of 2015 as reflected in the table below.

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The following table summarizes the preliminary and final fair value allocation of assets acquired and liabilities assumed at the Hamilton Acquisition Date, incorporating fair value adjustments made subsequent to the Hamilton Acquisition Date:

	Preliminary	Adjustments (in thousands)	Final
Cash and cash equivalents	\$ 3,125	-	\$ 3,125
Trade receivables	3,122	(104)	3,018
Prepaid expenses	4,364	(422)	3,942
Inventories	7,240	-	7,240
Other current assets	9,415	41	9,456
Property, plant and equipment	258,798	40,416	299,214
Advance royalties	3,349	-	3,349
Deposits	6,981	-	6,981
Other assets	5,580	7,249	12,829
Total identifiable assets acquired	301,974		349,154
Accounts payable	(31,399)	218	(31,181)
Accrued expenses	(18,609)	(2,378)	(20,987)
Deferred revenue	(517)	-	(517)
Current maturities, long-term debt	(29,529)	-	(29,529)
Long-term debt, excluding current maturities	(64,588)	615	(63,973)
Other long-term liabilities	(15,175)	3,000	(12,175)
Asset retirement obligations	(12,484)	-	(12,484)
Total liabilities assumed	(172,301)		(170,846)
Net identifiable assets acquired	\$ 129,673		\$ 178,308
Goodwill	157,612	(25,586)	132,026
Net assets acquired	\$ 287,285		\$ 310,334

The goodwill recognized is attributable to expected synergies and operational cost reductions by using our other owned facilities and reserves as well as utilizing our centralized marketing, operations and administrative functions. All of the goodwill has been allocated to our Hamilton reporting unit included in our Illinois Basin reporting segment.

We recognized intangible assets and liabilities associated with the above- and below-market customer contracts in addition to a mining permit as follows:

	(in thousands)	Weighted-average amortization period	Account in table above
Customer contracts and intangibles			
Current above-market contracts	\$ 9,333		Other current assets
Non-current above-market contracts	3,671		Other assets
Current below-market contracts	(4,702)		Accrued expenses
Non-current below-market contracts	(1,525)		Other long-term liabilities
Total customer contract intangibles	6,777	3 years	
Mining permit	1,500	20 years	Other assets
Total intangibles acquired	\$ 8,277		Other current assets

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We determined the fair value of cash and cash equivalents, trade receivables, prepaid expenses, advanced royalties, deposits, accounts payable, accrued expenses, and deferred revenue approximated White Oak's carrying value given the highly liquid and short-term nature of these assets and liabilities. We determined the fair value of inventories, PP&E (inclusive of mineral interests), and mining permits using a market approach. The market approach included the development of an entity-wide value using discounted cash flows and allocating the entity-wide value back to the underlying assets based on observed market prices. We have recorded the fair value of the above- and below-market components of customer contracts acquired as assets and liabilities. We determined these fair values through

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comparison of the terms in the contracts against projected coal prices. We also evaluated the acquired asset retirement obligation to determine the cost to fulfill the obligation and apply an appropriate discount rate to determine the fair value. The assumptions used in these fair value measurements are not observable in active markets and thus represent Level 3 fair value measurements. We determined the fair value of the long-term debt acquired through comparison of similar debt instruments and interest rates in active markets, and thus the assumptions used for the long-term debt represent Level 2 fair value measurements. (See Note 2 Summary of Significant Accounting Policies Fair Value Measurements for more information regarding fair value hierarchy levels.)

In the fourth quarter of 2015, we finalized our purchase price accounting which resulted in the following changes during the measurement period to the allocations of assets acquired and liabilities assumed (All of the changes to the underlying valuations were the result of new or additional information about the fair value of the underlying assets and liabilities as of the Hamilton Acquisition Date):

- PP&E increased \$40.4 million to \$299.2 million due to the identification of additional assets acquired and an increase in the value of mineral interests as a result of changes to the discounted cash flows used to determine total entity value when the additional assets were included.
- The increase of \$7.2 million in Other Assets was a result of the identification of additional subsidence rights.
- The changes in Accrued Expenses and Other long-term liabilities were a result of a change in value and classification of acquired intangibles previously discussed. Other long-term liabilities were also affected by the removal of a liability associated with below market lease obligations which we subsequently determined were at market.
- Goodwill decreased by \$25.6 million to \$132.0 million. This decrease was the result of other changes identified above which increased the value of the underlying assets.

The amounts of revenue and earnings inclusive of the \$22.5 million in net gains associated with the settlement of pre-existing relationships and the Re-Measurement Loss, both discussed above, included in the Partnership's consolidated statements of income from the Hamilton Acquisition Date to the period ending December 31, 2015 are as follows:

	(in thousands)	
Revenue	\$	75,251
Net income		20,687

The following represents the pro forma condensed consolidated income statement as if Hamilton had been included in the consolidated results of the Partnership since January 1, 2014. These amounts have been calculated after applying the Partnership's accounting. Additionally, the Partnership's results have been adjusted to remove the effect of its equity investment in White Oak and the pre-existing relationships that it had in White Oak.

**Twelve Months Ended
December 31,**
2015 **2014**
(in thousands)

Total revenues

As reported	\$	2,273,733	\$	2,300,721
Pro forma		2,337,380		2,346,858

Net income

As reported	\$	306,171	\$	497,213
Pro forma		295,219		480,280

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Patriot Coal Corporation

On December 31, 2014 (the Initial Closing Date), we entered into asset purchase agreements with Patriot Coal Corporation (Patriot) regarding certain assets relating to two of Patriot's western Kentucky mining operations, including certain coal sales agreements, unassigned coal reserves and underground mining equipment and infrastructure. Both of the mining operations—the former Dodge Hill and Highland mining operations—were closed by Patriot in late 2014 prior to entering into these asset purchase agreements. Also on December 31, 2014, Patriot affiliates entered into agreements to sell other assets from Highland to a third party. Additional details of the transactions are discussed below.

On the Initial Closing Date, our subsidiary, Alliance Coal acquired the rights to certain coal supply agreements from an affiliate of Patriot for approximately \$21.0 million. Of the \$21.0 million purchase price, \$9.3 million was paid into escrow subject to obtaining certain assignment consents. In February 2015, \$7.5 million of the escrowed amount was released to Patriot for a consent received and \$1.8 million was returned to Alliance Coal as a result of a consent not received, reducing our purchase price to \$19.2 million. The acquired agreements provide for delivery of a total of approximately 5.1 million tons of coal from 2015 through 2017.

On February 3, 2015 (the Acquisition Date), Alliance Coal and Alliance Resource Properties acquired from Patriot an estimated 84.1 million tons of proven and probable high-sulfur coal reserves in western Kentucky (substantially all of which was leased by Patriot), and substantially all of Dodge Hill's assets related to its former coal mining operation in western Kentucky, which principally included underground mining equipment and an estimated 43.2 million tons of non-reserve coal deposits (substantially all of which was leased by Dodge Hill). In addition, we assumed Dodge Hill's reclamation liabilities totaling \$2.3 million. Also on the Acquisition Date, the Intermediate Partnership's subsidiaries, UC Mining, LLC and UC Processing, LLC, acquired certain underground mining equipment and spare parts inventory from Patriot's former Highland mining operation.

The mining and reserve assets acquired from Patriot described above are located in Union and Henderson Counties, Kentucky. The mining equipment, spare parts and underground infrastructure that we acquired from Patriot has been and is continuing to be dispersed to our existing operations in the Illinois Basin region in accordance with their highest and best use. Our purchase price of \$19.2 million and \$20.5 million paid on the Initial Closing Date and the Acquisition Date, respectively, described above was financed using existing cash on hand. In addition, our purchase price was increased by \$8.3 million, comprising \$2.1 million cash paid prior to the Acquisition Date related to the transaction and an agreement to pay approximately \$6.2 million additional consideration as discussed below. As we have no intentions of operating the former Dodge Hill mining complex as a business and only acquired certain assets of Highland, we believe unaudited pro forma information of revenue and earnings is not meaningful as it relates to the acquisition of Patriot assets described above and furthermore not materially different than revenue and earnings as presented in our consolidated statements of income. The primary ongoing benefit derived from the transaction relates to the coal supply agreements acquired, which would have permitted the sale of 3.2 million tons at average pricing of \$46.67 per ton sold during 2014 based on the contract price and sales volumes, if we had owned the contracts during that period. Revenues generated by these contracts since the Initial Closing Date were \$130.5 million for the year ended December 31, 2015.

In conjunction with our acquisitions on the Acquisition Date, WKY CoalPlay, LLC (WKY CoalPlay), a related party, acquired approximately 39.1 million tons of proven and probable high-sulfur owned coal reserves located in Henderson and Union Counties, Kentucky from Central States Coal Reserves of Kentucky, LLC (Central States), a subsidiary of Patriot, for \$25.0 million and in turn leased those reserves to us. See Note 19 Related-Party Transactions for further information on our lease terms with WKY CoalPlay.

The fair value of the acquired tangible and intangible assets and assumed liabilities are based on discounted cash flow projections and estimated replacement cost valuation techniques. We used an estimate of replacement cost based on comparable market prices to value the acquired

equipment and utilized discounted cash flows to value intangible assets and reserves. Key assumptions used in the valuations included projections of future cash flows, estimated weighted-average cost of capital, and internal rates of return. Due to the unobservable nature of these inputs, these estimates are considered Level 3 fair value measurements.

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The following table summarizes the consideration transferred from us to Patriot and the preliminary and final fair value allocation of assets acquired and liabilities assumed as valued at the Acquisition Date, incorporating fair value adjustments made subsequent to the Acquisition Date:

	Preliminary	Adjustments (in thousands)	Final
Consideration transferred	\$ 47,514		\$ 47,874
Recognized amounts of net tangible and intangible assets acquired and liabilities assumed:			
Inventories	3,255	(1,261)	1,994
Property, plant and equipment, including mineral rights and leased equipment	26,995	5,034	32,029
Customer contracts, net	19,193	-	19,193
Other assets	326	(326)	-
Asset retirement obligation	(2,255)	-	(2,255)
Other liabilities	-	(3,087)	(3,087)
Net tangible and intangible assets acquired	\$ 47,514		\$ 47,874

Included in the above consideration transferred was an agreement to pay an additional \$6.2 million related to the acquisition, which has been satisfied as of December 31, 2015. Additionally, a fair value adjustment of \$3.1 million to increase liabilities and property, plant and equipment was recorded to reflect the impact of operating leases assumed in the acquisition. Other adjustments to the preliminary fair values resulted from additional information obtained about facts in existence on the Acquisition Date.

Intangible assets related to coal supply agreements, represented as Customer contracts, net in the table above, are reflected in the Prepaid expenses and other assets and Other long-term assets line items in our consolidated balance sheets. For the year ended December 31, 2015, amortization expense for the acquired coal supply agreements of \$11.8 million has been recognized based on the weighted-average term of the contracts on a per unit basis.

MAC

In March 2006, White County Coal, and Alexander J. House entered into a limited liability company agreement to form MAC. MAC was formed to engage in the development and operation of a rock dust mill and to manufacture and sell rock dust. White County Coal initially invested \$1.0 million in exchange for a 50% equity interest in MAC. Our equity investment in MAC was \$1.6 million at December 31, 2014. Effective on January 1, 2015, we purchased the remaining 50% equity interest in MAC from Mr. House for \$5.5 million cash paid at closing. In conjunction with the acquisition, we assumed \$0.2 million of liabilities and \$7.3 million in assets, net of cash acquired, including \$4.2 million of goodwill which is reflected in Other and Corporate in our segment presentation (Note 22 Segment Information) and is included in *Goodwill* in our consolidated balance sheets.

Peabody Energy Corporation

In December 2014, Alliance Resource Properties acquired the rights to approximately 86.2 million tons of proven and probable high-sulfur leased coal reserves in western Kentucky from Midwest Coal Reserves of Kentucky, LLC (Midwest) and Cyprus Creek Land Company, both subsidiaries of Peabody Energy Corporation (Peabody), in exchange for an overriding royalty to be paid to Peabody based on a percentage of the sales price of coal mined from the reserves acquired. In addition, WKY CoalPlay acquired the rights to approximately 54.1 million tons of owned coal reserves in western Kentucky, through its purchase of a wholly owned subsidiary of Midwest for \$29.6 million cash paid at closing. In conjunction with this acquisition, WKY CoalPlay s subsidiary leased 22.6 million tons of the acquired reserves to us and, as partial consideration for entering the lease, conveyed the remaining 31.5 million tons to us. The conveyed reserves have minimal value as a result of uncertainty regarding inclusion in a mine plan. See Note 19

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Related-Party Transactions for further information on our lease terms with WKY CoalPlay. This transaction allowed us to extend the expected life of our River View mine and provides potential greenfield mining opportunities.

CONSOL Energy Inc.

In June 2013, our subsidiary, Alliance Resource Properties acquired the rights to approximately 11.6 million tons of proven and probable medium-sulfur coal reserves, and an additional 5.9 million resource tons, in Grant and Tucker Counties, West Virginia from Laurel Run Mining Company, a subsidiary of CONSOL Energy Inc. (CONSOL). The purchase price of \$25.2 million was allocated to owned and leased coal rights and was financed using existing cash on hand. As a result of the coal reserve purchase, we reclassified certain tons of medium-sulfur, non-reserve coal deposits as reserves, which together with the reserves purchased above, extended the expected life of Mettiki (WV) s Mountain View mine.

In November 2014, Alliance Resource Properties acquired the rights to approximately 124.2 million tons of proven and probable high-sulfur coal reserves, most of which are leased reserves, and various surface properties in western Kentucky from CNX RCPC, LLC (CNX RCPC) and Island Creek Coal Company (Island Creek), both subsidiaries of CONSOL. The purchase price of \$11.6 million was financed using existing cash on hand and allocated to the owned and leased coal rights and surface properties acquired. We also assumed reclamation liabilities totaling \$6.0 million.

In conjunction with this acquisition, WKY CoalPlay acquired approximately 86.6 million tons of proven and probable high-sulfur owned coal reserves in western Kentucky and southern Indiana through its purchase of two wholly owned subsidiaries of CNX RCPC and Island Creek for \$57.2 million. In December 2014, WKY CoalPlay s subsidiaries leased 72.3 million tons of the acquired reserves to us and, as partial consideration for entering the leases, conveyed the remaining 14.3 million tons of its acquired reserves to us. The conveyed reserves have minimal value as a result of uncertainty regarding inclusion in a mine plan. See Note 19 Related-Party Transactions for further information on our lease terms with WKY CoalPlay. The reserves described in this paragraph extended the expected lives of our River View and Dotiki mines and provide potential greenfield mining opportunities.

4. LONG-LIVED ASSET IMPAIRMENTS

During the fourth quarter of 2015, we idled our Onton and Gibson North mines in response to market conditions and continued increases in coal inventories at our mines and customer locations. Our decision to idle these mines, as well as continued low coal prices and regulatory conditions, led to the conclusion that indicators of impairment were present and our carrying value for certain mines may not be fully recoverable. During our assessment of the recoverability of the carrying value of our operating segments, we determined that we would likely not recover the carrying value of the net assets at MC Mining within our Appalachia segment and Onton within our Illinois Basin segment. Accordingly, we estimated the fair values of the MC Mining and Onton net assets and then adjusted the carrying values to the fair values resulting in impairments of \$19.5 million and \$66.9 million, respectively.

The fair value of the assets was determined using a market approach and represents a Level 3 fair value measurement under the fair value hierarchy. The fair value analysis was based on assumptions of marketability of coal properties in the current environment and the probability assessment of multiple sales scenarios based on observations of other recent mine sales.

During the fourth quarter of 2015 we determined that certain undeveloped coal reserves and related property in western Pennsylvania were no longer a core part of our foreseeable development plans and thus surrendered the lease for the properties in order to avoid the high holding costs of those reserves. We recorded an impairment charge of \$3.0 million to our Appalachia segment during the quarter ended December 31, 2015 to remove advanced royalties associated with the lease from our consolidated balance sheet.

During the third quarter of 2015, we surrendered a lease agreement for certain undeveloped coal reserves and related property in western Kentucky. We determined that coal reserves held under this lease agreement were no longer a core part of our foreseeable development plans. As such, we surrendered the lease in order to avoid the high holding costs of those reserves. We recorded an impairment charge of \$10.7 million to our Illinois Basin segment to remove certain assets associated with the lease, including mineral rights, advanced royalties and mining permits from our consolidated balance sheet.

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In future periods, it is reasonably possible that a variety of circumstances could result in additional impairments of our long-lived assets.

5. INVENTORIES

Inventories consist of the following at December 31:

		2015		2014
		(in thousands)		
Coal	\$	83,682	\$	50,130
Supplies (net of reserve for obsolescence of \$3,841 and \$2,935, respectively)		37,399		33,025
Total inventory	\$	121,081	\$	83,155

6. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following at December 31:

		2015		2014
		(in thousands)		
Mining equipment and processing facilities	\$	1,923,310	\$	1,757,772
Land and mineral rights		418,668		376,937
Buildings, office equipment and improvements		291,106		278,283
Construction and mine development in progress		94,482		82,530
Mine development costs		316,694		320,098
Property, plant and equipment, at cost		3,044,260		2,815,620
Less accumulated depreciation, depletion and amortization		(1,243,985)		(1,150,414)
Total property, plant and equipment, net	\$	1,800,275	\$	1,665,206

Equipment leased by us under lease agreements which are determined to be capital leases are stated at an amount equal to the present value of the minimum lease payments during the lease term, less accumulated amortization. Equipment under capital leases totaling \$105.8 million included in mining equipment and processing facilities is amortized on the straight-line method over the shorter of its useful life or the related lease term. The provision for amortization of leased properties is included in depreciation, depletion and amortization expense. Accumulated amortization related to our capital leases was \$7.1 million, \$5.6 million and \$5.8 million as of December 31, 2015, 2014 and 2013, respectively, and amortization expense was \$5.7 million, \$1.6 million and \$2.0 million for the years ended December 31, 2015, 2014 and 2013, respectively. For information regarding long-lived asset impairments please see Note 4 Long-Lived Asset Impairments.

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Long-term debt consists of the following:

	December 31, 2015	December 31, 2014
	(in thousands)	
Revolving Credit facility	\$ 385,000	\$ 140,000
Series A senior notes	-	205,000
Series B senior notes	145,000	145,000
Term loan	206,250	231,250
Securitization facility	83,100	100,000
	819,350	821,250
Less current maturities	(239,350)	(230,000)
Total long-term debt	\$ 580,000	\$ 591,250

Credit Facility. On May 23, 2012, our Intermediate Partnership entered into a credit agreement (the *Credit Agreement*) with various financial institutions for a revolving credit facility (the *Revolving Credit Facility*) of \$700.0 million and a term loan (the *Term Loan*) in the aggregate principal amount of \$250.0 million (collectively, the *Revolving Credit Facility* and *Term Loan* are referred to as the *Credit Facility*). Borrowings under the *Credit Agreement* bear interest at a Base Rate or Eurodollar Rate, at our election, plus an applicable margin that fluctuates depending upon the ratio of Consolidated Debt to Consolidated Cash Flow (each as defined in the *Credit Agreement*). We have elected a Eurodollar Rate, which, with applicable margin, was 2.06% on borrowings outstanding as of December 31, 2015. The *Credit Facility* matures May 23, 2017, at which time all amounts then outstanding are required to be repaid. Interest is payable quarterly, with principal of the *Term Loan* due as follows: for each quarter commencing June 30, 2014 and ending March 31, 2016, quarterly principal payments in an amount per quarter equal to 2.50% of the aggregate amount of the *Term Loan* advances outstanding; for each quarter beginning June 30, 2016 through December 31, 2016, 20% of the aggregate amount of the *Term Loan* advances outstanding; and the remaining balance of the *Term Loan* advances at maturity. In June 2014, we began making quarterly principal payments on the *Term Loan*, leaving a balance of \$206.3 million at December 31, 2015. We have the option to prepay the *Term Loan* at any time in whole or in part subject to terms and conditions described in the *Credit Agreement*. Upon a change of control (as defined in the *Credit Agreement*), the unpaid principal amount of the *Credit Facility*, all interest thereon and all other amounts payable under the *Credit Agreement* would become due and payable. On October 16, 2015, the *Revolving Credit Facility* was amended to increase the baskets for capital lease obligations from \$10.0 million to \$100.0 million and sale-leaseback arrangements from \$10.0 million to \$100.0 million per annum.

At December 31, 2015, we had borrowings of \$385.0 million and \$5.9 million of letters of credit outstanding with \$309.1 million available for borrowing under the *Revolving Credit Facility*. We utilize the *Revolving Credit Facility*, as appropriate, for working capital requirements, capital expenditures and investments in affiliates, scheduled debt payments and distribution payments. We incur an annual commitment fee of 0.25% on the undrawn portion of the *Revolving Credit Facility*.

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

The Series B Senior Notes and the Credit Facility described above (collectively, *ARLP Debt Arrangements*) are guaranteed by all of the material 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, incurrence of additional indebtedness and liens, sale of assets, investments, mergers and consolidations and transactions with affiliates, in each case subject to various exceptions. See Note 11 *Variable Interest Entities* for further discussion of restrictions on the cash available for distribution. 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 (a) debt to cash flow ratio of not more than 3.0 to 1.0 and (b) cash flow to interest expense ratio of not less than 3.0 to 1.0, in each case, during the four most recently ended fiscal quarters. The

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debt to cash flow ratio and cash flow to interest expense ratio were 1.19 to 1.0 and 24.2 to 1.0, respectively, for the trailing twelve months ended December 31, 2015. We were in compliance with the covenants of the ARLP Debt Arrangements as of December 31, 2015.

Accounts Receivable Securitization. On December 5, 2014, certain direct and indirect wholly owned subsidiaries of our Intermediate Partnership entered into a \$100.0 million accounts receivable securitization facility (*Securitization Facility*) providing additional liquidity and funding. Under the Securitization Facility, certain subsidiaries sell trade receivables on an ongoing basis to our Intermediate Partnership, which then sells the trade receivables to AROP Funding, a wholly owned bankruptcy-remote special purpose subsidiary of our Intermediate Partnership, which in turn borrows on a revolving basis up to \$100.0 million secured by the trade receivables. After the sale, Alliance Coal, as servicer of the assets, collects the receivables on behalf of AROP Funding. The Securitization Facility bears interest based on a Eurodollar Rate. It was renewed in December 2015 and matures in December 2016. At December 31, 2015, we had \$83.1 million outstanding under the Securitization Facility.

Hamilton Revolving Credit Facility and Hamilton Equipment Financing Agreement. In connection with the Hamilton Acquisition (see Note 3 *Acquisitions*), we assumed a \$10.0 million revolving credit facility (*Hamilton Revolving Credit Facility*). In November 2014, White Oak entered into the Hamilton Revolving Credit Facility allowing for periodic borrowings up to \$10.0 million, collateralized by White Oak's accounts receivable. Borrowings under the Hamilton Revolving Credit Facility carried interest at the prime rate plus 0.1%. On October 19, 2015, the outstanding balance of the Hamilton Revolving Credit Facility totaling \$10.0 million was repaid.

Also in connection with the Hamilton Acquisition, we assumed an equipment financing agreement (*Hamilton Equipment Financing Agreement*). In 2012, White Oak acquired vendor financing totaling \$100.0 million through the Hamilton Equipment Financing Agreement, which was secured by continuous mining, long-wall mining, and underground belt system equipment purchased from the vendor. The Hamilton Equipment Financing Agreement required repayment of principal and interest in equal monthly installments of \$2.1 million from July 2014 until June 2019. On October 16, 2015, the outstanding balance of the Hamilton Equipment Financing Agreement totaling \$80.6 million was repaid without penalty with funds drawn on the Revolving Credit Facility.

On October 29, 2015, we entered into a sale-leaseback transaction whereby we sold certain mining equipment for \$100.0 million and concurrently entered into a lease agreement for that equipment. See Note 20 *Commitments and Contingencies* for further information.

Cavalier Credit Agreement. On October 6, 2015, Cavalier Minerals (see Note 11 *Variable Interest Entities*) entered into a credit agreement (the *Cavalier Credit Agreement*) with Mineral Lending, LLC (*Mineral Lending*) for a \$100.0 million line of credit (the *Cavalier Credit Facility*). Mineral Lending is an entity owned by a) Alliance Resource Holdings II, Inc. (*ARH II*, the parent of ARH), b) an entity owned by an officer of ARH who is also a director of ARH II (*ARH Officer*) and c) foundations established by the President and Chief Executive Officer of MGP and Kathleen S. Craft. There is no commitment fee under the facility. Borrowings under the Cavalier Credit Facility bear interest at a one month LIBOR rate plus 6% with interest payable quarterly. Repayment of the principal balance will begin following the first fiscal quarter after the earlier of the date on which the aggregate amount borrowed exceeds \$90.0 million or December 31, 2017, in quarterly payments of an amount equal to the greater of \$1.3 million initially, escalated to \$2.5

million after two years, or fifty percent of Cavalier Minerals' excess cash flow. The Cavalier Credit Facility matures September 30, 2024, at which time all amounts then outstanding are required to be repaid. To secure payment of the facility, Cavalier Minerals pledged all of its partnership interests, then owned or later acquired, in AllDale Minerals, L.P. and AllDale Minerals II, L.P. Cavalier Minerals may prepay the Cavalier Credit Facility at any time in whole or in part subject to terms and conditions described in the Cavalier Credit Agreement. As of December 31, 2015, Cavalier Minerals had not drawn on the Cavalier Credit Facility.

Other. In addition to the letters of credit available under the 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 December 31, 2015, we had \$30.7 million in letters of credit outstanding under agreements with these two banks.

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Aggregate maturities of long-term debt are payable as follows:

Year Ending December 31,	(in thousands)
2016	\$ 239,350
2017	435,000
2018	145,000
2019	-
2020	-
Thereafter	-
	\$ 819,350

8. FAIR VALUE MEASUREMENTS

The following table summarizes our recurring fair value measurements within the hierarchy not included elsewhere in these notes:

	December 31, 2015			December 31, 2014		
	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
	(in thousands)					
Long-term debt	\$ -	\$ 819,099	\$ -	\$ -	\$ 833,351	\$ -
Contingent consideration	-	-	10,400	-	-	-
Total	\$ -	\$ 819,099	\$ 10,400	\$ -	\$ 833,351	\$ -

See Note 2 Summary of Significant Accounting Policies Fair Value Measurements for more information regarding fair value hierarchy levels.

The carrying amounts for cash equivalents, accounts receivable, accounts payable, due from affiliates and due to affiliates approximate fair value due to the short maturity of those instruments.

The estimated fair value of our long-term debt, including current maturities, is based on interest rates that we believe are currently available to us in active markets for issuance of debt with similar terms and remaining maturities (See Note 7 Long-Term Debt). The fair value of debt, which is based upon these interest rates, is classified as a Level 2 measurement under the fair value hierarchy.

As discussed in Note 3 Acquisitions, the fair value of the contingent consideration on the Hamilton Acquisition Date was \$14.8 million. This fair value decreased to \$10.4 million as of December 31, 2015 due to changes in projected coal prices, changes in the estimated cost of debt in the coal industry, and a change in the discount rate. The fair value measurement is based on significant inputs not observable in active markets and thus represents a Level 3 fair value measurement under the fair value hierarchy.

9. DISTRIBUTIONS OF AVAILABLE CASH

We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partners. Available cash is generally defined in the partnership agreement as all cash and cash equivalents on hand at the end of each quarter less reserves established by our managing general partner in its reasonable discretion for future cash requirements. These reserves are retained to provide for the conduct of our business, the payment of debt principal and interest and to provide funds for future distributions. These reserves are also considered in our review of certain VIEs discussed in Note 11 Variable Interest Entities.

As quarterly distributions of available cash exceed the target distribution levels established in our partnership agreement, our managing general partner receives distributions based on specified increasing percentages of the available cash that exceeds the target distribution levels. The target distribution levels are based on the amounts of available cash from our operating surplus distributed for a given quarter that exceed the minimum quarterly distribution (MQD) and common unit arrearages, if any. Our partnership agreement defines the MQD as \$0.125 per unit (\$0.50 per unit on an annual basis).

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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 \$0.1375 per unit, 25% of the amount we distribute in excess of \$0.15625 per unit, and 50% of the amount we distribute in excess of \$0.1875 per unit. For the years ended December 31, 2015, 2014 and 2013, we allocated to our managing general partner incentive distributions of \$141.7 million, \$129.8 million and \$115.6 million, respectively. The following table summarizes the quarterly per unit distribution paid during the respective quarter:

	2015	Year 2014	2013
First Quarter	\$0.65000	\$0.59875	\$0.55375
Second Quarter	\$0.66250	\$0.61125	\$0.56500
Third Quarter	\$0.67500	\$0.62500	\$0.57625
Fourth Quarter	\$0.67500	\$0.63750	\$0.58750

On January 26, 2016, we declared a quarterly distribution of \$0.675 per unit, totaling approximately \$87.5 million (which includes our managing general partner's IDR distributions), on all our common units outstanding, which was paid on February 12, 2016, to all unitholders of record on February 5, 2016.

10. INCOME TAXES

Our subsidiaries, ASI and Wildcat Insurance, are subject to federal and state income taxes. Wildcat Insurance's income is due to insurance premiums provided by our other subsidiaries. ASI's income is principally due to its subsidiary, Matrix Design. There are minor temporary differences between our taxable entities financial reporting basis and the tax basis of their assets and liabilities. Components of income tax expense are as follows:

	2015	Year Ended December 31, 2014	2013
		(in thousands)	
Current:			
Federal	\$ 13	\$ -	\$ 7
State	14	-	16
Deferred:			
Federal	7	-	1,022
State	-	-	351
	7	-	1,373
Income tax expense	\$ 21	\$ -	\$ 1,396

We have deferred tax assets due to net operating losses and research and development credits associated with ASI's operations in the amount of \$8.3 million, partially offset by liabilities of \$1.6 million. State and federal valuation allowances have been established to reduce these deferred tax assets to an amount that will, more likely than not, be realized. During 2015, the federal and state valuation allowances increased to \$5.2 million and \$1.5 million, respectively, primarily due to the ongoing evaluation process of the losses and credits anticipated to be realized in

future years.

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

	2015	Year Ended December 31, 2014 (in thousands)	2013
Income taxes at statutory rate	\$ 107,167	\$ 174,024	\$ 138,210
Less: Income taxes at statutory rate on Partnership income not subject to income taxes	(108,306)	(174,912)	(139,771)
Increase/(decrease) resulting from:			
State taxes, net of federal income tax	(123)	(112)	(192)
Change in valuation allowance of deferred tax assets	1,557	1,636	3,483
Other	(274)	(636)	(334)
Income tax expense	\$ 21	\$ -	\$ 1,396

11. VARIABLE INTEREST ENTITIES

Cavalier Minerals

On November 10, 2014, our subsidiary, Alliance Minerals, and Bluegrass Minerals Management, LLC (Bluegrass Minerals) entered into a limited liability company agreement (the Cavalier Agreement) to create Cavalier Minerals, which was formed to indirectly acquire oil and gas mineral interests, initially through its 71.7% noncontrolling ownership interest in AllDale I and subsequently through its 72.8% noncontrolling ownership interest in AllDale II, collectively with AllDale I, AllDale Minerals (see Note 12 Equity Investments). Alliance Minerals and Bluegrass Minerals initially committed funding of \$48.0 million and \$2.0 million, respectively, to Cavalier Minerals, and Cavalier Minerals committed funding of \$49.0 million to AllDale I. On October 6, 2015, Alliance Minerals and Bluegrass Minerals committed to fund an additional \$96.0 million and \$4.0 million, respectively, to Cavalier Minerals, and Cavalier Minerals committed to fund \$100.0 million to AllDale II. Alliance Minerals' contributions through December 31, 2014 to Cavalier Minerals totaled \$11.5 million. During the year ended December 31, 2015, Alliance Minerals contributed an additional \$51.6 million fulfilling our initial commitment and bringing our total investment in Cavalier Minerals to \$63.1 million at December 31, 2015. Our remaining commitment to Cavalier Minerals at December 31, 2015 was \$80.9 million. Bluegrass Minerals, which is owned and controlled by the ARH Officer as discussed in Note 7 Long-Term Debt and is Cavalier Minerals' managing member, contributed \$2.6 million as of December 31, 2015 and has a remaining commitment of \$3.4 million. At Alliance Minerals' election, Cavalier Minerals will meet its remaining funding commitment to AllDale Minerals through contributions from Alliance Minerals and Bluegrass Minerals or from borrowings under the Cavalier Credit Facility (see Note 7 Long-Term Debt). We expect to fund our remaining commitments utilizing existing cash balances, future cash flows from operations, borrowings under credit and securitization facilities and cash provided from the issuance of debt or equity, or by requiring Cavalier Minerals to draw on the Cavalier Credit Facility.

In accordance with the Cavalier Agreement, Bluegrass Minerals is entitled to receive an incentive distribution from Cavalier Minerals equal to 25% of all distributions (including in liquidation) after return of members' capital reduced by certain distributions received by Bluegrass Minerals or its owner from AllDale Minerals Management, LLC (AllDale Minerals Management), the managing member of AllDale Minerals. Alliance Minerals' ownership interest in Cavalier Minerals at December 31, 2015 was 96%. The remainder of the equity ownership is held by Bluegrass Minerals. We have consolidated Cavalier Minerals' financial results as we concluded that Cavalier Minerals is a VIE and we are the

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primary beneficiary because our consent is required for significant activities of Cavalier Minerals and due to Bluegrass Minerals' relationship to us as described above. Bluegrass Minerals' equity ownership of Cavalier Minerals is accounted for as noncontrolling ownership interest in our consolidated balance sheets. In addition, earnings attributable to Bluegrass Minerals are recognized as net loss attributable to noncontrolling interest in our consolidated statements of income. Furthermore, we have concluded that Cavalier Minerals has a variable interest in AllDale Minerals, which qualifies as a VIE. For more information on AllDale Minerals, see Note 12 - Equity Investments.

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WKY CoalPlay

On November 17, 2014, SGP Land, LLC (SGP Land) and two limited liability companies owned by irrevocable trusts established by the President and Chief Executive Officer of MGP (Craft Companies) entered into a limited liability company agreement to form WKY CoalPlay. WKY CoalPlay was formed, in part, to purchase and lease coal reserves. WKY CoalPlay is managed by the ARH Officer discussed in Note 7 Long-Term Debt, who is also an employee of SGP Land and trustee of the irrevocable trusts owning the Craft Companies. In December 2014 and February 2015, we entered into various coal reserve leases with WKY CoalPlay. See Note 19 Related-Party Transactions for further information on our lease terms with WKY CoalPlay.

We have concluded that WKY CoalPlay is a VIE because of our ability to exercise options to acquire reserves under lease with WKY CoalPlay (Note 19 Related-Party Transactions), which is not within the control of the equity holders and, if it occurs, could potentially limit the expected residual return to the owners of WKY CoalPlay. We do not have any economic or governance rights related to WKY CoalPlay and our options that provide us with a variable interest in WKY CoalPlay's reserve assets do not give us any rights that constitute power to direct the primary activities that most significantly impact WKY CoalPlay's economic performance. SGP Land has the sole ability to replace the manager of WKY CoalPlay at its discretion and therefore has power to direct the activities of WKY CoalPlay. Consequently, we concluded that SGP Land is the primary beneficiary of WKY CoalPlay.

White Oak

Prior to our acquisition of the remaining equity interests in White Oak as discussed in Note 3 Acquisitions, White Oak was a variable interest entity of which we were not the primary beneficiary. We held a majority of the Series A Units that had certain distribution and liquidation preferences but only gave us a 40% voting interest in the primary activities of the company. We had protective rights and limited participating rights, such as minority representation on their board of directors, restrictions on indebtedness and other obligations, the ability to assume control of the board of directors in certain circumstances, such as an event of default, and the right to approve certain coal sales agreements.

These protective and participating rights did not provide us the ability to unilaterally direct any of the primary activities of White Oak that most significantly impacted its economic performance and thus, we were not the primary beneficiary for consolidation purposes. Consequentially, we accounted for our Series A Units investment as an equity investment. See Note 12 Equity Method Investments for further information.

Alliance Coal and the Intermediate Partnership

Alliance Coal is a limited liability company designed to operate as the operating subsidiary of the Intermediate Partnership and holds the interests in the mining operations and ASI. The Intermediate Partnership is a limited liability partnership that holds the non-managing member interest in Alliance Coal, the sole member interests in Alliance Resource Properties and other miscellaneous businesses. Together Alliance Coal and the Intermediate Partnership and their subsidiaries represent virtually all the net assets of ARLP. Both the Intermediate Partnership and Alliance Coal were designed to operate as the operating subsidiaries of ARLP and to distribute available cash to ARLP so that ARLP can distribute available cash to its partners. Although MGP, ARLP, and the Intermediate Partnership are under common control due to AHGP's control of both MGP and ARLP, we considered MGP's and ARLP's ownership in the Intermediate Partnership and MGP's and the Intermediate Partnership's ownership in Alliance Coal separately for the purposes of determining whether the Intermediate Partnership and Alliance Coal are

VIE s.

The Intermediate Partnership holds a 99.999% non-managing interest and MGP holds the 0.001% managing member interest in Alliance Coal. To determine whether Alliance Coal is a VIE we considered that MGP has the power to direct the activities of Alliance Coal, but it does not have the obligation to absorb losses nor the right to receive benefits that could be potentially significant to Alliance Coal. The Intermediate Partnership does not have the power to direct the activities of Alliance Coal, but does have the obligation to absorb losses or receive benefits that could be potentially significant to Alliance Coal. As a result, we have determined that Alliance Coal is a VIE.

To determine whether the Intermediate Partnership is the primary beneficiary of Alliance Coal, we determined that because neither MGP nor the Intermediate Partnership have both the power and the benefits related to Alliance Coal, the entity to which Alliance Coal is most closely aligned is the Intermediate Partnership and therefore the Intermediate Partnership is the primary beneficiary. We based our determination of alignment on 1) the purpose and design of

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Alliance Coal to a) be the operating subsidiary of the Intermediate Partnership and b) distribute all of its cash to the Intermediate Partnership such that the Intermediate Partnership can pay its partners and debt obligations, 2) the Intermediate Partnership's significant majority interest in the economics of Alliance Coal and 3) the Intermediate Partnership's debt funding for Alliance Coal for capital expenditures, operations and other purposes as needed and related risks and collateral requirements in the debt arrangement.

ARLP holds a 98.9899% limited partnership interest in the Intermediate Partnership and MGP holds the 1.0001% managing partner interest in the Intermediate Partnership. To determine whether the Intermediate Partnership is a VIE we considered that MGP has the power to direct the activities of the Intermediate Partnership, but it does not have the obligation to absorb losses or the right to receive benefits that could be potentially significant to the Intermediate Partnership. ARLP does not have the power to direct the activities of the Intermediate Partnership, but does have the obligation to absorb losses or receive benefits that could be potentially significant to the Intermediate Partnership. As a result, we have determined that the Intermediate Partnership represents a VIE.

To determine whether ARLP is the primary beneficiary of the Intermediate Partnership, we determined that because neither MGP nor ARLP have both the power and the benefits related to the Intermediate Partnership, the entity to which the Intermediate Partnership is most closely aligned is ARLP and therefore ARLP is the primary beneficiary. We based our determination of alignment on 1) the purpose and design of the Intermediate Partnership to a) be the operating subsidiary to ARLP and b) distribute all of its available cash to the ARLP to pay its partners and 2) ARLP's significant majority interest in the economics of the Intermediate Partnership.

The Partnership Agreements of ARLP and the Intermediate Partnership and the Operating Agreement of Alliance Coal (collectively the Agreements) use the term Partnership Group to comprise all three entities. The Agreements require MGP to distribute on a quarterly basis 100% of available cash from the Partnership Group to ARLP and then to ARLP's partners in addition to nominal distributions from the Intermediate Partnership and Alliance Coal to MGP and SGP. Available cash is determined as defined in the Agreements and represents all cash with the exception of cash reserves (i) required for the proper conduct of the business including reserves for future capital expenditures and for anticipated credit needs of the Partnership Group, (ii) to comply with debt obligations or (iii) to provide funds for certain subsequent distributions. MGP is required under the terms of the Agreements to distribute this cash to ARLP to meet the distribution requirements discussed in Note 9 - Distributions. As discussed in Note 7 - Long-Term Debt, the Intermediate Partnership's debt covenants place additional restrictions on distributions to ARLP by limiting cash available for distribution from the Intermediate Partnership based on various debt covenants pertaining to the most recent preceding quarter. In the definition of Available Cash in the Agreements, MGP cannot hold cash reserves from ARLP to provide funds for subsequent distributions if that would prevent ARLP from making its minimum quarterly distributions or any cumulative distributions in arrears. MGP does not have the ability to amend the Agreements without the consent of the Partnership Group.

12. EQUITY INVESTMENTS

AllDale Minerals

On November 10, 2014, Cavalier Minerals (see Note 11 - Variable Interest Entities) made an initial contribution of \$7.4 million in return for a limited partner interest in AllDale Minerals, which was created to purchase oil and gas mineral interests in various geographic locations within producing basins in the continental U.S. As of December 31, 2014, Cavalier Minerals had contributed \$11.6 million to AllDale Minerals. During the year ended December 31, 2015, Cavalier Minerals contributed an additional \$54.3 million bringing the total investment in AllDale Minerals to \$65.9 million as of December 31, 2015. We continually review all rights provided to Cavalier Minerals and us by various agreements and continue to conclude all such rights do not provide Cavalier Minerals or us the ability to unilaterally direct any of the activities

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of AllDale Minerals that most significantly impact its economic performance. As such, we account for Cavalier Minerals' ownership interest in the income or loss of AllDale Minerals as an equity investment in our consolidated financial statements. We record equity income or loss based on AllDale Minerals' distribution structure as described below. For the years ended December 31, 2015 and 2014, we have been allocated losses of \$0.6 million and \$0.4 million, respectively, from AllDale Minerals.

In accordance with AllDale Minerals' partnership agreements, limited partners, such as Cavalier Minerals, will initially receive all distributions of proceeds from certain producing basins based upon the greater of the limited partner's cumulative contributions plus 25.0% or an amount sufficient to cause the limited partner to receive an effective internal rate of return of 10.0%. Afterwards, 20.0% of all distributions will be allocated to AllDale Minerals Management, as an

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incentive distribution to the general partner, with the remaining 80.0% allocated to limited partners based upon ownership percentages. In addition, upon an event of liquidation, any proceeds will be distributed using the same methodology. AllDale Minerals distributed \$0.4 million to Cavalier Minerals during 2015. AllDale Minerals did not make any distributions to its owners during 2014.

White Oak

On September 22, 2011, we entered into a series of transactions (Initial Transactions) with White Oak to support development of a longwall mining operation, which we assumed control of in July 2015 through our acquisition of the remaining equity interests in White Oak (see Note 3 - Acquisitions). The Initial Transactions featured several components, including an equity investment in White Oak, the acquisition and lease-back of certain coal reserves and surface rights, a loan and a coal handling and preparation agreement, pursuant to which we constructed and operated Hamilton's preparation plant and other surface facilities. Prior to the Hamilton Acquisition, we recorded our previous equity in income or losses of affiliates from White Oak under the hypothetical liquidation at book value method of accounting due to the preferences to which we were entitled with respect to distributions. See Note 11 Variable Interest Entities regarding our determination to account for White Oak as an equity investment prior to the Hamilton Acquisition.

White Oak's results prior to the Hamilton Acquisition for the period from January 1, 2015 to July 31, 2015 and for the years ended December 31, 2014 and 2013 are summarized as follows:

	January 1, 2015 to July 31, 2015	December 31, 2014 (in thousands)	December 31, 2013
Total revenues	\$ 108,256	\$ 42,748	\$ -
Gross loss	(2,919)	(1,134)	(5,404)
Loss from operations	(38,148)	(21,018)	(24,103)
Net loss	(69,075)	(46,324)	(30,263)

White Oak's financial position as of December 31, 2015 and 2014 are summarized as follows:

	2015 (1)	2014
	(in thousands)	
Current assets	\$ -	\$ 37,105
Noncurrent assets	-	639,953
Current liabilities	-	71,489
Noncurrent liabilities	-	372,507

(1) White Oak was not an equity method investee as of December 31, 2015 (see Note 3 Acquisitions).

13. NET INCOME OF ARLP PER LIMITED PARTNER UNIT

We utilize the two-class method in calculating basic and diluted earnings per unit (EPU). 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 or expense allocations, including incentive distributions to our managing general partner, the holder of the IDR pursuant to our partnership agreement, which are declared and paid following the end of each quarter (see Note 9 Distributions). 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 \$0.1375 per unit, 25% of the amount we distribute in excess of \$0.15625 per unit, and 50% of the amount we distribute in excess of \$0.1875 per unit. Our partnership agreement contractually limits our distributions to available cash and therefore, undistributed earnings of the ARLP Partnership are not allocated to the IDR holder. In addition, our outstanding unvested awards under our LTIP, SERP and Deferred Compensation Plan contain rights to nonforfeitable distributions and are therefore considered participating securities. As such, we allocate undistributed and distributed earnings to the outstanding awards in our calculation of EPU.

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The following is a reconciliation of net income of ARLP and net income used for calculating EPU and the weighted-average units used in computing EPU for the years ended December 31, 2015, 2014 and 2013, respectively:

	2015	Year Ended December 31, 2014	2013
	(in thousands, except per unit data)		
Net income of ARLP	\$ 306,198	\$ 497,229	\$ 393,490
Adjustments:			
Managing general partner priority distributions	(144,576)	(132,449)	(117,995)
General partners 2% equity ownership	(3,262)	(7,325)	(5,554)
General partners special allocation of certain general and administrative expenses	1,500	1,500	2,200
Limited partners interest in Net income of ARLP	159,860	358,955	272,141
Less:			
Distributions to participating securities	(3,493)	(2,956)	(2,362)
Undistributed earnings attributable to participating securities	-	(2,669)	(1,350)
Net income of ARLP available to limited partners	\$ 156,367	\$ 353,330	\$ 268,429
Weighted-average limited partner units outstanding Basic and Diluted (1)	74,174	74,044	73,904
Basic and Diluted Net income of ARLP per limited partner unit (1)	\$ 2.11	\$ 4.77	\$ 3.63

(1) Diluted EPU gives effect to all dilutive potential common units outstanding during the period using the treasury stock method. Diluted EPU excludes all dilutive potential units calculated under the treasury stock method if their effect is anti-dilutive. For the year ended December 31, 2015, 2014 and 2013, the combined total of LTIP, SERP and Deferred Compensation Plan units of 734, 799 and 683, respectively, were considered anti-dilutive.

During 2015, 2014 and 2013, an affiliated entity controlled by Mr. Craft made capital contributions of \$1.5 million, \$1.5 million and \$2.2 million, respectively, to AHGP for the purpose of funding certain general and administrative expenses. Upon AHGP's receipt of each contribution, it contributed the same to its subsidiary MGP, our managing general partner, which in turn contributed the same to our subsidiary, Alliance Coal. As provided under our partnership agreement, we made special allocations to our managing general partner of certain general and administrative expenses equal to its contributions. Net income of ARLP allocated to the limited partners was not burdened by this expense.

14. EMPLOYEE BENEFIT PLANS

Defined Contribution Plans Our eligible employees currently participate in a defined contribution profit sharing and savings plan (PSSP) that we sponsor. The PSSP covers substantially all regular full-time employees. PSSP participants may elect to make voluntary contributions to this plan up to a specified amount of their compensation. We make matching contributions based on a percent of an employee's eligible compensation and also make an additional non-matching

contribution. Our contribution expense for the PSSP was approximately \$22.6 million, \$21.8 million and \$20.4 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Defined Benefit Plan Eligible employees at certain of our mining operations participate in a defined benefit plan (the Pension Plan) that we sponsor. The Pension Plan is currently closed to new applicants; however, participants in the plan continue to accrue benefits. The benefit formula for the Pension Plan is a fixed-dollar unit based on years of service.

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The following sets forth changes in benefit obligations and plan assets for the years ended December 31, 2015 and 2014 and the funded status of the Pension Plan reconciled with the amounts reported in our consolidated financial statements at December 31, 2015 and 2014, respectively:

	2015		2014
	(dollars in thousands)		
Change in benefit obligations:			
Benefit obligations at beginning of year	\$ 109,626	\$	85,662
Service cost	2,473		2,174
Interest cost	4,296		4,074
Actuarial (gain) loss	(6,420)		19,841
Benefits paid	(2,499)		(2,125)
Benefit obligations at end of year	107,476		109,626
Change in plan assets:			
Fair value of plan assets at beginning of year	69,521		67,480
Employer contribution	3,116		2,671
Actual return on plan assets	(1,693)		1,495
Benefits paid	(2,499)		(2,125)
Fair value of plan assets at end of year	68,445		69,521
Funded status at the end of year	\$ (39,031)	\$	(40,105)
Amounts recognized in balance sheet:			
Non-current liability	\$ (39,031)	\$	(40,105)
	\$ (39,031)	\$	(40,105)
Amounts recognized in accumulated other comprehensive income consists of:			
Net actuarial loss	\$ (38,787)	\$	(41,278)
Weighted-average assumptions to determine benefit obligations as of December 31,			
Discount rate	4.27%		3.92%
Expected rate of return on plan assets	8.00%		8.00%
Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31,			
Discount rate	3.92%		4.89%
Expected return on plan assets	8.00%		8.00%

The actuarial gain component of the change in benefit obligation in 2015 was primarily attributable to an increase in the discount rate compared to December 31, 2014 and the adoption of newly issued mortality tables reflecting improved life expectancies offset by updated retirement and withdrawal rate estimates. The actuarial loss component of the change in benefit obligation in 2014 was primarily attributable to a decrease in the discount rate and the actual rate of return on plan assets compared to December 31, 2013, adoption of newly issued mortality tables reflecting improved life expectancies and updated retirement and withdrawal rate estimates.

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The expected long-term rate of return used to determine our pension liability was 8.0% for both December 31, 2015 and 2014 based on an asset allocation assumption of:

As of December 31, 2015	Asset allocation assumption	Expected long- term rate of return
Domestic equity securities	70%	8.6%
Foreign equity securities	10%	5.3%
Fixed income securities/cash	20%	5.1%
	100%	

The actual return on plan assets was (2.0)% and 5.4% for the years ended December 31, 2015 and 2014, respectively.

	2015	2014	2013
	(in thousands)		
Components of net periodic benefit cost:			
Service cost	\$ 2,473	\$ 2,174	\$ 2,783
Interest cost	4,296	4,074	3,640
Expected return on plan assets	(5,590)	(5,475)	(4,446)
Amortization of net loss	3,354	773	2,653
Net periodic benefit cost	\$ 4,533	\$ 1,546	\$ 4,630

	2015	2014
	(in thousands)	
Other changes in plan assets and benefit obligation recognized in accumulated other comprehensive income:		
Net actuarial loss	\$ (863)	\$ (23,821)
Reversal of amortization item:		
Net actuarial loss	3,354	773
Total recognized in accumulated other comprehensive income (loss)	2,491	(23,048)
Net periodic benefit cost	(4,533)	(1,546)
Total recognized in net periodic benefit cost and accumulated other comprehensive loss	\$ (2,042)	\$ (24,594)

Estimated future benefit payments as of December 31, 2015 are as follows:

Year Ending December 31,	(in thousands)
2016	\$ 2,972
2017	3,340
2018	3,766
2019	4,193
2020	4,653

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\$ 29,193
48,117

We expect to contribute \$2.6 million to the Pension Plan in 2016. The estimated net actuarial loss for the Pension Plan that will be amortized from AOCI into net periodic benefit cost during the 2016 fiscal year is \$3.2 million.

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The compensation committee of our managing general partner (Compensation Committee) maintains a Funding and Investment Policy Statement (Policy Statement) for the Pension Plan. The Policy Statement provides that the assets of the Pension Plan be invested in a prudent manner based on the stated purpose of the Pension Plan and diversified among a broad range of investments including domestic and international equity securities, domestic fixed income securities and cash equivalents. The Pension Plan allows for the utilization of options in a collar strategy to limit potential exposure to market fluctuations. The investment goal of the Pension Plan is to ensure that the assets provide sufficient resources to meet or exceed the benefit obligations as determined under terms and conditions of the Pension Plan. The Policy Statement provides that the Pension Plan shall be funded by employer contributions in amounts determined in accordance with generally accepted actuarial standards. The investment objectives as established by the Policy Statement are, first, to increase the value of the assets under the Pension Plan and, second, to control the level of risk or volatility of investment returns associated with Pension Plan investments.

In general, increases in benefit obligations will be offset by employer contributions and market returns. However, general market conditions may result in market losses. When the Pension Plan experiences market losses, significant variations in the funded status of the Pension Plan can, and often do, occur. Actuarial methods utilized in determining required future employer contributions take into account the long-term effect of market losses and result in increased future employer contributions, thus offsetting such market losses. Conversely, the long-term effect of market gains will result in decreased future employer contributions. Total account performance is reviewed at least annually, using a dynamic benchmark approach to track investment performance.

The Compensation Committee has selected an investment manager to implement the selection and on-going evaluation of Pension Plan investments. The investments shall be selected from the following assets classes (which may include mutual funds, collective funds, or the direct investment in individual stocks, bonds or cash equivalent investments): (a) money market accounts, (b) U.S. Government bonds, (c) corporate bonds, (d) large, mid, and small capitalization stocks, and (e) international stocks. The Policy Statement provides the following guidelines and limitations, subject to exceptions authorized by the Compensation Committee: (i) the maximum investment in any one stock should not exceed 10.0% of the total stock portfolio, (ii) the maximum investment in any one industry should not exceed 30.0% of the total stock portfolio, and (iii) the average credit quality of the bond portfolio should be at least AA with a maximum amount of non-investment grade debt of 10.0%.

The Policy Statement s asset allocation guidelines are as follows:

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

Domestic equity securities primarily include investments in individual common stocks or registered investment companies that hold positions in companies that are based in the U.S. Foreign equity securities primarily include investments in individual common stocks or registered investment companies that hold positions in companies based outside the U.S. Fixed income securities primarily include individual bonds or registered investment companies that hold positions in U.S. Treasuries, U.S. government obligations, corporate bonds, mortgage-backed securities, and preferred stocks. Short-term market conditions may result in actual asset allocations that fall outside the minimum or maximum guidelines reflected in the Policy Statement.

Asset allocations as of December 31,

2015

2014

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Domestic equity securities	70%	71%
Foreign equity securities	10%	8%
Fixed income securities/cash	20%	21%
	100%	100%

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We consider multiple factors in our investment strategy. The following factors have been taken into consideration with respect to the Pension Plan's long-term investment goals and objectives and in the establishment of the Pension Plan's target investment allocation:

- The long-term nature of providing retirement income benefits to Pension Plan participants;
- The projected annual funding requirements necessary to meet the benefit obligations;
- The current level of benefit payments to Pension Plan participants and beneficiaries; and
- Ongoing analysis of economic conditions and investment markets.

The following information discloses the fair values of our Pension Plan assets, by asset category, for the periods indicated:

	December 31, 2015			December 31, 2014		
	Level 1 (a)	Level 2 (a)	Level 3 (a)	Level 1 (a)	Level 2 (a)	Level 3 (a)
			(in thousands)			
Cash and cash equivalents	\$ 883	\$ -	\$ -	\$ 917	\$ -	\$ -
Equity securities (b):						
U.S. large-cap growth	17,977	-	-	19,147	-	-
U.S. large-cap value	17,635	-	-	19,196	-	-
U.S. small/mid-cap blend	7,609	-	-	8,681	-	-
International large-cap core	3,257	-	-	2,934	-	-
Fixed income securities:						
U.S. Treasury securities (c)	1,234	-	-	1,455	-	-
Corporate bonds (d)	-	1,938	-	-	1,802	-
Preferred stock	-	-	-	-	61	-
Taxable municipal bonds (d)	-	182	-	-	193	-
International bonds (d)	-	319	-	-	227	-
Equity mutual funds (e):						
U.S. mid-cap growth	-	4,948	-	-	2,537	-
International	-	3,322	-	-	2,856	-
Fixed income mutual funds (e):						
Corporate bond	-	4,668	-	-	4,729	-
Mortgage backed-securities	-	1,277	-	-	1,226	-
Short term investment grade bond	-	1,322	-	-	1,417	-
Intermediate investment grade bond	-	801	-	-	1,013	-
High yield bond	-	693	-	-	689	-
International bond	-	226	-	-	296	-
Stock market index options (f):						
Puts	143	-	-	111	-	-
Calls	(54)	-	-	(40)	-	-
Accrued income (g)	-	65	-	-	74	-
Total	\$ 48,684	\$ 19,761	\$ -	\$ 52,401	\$ 17,120	\$ -

(a) See Note 2 Summary of Significant Accounting Policies Fair Value Measurements for more information regarding the definitions of fair value hierarchy levels.

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- (b) Equity securities include investments in publicly traded common stock and preferred stock. Publicly-traded common stocks are traded on a national securities exchange and investments in common and preferred stocks are valued using quoted market prices multiplied by the number of shares owned.
- (c) U.S. Treasury securities include agency and treasury debt. These investments are valued using dealer quotes in an active market.
- (d) Bonds are valued utilizing a market approach that includes various valuation techniques and sources such as value generation models, broker quotes in active and non-active markets, benchmark yields and securities, reported trades, issuer spreads, and/or other applicable reference data. The corporate bonds and notes category is primarily comprised of U.S. dollar denominated, investment grade securities. Less than 5 percent of the securities have a rating below investment grade.
- (e) Mutual funds are valued daily in actively traded markets by an independent custodian for the investment manager. For purposes of calculating the value, portfolio securities and other assets for which market quotes are readily available are valued at market value. Market value is generally determined on a basis of last reported sales prices, or if no sales are reported, based on quotes obtained from a quotation reporting system, established market makers, or pricing services. Investments initially valued in currencies other than the U.S. dollars are converted to the U.S. dollar using exchange rates obtained from pricing services.
- (f) Options are valued utilizing quotes in active markets.
- (g) Accrued income represents dividends declared, but not received, on equity securities owned at December 31, 2015 and 2014.

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15. COMPENSATION PLANS

Long-Term Incentive Plan

We have the LTIP for certain employees and officers of MGP and its affiliates who perform services for us. The LTIP awards are grants of non-vested phantom or notional units, which upon satisfaction of vesting requirements, entitle the LTIP participant to receive ARLP common units. Annual grant levels and vesting provisions for designated participants are recommended by the President and Chief Executive Officer of MGP, subject to review and approval of the Compensation Committee.

On January 22, 2016, the Compensation Committee determined that the vesting requirements for the 2013 grants of 284,272 restricted units (which was net of 9,178 forfeitures) had been satisfied as of January 1, 2016. As a result of this vesting, on February 11, 2016, we issued 176,319 unrestricted common units to the LTIP participants. The remaining units were settled in cash to satisfy the individual statutory minimum tax obligations of the LTIP participants. On January 26, 2015, the Compensation Committee determined that the vesting requirements for the 2012 grants of 202,778 restricted units (which was net of 11,450 forfeitures) had been satisfied as of January 1, 2015. As a result of this vesting, on February 11, 2015, we issued 128,150 unrestricted common units to the LTIP participants. The remaining units were settled in cash to satisfy the individual statutory minimum tax obligations of the LTIP participants.

On January 22, 2016, the Compensation Committee authorized additional grants of 969,028 restricted units, of which 959,028 units were granted. During the years ended December 31, 2015 and 2014, we issued grants of 303,165 units and 356,154 units, respectively. Grants issued during the year ended December 31, 2015 vest on January 1, 2018. Grants issued during the year ended December 31, 2014 vest on January 1, 2017. Vesting of all grants is subject to the satisfaction of certain financial tests, which management currently believes is probable. As of December 31, 2015, 12,976 of these outstanding LTIP grants have been forfeited. After consideration of the January 1, 2016 vesting and subsequent issuance of 176,319 common units, 3.8 million units remain available for issuance in the future, assuming that all grants issued in 2015 and 2014 and currently outstanding are settled with common units, without reduction for tax withholding, and no future forfeitures occur.

For the years ended December 31, 2015, 2014 and 2013, our LTIP expense was \$11.2 million, \$9.6 million and \$7.4 million, respectively. The total obligation associated with the LTIP as of December 31, 2015 and 2014 was \$21.4 million and \$17.9 million, respectively, and is included in the partners' capital *Limited partners-common unitholders* line item in our consolidated balance sheets.

The fair value of the 2015, 2014 and 2013 grants is based upon the intrinsic value at the date of grant, which was \$37.18, \$40.72 and \$31.51 per restricted unit, respectively, on a weighted-average basis. We expect to settle the non-vested LTIP grants by delivery of ARLP common units, except for the portion of the grants that will satisfy the minimum statutory tax withholding requirements. As provided under the distribution equivalent rights provision of the LTIP and the terms of the LTIP awards, all non-vested grants include contingent rights to receive quarterly cash distributions in an amount or, in the case of the 2016 grants, in the discretion of the Compensation Committee, phantom units credited to a bookkeeping account with value, equal to the cash distribution we make to unitholders during the vesting period.

A summary of non-vested LTIP grants as of and for the year ended December 31, 2015 is as follows:

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Non-vested grants at January 1, 2015	843,340
Granted	303,165
Vested	(202,778)
Forfeited	(3,934)
Non-vested grants at December 31, 2015	939,793

As of December 31, 2015, there was \$12.1 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 1.5 years. As of December 31, 2015, the intrinsic value of the non-vested LTIP grants was \$12.7 million.

Table of Contents*SERP and Directors Deferred Compensation Plan*

We utilize the SERP to provide deferred compensation benefits for certain officers and key employees. All allocations made to participants under the SERP are made in the form of phantom ARLP units. The SERP is administered by the Compensation Committee.

Our directors participate in the Deferred Compensation Plan. Pursuant to the Deferred Compensation Plan, for amounts deferred either automatically or at the election of the director, a notional account is established and credited with notional common units of ARLP, described in the plan as phantom units.

For both the SERP and Deferred Compensation Plan, when quarterly cash distributions are made with respect to ARLP common units, an amount equal to such quarterly distribution is credited to each participant's notional account as additional phantom units. All grants of phantom units under the SERP and Deferred Compensation Plan vest immediately.

For the years ended December 31, 2015 and 2014, SERP and Deferred Compensation Plan participant notional account balances were credited with a total of 60,160 and 27,577 phantom units, respectively, and the fair value of these phantom units was \$21.38 and \$44.56, respectively, on a weighted-average basis. Total SERP and Deferred Compensation Plan expense was approximately \$1.3 million, \$1.2 million and \$1.2 million for the years ended December 31, 2015, 2014 and 2013, respectively.

As of December 31, 2015, there were 429,141 total phantom units outstanding under the SERP and Deferred Compensation Plan and the total intrinsic value of the SERP and Deferred Compensation Plan phantom units was \$5.8 million. As of December 31, 2015 and 2014, the total obligation associated with the SERP and Deferred Compensation Plan was \$13.8 million and \$12.6 million, respectively, and is included in the partners' capital *Limited partners-common unitholders* line item in our consolidated balance sheets. On February 11, 2016, we issued 9,922 ARLP common units to a director under the Deferred Compensation Plan.

16. SUPPLEMENTAL CASH FLOW INFORMATION

	2015	Year Ended December 31,		2013
		2014		
		(in thousands)		
Cash Paid For:				
Interest	\$ 30,438	\$ 34,005	\$	35,362
Income taxes	\$ 21	\$ -	\$	-
Non-Cash Activity:				
Accounts payable for purchase of property, plant and equipment	\$ 12,634	\$ 15,654	\$	17,924
Assets acquired by capital lease	\$ 99,543	\$ -	\$	-
Market value of common units vested in Long-Term Incentive Plan and Deferred Compensation Plan before minimum statutory tax withholding requirements	\$ 7,389	\$ 8,417	\$	8,583

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Acquisition of businesses:

Fair value of assets assumed, net of cash acquired	\$	519,384	\$	-	\$	-
Contingent consideration		(20,907)		-		-
Settlement of pre-existing relationships		(124,379)		-		-
Previously held equity-method investment		(122,764)		-		-
Cash paid, net of cash acquired		(74,953)		-		-
Fair value of liabilities assumed	\$	176,381	\$	-	\$	-
Disposition of property, plant and equipment:						
Net change in assets	\$	-	\$	846	\$	-
Book value of liabilities transferred		-		(5,246)		-
Gain recognized	\$	-	\$	(4,400)	\$	-

17. ASSET RETIREMENT OBLIGATIONS

The majority of our operations are governed by various state statutes and the Federal Surface Mining Control and Reclamation Act of 1977, which establish reclamation and mine closing standards. These regulations require, among

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other things, restoration of property in accordance with specified standards and an approved reclamation plan. We account for our asset retirement obligations by recognizing the fair value of the liability in the period in which it is incurred. We have estimated the costs and timing of future asset retirement obligations escalated for inflation, then discounted and recorded at the present value of those estimates. Federal and state laws require bonds to secure our obligations to reclaim lands used for mining and are typically renewable on a yearly basis. As of December 31, 2015 and 2014, we had approximately \$153.5 million and \$142.3 million, respectively, in surety bonds outstanding to secure the performance of our reclamation obligations.

The impact of discounting our estimated cash flows resulted in reducing the accrual for asset retirement obligations by \$104.8 million and \$88.8 million at December 31, 2015 and 2014, respectively. Estimated payments of asset retirement obligations as of December 31, 2015 are as follows:

Year Ending December 31,	(in thousands)	
2016	\$	1,251
2017		1,073
2018		4,582
2019		4,832
2020		5,093
Thereafter		211,654
Aggregate undiscounted asset retirement obligations		228,485
Effect of discounting		(104,800)
Total asset retirement obligations		123,685
Less: current portion		(1,251)
Asset retirement obligations	\$	122,434

The following table presents the activity affecting the asset retirement and mine closing liability:

	Year ended December 31,	
	2015	2014
	(in thousands)	
Beginning balance	\$ 93,140	\$ 82,898
Accretion expense	3,192	2,730
Payments	(519)	(1,134)
Assumption of existing liability	31,372	6,042
Disposition	-	(5,246)
Allocation of liability associated with acquisitions, mine development and change in assumptions	(3,500)	7,850
Ending balance	\$ 123,685	\$ 93,140

For the year ended December 31, 2015, the increase in the total liability was primarily attributable to the acquisition of additional property with certain existing reclamation liabilities (See Note 3 – Acquisitions). The allocation of liability associated with mine development and change in assumptions was a net decrease of \$3.5 million. This decrease was primarily attributable to decreased estimates of reclamation requirements at

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property of our subsidiary, Rough Creek Mining, LLC, offset by increased refuse site reclamation acreage and material required at Pattiki, along with updated estimates at all other operations, offset in part by the net impact of overall general changes in inflation and discount rates, current estimates of the costs and scope of remaining reclamation work, reclamation work completed and fluctuations in other projected mine life estimates.

For the year ended December 31, 2014, the allocation of liability associated with acquisition, mine development and change in assumptions was a net increase of \$7.9 million. This increase was attributable to increased size of refuse sites primarily at our Onton, Gibson South, Tunnel Ridge, Dotiki and River View operations, offset in part by the net impact of overall general changes in inflation and discount rates, current estimates of the costs and scope of remaining

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reclamation work, reclamation work completed and fluctuations in other projected mine life estimates. The increase in the total liability was also attributed to the acquisition of additional property with certain existing reclamation liabilities (Note 3 Acquisitions), offset in part by the sale of property associated with the Pontiki mine.

18. ACCRUED WORKERS COMPENSATION AND PNEUMOCONIOSIS BENEFITS

Certain of our mine operating entities are liable under state statutes and the Federal Coal Mine Health and Safety Act of 1969, as amended, to pay pneumoconiosis, or black lung, benefits to eligible employees and former employees and their dependents. In addition, we are liable for workers compensation benefits for traumatic injuries. Both black lung and traumatic claims are covered through our self-insured programs.

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

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. Workers compensation laws also compensate survivors of workers who suffer employment related deaths. Our liability for traumatic injury claims is the estimated present value of current workers compensation benefits, based on our actuarial estimates. Our actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including claim development patterns, mortality, medical costs and interest rates. The discount rate used to calculate the estimated present value of future obligations for black lung was 4.16%, 3.82% and 4.69% at December 31, 2015, 2014 and 2013, respectively, and for workers compensation was 3.63%, 3.41% and 4.11% at December 31, 2015, 2014 and 2013, respectively.

The black lung and workers compensation expense consists of the following components for the year ended December 31, 2015, 2014 and 2013:

	2015		2014		2013
			(in thousands)		
Black lung benefits:					
Service cost	\$ 3,081	\$	3,424	\$	3,810
Interest cost	2,094		2,262		2,253
Net amortization	(451)		(1,051)		670
Total black lung	4,724		4,635		6,733
Workers compensation expense (benefit)	9,759		7,776		(110)
Total expense	\$ 14,483	\$	12,411	\$	6,623

The following is a reconciliation of the changes in the black lung benefit obligation recognized in AOCI for the years ended December 31, 2015, 2014 and 2013:

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	2015	2014	2013
	(in thousands)		
Net actuarial (loss) gain	\$ (750)	\$ (2,029)	\$ 16,750
Reversal of amortization item:			
Net actuarial (gain) loss	(451)	(1,051)	670
Total recognized in accumulated other comprehensive income (loss)	\$ (1,201)	\$ (3,080)	\$ 17,420

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The following is a reconciliation of the changes in workers' compensation liability (including current and long-term liability balances) at December 31, 2015 and 2014:

	2015	(in thousands)	2014
Beginning balance	\$ 57,557		\$ 62,909
Accruals	13,220		14,978
Payments	(8,906)		(10,563)
Interest accretion	1,954		2,585
Valuation gain	(9,267)		(12,352)
Ending balance	\$ 54,558		\$ 57,557

The valuation gain component of the change in benefit obligation in 2015 was primarily attributable to favorable changes in claims development and an increase in the discount rate used to calculate the estimated present value of future obligations. The 2014 valuation gain was primarily attributable to favorable reserve adjustments for claims incurred in prior years partially offset by a decrease in the discount rate used to calculate the estimated present value of future obligations.

The following is a reconciliation of the changes in black lung benefit obligations at December 31, 2015 and 2014:

	2015	(in thousands)	2014
Benefit obligations at beginning of year	\$ 56,386		\$ 49,560
Service cost	3,081		3,424
Interest cost	2,094		2,262
Actuarial loss	750		2,029
Acquisition	790		-
Benefits and expenses paid	(1,408)		(889)
Benefit obligations at end of year	\$ 61,693		\$ 56,386

	2015	(in thousands)	2014	2013
Amount recognized in accumulated other comprehensive income consist of:				
Net actuarial (gain) loss	\$ (4,230)		\$ (5,431)	\$ (8,511)

The actuarial loss component of the change in benefit obligations in 2015 was primarily attributable to unfavorable changes in anticipated claims development and filing assumptions and higher expected claim benefit costs partially offset by an increase in the discount rate used to calculate the estimated present value of future obligations. The actuarial loss component of the change in benefit obligations in 2014 was primarily attributable to a decrease in the discount rate used to calculate the estimated present value of future obligations as well as unfavorable changes in claims development and disability incident rate assumptions.

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Summarized below is information about the amounts recognized in the accompanying consolidated balance sheets for black lung and workers compensation benefits at December 31, 2015 and 2014:

	2015		2014
	(in thousands)		
Black lung claims	\$	61,693	\$ 56,386
Workers' compensation claims		54,558	57,557
Total obligations		116,251	113,943
Less current portion		(8,688)	(8,868)
Non-current obligations	\$	107,563	\$ 105,075

Both the black lung and workers' compensation obligations were unfunded at December 31, 2015 and 2014.

As of December 31, 2015 and 2014, we had \$90.0 million and \$79.3 million, respectively, in surety bonds and letters of credit outstanding to secure workers' compensation obligations.

19. RELATED-PARTY TRANSACTIONS

The board of directors of our managing general partner (Board of Directors) and its conflicts committee (Conflicts Committee) review our related-party transactions that involve a potential conflict of interest between a general partner and ARLP or its subsidiaries or another partner to determine that such transactions reflect market-clearing terms and conditions customary in the coal industry. As a result of these reviews, the Board of Directors and the Conflicts Committee approved each of the transactions described below that had such potential conflict of interest as fair and reasonable to us and our limited partners.

White Oak On September 22, 2011, we entered into the Initial Transactions (See Note 12 Equity Investments) with White Oak and related entities to support development of a longwall mining operation. The Initial Transactions and subsequent transactions with White Oak involved several components, including an equity investment containing certain distribution and liquidation preferences, the acquisition and lease-back of certain reserves and surface rights which generated royalties of \$11.4 million, \$0.2 million and \$15.0 thousand in 2015, 2014 and 2013, respectively, a coal handling and services agreement which generated throughput revenues of \$28.2 million, \$19.6 million and \$2.1 million in 2015, 2014 and 2013, respectively, a coal supply agreement, export marketing and transportation agreements and certain debt agreements. On July 31, 2015 we purchased the remaining equity interests in White Oak. See Note 3 Acquisitions for a detailed discussion of this acquisition.

In addition to the agreements discussed above, White Oak also had agreements with our subsidiaries for the purchase of various services and products, including for coal handling services provided by our Mt. Vernon transloading facility. For the years ended December 31, 2015, 2014

and 2013, we recorded revenues of \$4.6 million, \$3.9 million and \$2.4 million, respectively, for services and products provided by Mt. Vernon and Matrix Design to White Oak, which are included in *Other sales and operating revenues* on our consolidated statements of income.

SGP Land In 2001, SGP Land, as successor in interest to an unaffiliated third party, entered into an amended mineral lease with MC Mining. Under the terms of the lease, MC Mining has paid and will continue to pay an annual minimum royalty of \$0.3 million until \$6.0 million of cumulative annual minimum and/or earned royalty payments have been paid. As of December 31, 2015, the cumulative annual minimum was met. MC Mining paid royalties of \$1.9 million, \$0.9 million and \$0.3 million for the years ended December 31, 2015, 2014 and 2013, respectively. As of December 31, 2015, all advanced minimum royalties paid under the lease have been recouped.

SGP In January 2005, we acquired Tunnel Ridge from ARH. In connection with this acquisition, we assumed a coal lease with SGP. Under the terms of the lease, Tunnel Ridge has paid and will continue to pay an annual minimum royalty of \$3.0 million until the earlier of January 1, 2033 or the exhaustion of the mineable and merchantable leased coal. Tunnel Ridge paid advance minimum royalties of \$3.0 million during each of the years ended December 31, 2015,

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2014 and 2013. As of December 31, 2015, \$5.5 million of advance minimum royalties paid under the lease is available for recoupment and management expects that it will be recouped against future production.

WKY CoalPlay In February 2015, WKY CoalPlay entered into a coal lease agreement with Alliance Resource Properties regarding coal reserves located in Henderson and Union Counties, Kentucky. The lease has an initial term of 20 years and provides for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of \$2.1 million. All annual minimum royalty payments are recoupable against earned royalty payments. Alliance Resource Properties also was granted an option to acquire the leased reserves at any time during a three-year period beginning in February 2018 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the lease (See Note 11 Variable Interest Entities). We paid WKY CoalPlay \$2.1 million in February 2015 for the initial annual minimum royalty payment.

In December 2014, WKY CoalPlay's subsidiary, Towhead Coal Reserves, LLC, entered into a coal lease agreement with Alliance Resource Properties regarding coal reserves located in Henderson and Union Counties, Kentucky. The lease has an initial term of 20 years and provides for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of \$3.6 million. All annual minimum royalty payments are recoupable against earned royalty payments. Alliance Resource Properties also was granted an option to acquire the leased reserves at any time during a three-year period beginning in December 2017 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the leases (See Note 11 Variable Interest Entities). We paid WKY CoalPlay \$3.6 million in January 2015 for the initial annual minimum royalty payment.

In December 2014, WKY CoalPlay's subsidiary, Webster Coal Reserves, LLC, entered into a coal lease agreement with Alliance Resource Properties regarding coal reserves located in Webster County, Kentucky. The lease has an initial term of 7 years and provides for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of \$2.6 million. All annual minimum royalty payments are recoupable against earned royalty payments. Alliance Resource Properties also was granted an option to acquire the leased reserves at any time during a three-year period beginning in December 2017 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the leases (See Note 11 Variable Interest Entities). We paid WKY CoalPlay \$2.6 million in January 2015 for the initial annual minimum royalty payment.

In December 2014, WKY CoalPlay's subsidiary, Henderson Coal Reserves, LLC, entered into a coal lease agreement with Alliance Resource Properties regarding coal reserves located in Henderson County, Kentucky. The lease has an initial term of 20 years and provides for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of \$2.5 million. All annual minimum royalty payments are recoupable against earned royalty payments. Alliance Resource Properties also was granted an option to acquire the leased reserves at any time during a three-year period beginning in December 2017 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the leases (See Note 11 Variable Interest Entities). We paid WKY CoalPlay \$2.5 million in January 2015 for the initial annual minimum royalty payment.

As of December 31, 2015, we had \$10.8 million of advanced royalties outstanding with WKY CoalPlay which is reflected in the *Advance royalties* line item in our consolidated balance sheets.

Cavalier Minerals As discussed in Note 11 Variable Interest Entities, we consolidate Cavalier Minerals which holds limited partner interests in the AllDale Minerals entities, which were created to purchase oil and gas mineral interests in various geographical locations within producing basins in the continental U.S. As of December 31, 2014, Cavalier Minerals had contributed \$11.6 million to AllDale Minerals. During the year ended December 31, 2015, Cavalier Minerals contributed an additional \$54.3 million bringing the total investment in AllDale Minerals to \$65.9 million as of December 31, 2015. See Note 12 Equity Investments for further information.

Mineral Lending See Note 7 Long-Term Debt for discussion of the Cavalier Credit Agreement and Mineral Lending.

Table of Contents**20. COMMITMENTS AND CONTINGENCIES**

Commitments We lease buildings and equipment under operating lease agreements that provide for the payment of both minimum and contingent rentals. We also have a noncancelable lease with SGP (See Note 19 Related-Party Transactions) and a noncancelable lease for equipment under a capital lease obligation. In 2015, we acquired equipment and other assets under operating and capital lease agreements as a result of the Hamilton and Patriot acquisitions (See Note 3 Acquisitions). Future minimum lease payments are as follows:

Year Ending December 31,	Capital Lease	Other Operating Leases		Total
		Affiliate	Others	
			(in thousands)	
2016	\$ 24,138	\$ 240	\$ 15,107	\$ 15,347
2017	23,572	-	11,334	11,334
2018	23,521	-	9,372	9,372
2019	39,716	-	5,371	5,371
2020	690	-	1,239	1,239
Thereafter	-	-	-	-
Total future minimum lease payments	\$ 111,637	\$ 240	\$ 42,423	\$ 42,663
Less: amount representing interest	(11,723)			
Present value of future minimum lease payments	99,914			
Less: current portion	(19,764)			
Long-term capital lease obligation	\$ 80,150			

As a result of the idling of our Onton mine, we have removed certain rental payments currently under negotiation from the table above (See Note 4 Long-Lived Asset Impairments). Rental expense (including rental expense incurred under operating lease agreements) was \$11.7 million, \$4.7 million and \$5.1 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Contractual Commitments In connection with planned capital projects, we have contractual commitments of approximately \$28.7 million at December 31, 2015. As of December 31, 2015, we had no material commitments to purchase coal from external production sources in 2016.

On November 10, 2014, Cavalier Minerals purchased equity interests in AllDale Minerals, an entity created to purchase oil and gas mineral interests in various geographic locations within producing basins in the continental U. S. Cavalier Minerals has an investment funding commitment to AllDale Minerals of \$83.1 million at December 31, 2015, which it expects to fund over the next two years. For more information on Cavalier Minerals and AllDale Minerals, see Note 11 Variable Interest Entities and Note 12 Equity Investments.

On October 29, 2015, we entered into a sale-leaseback transaction whereby we sold certain mining equipment for \$100.0 million and concurrently entered into a lease agreement for the sold equipment with a four-year term. Under the lease agreement, we will pay an initial monthly rent of \$1.9 million. A balloon payment equal to 20% of the equipment cost is due at the end of the lease term. As a result of this

transaction, we recognized a deferred gain of \$5.0 million which will be amortized over the lease term. We have recognized this transaction as a capital lease and it is reflected in the future minimum lease payments presented above.

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

Other Effective October 1, 2015, we renewed our annual property and casualty insurance program. In an effort to reduce cost, our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance. Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased

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reinsurance for the program in the standard market. The maximum limit in the commercial property program is \$100.0 million per occurrence, excluding a \$1.5 million deductible for property damage, a 75, 90 or 120 day waiting period for underground business interruption depending on the mining complex and an additional \$10.0 million overall aggregate deductible. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future.

21. CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS

We have significant long-term coal supply agreements, some of which contain prospective price adjustment provisions designed to reflect changes in market conditions, labor and other production costs and, in the infrequent circumstance when the coal is sold other than free on board the mine, changes in transportation rates. Total revenues from major customers, including transportation revenues, which are at least ten percent of total revenues, are as follows:

	Segment	2015	Year Ended December 31,		2013
			2014	(in thousands)	
Customer A	Illinois Basin	\$ 343,483	\$ 301,191		\$ 319,932
Customer B	Illinois Basin	305,048	276,094		263,582

Trade accounts receivable from these customers totaled approximately \$37.5 million and \$43.5 million at December 31, 2015 and 2014, respectively. Our bad debt experience has historically been insignificant. Financial conditions of our customers could result in a material change to our bad debt expense in future periods. The coal supply agreements expire in 2018 for customer A and 2016 for customer B.

22. SEGMENT INFORMATION

We operate in the eastern U.S. as a producer and marketer of coal to major utilities and industrial users. We aggregate multiple operating segments into two reportable segments: Illinois Basin and Appalachia and an all other category referred to as Other and Corporate. Our reportable segments correspond to major coal producing regions in the eastern U.S. Similar economic characteristics for our operating segments within each of these two reportable segments generally include coal quality, geology, coal marketing opportunities, mining and transportation methods and regulatory issues.

As a result of acquiring the remaining equity interests in White Oak (the mining complex is now known as Hamilton Mine No. 1) (Note 3 Acquisitions), we restructured our reportable segments to include Hamilton as part of our Illinois Basin segment due to the similarities in product, management, location, and operation with other mines included in the segment. This new organization reflects how our chief operating decision maker manages and allocates resources to our various operations. Prior periods have been recast to include White Oak in our Illinois Basin segment.

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The Illinois Basin reportable segment is comprised of multiple operating segments, including Webster County Coal's Dotiki mining complex, Gibson County Coal's mining complex, which includes the Gibson North mine and Gibson South mine, Hopkins County Coal's mining complex, which includes the Elk Creek mine, White County Coal's Pattiki mining complex, Warrior's mining complex, Sebree Mining's mining complex, which includes the Onton mine, Steamport and certain Sebree Reserves, River View's mining complex and the Hamilton County Coal mining complex. In April 2014, production began at the Gibson South mine. Illinois Basin reserves and other assets increased as a result of multiple acquisitions in 2014 and 2015 as discussed in Note 3 Acquisitions. The Elk Creek mine is currently expected to cease production in early 2016. The Sebree Mining and Fies properties are held by us for future mine development. During the fourth quarter of 2015, we idled our Onton and Gibson North mines in response to market conditions and continued increases in coal inventories at our mines and customer locations.

The Appalachia reportable segment is comprised of multiple operating segments, including the Mettiki mining complex, the Tunnel Ridge mining complex and the MC Mining mining complex. The Mettiki mining complex includes Mettiki Coal (WV)'s Mountain View mine and Mettiki Coal's preparation plant. During the fourth quarter 2015, we surrendered the Penn Ridge leases as they were no longer a core part of our foreseeable development plans. See Note 4 Long-Lived Asset Impairment for further discussion of this surrender. In June 2013, Alliance Resource Properties

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acquired reserves that extended the life of the Mettiki (WV) Mountain View mine. For information regarding the reserves acquired, see Note 3 Acquisitions.

Other and Corporate includes marketing and administrative expenses, ASI and its subsidiary, Matrix Design and its subsidiaries Matrix Design International, LLC and Matrix Design Africa (PTY) LTD, Alliance Design (collectively, the Matrix Design entities and Alliance Design are referred to as the Matrix Group), ASI's ownership of aircraft, our Mt. Vernon dock activities, coal brokerage activity, MAC (Note 3 Acquisitions), certain activities of Alliance Resource Properties, the Pontiki Coal, LLC mining complex, which sold most of its assets in May 2014, Wildcat Insurance, Alliance Minerals, and its affiliate, Cavalier Minerals (Note 11 Variable Interest Entities), which holds an equity investment in AllDale Minerals (Note 12 Equity Investments), and AROP Funding (Note 7 Long-Term Debt).

Reportable segment results as of and for the years ended December 31, 2015, 2014 and 2013 are presented below.

	Illinois Basin	Appalachia	Other and Corporate (in thousands)	Elimination (1)	Consolidated
<i>Year ended December 31, 2015</i>					
Total revenues (2)	\$ 1,636,217	\$ 596,299	\$ 181,044	\$ (139,827)	\$ 2,273,733
Segment Adjusted EBITDA Expense (3)	949,271	400,681	153,720	(127,247)	1,376,425
Segment Adjusted EBITDA (4)(5)	617,148	183,908	26,189	(12,580)	814,665
Total assets (6)	1,694,044	517,972	265,661	(114,547)	2,363,130
Capital expenditures (7)	145,352	61,279	6,166	-	212,797
<i>Year ended December 31, 2014 (recast)</i>					
Total revenues (2)	\$ 1,647,694	\$ 630,452	\$ 34,090	\$ (11,515)	\$ 2,300,721
Segment Adjusted EBITDA Expense (3)	1,000,028	364,689	25,487	(8,396)	1,381,808
Segment Adjusted EBITDA (4)(5)	616,727	254,037	8,599	(3,119)	876,244
Total assets (6)	1,581,279	604,352	258,424	(158,996)	2,285,059
Capital expenditures (7)	243,167	56,840	11,462	-	311,469
<i>Year ended December 31, 2013 (recast)</i>					
Total revenues (2)	\$ 1,631,283	\$ 493,689	\$ 98,272	\$ (17,683)	\$ 2,205,561
Segment Adjusted EBITDA Expense (3)	953,798	375,923	86,864	(17,683)	1,398,902
Segment Adjusted EBITDA (4)(5)	632,175	105,123	12,278	-	749,576
Total assets (6)	1,394,592	594,466	133,915	(1,075)	2,121,898
Capital expenditures (7)	272,861	72,926	8,636	-	354,423

(1) The elimination column represents the elimination of intercompany transactions and is primarily comprised of sales from the Matrix Group and MAC to our mining operations, coal sales and purchases between operations within different segments, sales of receivables to AROP Funding and insurance premiums paid to Wildcat Insurance (2015

and 2014 only).

(2) Revenues included in the Other and Corporate column are primarily attributable to the Matrix Group revenues, Mt. Vernon transloading revenues, administrative service revenues from affiliates, MAC revenues, Wildcat Insurance revenues, brokerage sales and Pontiki's coal sales revenue (2013 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. We review Segment Adjusted EBITDA Expense per ton for cost trends.

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

	2015	Year Ended December 31, 2014 (in thousands)		2013
Segment Adjusted EBITDA Expense	\$ 1,376,425	\$ 1,381,808	\$ 1,398,902	\$ 1,398,902
Outside coal purchases	(327)	(14)	(2,030)	(2,030)
Other income	955	1,566	1,891	1,891
Operating expenses (excluding depreciation, depletion and amortization)	\$ 1,377,053	\$ 1,383,360	\$ 1,398,763	\$ 1,398,763

(4) Segment Adjusted EBITDA is defined as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes, depreciation, depletion and amortization, asset impairment charge, acquisition gain, net and general and administrative expenses. Management therefore is able 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. Consolidated Segment Adjusted EBITDA is reconciled to net income as follows:

	2015	Year Ended December 31, 2014 (in thousands)		2013
Consolidated Segment Adjusted EBITDA	\$ 814,665	\$ 876,244	\$ 749,576	\$ 749,576
General and administrative	(67,484)	(72,552)	(63,697)	(63,697)
Depreciation, depletion and amortization	(333,713)	(274,566)	(264,911)	(264,911)
Asset impairment charge	(100,130)	-	-	-
Interest expense, net	(29,694)	(31,913)	(26,082)	(26,082)
Acquisition gain, net	22,548	-	-	-
Income tax expense	(21)	-	(1,396)	(1,396)
Net income	\$ 306,171	\$ 497,213	\$ 393,490	\$ 393,490

(5) Includes equity in income (loss) of affiliates for the years ended December 31, 2015, 2014 and 2013 of \$(48.5) million, \$(16.6) million and \$(25.3) million, respectively, for the Illinois Basin segment and \$(0.5) million, \$(3) thousand and \$0.9 million, respectively, for Other and Corporate.

(6) Total assets at December 31, 2015, 2014 and 2013 include investments in affiliate of \$64.5 million, \$12.9 million and \$1.7 million, respectively, within Other and Corporate. Total assets at December 31, 2014 and 2013 include investments in affiliate of \$211.7 million and \$128.7 million, respectively, for the Illinois Basin segment.

(7) Capital expenditures shown above include funding to White Oak of \$4.1 million and \$25.3 million, for the years

ended December 31, 2014 and 2013, respectively, for the acquisition and development of coal reserves from White Oak, which is described as *Payments to affiliate for acquisition and development of coal reserves* in our consolidated statements of cash flow. Capital expenditures shown above exclude the Hamilton Acquisition on July 31, 2015, the Patriot acquisition on February 3, 2015, the MAC acquisition on January 1, 2015 and purchase of coal supply agreements from Patriot on December 31, 2014 (Note 3 Acquisitions).

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A summary of our consolidated quarterly operating results in 2015 and 2014 is as follows:

	Quarter Ended			
	March 31, 2015	June 30, 2015	September 30, 2015 (1)	December 31, 2015 (1)
	(in thousands, except unit and per unit data)			
Revenues	\$ 560,416	\$ 604,720	\$ 566,445	\$ 542,152
Income from operations	123,470	124,530	107,217	6,212
Income before income taxes	106,465	94,864	83,384	21,479
Net income of ARLP	106,480	94,864	83,379	21,475
Basic and diluted net income of ARLP per limited partner unit	\$ 0.92	\$ 0.76	\$ 0.61	\$ (0.19)
Weighted-average number of units outstanding basic and diluted	74,130,405	74,188,784	74,188,784	74,188,784

	Quarter Ended			
	March 31, 2014	June 30, 2014 (1)	September 30, 2014	December 31, 2014
	(in thousands, except unit and per unit data)			
Revenues	\$ 542,038	\$ 598,562	\$ 569,328	\$ 590,793
Income from operations	129,513	153,034	127,513	134,148
Income before income taxes	115,904	137,653	119,978	123,678
Net income of ARLP	115,904	137,653	119,978	123,694
Basic and diluted net income of ARLP per limited partner unit	\$ 1.10	\$ 1.37	\$ 1.13	\$ 1.18
Weighted-average number of units outstanding basic and diluted	73,994,866	74,060,634	74,060,634	74,060,634

(1) The comparability of our December 31, 2015 quarterly results to other quarters presented was affected by \$89.4 million of asset impairment charges relating to our Onton mine, MC Mining mine and a surrendered lease (Note 4 - Long-Lived Asset Impairments), which was partially offset by a \$22.5 million net gain relating to final business combination accounting for the Hamilton Acquisition (Note 3 - Acquisitions). An impairment charge of \$10.7 million impacted the comparability of our September 30, 2015 quarterly results to other quarters presented. The comparability of our June 30, 2014 quarterly results to other quarters presented was affected by a \$7.0 million insurance settlement related to adverse geological events at the Onton mine in 2013 and a gain of \$4.4 million recognized on the sale of Pontiki's assets.

24. SUBSEQUENT EVENTS

Other than those events described in Notes 9 and 15, there were no subsequent events.

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SCHEDULE II

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013

	Balance At Beginning of Year		Additions Charged to Income		Deductions (in thousands)		Balance At End of Year
2015							
Allowance for doubtful accounts	\$ -		\$ -		\$ -		\$ -
2014							
Allowance for doubtful accounts	\$ -		\$ -		\$ -		\$ -
2013							
Allowance for doubtful accounts	\$ -		\$ -		\$ -		\$ -

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. We maintain controls and procedures designed to provide reasonable assurance that information required to be disclosed in the reports we file with the SEC is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, 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 Exchange Act) as of December 31, 2015. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that these controls and procedures are effective as of December 31, 2015.

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

Management's Annual Report on Internal Control over Financial Reporting. Management of the ARLP Partnership is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Exchange Act. The ARLP Partnership's internal control over financial reporting is designed to provide reasonable assurance to our management and Board of Directors of our managing general partner regarding the preparation and fair presentation of published financial statements. Our controls are designed to provide reasonable assurance that the ARLP Partnership's assets are protected from unauthorized use and that transactions are executed in accordance with established authorizations and properly recorded. The internal controls are supported by written policies and are

complemented by a staff of competent business process owners and an internal auditor supported by competent and qualified external resources used to assist in testing the operating effectiveness of the ARLP Partnership's internal control over financial reporting. Management concluded that the design and operations of our internal controls over financial reporting at December 31, 2015 are effective and provide reasonable assurance the books and records accurately reflect the transactions of the ARLP Partnership.

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

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control - Integrated Framework (2013)*. Based on its assessment, management concluded that, as of December 31, 2015, the ARLP Partnership's internal control over financial reporting was effective based on those criteria, and management believes that we have no material internal control weaknesses in our financial reporting process.

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Ernst & Young LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2015, as stated in their report that is included herein.

As permitted by the SEC rules, we have excluded operations acquired on July 31, 2015 from White Oak from our evaluations of the effectiveness of internal control over financial reporting for the year ended December 31, 2015 due to the size and complexity and the limited time available to complete the evaluation. The operations excluded from our evaluation represent approximately 16.8% of our total assets at December 31, 2015 and approximately 3.4% of our total coal sales for the year ended December 31, 2015.

Changes in Internal Controls Over Financial Reporting. Other than changes that have resulted or may result from our purchase of the remaining equity of White Oak as described below, there has been no change in our internal controls over financial reporting (as defined in Rule 13a-15(f) or Rule 15d-15(f) of the Exchange Act) in the three months ended December 31, 2015 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

On July 31, 2015 (the Hamilton Acquisition Date), we acquired the remaining Series A and B Units, representing 60.0% of the voting interest in White Oak as described in Item 8. Financial Statements and Supplementary Data Note 3. Acquisitions of this Annual Report on Form 10-K. As of the Hamilton Acquisition Date, we owned 100% of the equity interests in White Oak and assumed operating control of the Hamilton Mine No. 1 and began accounting for White Oak on a consolidated basis. At this time, we continue to evaluate the business and internal controls and processes of Hamilton and are making various changes to their operating and organizational structures based on our business plan. We are in the process of implementing our internal control structure over the acquired business. We expect to complete the evaluation and integration of the internal controls and processes of Hamilton in fiscal year 2016.

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Report of Independent Registered Public Accounting Firm

The Board of Directors of Alliance Resource Management GP, LLC

and the Partners of Alliance Resource Partners, L.P.

We have audited Alliance Resource Partners, L.P.'s and subsidiaries (the Partnership) internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). The Partnership's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

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

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of White Oak Resources LLC (White Oak), which is included in the 2015 consolidated financial statements of the Partnership and constituted 16.8% and 31.4% of total and net assets, respectively, as of December 31, 2015 and 3.4% and 6.8% of revenues and net income, respectively, for the year then ended. Our audit of internal control over financial reporting of the Partnership also did not include an evaluation of the internal control over financial reporting of White Oak.

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In our opinion, Alliance Resource Partners, L.P. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Alliance Resource Partners, L.P. and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, cash flows, and partners' capital for each of the three years in the period ended December 31, 2015 and our report dated February 26, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

February 26, 2016

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ITEM 9B. OTHER INFORMATION

None.

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As is commonly the case with publicly traded limited partnerships, we are managed and operated by our managing general partner. The following table shows information for executive officers and members of the Board of Directors as of the date of the filing of this Annual Report on Form 10-K. Executive officers and directors are elected until death, resignation, retirement, disqualification, or removal.

Name	Age	Position With Our Managing General Partner
Joseph W. Craft III	65	President, Chief Executive Officer and Director
Brian L. Cantrell	56	Senior Vice President and Chief Financial Officer
R. Eberley Davis	58	Senior Vice President, General Counsel and Secretary
Robert G. Sachse	67	Executive Vice President Marketing
Charles R. Wesley	61	Executive Vice President and Director
Thomas M. Wynne	59	Senior Vice President and Chief Operating Officer
Nick Carter	69	Director and Member of Audit, Compensation and Conflicts Committees
Michael J. Hall	71	Former Director and Member of Audit* and Compensation Committees
John P. Neafsey	76	Chairman of the Board and Member of Compensation and Conflicts* Committees
John H. Robinson	65	Director and Member of Audit, Compensation* and Conflicts Committees
Wilson M. Torrence	74	Director and Member of Audit* and Compensation Committees

* Indicates Chairman of Committee

Joseph W. Craft III has been President, Chief Executive Officer and a Director since August 1999 and has indirect majority ownership of our managing general partner. Mr. Craft also serves as President, Chief Executive Officer and Chairman of the Board of Directors of AGP, the general partner of AHGP. Previously Mr. Craft served as President of MAPCO Coal Inc. since 1986. During that period, he also was Senior Vice President of MAPCO Inc. and had previously been that company's General Counsel and Chief Financial Officer. He is a former Chairman and current Board member of the National Coal Council, a Board Member of the National Mining Association, and a Director and current Chairman of American Coalition for Clean Coal Electricity (ACCCE), and has been a Director of BOK Financial Corporation (NASDAQ: BOKF) since April of 2007 and became chairman of its compensation committee

in 2014. Mr. Craft holds a Bachelor of Science degree in Accounting and a Juris Doctorate degree from the University of Kentucky. Mr. Craft also is a graduate of the Senior Executive Program of the Alfred P. Sloan School of Management at Massachusetts Institute of Technology. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Craft should serve as a Director include his long history of significant involvement in the coal industry, his demonstrated business acumen and his exceptional leadership of the Partnership since its inception.

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

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

Robert G. Sachse has been Executive Vice President since August 2000. Effective November 1, 2006, Mr. Sachse assumed responsibility for our coal marketing, sales and transportation functions. Mr. Sachse was also Vice Chairman of our managing general partner from August 2000 to January 2007. Mr. Sachse was Executive Vice President and Chief Operating Officer of MAPCO Inc. from 1996 to 1998 when MAPCO merged with The Williams Companies. Following the merger, Mr. Sachse had a two year non-compete consulting agreement with The Williams Companies. Mr. Sachse held various positions while with MAPCO Coal Inc. from 1982 to 1991, and was promoted to President of MAPCO Natural Gas Liquids in 1992. Mr. Sachse holds a Bachelor of Science degree in Business Administration from Trinity University and a Juris Doctorate degree from the University of Tulsa.

Charles R. Wesley has been a Director since January 2009 and Executive Vice President since March 2009. Mr. Wesley has served in a variety of capacities since joining the company in 1974, including as Senior Vice President Operations from August 1996 through February 2009. Mr. Wesley is a former Chairman of the Board of Directors of the Kentucky Coal Association and also has served the industry as past President of the West Kentucky Mining Institute and National Mine Rescue Association Post 11, and as a director of the Kentucky Mining Institute. Mr. Wesley holds a Bachelor of Science degree in Mining Engineering from the University of Kentucky. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Wesley should serve as a Director include his long history of significant involvement in the coal industry, his successful leadership of the Partnership's operations, and his knowledge and technical expertise in all aspects of producing and marketing coal.

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

Nick Carter became a Director in April 2015. Mr. Carter is a member of the Audit, Compensation and Conflicts Committees. Mr. Carter retired as President and Chief Operating Officer of Natural Resource Partners L.P. (NYSE: NRP) on September 1, 2014, having served in such capacities since 2002 and in other roles for NRP or its affiliates

since 1990. Prior to 1990, Mr. Carter held various positions with MAPCO Coal Corporation and was engaged in the private practice of law. Mr. Carter also serves on the board of directors, the audit committee and as chairman of the compensation committee of Community Trust Bancorp, Inc. (NASDAQ: CTBI), and as non-executive chairman of New Birmingham, Inc., a private frack sand and iron ore producer. Mr. Carter previously served as chairman of the National Council of Coal Lessors for 12 years and as chairman of the West Virginia Chamber of Commerce. He also previously served as a board member of the Kentucky Coal Association, the West Virginia Coal Association, the Indiana Coal Council, the National Mining Association, and ACCCE. Mr. Carter holds Bachelor and Juris Doctorate degrees from the University of Kentucky and a Master of Business Administration degree from the University of Hawaii. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Carter should serve as a Director include his extensive experience in the coal and energy industries and in senior corporate leadership.

Michael J. Hall became a Director in March 2003 and retired on April 23, 2015. Mr. Hall was Chairman of the Audit Committee and a member of the Compensation Committee. From March 2006 until retiring April 23, 2015, Mr. Hall also served as a Director and Chairman of the audit committee of AGP, the general partner of AHGP. Mr. Hall is Chairman of the Board of Directors of Matrix Service Company (Matrix) (NASDAQ: MTRX). Previously, Mr. Hall served as President and Chief Executive Officer of Matrix from March 2005 until he retired in November 2006. Mr. Hall also served as Vice President Finance and Chief Financial Officer, Secretary and Treasurer of Matrix from September 1998 to May 2004. Mr. Hall became a Director of Matrix in October 1998, and was elected Chairman of its Board in November 2006. Matrix is a company that provides general industrial construction and repair and maintenance

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services principally to the petroleum, petrochemical, power, bulk storage terminal, pipeline and industrial gas industries. Prior to working for Matrix, Mr. Hall was Vice President and Chief Financial Officer of Pexco Holdings, Inc., Vice President Finance and Chief Financial Officer for Worldwide Sports & Recreation, Inc., an affiliated company of Pexco, and worked for T.D. Williamson, Inc., as Senior Vice President, Chief Financial and Administrative Officer, and Director of Operations Europe, Africa and Middle East Region. Mr. Hall was a member and Chairman of the Board of Directors of Integrated Electrical Services, Inc. (NASDAQ: IESC) and served in that capacity from May 2006 to February 2011, and was a member of its audit, compensation and nominating/governance committees. Mr. Hall served as Chairman of the Board of Directors of American Performance Funds, was a member of its audit and nominating committees and served as independent trustee from July 1990 to May 2008. Mr. Hall holds a Bachelor of Science degree in Accounting from Boston College and a Master of Business Administration from Stanford University. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Hall could serve as a Director include his long history of service in senior corporate leadership positions, his significant knowledge of the energy industry, and his extensive expertise and experience in financial reporting matters gained from his service as Chief Financial Officer of a public company.

John P. Neafsey has served as Chairman of the Board of Directors since June 1996. Mr. Neafsey is also Chairman of the Conflicts Committee and a member of the Compensation Committee. Mr. Neafsey is President of JN Associates, an investment consulting firm formed in 1993. Mr. Neafsey served as President and CEO of Greenwich Capital Markets from 1990 to 1993 and as a Director since its founding in 1983. Positions that Mr. Neafsey held during a 23-year career at The Sun Company include Director; Executive Vice President responsible for Canadian operations, Sun Coal Company and Helios Capital Corporation; Chief Financial Officer; and other executive and director positions with numerous subsidiary companies. He is or has been active in a number of organizations, including the following: former Director and Chairman of the audit committee for The West Pharmaceutical Services Company and former Chairman and a member of the audit and compensation committees of Constar, Inc., former Chairman and member of the audit and compensation committees of NES Rentals, Inc., Trustee Emeritus and Presidential Counselor, Cornell University, and Overseer of Cornell-Weill Medical Center. Mr. Neafsey holds a Bachelor of Science degree in Engineering and a Master of Business Administration degree from Cornell University. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Neafsey should serve as a Director include his extensive service in senior corporate leadership positions in both the energy and financial services industries, and his technical expertise, knowledge and experience with financial markets.

John H. Robinson became a Director in December 1999. Mr. Robinson is Chairman of the Compensation Committee and a member of the Audit and Conflicts Committees. Mr. Robinson is Chairman of Hamilton Ventures, LLC. From 2003 to 2004, he was Chairman of EPC Global, Ltd., an engineering staffing company. From 2000 to 2002, he was Executive Director of Amey plc, a British business process outsourcing company. Mr. Robinson served as Vice Chairman of Black & Veatch, Inc. from 1998 to 2000. He began his career at Black & Veatch in 1973 and was a General Partner and Managing Partner prior to becoming Vice Chairman when the firm incorporated. Mr. Robinson is a Director of Coeur Mining Corporation and a member of its executive and audit committees and chairman of its compensation committee, and he is a Director of the Federal Home Loan Bank of Des Moines, also serving on its mission, member and housing committee and as chairman of its compensation committee. Mr. Robinson is also a Director of Olsson Associates. He holds Bachelor and Master of Science degrees in Engineering from the University of Kansas and is a graduate of the Owner-President-Management Program at the Harvard Business School. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Robinson should serve as a Director include his significant experience in the engineering and consulting industries, his extensive service in senior corporate leadership positions in both industries and his familiarity with financial matters.

Wilson M. Torrence became a Director in January 2007. Mr. Torrence is Chairman of the Audit Committee and a member of the Compensation Committee. Mr. Torrence retired from Fluor Corporation in 2006 as a Senior Vice President of Project Development and Investments and since that time has performed investment and business consulting services for various clients. Mr. Torrence was employed at Fluor from 1989 to 2006 where, among other roles, he was responsible for the global Project Investment and Structured Finance Group and served as Chairman of Fluor's Investment Committee. In that position, Mr. Torrence had executive responsibility for Fluor's global activities in developing and arranging third-party financing for some of Fluor's clients' construction projects. Prior to joining Fluor in 1989, Mr. Torrence was President and CEO of Combustion Engineering Corporation's Waste to Energy Division and, during that time, also served as Chairman of the Institute of Resource Recovery, a Washington-based industry advocacy organization. Mr. Torrence began his career at Mobil Oil Corporation, where he held several executive positions, including Assistant Treasurer of Mobil's International Marketing and Refining Division and Chief Financial and Planning Officer of Mobil Land Development Company. From October 2006 to March 2007, Mr. Torrence served as Chief Financial Officer and

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as a Director of Cleantech America, LLC, a private company involved in development of central station solar generating plants. Mr. Torrence holds a Bachelor and a Master of Business Administration degree from Virginia Tech University. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Torrence should serve as a Director include his extensive experience in the construction and energy businesses, his senior corporate finance-related and other leadership positions and his participation in numerous financing transactions.

Board of Directors

The leadership structure of the Board of Directors has been consistent since the Partnership's inception. The President and Chief Executive Officer is a member of the Board of Directors but is not its Chairman, and its Chairman is an independent Director. We believe this structure is appropriate for the Partnership because it allows for leadership of the Board of Directors that is independent of management, enhancing the effectiveness of the Board of Directors' oversight.

The Board of Directors generally administers its risk oversight function through the board as a whole. The President and Chief Executive Officer, who reports to the Board of Directors, and the other executives named above, who report to the President and Chief Executive Officer, have day-to-day risk management responsibilities. At the Board of Director's request, each of these executives attends the meetings of the Board of Directors, where the Board of Directors routinely receives reports on our financial results, the status of our operations and our safety performance, and other aspects of implementation of our business strategy, with ample opportunity for specific inquiries of management. In addition, management provides periodic reports of the Partnership's financial and operational performance to each member of the Board of Directors. The Audit Committee provides additional risk oversight through its quarterly meetings, where it receives a report from the Partnership's internal auditor, who reports directly to the Audit Committee, and reviews the Partnership's contingencies, significant transactions and subsequent events, among other matters, with management and our independent auditors.

The Board of Directors has selected as director nominees individuals with experience, skills and qualifications relevant to the business of the Partnership, such as experience in energy or related industries or with financial markets, expertise in mining, engineering or finance, and a history of service in senior leadership positions. The Board of Directors has not established a formal process for identifying director nominees, nor does it have a formal policy regarding consideration of diversity in identifying director nominees, but has endeavored to assemble a diverse group of individuals with the qualities and attributes required to provide effective oversight of the Partnership.

Audit Committee

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

Report of the Audit Committee

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

- filings with the SEC pursuant to the Securities Act of 1933 (the Securities Act) and the Exchange Act (i.e., Forms 10-K, 10-Q, and 8-K);
- press releases and other communications by us to the public concerning earnings, financial condition and results of operations, including changes in distribution policies or practices affecting the holders of our units, if such review is not undertaken by the Board of Directors;

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- systems of internal controls regarding finance and accounting that management and the Board of Directors have established; and
- auditing, accounting and financial reporting processes generally.

In fulfilling its oversight and other responsibilities, the Audit Committee met eight times during 2015. The Audit Committee's activities included, but were not limited to: (a) selecting the independent registered public accounting firm, (b) meeting periodically in executive session with the independent registered public accounting firm, (c) reviewing the Quarterly Reports on Form 10-Q for the three months ended March 31, June 30, and September 30, 2015, (d) performing a self-assessment of the committee, (e) reviewing the Audit Committee charter, and (f) reviewing the overall scope, plans and findings of our internal auditor. Based on the results of the annual self-assessment, the Audit Committee believes that it satisfied the requirements of its charter. The Audit Committee also reviewed and discussed with management and the independent registered public accounting firm this Annual Report on Form 10-K, including the audited financial statements.

Our independent registered public accounting firm, Ernst & Young LLP, is responsible for expressing an opinion on the conformity of the audited financial statements with GAAP. The Audit Committee reviewed with Ernst & Young LLP its judgment as to the quality, not just the acceptability, of our accounting principles and such other matters as are required to be discussed with the Audit Committee under generally accepted auditing standards.

The Audit Committee discussed with Ernst & Young LLP the matters required to be discussed by the Statement of Auditing Standards (SAS) 114, *The Auditor's Communication with Those Charged with Governance*, as may be modified or supplemented. The Audit Committee received written disclosures and the letter from Ernst & Young LLP required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent accountant's communication with the Audit Committee regarding independence, and has discussed with Ernst & Young LLP its independence from management and the ARLP Partnership.

Based on the reviews and discussions referred to above, the Audit Committee recommended to the Board of Directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2015 for filing with the SEC.

Members of the Audit Committee:

Wilson M. Torrence, Chairman

Nick Carter

John H. Robinson

Code of Ethics

We have adopted a code of ethics with which the President and Chief Executive Officer and the senior financial officers (including the principal financial officer and the principal accounting officer or controller) are expected to comply. The code of ethics is publicly available on our website under Investor Relations [at www.arlp.com](http://www.arlp.com) and is available in print without charge to any unitholder who requests it. Such requests should be directed to Investor Relations at (918) 295-7674. If any substantive amendments are made to the code of ethics or if there is a grant of a waiver, including any implicit waiver, from a provision of the code to the President and Chief Executive Officer, Chief Financial Officer, or Controller, we will disclose the nature of such amendment or waiver on our website or in a report on Form 8-K.

Communications with the Board

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

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Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act, as amended, requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC initial reports of ownership and reports or changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms they file. Based upon a review of the copies of the forms furnished to us and written representations from certain reporting persons, we believe that, other than as described below, from 2011 through 2015 none of our officers and directors were delinquent with respect to any of the filing requirements under Rule 16(a), with the following exceptions:

- Mr. Craft had a delinquent Form 4 filing on February 24, 2016 for a transaction occurring on November 10, 2011;
- Mr. Carter had a delinquent Form 3 filing on February 3, 2016 for a transaction occurring on April 23, 2015; and
- Mr. Torrence had a delinquent Form 4 filing on February 20, 2014 for a transaction occurring on February 14, 2014.

Reimbursement of Expenses of our Managing General Partner and its Affiliates

Our managing general partner does not receive any management fee or other compensation in connection with its management of us. Our managing general partner is reimbursed by us for all expenses incurred on our behalf. Please see Item 13. Certain Relationships and Related Transactions, and Director Independence *Administrative Services*.

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ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Introduction

The Compensation Committee oversees the compensation of our managing general partner's executive officers, including the President and Chief Executive Officer, our principal executive officer, the Senior Vice President and Chief Financial Officer, our principal financial officer, and the three most highly compensated executive officers in 2015, each of whom is named in the Summary Compensation Table (collectively, our Named Executive Officers). Our Named Executive Officers are employees of our operating subsidiary, Alliance Coal. Certain of our Named Executive Officers devote a portion of their time to the business of one or more related parties and, to the extent they do so, Alliance Coal is reimbursed for such services by those related parties pursuant to an administrative services agreement. Please see Item 13 Certain Relationships and Related Transactions, and Director Independence *Administrative Services*. We do not have employment agreements with any of our Named Executive Officers.

Compensation Objectives and Philosophy

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

Setting Executive Compensation

Role of the Compensation Committee

The Compensation Committee discharges the Board of Directors' responsibilities relating to our managing general partner's executive compensation program. The Compensation Committee oversees our compensation and benefit plans and policies,

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

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

Role of Executive Officers

Each year, the President and Chief Executive Officer submits recommendations to the Compensation Committee for adjustments to the salary, bonuses and long-term equity incentive awards payable to our Named Executive Officers, excluding himself. The President and Chief Executive Officer bases his recommendations on his assessment of each executive's performance, experience, demonstrated leadership, job knowledge and management skills. The Compensation

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Committee considers the recommendations of the President and Chief Executive Officer as one factor in making compensation decisions regarding our Named Executive Officers. Historically, and in 2015, the Compensation Committee and the President and Chief Executive Officer have been substantially aligned on decisions regarding compensation of the Named Executive Officers. As executive officers are promoted or hired during the year, the President and Chief Executive Officer makes compensation recommendations to the Compensation Committee and works closely with the Compensation Committee to ensure that all compensation arrangements for executive officers are consistent with our compensation philosophy and are approved by the Compensation Committee. At the direction of the Compensation Committee, the President and Chief Executive Officer and the Senior Vice President, General Counsel and Secretary attend certain meetings of the Compensation Committee.

Use of Peer Group Comparisons

The Compensation Committee believes that it is important to review and compare our performance with that of peer companies in the coal industry, and reviews the composition of the peer group annually. The peer group for 2015 included CONSOL, Arch Coal, Inc., Alpha Natural Resources Inc., Walter Energy, Inc., Westmoreland Resource Partners, L.P., Foresight Energy, L.P., and Natural Resource Partners L.P. In assessing the competitiveness of our executive compensation program for 2015, the Compensation Committee, with the assistance of the President and Chief Executive Officer, collected and analyzed peer group proxy information and developed a comparative analysis of base salaries, short-term incentives, total cash compensation, long-term incentives and total direct compensation. The Compensation Committee uses the peer group data as a point of reference for comparative purposes, but it is not the determinative factor for the compensation of our Named Executive Officers. The Compensation Committee exercises discretion in determining the nature and extent of the use of comparative pay data.

Consideration of Equity Ownership

Mr. Craft, the President and Chief Executive Officer, is evaluated and treated differently with respect to compensation than our other Named Executive Officers. Mr. Craft and related entities own significant equity positions in AHGP, which owns MGP, the IDR in ARLP and, as of December 31, 2015, 41.9% of ARLP's outstanding common units. Because of these ownership positions, the interests of Mr. Craft are directly aligned with those of our unitholders. Mr. Craft has not received an increase in base salary since 2002, has not received a bonus under our short-term incentive plan (STIP) since 2005 and did not receive any grants of LTIP awards from 2005 through 2015. For 2016, at Mr. Craft's request, his annual salary has been reduced to \$1. On January 22, 2016 the Compensation Committee approved an LTIP award for Mr. Craft that will cliff vest on January 1, 2019 provided the vesting requirement for the 2016 awards, discussed below, is met.

Compensation Components

Overview

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

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

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

Each of our Named Executive Officers also receives supplemental retirement benefits through the SERP. In addition, all executive officers are entitled to customary benefits available to our employees generally, including group medical, dental, and life insurance and participation in our profit sharing and savings plan (PSSP). Our PSSP is a defined contribution plan and includes an employer matching contribution of 75% on the first 3% of eligible compensation contributed by the employee, an employer non-matching contribution of 0.75% of eligible compensation, and an employer supplemental contribution of 5% of eligible compensation. The PSSP provides an additional means of attracting and retaining qualified employees by providing tax-advantaged opportunities for employees to save for retirement.

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Base Salary

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

Annual Cash Incentive Bonus Awards

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

The performance target historically has been EBITDA-based, with items added or removed from the EBITDA calculation to ensure that the performance target reflects the operating results of the core mining business. (EBITDA is defined as net income of ARLP before net interest expense, income taxes, depreciation, depletion and amortization and net income attributable to noncontrolling interest.) The aggregate cash available for awards under the STIP each year is dependent on our actual financial results for the year compared to the annual performance target, and it increases in relationship to our EBITDA, as adjusted, exceeding the minimum threshold. The Compensation Committee may determine satisfactory results and adjust the size of the pay-out pool in its sole discretion. In 2015, the Compensation Committee approved a minimum financial performance target of \$621.2 million in EBITDA from current operations plus net cash flow from our White Oak investments, normalized by excluding any charges for unit-based and directors' compensation and affiliate contributions, if any. The Compensation Committee later amended the performance measure to remove the net cash flow from our White Oak investments component and exclude other results attributable to White Oak, and amended the target to \$585.4 million, as a result of our acquisition of the remaining equity interests and assumption of control of White Oak on July 31, 2015. For 2015, we exceeded the minimum performance target.

Awards to our Named Executive Officers each year are determined by and in the discretion of the Compensation Committee. However, the Compensation Committee does not establish individual target payout amounts for the Named Executive Officers' STIP awards or otherwise communicate with the Named Executive Officers regarding their STIP awards or the payout amounts thereunder until the individual STIP awards are paid. As it does when reviewing base salaries, in determining individual awards under the STIP the Compensation Committee considers its assessment of the individual's performance, our financial performance, comparative compensation data of companies in our peer group and the recommendation of the President and Chief Executive Officer. The compensation expense associated with STIP awards is recognized in the year earned, with the cash awards payable in the first quarter of the following calendar year. Termination of employment of an executive officer for any reason prior to payment of a cash award will result in forfeiture of any right to the award, unless and to the extent waived by the Compensation Committee in its discretion.

The performance measure for the STIP in 2016 will be EBITDA for current operations, excluding charges for unit-based and directors compensation and affiliate contributions, if any. As discussed above, the Compensation Committee may, in its discretion, make equitable adjustments to the performance criteria under the STIP and adjust the amount of the aggregate pay-out. The Compensation Committee believes the STIP performance criteria for 2016 will be reasonably difficult to achieve and therefore support our key compensation objectives discussed above.

Equity Awards under the LTIP

Equity compensation pursuant to the LTIP is a key component of our executive compensation program. Our LTIP is sponsored by Alliance Coal. Under the LTIP, grants may be made of either (a) restricted units or (b) options to purchase common units, although to date, no grants of options have been made. The Compensation Committee has authority to determine the participants to whom restricted units are granted, the number of restricted units to be granted to each such participant, and the conditions under which the restricted units may become vested, including the duration of any vesting period. Annual grant levels for designated participants (including our Named Executive Officers) are recommended by our

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managing general partner's President and Chief Executive Officer, subject to review and approval by the Compensation Committee. Grant levels are intended to support the objectives of the comprehensive compensation package described above. The LTIP grants provide our Named Executive Officers with the opportunity to achieve a meaningful ownership stake in the Partnership, thereby assuring that their interests are aligned with our success. Even though Mr. Craft was not granted an award under the LTIP from 2005 through 2015, the Compensation Committee believes Mr. Craft's interests are directly aligned with the interests of our unitholders as a result of his ownership positions. In addition, as noted above, Mr. Craft was granted an LTIP award for 2016. There is no formula for determining the size of awards to any individual recipient and, as it does when reviewing base salaries and individual STIP payments, the Compensation Committee considers its assessment of the individual's performance, our financial performance, compensation levels at peer companies in the coal industry and the recommendation of the President and Chief Executive Officer. Amounts realized from prior grants, including amounts realized due to changes in the value of our common units, are not considered in setting grant levels or other compensation for our Named Executive Officers.

Restricted Units. Restricted units granted under the LTIP are phantom or notional units that upon vesting entitle the participant to receive an ARLP common unit. Restricted units granted under the LTIP vest at the end of a stated period from the grant date (which is currently approximately three years for all outstanding restricted units), provided we achieve an aggregate performance target for that period. However, if a grantee's employment is terminated for any reason prior to the vesting of any restricted units, those restricted units will be automatically forfeited, unless the Compensation Committee, in its sole discretion, determines otherwise. The number of units actually distributed upon satisfaction of the applicable vesting requirements is reduced to cover the minimum statutory income tax withholding requirement for each individual participant based upon the fair market value of the common units as of the date of distribution. At the Compensation Committee's discretion, grants of restricted units under the LTIP may include the contingent right to receive quarterly distributions in an amount equal to the cash distributions we make to unitholders during the vesting period (DERs). DERs are payable, in the discretion of the Compensation Committee, either in cash or in the form of additional Restricted Units credited to a book keeping account subject to the same vesting restrictions as the tandem award.

The performance target applicable to restricted unit awards under the LTIP is based on a normalized EBITDA measure, with that measure typically being similar to the STIP measure for the year of the grant. The target, however, requires achieving an aggregate performance level for the three-year period. We typically issue grants under the LTIP at the beginning of each year, with the exceptions of new employees who begin employment with us at some other time and job promotions that may occur at some other time. The compensation expense associated with LTIP grants is recognized over the vesting period in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 718, *Compensation - Stock Compensation*.

Our managing general partner's policy is to grant restricted units pursuant to the LTIP to serve as a means of incentive compensation for performance. Therefore, no consideration will be payable by the LTIP participants upon receipt of the common units. Common units to be delivered upon the vesting of restricted units may be common units we already own, common units we acquire in the open market or from any other person, newly issued common units, or any combination of the foregoing. If we issue new common units upon payment of the restricted units instead of purchasing them, the total number of common units outstanding will increase.

Grants for 2015 under the LTIP, made January 26, 2015, will cliff vest on January 1, 2018, provided we achieve a target level of aggregate EBITDA for current operations plus net cash flow from our White Oak investments, excluding any charges for unit-based and directors compensation and affiliate contributions, if any, for the period January 1, 2015 through December 31, 2017. Grants for 2016 under the LTIP, made January 22, 2016, will cliff vest on January 1, 2019, provided we achieve a target level of aggregate EBITDA for current operations, excluding any charges for unit-based and directors compensation and affiliate contributions, if any, for the period January 1, 2016 through December 31, 2018. The LTIP provides the Compensation Committee with discretion to determine the conditions for vesting (as well as all other terms and conditions) associated with any award under the plan, and to amend any of those conditions so long as an amendment does not materially reduce the benefit to the participant. The Compensation Committee believes the performance-related vesting conditions of all outstanding awards under the LTIP will be reasonably difficult to satisfy and therefore support our key compensation objectives discussed above.

Unit Options. We have not made any grants of unit options. The Compensation Committee, in the future, may decide to make unit option grants to employees and directors on terms determined by the Compensation Committee.

Grant Timing. The Compensation Committee does not time, nor has the Compensation Committee in the past timed, the grant of LTIP awards in coordination with the release of material non-public information. Instead, LTIP awards are

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granted only at the time or times dictated by our normal compensation process as developed by the Compensation Committee.

Effect of a Change in Control. Upon a change in control as defined in the LTIP, all awards outstanding under the LTIP will automatically vest and become payable or exercisable, as the case may be, in full. Please see Item 11. Executive Compensation *Potential Payments Upon a Termination or Change of Control.*

Amendments and Termination. The Board of Directors or the Compensation Committee may, in its discretion, terminate the LTIP at any time with respect to any common units for which a grant has not previously been made. Except as required by the rules of the exchange on which the common units may be listed at that time, the Board of Directors or the Compensation Committee may alter or amend the LTIP in any manner from time to time; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the affected participant. In addition, the Board of Directors or the Compensation Committee may, in its discretion, establish such additional compensation and incentive arrangements as it deems appropriate to motivate and reward our employees.

Supplemental Executive Retirement Plan

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

Under the terms of the SERP, a participant is entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to his or her percentage allocation multiplied by the sum of the participant's base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year. A participant's cumulative notional phantom unit account balance earns the equivalent of common unit distributions, which are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant's termination from employment in ARLP common units equal to the number of phantom units then credited to the participant's account, less the number of units required to satisfy our tax withholding obligations. A participant in the SERP is not entitled to an allocation for the year in which his termination from employment occurs, except as described below.

A participant in the SERP, including any of our Named Executive Officers, is entitled to receive an allocation under the SERP for the year in which his employment is terminated only if such termination results from one of the following events:

- (1) the participant's employment is terminated other than for cause ;
- (2) the participant terminates employment for good reason ;
- (3) a change of control of us or our managing general partner occurs and, as a result, the participant's employment is terminated (whether voluntary or involuntary);
- (4) death of the participant;
- (5) the participant attains (or has attained) retirement age of 65 years; or
- (6) the participant incurs a total and permanent disability, which shall be deemed to occur if the participant is eligible to receive benefits under the terms of the long-term disability program we maintain.

This allocation for the year in which a participant's termination occurs shall equal the participant's eligible compensation for such year (including any severance amount, if applicable) multiplied by his percentage allocation under the SERP, reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year.

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Other Compensation-Related Matters

Trading in Derivatives

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

Tax Deductibility of Compensation

The deduction limitations imposed under Section 162(m) of the Internal Revenue Code do not apply to compensation paid to our Named Executive Officers because we are a limited partnership and not a corporation within the meaning of Section 162(m).

Perquisites and Personal Benefits

The Partnership provides a limited amount of perquisites and personal benefits to the Named Executive Officers in keeping with the Compensation Committee's objectives to provide competitive compensation to motivate and reward executive officers for creating sustainable, capital-efficient growth in available cash. These perquisites and personal benefits typically include amounts for items such as tax preparation fees and social club dues, and are reviewed annually by the Compensation Committee.

Compensation Committee Report

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

Our Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis contained in this Annual Report on Form 10-K with management. Based on our Compensation Committee's review of and the discussions with management with respect to the Compensation Discussion and Analysis, our Compensation Committee recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

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

Members of the Compensation Committee:

John H. Robinson, Chairman

Nick Carter

John P. Neafsey

Wilson M. Torrence

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

The comparative unit amounts and unit prices reflected in the following tables have been adjusted for the two-for-one unit split completed on June 16, 2014.

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Summary Compensation Table

Name and Principal Position	Year	Salary (2)	Bonus (1)	Unit Awards (3)	Option Awards (1)	Non-Equity Incentive Plan Compensation (4)	Change in Pension Value and	All Other Compensation (5)	Total
							Nonqualified Deferred Compensation Earnings (1)		
Joseph W. Craft III, President, Chief Executive Officer and Director	2015	\$ 341,267	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 478,458	\$ 819,725
	2014	334,828	-	-	-	-	-	409,828	744,656
	2013	334,828	-	-	-	-	-	372,326	707,154
Brian L. Cantrell, Senior Vice President - Chief Financial Officer	2015	289,462	-	499,239	-	218,600	-	96,941	1,104,242
	2014	282,096	-	607,401	-	412,500	-	87,592	1,389,589
	2013	275,000	-	451,664	-	370,000	-	65,901	1,162,565
R. Eberley Davis Senior Vice President, General Counsel and Secretary	2015	331,250	-	584,590	-	246,500	-	114,783	1,277,123
	2014	321,827	-	775,808	-	465,000	-	102,304	1,664,939
	2013	310,000	-	494,707	-	415,000	-	84,432	1,304,139
Robert G. Sachse, Executive Vice President-Marketing	2015	329,212	-	748,895	-	245,000	-	150,441	1,473,548
	2014	320,250	-	880,992	-	511,500	-	136,627	1,849,369
	2013	310,000	-	572,411	-	465,000	-	124,128	1,471,539
Thomas M. Wynne, Senior Vice President and Chief Operating Officer	2015	381,192	-	708,023	-	285,300	-	103,191	1,477,706
	2014	370,827	-	856,968	-	538,500	-	106,226	1,872,521
	2013	359,000	-	651,186	-	400,000	-	74,427	1,484,613

(1) Column is not applicable.

(2) Certain of our Named Executive Officers devote a portion of their time to the business of one or more related parties and, to the extent they do so, the base salary of those executive officers is reimbursed to Alliance Coal by those related parties pursuant to an administrative services agreement. Please see Item 1. Business Employees *Administrative Services Agreement*. In 2015, 2014 and 2013, the percentage of base salary reimbursed to Alliance Coal was 5% for Mr. Craft, 4% for Mr. Cantrell and 8% for Mr. Davis.

(3) The Unit Awards represent the aggregate grant date fair value of equity awards granted (computed in accordance with FASB ASC 718) to each Named Executive Officer under the LTIP in the respective year. Please see Item 11. Compensation Discussion and Analysis Compensation Program Components *Equity Awards under the LTIP*.

(4) Amounts represent the STIP bonus earned for the respective year. STIP payments are made in the first quarter of the year following the year in which they are earned. Other than this bonus, there were no other applicable bonuses earned or deferred associated with year 2015. Please see Item 11. Compensation Discussion and Analysis Compensation Program Components *Annual Cash Incentive Bonus Awards*.

(5) For all Named Executive Officers, the amounts represent the sum of the (a) SERP phantom unit contributions valued at the market closing price of our common units on the date the phantom unit was granted, (b) profit sharing savings plan employer contribution and (c) perquisites in excess of \$10,000. A reconciliation of the amounts shown is as follows:

Year	SERP	Profit Sharing Plan Employer Contribution	Perquisites (a)	Total
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Joseph W. Craft III	2015	\$ 445,785	\$ 21,200	\$ 11,473	\$ 478,458
	2014	389,028	20,800	-	409,828
	2013	341,873	20,400	10,053	372,326
Brian L. Cantrell	2015	64,765	21,200	10,976	96,941
	2014	56,307	20,800	10,485	87,592
	2013	45,501	20,400	-	65,901
R. Eberley Davis	2015	93,583	21,200	-	114,783
	2014	81,504	20,800	-	102,304
	2013	64,032	20,400	-	84,432
Robert G. Sachse	2015	118,363	21,200	10,878	150,441
	2014	103,941	20,800	11,886	136,627
	2013	78,228	20,400	25,500	124,128
Thomas M. Wynne	2015	81,991	21,200	-	103,191
	2014	66,581	20,800	18,845	106,226
	2013	54,027	20,400	-	74,427

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a) For Mr. Craft, the 2015 amount includes perquisites and other personal benefits comprised of club dues of \$11,473. For Mr. Cantrell, the 2015 amount includes perquisites and other personal benefits totaling \$10,976 comprised of club dues of \$9,701 and tax preparation fees of \$1,275. For Mr. Sachse, the 2015 amount includes perquisites and other personal benefits comprised of club dues of \$10,878.

Grants of Plan-Based Awards Table

Name	Grant Date	Approved Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards		Estimated Future Payouts Under Equity Incentive Plan Awards		Number of Units (3)	All Other Awards: Securities Options (1)	All Other Option Awards: or Base Price of Options Awards (1)	Grant Date Fair Value of Unit Awards (5)
			Threshold (9)	Target (8)	Maximum (9)	Threshold (4)				
Joseph W. Craft III	February 13, 2015	(6), (7)					-	2,668		\$ 104,826
	May 15, 2015	(6), (7)					-	3,199		104,351
	August 14, 2015	(6), (7)					-	4,488		111,347
	November 13, 2015	(6), (7)					-	5,462		103,232
	December 31, 2015	(7)		\$ -			-	1,633		22,029
				-		-	17,450		445,785	
Brian L. Cantrell	February 5, 2015	February 5, 2015				13,424		-		499,239
	February 13, 2015	(6), (7)					-	187		7,347
	May 15, 2015	(6), (7)					-	224		7,307
	August 14, 2015	(6), (7)					-	314		7,790
	November 13, 2015	(6), (7)					-	382		7,220
	December 31, 2015	(7)					-	2,602		35,101
	February 11, 2016		218,600			-	-			-
			218,600			13,424		3,709		564,004
R. Eberley Davis	February 5, 2015	February 5, 2015				15,719		-		584,590
	February 13, 2015	(6), (7)					-	215		8,447
	May 15, 2015	(6), (7)					-	258		8,416
	August 14, 2015	(6), (7)					-	362		8,981
	November 13, 2015	(6), (7)					-	440		8,316
	December 31, 2015	(7)					-	4,405		59,423

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	February 11, 2016	246,500	-	-	-
		246,500	15,719	5,680	678,173
Robert G. Sachse	February 5, 2015	February 5, 2015	20,137	-	748,895
	February 13, 2015	(6), (7)	-	288	11,316
	May 15, 2015	(6), (7)	-	346	11,287
	August 14, 2015	(6), (7)	-	485	12,033
	November 13, 2015	(6), (7)	-	590	11,151
	December 31, 2015	(7)	-	5,380	72,576
	February 11, 2016	245,000	-	-	-
		245,000	20,137	7,089	867,258
Thomas M. Wynne	February 5, 2015	February 5, 2015	19,038	-	708,023
	February 13, 2015	(6), (7)	-	242	9,508
	May 15, 2015	(6), (7)	-	290	9,460
	August 14, 2015	(6), (7)	-	406	10,073
	November 13, 2015	(6), (7)	-	494	9,337
	December 31, 2015	(7)	-	3,233	43,613
	February 11, 2016	285,300	-	-	-
		\$285,300	19,038	4,665	\$ 790,014

(1) Column not applicable.

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

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

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

(5) We calculated the fair value of LTIP awards using a value of \$37.19 per unit, the unit price applicable for 2015 grants. We calculated the fair value of SERP phantom unit awards using the market closing price on the date the phantom unit award was granted. Phantom units granted under the SERP vest on the date granted.

(6) In accordance with the provisions of the SERP, a participant's cumulative notional phantom unit account balance earns the equivalent of common unit distributions when we pay a distribution to our common unitholders, which is added to the account balance in the form of phantom units.

(7) These contributions are made in accordance with the SERP plan document that has been approved by the Compensation Committee. Therefore, these contributions are not separately approved by the Compensation Committee.

(8) These amounts represent awards pursuant to our STIP. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Annual Cash Incentive Bonus Awards* for additional information regarding the STIP awards.

(9) Awards under our STIP are subject to a minimum financial performance target each year. However, determination of individual awards under the STIP is based upon an assessment of the Named Executive Officer's performance, comparative compensation data of companies in our peer group and recommendation of the President and Chief Executive Officer. The STIP does not specify any threshold or maximum payout amounts. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Annual Cash Incentive Bonus Awards* for additional information regarding the STIP awards.

Annual Cash Incentive Bonus Awards

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

Long-Term Incentive Plan

Under the LTIP, grants may be made of either (a) restricted units or (b) options to purchase common units, although to date, no grants of options have been made. Annual grant levels for designated participants (including our Named Executive Officers) are recommended by our managing general partner's President and Chief Executive Officer, subject to the review and approval of the Compensation Committee. Restricted units granted under the LTIP are phantom or notional units that upon vesting entitle the participant to receive an ARLP unit. Restricted units granted under the LTIP vest at the end of a stated period from the grant date (which is currently approximately three years for all outstanding restricted units), provided

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we achieve an aggregate performance target for that period. The performance target is based on a normalized EBITDA measure, with that measure typically being similar to the STIP measure for the year of the grant. The target, however, requires achieving an aggregate performance level for the three-year period. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*.

Supplemental Executive Retirement Plan

Under the terms of the SERP, participants are entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to his or her percentage allocation multiplied by the sum of base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year. A participant's cumulative notional phantom unit account balance earns the equivalent of common unit distributions. The calculated distributions are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant's termination or death in ARLP common units equal to the number of phantom units then credited to the participant's account, subject to reduction of the number of units distributed to cover withholding obligations. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Supplemental Executive Retirement Plan*.

Salary and Bonus in Proportion to Total Compensation

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

Name	Year	Salary and Bonus (\$)	Total Compensation (\$)	Salary and Bonus as a % of Total Compensation
Joseph W. Craft III	2015	\$ 341,267	\$ 819,725	41.6%
	2014	334,828	744,656	45.0%
	2013	334,828	707,154	47.3%
Brian L. Cantrell	2015	289,462	1,104,242	26.2%
	2014	282,096	1,389,589	20.3%
	2013	275,000	1,162,565	23.7%
R. Eberley Davis	2015	331,250	1,277,123	25.9%
	2014	321,827	1,664,939	19.3%
	2013	310,000	1,304,139	23.8%
Robert G. Sachse	2015	329,212	1,473,548	22.3%
	2014	320,250	1,849,369	17.3%
	2013	310,000	1,471,539	21.1%
Thomas M. Wynne	2015	381,192	1,477,706	25.8%
	2014	370,827	1,872,521	19.8%

2013	359,000	1,484,613	24.2%
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Name	Number of Securities Underlying Unexercised Options Exercisable (1)	Number of Securities Underlying Unexercised Options Unexercisable (1)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Options (1)	Option Exercise Price (1)	Option Expiration Date (1)	Market Value of Units That Have Not Vested (1)	Equity Incentive Plan Awards:	
							Number of Units or Other Rights That Have Vested (2)	Market or Payout Value of Unearned Units or Other Rights That Have Not Vested (3)
Joseph W. Craft III							-	\$ -
Brian L. Cantrell							42,726	576,374
R. Eberley Davis							50,537	681,744
Robert G. Sachse							60,013	809,575
Thomas M. Wynne							60,822	820,489

(1) Column is not applicable.

(2) Amounts represent restricted units awarded under the LTIP that were not vested as of December 31, 2015. Subject to our achieving financial performance targets, the units vested, or will vest, as follows: For Mr. Cantrell, 14,334 on January 1, 2016, 14,968 units on January 1, 2017 and 13,424 on January 1, 2018; Mr. Davis, 15,700 on January 1, 2016, 19,118 units on January 1, 2017 and 15,719 on January 1, 2018; for Mr. Sachse, 18,166 on January 1, 2016, 21,710 units on January 1, 2017 and 20,137 on January 1, 2018; and for Mr. Wynne, 20,666 on January 1, 2016, 21,118 units on January 1, 2017 and 19,038 on January 1, 2018. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*. All grants of restricted units under the LTIP include the contingent right to receive quarterly cash distributions in an amount equal to the cash distributions we make to unitholders during the vesting period.

(3) Stated values are based on \$13.49 per unit, the closing price of our common units on December 31, 2015, the final market trading day of 2015.

Option Exercises and Units Vested Table

Name	Option Awards		Unit Awards	
	Number of Units Acquired on Exercise (1)	Value Realized on Exercise (1)	Number of Units Acquired on Vesting (2)	Value Realized on Vesting (2)
Joseph W. Craft III			-	\$ -
Brian L. Cantrell			9,524	411,246
R. Eberley Davis			12,880	556,158
Robert G. Sachse			11,868	512,460
Thomas M. Wynne			13,138	567,299

(1) Column is not applicable.

(2) Amounts represent the number and value of restricted units granted under the LTIP that vested in 2015. All of these units vested on January 1, 2015 and are valued at \$43.18 per unit, the closing price on January 2, 2015, the first market trading date of 2015. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Equity Awards under the LTIP*.

Table of Contents**Pension Benefits Table**

Name	Plan Name	Year	Number of Years Credited Service (1)	Present Value of Accumulated Benefit (2)	Payments During Last Fiscal Year
Joseph W. Craft III	SERP	2015		\$ 2,320,226	\$ -
Brian L. Cantrell	SERP	2015		195,470	-
R. Eberley Davis	SERP	2015		244,344	-
Robert G. Sachse	SERP	2015		320,590	-
Thomas M. Wynne	SERP	2015		251,386	-

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

(2) Amounts represent the Named Executive Officer's cumulative notional account balance of phantom units valued at \$13.49, the closing price of our common units on December 31, 2015, the final market trading day of 2015. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Supplemental Executive Retirement Plan*.

*Narrative Discussion Relating to the Pension Benefits Table for 2015**Supplemental Executive Retirement Plan*

Under the terms of the SERP, participants are entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to their percentage allocation multiplied by the sum of base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year. A participant's cumulative notional phantom unit account balance earns the equivalent of common unit distributions. The calculated distributions are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant's termination or death in ARLP common units equal to the number of phantom units then credited to the participant's account, subject to reduction of the number of units distributed to cover withholding obligations. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Supplemental Executive Retirement Plan*.

Potential Payments Upon a Termination or Change of Control

Each of our Named Executive Officers is eligible to receive accelerated vesting and payment under the LTIP and the SERP upon certain terminations of employment or upon our change in control. Upon a change of control, as defined in the LTIP, all awards outstanding under the LTIP will automatically vest and become payable or exercisable, as the case may be, in full. In this regard, all restricted periods shall terminate and all performance criteria, if any, shall be deemed to have been achieved at the maximum level. The LTIP defines a change in control as one of the following events: (1) any sale, lease, exchange or other transfer of all or substantially all of our assets or Alliance Coal's assets to any person other than a person who is our affiliate; (2) the consolidation or merger of Alliance Coal with or into another person pursuant to a transaction in which the outstanding voting interests of Alliance Coal are changed into or exchanged for cash, securities or other property, other than any such transaction where (a) the outstanding voting interests of Alliance Coal are changed into or exchanged for voting stock or interests of the surviving corporation or its parent and (b) the holders of the voting interests of Alliance Coal immediately prior to such transaction own, directly or indirectly, not less than a majority of the voting stock or interests of the surviving corporation or its parent immediately after such transaction; or (3) a person or group being or becoming the beneficial owner of more than 50% of all voting interests of Alliance Coal then outstanding.

The amounts each of our Named Executive Officers could receive under the SERP have been previously disclosed in Item 11. Pension Benefits Table for 2015 and the amounts each of the Named Executive Officers could receive under the LTIP have been previously disclosed in Item 11. Outstanding Equity Awards at Fiscal Year-End 2015 Table, in each case assuming the triggering event occurred on December 31, 2015. In addition, if a Named Executive Officer's employment were terminated as a result of one of certain enumerated events, the Named Executive Officer would

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receive an amount based on an allocation for the year of termination. Please see Item 11. Compensation Discussion and Analysis Compensation Components *Supplemental Executive Retirement Plan* for additional information regarding the enumerated events and allocation determination. The exact amount that any Named Executive Officer would receive could only be determined with certainty upon an actual termination or change in control.

Director Compensation

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

Director Compensation Table for 2015

Name	Fees earned or Paid in Cash (\$)	Unit Awards (\$)(3)(5)	Option Awards (\$)(1)	Non-Equity Incentive Plan Compensation (\$)(1)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (\$)(1)	All Other Compensation (\$)(4)	Total (\$)
Michael J. Hall (2)	\$ 26,875	\$ 22,799	\$ -	\$ -	\$ -	\$ -	\$ 49,674
John P. Neafsey	193,750	130,459	-	-	-	5,000	329,209
John H. Robinson	165,000	-	-	-	-	3,875	168,875
Wilson M. Torrence	108,125	13,869	-	-	-	2,000	123,994
Nick Carter (2)	106,882	-	-	-	-	-	106,882

(1) Column is not applicable.

(2) Mr. Hall retired from the Board of Directors and Mr. Carter was elected to the Board of Directors, in each case, in April 2015. Amounts reported in the Fees earned or Paid in Cash column represent (a) amounts earned by Mr. Hall for service from January 1, 2015 through his date of retirement and (b) amounts earned by Mr. Carter from the date of his election through December 31, 2015.

(3) Amounts represent the grant date fair value of equity awards in 2015 related to deferrals of annual retainer and distributions earned on deferred units (computed in accordance with FASB ASC 718, using the same assumptions as used for financial reporting purposes). Please see *Narrative to Director Compensation Table*, below.

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(4) All Other Compensation for Messrs. Neafsey, Robinson and Torrence includes matching charitable contributions made by us. We match individual contributions of \$25 or more to educational institutions and not-for-profit organizations on a one-to-one basis up to \$5,000 per individual, per calendar year.

(5) At December 31, 2015, each director had the following number of phantom ARLP common units credited to his notional account under the MGP's Amended and Restated Deferred Compensation Plan for Directors (Deferred Compensation Plan):

Name	Directors Deferred Compensation Plan (in Units)
Michael J. Hall	9,406
John P. Neafsey	53,924
John H. Robinson	-
Wilson M. Torrence	5,707
Nick Carter	-

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Please see Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters for information regarding our Directors' beneficial ownership of ARLP common units.

Narrative to Directors Compensation Table

Compensation for our non-employee directors includes an annual cash retainer paid quarterly in advance on a pro rata basis. The annual retainer for calendar year 2015 was \$155,000 for each director other than Mr. Hall, and \$77,500 for Mr. Hall (who also served, and received additional compensation, as a director and chairman of the audit committee of AGP, the general partner of AHGP). Mr. Hall retired from the Board of Directors and from the AGP board of directors April 23, 2015, and Mr. Torrence was elected to replace Mr. Hall as Chairman of the Audit Committee. Mr. Torrence's annual retainer was reduced to \$82,500, as he was also elected to replace Mr. Hall as a director and chairman of the audit committee of AGP, and received additional compensation for his service in those roles. Mr. Neafsey also was entitled to cash compensation of \$38,750 for service as Chairman of the Board of Directors, the Chairmen of the Compensation Committee and Audit Committee were each entitled to additional cash compensation of \$10,000. Directors have the option to defer all or part of their cash compensation pursuant to the Deferred Compensation Plan by completing an election form prior to the beginning of each calendar year. Only Mr. Hall elected to defer cash compensation in 2015 pursuant to the Deferred Compensation Plan, deferring all of his cash compensation for 2015.

Pursuant to the Deferred Compensation Plan, a notional account is established for deferred amounts of cash compensation and credited with notional common units of ARLP, described in the plan as phantom units. The number of phantom units credited is determined by dividing the amount deferred by the average closing unit price for the ten trading days immediately preceding the deferral date. When quarterly cash distributions are made with respect to ARLP common units, an amount equal to such quarterly distribution is credited to the notional account as additional phantom units. Payment of accounts under the Deferred Compensation Plan will be made in ARLP common units equal to the number of phantom units then credited to the director's account.

Directors may elect to receive payment of the account resulting from deferrals during a plan year either (a) on the January 1 on or next following their separation from service as a director or (b) on the earlier of a specified January 1 or the January 1 on or next following their separation from service. The payment election must be made prior to each plan year; if no election is made, the account will be paid on the January 1 on or next following the director's separation from service. The Deferred Compensation Plan is administered by the Compensation Committee, and the Board of Directors may change or terminate the plan at any time; provided, however, that accrued benefits under the plan cannot be impaired.

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

The Board of Directors has established a recommendation that each non-employee director should attain within five years following such person's election to the Board of Directors, and thereafter maintain during service on the Board of Directors, ownership of equity of ARLP (including phantom equity ownership under the Deferred Compensation Plan) with an aggregate value of \$220,000.

Compensation Committee Interlocks and Insider Participation

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

Table of Contents**ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS**

The following table sets forth certain information as of February 11, 2016, regarding the beneficial ownership of common units held by (a) each director of our managing general partner, (b) each executive officer of our managing general partner identified in the Summary Compensation Table included in Item 11. Executive Compensation above, (c) all such directors and executive officers as a group, and (d) each person known by our managing general partner to be the beneficial owner of 5% or more of our common units. Our managing general partner is owned by AHGP, which is reflected as a 5% common unitholder in the table below. Approximately 69% of the equity of AHGP is owned by certain parties (some of whom are current or former members of management) who may comprise a group under Rule 13d-5(b) of the Exchange Act as a result of being subject to a transfer restrictions agreement entered into in connection with the AHGP IPO. Our special general partner is a wholly owned subsidiary of ARH, which is indirectly owned by Mr. Craft and Kathleen S. Craft. The address of each of AHGP, ARH, our managing general partner, our special general partner, and unless otherwise indicated in the footnotes to the table below, each of the directors and executive officers reflected in the table below is 1717 South Boulder Avenue, Suite 400, Tulsa, Oklahoma 74119. Unless otherwise indicated in the footnotes to the table below, the common units reflected as being beneficially owned by our managing general partner S directors and Named Executive Officers are held directly by such directors and officers. The percentage of common units beneficially owned is based on 74,375,025 common units outstanding as of February 11, 2016.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Directors and Executive Officers		
Joseph W. Craft III (1)	31,447,790	42.3%
Nick Carter	3,000	*
John P. Neafsey	41,604	*
John H. Robinson	18,462	*
Wilson M. Torrence	34,796	*
Charles R. Wesley III	-	*
Brian L. Cantrell	89,155	*
R. Eberley Davis	56,487	*
Robert G. Sachse (2)	92,739	*
Thomas M. Wynne	48,734	*
All directors and executive officers as a group (10 persons)	31,832,767	42.8%
5% Common Unit Holders		
Alliance Holdings GP, L.P. (3)	31,088,338	41.8%
Energy Income Partners, LLC	4,603,237	6.2%

* Less than one percent.

(1) The common units attributable to Mr. Craft consist of (i) 357,452 common units held directly by him, (ii) 2,000 common units held by his son, and (iii) 31,088,338 common units held by AHGP. Mr. Craft is Chairman of the Board of Directors, and through his ownership of C-Holdings, LLC, the sole owner of AGP, the general partner of AHGP, and he holds, directly or indirectly, or may be deemed to be the beneficial owner of, a majority of the outstanding common units of AHGP. AHGP owned approximately 41.8% of our common units as of February 11, 2016. Mr. Craft disclaims beneficial ownership of the common units held by AHGP except to the extent of his pecuniary

interest therein.

(2) Of the common units held by Mr. Sachse, 80,123 ARLP common units are subject to a pledge agreement in favor of JPMorgan Chase Bank, N.A.

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

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Equity Compensation Plan Information

Plan Category	Number of units to be issued upon exercise/vesting of outstanding options, warrants and rights as of December 31, 2015	Weighted-average exercise price of outstanding options, warrants and rights	Number of units remaining available for future issuance under equity compensation plans as of December 31, 2015
Equity compensation plans approved by unitholders:			
Long-Term Incentive Plan	939,793	N/A	3,683,627
Equity compensation plans not approved by unitholders:			
Supplemental Executive Retirement Plan	360,104	N/A	N/A
Deferred Compensation Plan for Directors	69,037	N/A	N/A

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

In addition to the related-party transactions discussed in Item 8. Financial Statements and Supplementary Data Note 19. Related-Party Transactions, ARLP has the following additional related-party transactions:

Certain Relationships

As of December 31, 2015, AHGP owned 31,088,338 common units representing 41.9% of our common units and through its 100% ownership in MGP our IDR. In addition, our general partners own, on a combined basis, an aggregate 2% general partner interest in us, the Intermediate Partnership and the subsidiaries. MGP's ability, as managing general partner, to control us together with AHGP's ownership of 41.9% of our common units, effectively gives our managing general partner the ability to veto our actions and to control our management.

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

Related-Party Transactions

The Board of Directors and its Conflicts Committee review our related-party transactions that involve a potential conflict of interest between a general partner and ARLP or its subsidiaries or another partner to determine that such transactions reflect market-clearing terms and conditions customary in the coal industry. As a result of these reviews, the Board of Directors and the Conflicts Committee approved each of the transactions described below that had such potential conflict of interest as fair and reasonable to us and our limited partners.

Administrative Services

On April 1, 2010, effective January 1, 2010, ARLP entered into an Administrative Services Agreement with our managing general partner, our Intermediate Partnership, AHGP and its general partner AGP, and ARH II. The Administrative Services Agreement superseded a similar agreement signed in connection with the AHGP IPO in 2006. Under the Administrative Services Agreement, certain employees, including some executive officers, provide administrative services for AHGP, AGP and ARH II and their respective affiliates. We are reimbursed for services rendered by our employees on behalf of these entities as provided under the Administrative Services Agreement. We billed and recognized administrative service revenue under this agreement for the year ended December 31, 2015 of \$0.4 million from AHGP and \$0.1 million from ARH II.

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Our partnership agreement provides that our managing general partner and its affiliates be reimbursed for all direct and indirect expenses incurred or payments made on behalf of us, including, but not limited to, director fees and expenses, management's salaries and related benefits (including incentive compensation), and accounting, budgeting, planning, treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers' compensation management, legal and information technology services. Our managing general partner may determine in its sole discretion the expenses that are allocable to us. Total costs billed to us by our managing general partner and its affiliates were approximately \$0.9 million for the year ended December 31, 2015. The executive officers of our managing general partner are employees of and paid by Alliance Coal, and the reimbursement we pay to our managing general partner pursuant to the partnership agreement does not include any compensation expenses associated with them.

Managing General Partner Contribution

During December 2015, an affiliated entity controlled by Mr. Craft contributed \$1.5 million to AHGP for the purpose of funding certain of our general and administrative expenses. Upon AHGP's receipt of this contribution, it contributed the same to its subsidiary MGP, our managing general partner, which in turn contributed the same to our subsidiary, Alliance Coal. As provided under our partnership agreement, we made a special allocation to our managing general partner of certain general and administrative expenses equal to the amount of its contribution.

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SGP

We have a noncancelable lease arrangement for the Gibson North coal preparation plant and ancillary facilities with SGP. The lease arrangement is considered a capital lease based on the terms of the arrangement. Lease payments for the year ended December 31, 2015 were \$0.6 million. The lease term expires February 1, 2017, at which time we have the right to either purchase the facilities at fair market value or renew the lease for a mutually agreeable term at fair market rental value.

JC Land

Our subsidiary, ASI, has a time-sharing agreement with Mr. Craft and Mr. Craft's affiliate, JC Land, LLC (JC Land), concerning their use of aircraft owned by ASI for purposes other than our business. In accordance with the provisions of that agreement, Mr. Craft and JC Land paid ASI \$0.1 million for the year ended December 31, 2015 for use of the aircraft. In addition, Alliance Coal has a time-sharing agreement with JC Land concerning Alliance Coal's use of an airplane owned by JC Land. In accordance with the provisions of that agreement, Alliance Coal paid JC Land \$0.2 million for the year ended December 31, 2015 for use of the aircraft.

Effective August 1, 2013, Alliance Coal entered into an expense reimbursement agreement with JC Land regarding pilots hired by Alliance Coal to operate aircraft owned by ASI and JC Land. In accordance with the expense reimbursement agreement, JC Land reimburses Alliance Coal for a portion of the compensation expense for its pilots. JC Land paid us \$0.2 million in 2015 pursuant to this agreement.

Omnibus Agreement

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

Director Independence

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

All members of the Audit Committee Messrs. Torrence, Carter, and Robinson and all members of the Compensation Committee Messrs. Robinson, Carter, Neafsey and Torrence are independent directors as defined under applicable NASDAQ and Exchange Act rules. Please see Item 10. Directors, Executive Officers and Corporate Governance of the Managing General Partner Audit Committee and Item 11. Executive Compensation Compensation Discussion and Analysis.

Table of Contents**ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES**

The firm of Ernst & Young LLP is our independent registered public accounting firm. The following table sets forth fees paid to Ernst & Young LLP during the years ended December 31, 2015 and 2014:

	2015	2014
	(in thousands)	
Audit Fees (1)	\$ 960	\$ 911
Audit-related fees (2)	-	-
Tax fees (3)	290	347
All other fees	-	-
Total	\$ 1,250	\$ 1,258

(1) Audit fees consist primarily of the audit and quarterly reviews of the consolidated financial statements, but can also be related to statutory audits of subsidiaries required by governmental or regulatory bodies, attestation services required by statute or regulation, comfort letters, consents, assistance with and review of documents filed with the SEC, work performed by tax professionals in connection with the audit and quarterly reviews, and accounting and financial reporting consultations and research work necessary to comply with GAAP.

(2) Audit-related fees include fees related to acquisition due diligence and accounting consultations.

(3) Tax fees consist primarily of services rendered for tax compliance, tax advice, and tax planning.

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

Table of Contents**PART IV****ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES**

(a) (1) Financial Statements.

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

(a)(2) Financial Statement Schedule.

Schedule II Valuation and Qualifying Accounts Years ended December 31, 2015, 2014 and 2013, is set forth under Item 8. Financial Statements and Supplementary Data. All other schedules are omitted because they are not applicable or the information is shown in the financial statements or notes thereto.

(a)(3) and (c) The exhibits listed below are filed as part of this annual report.

Exhibit Number	Exhibit Description	Form	Incorporated by Reference			Filed Herewith*
			SEC File No. and Film No.	Exhibit	Filing Date	
3.1	Third Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.	8-K	000-26823 14922391	3.1	06/16/2014	
3.2	Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.	8-K	000-26823 051159681	3.1	10/27/2005	
3.3	Amended and Restated Agreement of Limited Partnership of Alliance Resource Operating Partners, L.P.	10-K	000-26823 583595	3.2	03/29/2000	
3.4	Certificate of Limited Partnership of Alliance Resource Partners, L.P.	S-1	333-78845 99630855	3.6	05/20/1999	
3.5		S-1/A	333-78845	3.8	07/23/1999	

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	Certificate of Limited Partnership of Alliance Resource Operating Partners, L.P.		99669102		
3.6	Certificate of Formation of Alliance Resource Management GP, LLC	S-1/A	333-78845	3.7	07/23/1999
			99669102		
3.7	Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC	S-3	333-85282	3.4	04/01/2002
			02596627		
3.8	Amendment No. 1 to Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC	S-3	333-85282	3.5	04/01/2002
			02596627		
3.9	Amendment No. 2 to Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC	S-3	333-85282	3.6	04/01/2002
			02596627		
3.10	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.	8-K	000-26823	3.1	08/01/2006
			06993800		
3.11	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L. P. dated October 25, 2007	10-K	000-26823	3.10	02/29/2008
			08654096		

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Exhibit Number	Exhibit Description	Form	Incorporated by Reference			Filed Herewith*
			SEC File No. and Film No.	Exhibit	Filing Date	
3.12	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., dated April 14, 2008	8-K	000-26823 08763867	3.1	04/18/2008	
4.1	Form of Common Unit Certificate (Included as Exhibit A to the Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., included in this Exhibit Index as Exhibit 3.1).	8-K	000-26823 08763867	3.1	04/18/2008	
10.1	Note Purchase Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC and the purchasers named therein.	10-K	000-26823 583595	10.2	03/29/2000	
10.2	Amendment and Restatement of Letter of Credit Facility Agreement dated October 2, 2010.	10-Q	000-26823 11823116	10.1	05/09/2011	
10.3	Letter of Credit Facility Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association.	10-Q	000-26823 1782487	10.25	11/13/2001	
10.4	First Amendment to the Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association.	10-Q	000-26823 02827517	10.32	11/14/2002	
10.5	Promissory Note Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, N.A.	10-Q	000-26823 1782487	10.26	11/13/2001	
10.6	Guarantee Agreement, dated as of October 2, 2001, between Alliance Resource GP, LLC and Bank of the Lakes, N.A.	10-Q	000-26823 1782487	10.27	11/13/2001	
10.7	Contribution and Assumption Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC, Alliance Resource Partners, L.P., Alliance Resource Operating Partners, L.P. and the other parties named therein	10-K	000-26823 583595	10.3	03/29/2000	
10.8	Omnibus Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC and Alliance Resource Partners, L.P.	10-K	000-26823 583595	10.4	03/29/2000	

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10.9(1)	Amended and Restated Alliance Coal, LLC 2000 Long-Term Incentive Plan	10-K	000-26823 04667577	10.17	03/15/2004
10.10(1)	First Amendment to the Alliance Coal, LLC 2000 Long-Term Incentive Plan	10-K	000-26823 04667577	10.18	03/15/2004
10.11(1)	Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 583595	10.12	03/29/2000
10.12(1)	Alliance Coal, LLC Supplemental Executive Retirement Plan	S-8	333-85258 02595143	99.2	04/01/2002
10.13(1)	Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors	S-8	333-85258 02595143	99.3	04/01/2002

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Exhibit Number	Exhibit Description	Form	Incorporated by Reference			Filed Herewith*
			SEC File No. and Film No.	Exhibit	Filing Date	
10.14	Guaranty by Alliance Resource Partners, L.P. dated March 16, 2012	10-Q	000-26823 12825281	10.3	05/09/2012	
10.15(2)	Base Contract for Purchase and Sale of Coal, dated March 16, 2012, between Seminole Electric Cooperative, Inc. and Alliance Coal, LLC	10-Q	000-26823 12825281	10.1	05/09/2012	
10.16(2)	Contract of Confirmation, effective March 16, 2012, between Seminole Electric Cooperative, Inc., Alliance Coal, LLC and Alliance Resource Partners, L.P.	10-Q/A	000-26823 12947715	10.2	07/05/2012	
10.17	Amended and Restated Charter for the Audit Committee of the Board of Directors dated February 23, 2009	10-K	000-26823 09647063	10.35	03/02/2009	
10.18	Second Amendment to the Omnibus Agreement dated May 15, 2006 by and among Alliance Resource Partners, L.P., Alliance Resource GP, LLC, Alliance Resource Management GP, LLC, Alliance Resource Holdings, Inc., Alliance Resource Holdings II, Inc., AMH-II, LLC, Alliance Holdings GP, L.P., Alliance GP, LLC and Alliance Management Holdings, LLC	10-Q	000-26823 061017824	10.1	08/09/2006	
10.19	Administrative Services Agreement dated May 15, 2006 among Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC, Alliance Resource Holdings II, Inc., Alliance Holdings GP, L.P. and Alliance GP, LLC	10-Q	000-26823 061017824	10.2	08/09/2006	
10.20(1)	First Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan	10-K	000-26823 07660999	10.50	03/01/2007	
10.21(1)	Second Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan	10-K	000-26823 08654096	10.50	02/29/2008	
10.22(1)	Second Amendment to the Amended and Restated Alliance Coal, LLC Long-Term Incentive Plan	10-K	000-26823 07660999	10.51	03/01/2007	
10.23(1)	Third Amendment to the Amended and Restated Alliance Coal, LLC Long-Term Incentive Plan	8-K	000-26823 091143421	10.1	10/29/2009	

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10.24(1)	First Amendment to the Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 07660999	10.52	03/01/2007
10.25(1)	Second Amendment to the Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 08654096	10.53	02/29/2008
10.26	First Amendment to the Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors	10-K	000-26823 07660999	10.53	03/01/2007
10.27	Second Amendment to the Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors	10-K	000-26823 08654096	10.55	02/29/2008

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Exhibit Number	Exhibit Description	Form	Incorporated by Reference			Filed Herewith*
			SEC File No. and Film No.	Exhibit	Filing Date	
10.28	Third Amended and Restated Credit Agreement, dated as of May 23, 2012, by and among Alliance Resource Operating Partners, L.P., as borrower, the initial lenders, initial issuing banks and swingline bank named therein, JPMorgan Chase Bank, N.A., as administrative agent, J.P. Morgan Securities, LLC, Wells Fargo Securities, LLC and Citigroup Global Markets Inc. as joint lead arrangers and joint bookrunners, Wells Fargo Bank, National Association and Citibank, N.A., as syndication agents, and the other institutions named therein as documentation agents.	8-K	000-26823 12865660	99.1	05/24/2012	
10.29	Note Purchase Agreement, 6.28% Senior Notes Due June 26, 2015, and 6.72% Senior Notes due June 26, 2018, dated as of June 26, 2008, by and among Alliance Resource Operating Partners, L.P. and various investors	8-K	000-26823 08928968	10.1	07/01/2008	
10.30	First Amendment, dated as of June 26, 2008, to the Note Purchase Agreement, dated August 16, 1999, 8.31% Senior Notes due August 20, 2014, by and among Alliance Resource Operating Partners, L.P. (as successor to Alliance Resource GP, LLC) and various investors	8-K	000-26823 08928968	10.2	07/01/2008	
10.31(1)	Third Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan	10-K	000-26823 09647063	10.52	03/02/2009	
10.32(1)	Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan dated as of January 1, 2011	10-K	000-26823 11645603	10.40	02/28/2011	
10.33(1)	Second Amendment to the Amended and Restated Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors	10-K	000-26823 09647063	10.53	03/02/2009	
10.34(1)	Amended and Restated Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors dated as of January 1, 2011	10-K	000-26823 11645603	10.42	02/28/2011	
10.35	Amendment No. 2 to Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association, dated April 13, 2009	10-Q	000-26823 09811514	10.1	05/08/2009	

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10.36(2)	Agreement for the Supply of Coal, dated August 20, 2009 between Tennessee Valley Authority and Alliance Coal, LLC	10-Q	000-26823 091164883	10.2	11/06/2009
10.37	Amended and Restated Charter for the Compensation Committee of the Board of Directors dated February 23, 2010.	10-K	000-26823 10638795	10.49	02/26/2010

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Exhibit Number	Exhibit Description	Form	Incorporated by Reference			Filed Herewith*
			SEC File No. and Film No.	Exhibit	Filing Date	
10.38	Amended and Restated Administrative Services Agreement effective January 1, 2010, among Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC, Alliance Resource Holdings II, Inc., Alliance Resource Operating Partners, L.P., Alliance Holdings GP, L.P. and Alliance GP, LLC.	10-Q	000-26823 101000555	10.1	08/09/2010	
10.39	Uncommitted Line of Credit and Reimbursement Agreement dated April 9, 2010 between Alliance Resource Partners, L.P. and Fifth Third Bank.	10-Q	000-26823 101000555	10.2	08/09/2010	
10.40	Purchase and Sale Agreement, dated as of December 5, 2014, among Alliance Resource Operating Partners, L.P., as buyer and Alliance Coal, LLC, Gibson County Coal, LLC, Hopkins County Coal, LLC, Mettiki Coal (WV), LLC, Mt. Vernon Transfer Terminal, LLC, River View Coal, LLC, Sebree Mining, LLC, Tunnel Ridge, LLC and White County Coal, LLC, as originators	8-K	000-26823 141277053	10.1	12/10/2014	
10.41	Sale and Contribution Agreement, dated as of December 5, 2014, among Alliance Resource Operating Partners, L.P., as seller and AROP Funding, LLC, as buyer	8-K	000-26823 141277053	10.2	12/10/2014	
10.42	Receivables Financing Agreement, dated as of December 5, 2014, among Borrower, PNC Bank, National Association, as administrative agent as well as the letter of credit bank, the persons from time to time party thereto as lenders, the persons from time to time party thereto as letter of credit participants, and Alliance Coal, LLC, as initial servicer	8-K	000-26823 141277053	10.3	12/10/2014	
10.43	Performance Guaranty, dated as of December 5, 2014, by AROP in favor of PNC Bank, National Association, as administrative agent	8-K	000-26823 141277053	10.4	12/10/2014	
10.44	Amendment No. 1 to the Third Amended and Restated Credit Agreement dated as of October 16, 2015.	8-K	000-26823 151170915	10.1	10/22/2015	
10.45	Master Lease Agreement, dated as of October 29, 2015, between Alliance Resource Operating Partners, L.P., Hamilton County Coal, LLC and White Oak Resources LLC, as lessees, and PNC Equipment Finance, LLC and the other lessors named therein.	8-K	000-26823 151198024	10.1	11/04/2015	

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10.46(1) The Amended and Restated Alliance Coal,
LLC Long-Term Incentive Plan as amended by
the Third Amendment and Fourth Amendment

14.1	Code of Ethics for Principal Executive Officer and Senior Financial Officers	10-K	000-26823	14.1	03/01/2013
			13656028		

21.1 List of Subsidiaries.

23.1 Consent of Ernst & Young LLP.

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Exhibit Number	Exhibit Description	Form	Incorporated by Reference			Filed Herewith*
			SEC File No. and Film No.	Exhibit	Filing Date	
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 February 26, 2016, 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 February 26, 2016, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					
32.1	Certification of Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the managing general partner of Alliance Resource Partners, L.P., dated February 26, 2016, 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 February 26, 2016, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					
95.1	Federal Mine Safety and Health Act Information					
101	Interactive Data File (Form 10-K for the year ended December 31, 2015 filed in XBRL).					

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

(1) Denotes management contract or compensatory plan or arrangement.

(2) Portions of this exhibit have been omitted pursuant to a request for confidential treatment under Rule 24b-2 of the Exchange Act, as amended, and the omitted material has been separately filed with the SEC.

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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 February 26, 2016.

ALLIANCE RESOURCE PARTNERS, L.P.

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

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

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

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

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ Joseph W. Craft III</u> Joseph W. Craft III	President, Chief Executive Officer, and Director (Principal Executive Officer)	February 26, 2016
<u>/s/ Brian L. Cantrell</u> Brian L. Cantrell	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 26, 2016
<u>/s/ Nick Carter</u> Nick Carter	Director	February 26, 2016
<u>/s/ John P. Neafsey</u> John P. Neafsey	Director	February 26, 2016
<u>/s/ John H. Robinson</u> John H. Robinson	Director	February 26, 2016

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/s/ Wilson M. Torrence

Director

February 26, 2016

Wilson M. Torrence

/s/ Charles R. Wesley

Executive Vice President and Director

February 26, 2016

Charles R. Wesley