

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.

Regions	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(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 a 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 reopener provision can also lead to early termination of a contract.

Several of our long-term contracts also contain provisions that allow the customer to suspend or terminate performance under the contract upon the occurrence or continuation of certain events that are beyond the customer's reasonable control. Such events may include labor disputes, mechanical malfunctions and changes in government regulations, including changes in 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.

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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			