Section 1: 10-K (10-K)

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2017

OR

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

FOR THE TRANSITION PERIOD FROM _____TO_____

COMMISSION FILE NO.: 0-26823

ALLIANCE RESOURCE PARTNERS, L.P.

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

DELAWARE (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:

Title of Each Class	Name of Each Exchange On Which Registered
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. [X] Yes [ ] No

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

[ ] Yes [X] No

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

Indicate by check mark 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). [X] Yes [ ] No

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

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

Large Accelerated Filer [X] Accelerated Filer [ ] Non-Accelerated Filer [ ] Smaller Reporting Company [ ]
(Do not check if smaller reporting company)

Emerging Growth Company [ ]

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. [ ]

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

The aggregate value of the common units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $807,387,739 as of June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter, based on the reported closing price of the common units as reported on The NASDAQ Stock Market LLC on such date.

As of February 23, 2018, 130,903,256 common units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: None

TABLE OF CONTENTS

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. Without limiting the foregoing, all statements relating to our future outlook, anticipated capital expenditures, future cash flows and borrowings and sources of funding are forward-looking statements. These statements reflect our current views with respect to future events and are subject to numerous assumptions that we believe are reasonable, but are open to a wide range of uncertainties and business risks, and actual results may differ materially from those discussed in these statements. Among the factors that could cause actual results to differ from those in the forward-looking statements are:

- 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 gases, 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;
- changes in oil and gas prices, which could affect our investments in oil and gas mineral interests and gas compression services;
- 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 post-mine reclamation as well as 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 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.

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, ARLP's sole general partner and, prior to the Exchange Transaction discussed below, its managing general partner.
- References to "SGP" mean Alliance Resource GP, LLC, ARLP's special general partner prior to the Exchange Transaction discussed below.
- References to "Intermediate Partnership" mean Alliance Resource Operating Partners, L.P., the intermediate partnership of Alliance Resource Partners, L.P.
- References to "Alliance Resource Properties" mean Alliance Resource Properties, LLC, the land-holding company for the mining operations of Alliance Resource Operating Partners, L.P.
- References to "Alliance Coal" mean Alliance Coal, LLC, the holding company for the mining operations of Alliance Resource Operating Partners, L.P., also referred to as our primary operating subsidiary.
- References to "AHGP" mean Alliance Holdings GP, L.P., individually as the parent company, and not on a consolidated basis.
- References to "AGP" mean Alliance GP, LLC, the general partner of Alliance Holdings GP, L.P.

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, 2017, we had approximately 1.67 billion tons of coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. In 2017, we sold 37.8 million tons of coal and produced 37.6 million tons of coal, of which 25.4% was low-sulfur coal, 39.9% was medium-sulfur coal and 34.7% was high-sulfur coal. In 2017, we sold 80.0% of our total tons to electric utilities, of which 100% was sold to utility plants with installed pollution control devices. These devices, also known as scrubbers, eliminate substantially all emissions of sulfur dioxide. Based on market expectations, we classify low-sulfur coal as coal with a sulfur content of less than 1.5%, medium-sulfur coal as coal with a sulfur content of 1.5% to 3%, and high-sulfur coal as coal with a sulfur content of greater than 3%. The BTU content of our coal ranges from 11,400 to 13,200.

We operate eight 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. In addition, we own equity interests in various oil and gas mineral interests and gas compression services in various geographic locations within producing basins in the continental U.S. 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 general partner, MGP, a Delaware limited liability company, which holds a non-economic general partner interest in ARLP, a 1.0001% general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal. AHGP is a Delaware limited partnership that was formed to become the owner and controlling member of MGP. AHGP completed its initial public offering ("AHGP IPO") on May 15, 2006 and is listed on the NASDAQ Global Select Market under the ticker symbol "AHGP." AHGP owns indirectly, 100% of the members' interest of MGP and 87,188,338 common units of ARLP's 130,704,217 outstanding common units as of December 31, 2017.

Exchange Transaction

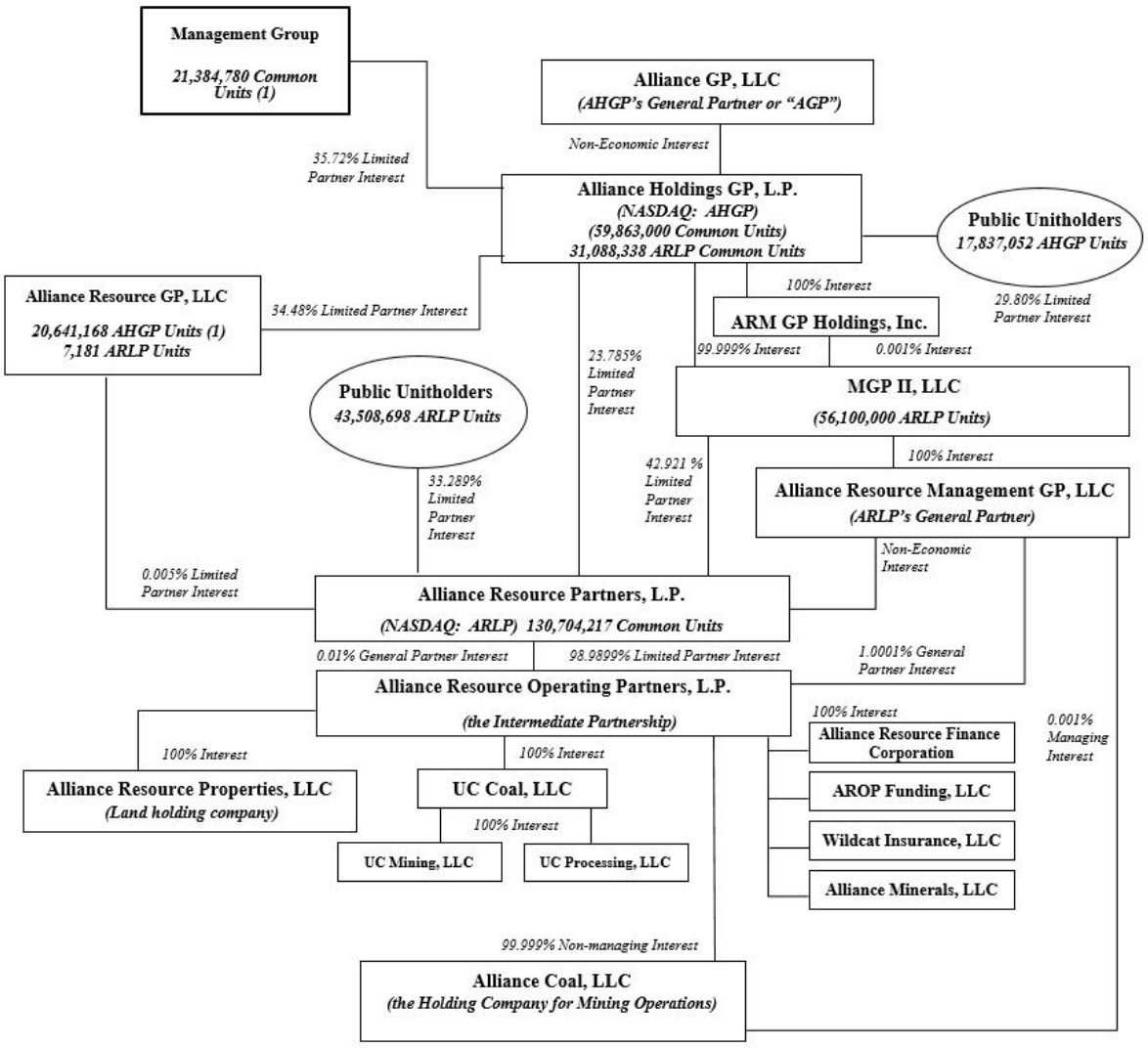
In 2017, the board of directors of our general partner ("Board of Directors") and its conflicts committee unanimously approved a transaction to simplify our partnership structure, and, on July 28, 2017, MGP contributed to ARLP all of its incentive distribution rights ("IDRs") and its 0.99% managing general partner interest in ARLP in exchange for 56,100,000 ARLP common units and a non-economic general partner interest in ARLP. In conjunction with this transaction and on the same economic basis as MGP, SGP also contributed to ARLP its 0.01% general partner interests in both ARLP and the Intermediate Partnership in exchange for 7,181 ARLP common units (collectively the "Exchange Transaction"). SGP 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 general partner, and Kathleen S. Craft. In connection with the Exchange Transaction, ARLP amended its partnership agreement to reflect, among other things, cancellation of the IDRs and the economic general partner interest in ARLP and issuance of a non-economic general partner interest to MGP. MGP is the sole general partner of ARLP following the Exchange Transaction, and no control, management or governance changes otherwise occurred.

Simultaneously with the Exchange Transaction discussed above, MGP became a wholly owned subsidiary of MGP II, LLC ("MGP II") which is owned 100% directly and indirectly by AHGP and was created in connection with the Exchange Transaction. As of December 31, 2017, MGP II held the 56,100,000 ARLP common units discussed above.

Simplification Transactions

On February 22, 2018, our Board of Directors and the board of directors of AHGP's general partner approved a simplification agreement (the "Simplification Agreement") pursuant to which, through a series of transactions (i) AHGP would become a wholly owned subsidiary of ARLP, (ii) all of the issued and outstanding AHGP common units would be canceled and converted into the right to receive all of the ARLP common units held by AHGP and its subsidiaries (collectively, the "Simplification Transactions") and (iii) MGP will remain the sole general partner of ARLP, and no control, management, or governance changes are otherwise expected to occur. The consummation of the Simplification Transactions is subject to the SEC declaring the effectiveness of a registration statement on Form S-4 under the Securities Act of 1933 to register the ARLP common units that will be distributed to former unitholders of AHGP and the affirmative vote or consent of the holders of a majority of the outstanding AHGP common units. Certain unitholders of AHGP that beneficially own a majority of the outstanding AHGP common units have entered into a unitholder support agreement pursuant to which such unitholders have agreed to execute a written consent approving the Simplification Agreement within two business days after the registration statement on Form S-4 is declared effective by the SEC.

The following diagram depicts our organization and ownership as of December 31, 2017:



(1) The AHGP units held by SGP and most of the AHGP 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.

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 and metallurgical 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.

	Year Ended December 31,				
Regions	**2017**	**2016**	**2015**	**2014**	**2013**
	(tons in millions)				
Illinois Basin	27.3	25.4	32.0	30.9	30.7
Appalachia	10.3	9.8	9.2	9.8	7.4
Other	—	—	—	—	0.7
Total	37.6	35.2	41.2	40.7	38.8

The following map shows the location of our coal mining operations:

Illinois Basin Operations:

1. HAMILTON COMPLEX
Hamilton Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Longwall
& Continuous Miner
Coal Type: Medium/High Sulfur
Transportation: Railroad,
Truck & Barge

2. RIVER VIEW COMPLEX
River View Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous
Miner
Coal Type: Medium/High Sulfur
Transportation: Barge

3. DOTIKI COMPLEX
Dotiki Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous
Miner
Coal Type: High Sulfur
Transportation: Railroad,
Truck & Barge

4. GIBSON COMPLEX
a. Gibson South Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous
Miner
Coal Type: Low/Medium Sulfur
Transportation: Railroad,
Truck & Barge

b. Gibson North Mine[1]
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous
Miner
Coal Type: Low/Medium Sulfur
Transportation: Railroad,
Truck & Barge

5. WARRIOR COMPLEX
Warrior Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous
Miner
Coal Type: Medium/High Sulfur
Transportation: Railroad,
Truck & Barge

6. SEBREE COMPLEX
Onton Mine (Idled)
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous
Miner
Coal Type: Medium/High Sulfur
Transportation: Barge & Truck

7. HENDERSON/UNION
RESERVES
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous Miner
Miner
Coal Type: Medium/High Sulfur
Transportation: Railroad
& Barge

Appalachian Operations:

8. MC MINING COMPLEX
Excel No. 4 Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous
Miner
Coal Type: Low Sulfur
Transportation: Railroad,
Truck & Barge

9. TUNNEL RIDGE COMPLEX
Tunnel Ridge Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Longwall
& Continuous Miner
Coal Type: Medium/High Sulfur
Transportation: Railroad
& Barge

10. METTIKI COMPLEX
Mountain View Mine
Mining Type: Underground
Mining Access: Slope
Mining Method: Longwall
& Continuous Miner
Coal Type: Low/Medium
Sulfur - Metallurgical
Transportation: Railroad
& Truck

Other Operations:

11. MOUNT VERNON
TRANSFER TERMINAL
Rail or Truck to Ohio River Barge
Transloading Facility

[1] Gibson North Mine is currently non-producing but is expected to resume production in 2018.

Illinois Basin Operations

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. As of January 25, 2018, we had 2,086 employees, and we operate five mining complexes in the Illinois Basin.

Hamilton Mining Complex. In July 2015, we acquired the remaining equity interest in White Oak Resources LLC ("White Oak"), thereby gaining complete ownership and control of the White Oak Mine No. 1 (now known as the Hamilton mine), located near the city of McLeansboro, Illinois ("White Oak Acquisition"). Our subsidiary, Hamilton County Coal,

LLC ("Hamilton"), operates the Hamilton mine, which is an underground longwall mining operation producing medium/high-sulfur coal from the Herrin No. 6 seam. 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 the Hamilton mine, including the preparation plant which has throughput capacity of 2,000 tons of raw coal per hour. Hamilton has the ability to ship production from the Hamilton mine via the CSX Transportation, Inc. ("CSX"), Evansville Western Railway and Norfolk Southern Railway Company ("NS") rail directly to customers or to various transloading facilities, including our Mt. Vernon Transfer Terminal, LLC ("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."

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 medium/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.

Dotiki Complex. Our subsidiary, Webster County Coal, LLC ("Webster County Coal"), operates Dotiki, which is an underground mining complex located near the city of Providence in Webster County, Kentucky. The complex was opened in 1966, and we purchased the mine in 1971. The Dotiki complex utilizes continuous mining units employing room-and-pillar mining techniques to produce high-sulfur coal. Dotiki's preparation plant has throughput capacity of 1,800 tons of raw coal per hour. Coal from the Dotiki complex is shipped via the 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 transloading facility, for barge deliveries.

Gibson Complex. Our subsidiary, Gibson County Coal, LLC ("Gibson County Coal"), operates the Gibson South mine, 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 low/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 on the CSX and NS railroads 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.

Gibson County Coal operates the Gibson North mine, an underground mine also 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 low/medium-sulfur coal. The Gibson North mine was idled in the fourth quarter of 2015 in response to market conditions but is expected to resume production in 2018.

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 medium/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 be completed during the second quarter of 2018.

Sebree Complex. On April 2, 2012, we acquired substantially all of Green River Collieries, LLC's 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"). The Onton mine was idled in the fourth quarter of 2015.

Alliance Resource Properties - Alliance Resource Properties owns or controls coal reserves that it leases to certain of our subsidiaries that operate our mining complexes.

Alliance WOR Properties, LLC. 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 medium/high-sulfur coal reserves. Prior to the White Oak Acquisition, 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 in the amount of $0.2 million were paid to WOR Properties by White Oak. Following the White Oak Acquisition, royalty activities under leases between Hamilton and Alliance Resource Properties are accounted for as intercompany transactions and are eliminated upon consolidation.

Other. In December 2014 and February 2015, WKY CoalPlay, LLC ("WKY CoalPlay"), a related party, or its subsidiaries entered into coal lease agreements with us regarding coal reserves located in Henderson and Union Counties, Kentucky ("Henderson/Union Reserves") and Webster County, Kentucky. For more information about the WKY CoalPlay transactions, please read "Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Note 18. Related-Party Transactions."

Pattiki Complex. Our subsidiary, White County Coal, LLC ("White County Coal"), operated Pattiki, an underground mining complex located near the city of Carmi in White County, Illinois. We began construction of the complex in 1980 and operated it until it ceased production in December 2016.

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") operated the Elk Creek underground mine until it ceased production on April 1, 2016.

Appalachian Operations

Our Appalachian mining operations are located in eastern Kentucky, Maryland and West Virginia. As of January 25, 2018, we had 880 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 2017 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.

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. The Tunnel Ridge preparation plant has throughput capacity of 2,000 tons of raw coal per hour. Coal produced from the Tunnel Ridge mine is a medium/high-sulfur coal and 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 and the NS.

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)"). 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 (including for shipment into the metallurgical coal market) 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.

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 with existing ground storage of approximately 60,000 to 70,000 tons. During 2017, the terminal loaded approximately 4.0 million tons for customers of Gibson County Coal and Hamilton.

Coal Brokerage

As markets allow, Alliance Coal buys coal from our mining operations and outside 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 2017, 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 mining technology products and services for our mining operations and certain industrial and mining technology products and services to third parties. Matrix Group's products and services include miner and equipment tracking systems and proximity detection systems. We acquired this business in September 2006.

Alliance Minerals

On November 10, 2014, 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 LP ("AllDale I") and subsequently acquired a 72.8% limited partner interest in AllDale Minerals II, LP ("AllDale II", collectively with AllDale I, "AllDale Minerals"). The AllDale Minerals entities were created to purchase oil and gas mineral interests in various geographic locations within producing basins in the continental U.S. As of December 31, 2017, Cavalier Minerals has contributed a total of $149.0 million to AllDale Minerals, of which $143.1 million was funded by Alliance Minerals. In February 2017, Alliance Minerals committed to directly (rather than through Cavalier Minerals) invest $30.0 million in AllDale Minerals III, LP ("AllDale III") in similar geographical locations discussed above and in 2017 invested $14.4 million in AllDale III. AllDale III, together with AllDale Minerals are considered the "AllDale Partnerships." On July 19, 2017, Alliance Minerals purchased $100 million of Series A-1 Preferred Interests from Kodiak Gas Services, LLC ("Kodiak"), a privately-held company providing large-scale, high-utilization gas compression assets to customers operating primarily in the Permian Basin. For more information about Cavalier Minerals, please read "Item 8. Financial Statements and Supplementary Data—Note 10. Variable Interest Entities." For more information about the AllDale Partnerships and Kodiak, please read "Item 8. Financial Statements and Supplementary Data—Note 11. 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 2017, outside revenues from these services were immaterial.

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 21. Segment Information" for information concerning our reportable segments.

Coal Marketing and Sales

As is customary in the coal industry, we have entered into long-term coal supply agreements with many of our customers. These arrangements are mutually beneficial to us and our customers in that they provide greater predictability of sales volumes and sales prices. Although many utility customers recently have appeared to favor a shorter-term contracting strategy, in 2017 approximately 71.7% and 74.7% 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 2018 to 2022. As of February 15, 2018, our nominal commitment under long-term contracts was approximately 34.7 million tons in 2018, 13.6 million tons in 2019, 8.5 million tons in 2020 and 1.3 million tons in 2021. 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 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

We did not derive 10.0% or more of our total revenues from any individual customer during 2017.

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 Arch Coal, Inc., CONSOL Coal Resources LP, CONSOL Energy, Inc., Contura Energy, Inc., Foresight Energy LP, Murray Energy, Inc., and Peabody Energy Corporation. While a number of our competitors have been involved in reorganization in bankruptcy, these events have not resulted in a material diminution in available coal supply and there remains 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 natural gas, nuclear energy, petroleum 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.

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 42.4% of our 2017 sales volume was initially shipped from the mines by barge, 36.6% was shipped from the mines by rail and 21.0% was shipped from the mines by truck. In 2017, the largest volume transporter of our coal shipments was the CSX railroad, which moved approximately 25.7% 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.

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.

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

- 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 increase mining costs. The second phase of the rule began in February 2016 and requires additional sampling for designated and other occupations using the new continuous personal dust monitor technology, which provides real time dust exposure information to the miner. Phase three of the rule began in August 2016, and resulted in lowering the current respirable dust level of 2.0 milligrams per cubic meter to 1.5 milligrams per cubic meter of air. Compliance with these rules can result in increased costs on our operations, including, but not limited to, the purchasing of new equipment and the hiring of additional personnel to assist with monitoring, reporting, and recordkeeping obligations.

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 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. MSHA subsequently proposed a rule requiring mine operators to also install proximity detection systems on other types of underground mobile mining equipment. The comment period for this proposed rule closed on April 10, 2017, and it is uncertain when MSHA will promulgate a final rule addressing the issue of proximity detection systems on underground mobile mining equipment, other than continuous mining machines.

In June 2016, MSHA published a request for information on Exposure of Underground Miners to Diesel Exhaust. Following a comment period that closed in November 2016, MSHA received requests for MSHA and the National Institute for Occupational Safety and Health to hold a Diesel Exhaust Partnership to address the issues covered by MSHA's request for information. The comment period for the request for information was reopened and closed in January 2018. It is uncertain whether MSHA will present a proposed rule pertaining to exposure of underground miners to diesel exhaust, after completing its evaluation of the comments received.

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. 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 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.

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 16. 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.

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 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 in December 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 issued its final Stream Protection Rule ("SPR") in December 2016 to replace the vacated SBZ rule. The rule would have generally prohibited the approval of permits issued pursuant to SMCRA where the proposed operations would result in "material damage to the hydrologic balance outside the permit area." Pursuant to the rule, permittees would have also been required to restore any perennial or intermittent streams that a permittee mined through. Finally, the rule would have also imposed additional baseline data collection, surface/groundwater monitoring, and bonding and financial assurance requirements. However, in February 2017, both the U.S. House of Representatives and the Senate passed resolutions disapproving the SPR under the Congressional Review Act ("CRA"). President Trump signed the resolution on February 16, 2017 and, pursuant to the CRA, the SPR "shall have no force or effect" and OSM cannot promulgate a substantially similar rule absent future legislation. Whether Congress will enact future legislation to require a new SPR rule remains uncertain.

Following the spill of coal combustion residues ("CCRs") in the Tennessee Valley Authority impoundment in Kingston, Tennessee, in December 2009, the U.S. Environmental Protection Agency ("EPA") issued proposed rules on CCRs in 2010. This final rule was published in December 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, but, to date, no further action has been taken. 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*."

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 completed or formally announced the retirement or conversion of over 600 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 2017, we sold 80.0% of our total tons to electric utilities, of which 100% 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 in December 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 in January 2015. In September 2016, EPA finalized the CSAPR Update to respond to the remand by the D.C. Circuit Court of Appeals. Implementation of Phase 2 began in 2017. Further litigation is expected against the CSAPR Update in the D.C. Circuit Court of Appeals. The impacts of CSAPR Update 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. In April 2014 the

D.C. Circuit Court of Appeals upheld MATS. In June 2015, the U.S. Supreme Court remanded the final rule back to the D.C. Circuit holding that the agency must consider cost before deciding whether regulation is necessary and appropriate. In December 2015, the EPA issued, for comment, the proposed Supplemental Finding. In April 2016, the EPA issued a final supplemental finding upholding the rule and concluding that a cost analysis supports the MATS rule. In April 2017, the D.C Circuit Court of Appeals granted EPA's request to cancel oral arguments and ordered the case held in abeyance for an EPA review of the supplemental finding. Many electric generators have already announced retirements due to the MATS rule. Although various issues surrounding the MATS rule remain subject to litigation in the D.C. Circuit, the 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 Update 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. In December 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. In August 2016, the D.C. Circuit Court of Appeals vacated a portion of the rule while remanding portions back to the EPA. In December 2016, the D.C. Circuit Court of Appeals agreed to the EPA request to remand the rule back to the EPA without vacatur. 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. In July 2016, EPA issued a final rule for states to use in creating their plans to address particulate matter. In October 2015, the EPA published a final rule that reduced the ozone NAAQS from 75 to 70 ppb. Murray Energy, Inc. 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 April 2017, the D.C. Court of Appeals granted EPA's request to cancel oral arguments and ordered the case held in abeyance for an EPA review of the 2015 Rule. 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. Under a consent decree published in the Federal Register in January 2017, EPA has agreed to review the NAAQS for nitrogen oxides with a final

decision due by 2018 and review the NAAQS for sulfur oxide with a final decision due by 2019. In July 2017, EPA proposed to retain the current NAAQS for nitrogen oxides. The comment period for the proposal closed in September 2017. New standards 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 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. Former President Obama 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. The United Nations Framework Convention on Climate Change met in Paris, France in December 2015 and agreed to an international climate agreement (the "Paris 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. In June of 2017, President Trump announced that the U.S. would withdraw from the Paris Agreement, which has a four year exit process. Future participation in the Paris Agreement by the U.S. remains uncertain. However, 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", which found 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 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 CO_2 BACT to apply, CAA permitting must be triggered by another regulated pollutant (e.g., SO_2).

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, 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. The EPA has also issued final rules requiring the monitoring and reporting of greenhouse gas emissions from certain sources.

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. CO_2/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. CO_2/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 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 CO_2/MWh (gross) and be constructed with CCS to capture 16% of CO_2 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. In April 2017, the EPA published notice in the federal register that the agency has initiated a review of the NSPS for new and modified fossil fuel fired power plants and that, following the review, the EPA will initiate reconsideration proceedings to suspend, revise or rescind this NSPS. Challenges to the NSPS have been filed in U.S. Court of Appeal for the D.C. Circuit and oral arguments were set for April 2017; however, in April 2017, the U.S Court of Appeal for the D.C. Circuit ordered the NSPS case held in abeyance for an EPA review of the rule. It is likely than any repeal or revisions to the NSPS will be subject to legal challenges as well. Future implementation of the NSPS is uncertain at this time.

In August 2015, the EPA issued its final Clean Power Plan ("CPP") rules that establish carbon pollution standards for power plants, called CO_2 emission performance rates. Judicial challenges led the U.S. Supreme Court to grant a stay in February 2016 of the implementation of the CPP before the United States Court of Appeals for the District of Columbia ("Circuit Court") even issued a decision. By its terms, this stay will remain in effect throughout the pendency of the appeals process including at the Circuit Court and the Supreme Court through any certiorari petition that may be granted. The Supreme Court's stay applies only to EPA's regulations for CO_2 emissions from existing power plants and will not affect EPA's standards for new power plants. It is not yet clear how either the Circuit Court or the Supreme Court will rule on the legality of the CPP. Additionally, in October 2017 EPA proposed to repeal the CPP, although the final outcome of this action and the pending litigation regarding the CPP is uncertain at this time. In connection with this proposed repeal, EPA issued an Advance Notice of Proposed Rulemaking ("ANPRM") in December 2017 regarding emission guidelines to limit GHG emissions from existing electricity utility generating units. The ANPRM seeks comment regarding what the EPA should include in a potential new, existing-source regulation under the Clean Air Act of GHG emissions from electric utility generating units that it may propose. If the effort to repeal the rules is unsuccessful and the rules were upheld at the conclusion of this appellate process and were implemented in their current form, or if the ANPRM results in a different proposal to control GHG emissions from electric utility generating units, demand for coal would likely be further decreased, potentially significantly, and our business would be adversely impacted.

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 from existing and modified power plants as proposed in the NSPS and CPP. 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 U.S. 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. In April 2017, CEQ withdrew its final 2016 guidance on how federal agencies should incorporate climate change and GHG considerations into NEPA reviews of federal actions.

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. Since its inception, several additional northeastern states and Canadian provinces have joined RGGI as participants or observers. In addition, New Jersey has announced its intention to rejoin RGGI following the change in state government administrations.

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.

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.

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 16. 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.

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 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 uncertainly with regard to our continued use of current permits, as well as impose additional time and cost burdens on future operations, potentially adversely affecting our coal revenues. In addition, the EPA initiated a preemptive veto prior to the filing of any actual permit application for a copper and gold mine based on fictitious mine scenario. The implications of this decision could allow the EPA to bypass the state permitting process and engage in watershed and land use planning.

Total Maximum Daily Load ("TMDL") regulations under the CWA establish a process to calculate the maximum amount of a pollutant that an impaired water body can receive and still meet state water quality standards, and to allocate pollutant loads among the point and non-point pollutant sources discharging into that water body. Likewise, when water quality in a receiving stream is better than required, states are required to conduct an antidegradation review before

approving discharge permits. The adoption of new TMDL-related allocations or any changes to antidegradation policies for streams near our coal mines could require more costly water treatment and could adversely affect our coal production.

Considerable legal uncertainty exists surrounding the standard for what constitutes jurisdictional waters and wetlands subject to the protections and requirements of the Clean Water Act. A 2015 rulemaking by EPA to revise the standard was stayed nationwide by the U.S. Court of Appeals for the Sixth Circuit and stayed for certain primarily western states by a United States District Court in North Dakota. In January 2018, the Supreme Court determined that the circuit courts do not have jurisdiction to hear challenges to the 2015 rule, removing the basis for the Sixth Circuit to continue its nationwide stay. Additionally, EPA has promulgated a final rule that extends the applicability date of the 2015 rule for another two years in order to allow EPA to undertake a rulemaking on the question of what constitutes a water of the United States. In the meantime, judicial challenges to the 2015 rulemaking are likely to continue to work their way through the courts along with challenges to the recent rulemaking that extends the applicability date of the 2015 rule. For now, EPA and the Corps of Engineers will continue to apply the existing standard for what constitutes a water of the United States as determined by the Supreme Court in the Rapanos case and post-Rapanos guidance. Should the 2015 rule take effect, or should a different rule expanding the definition of what constitutes a water of the United States be promulgated as a result of EPA and the Corps of Engineers' rulemaking process, we could face increased costs and delays due to additional permitting and regulatory requirements and possible challenges to permitting decisions.

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 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 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 of Subtitle D of RCRA and not the hazardous waste provisions of 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. In April 2017, EPA granted petitions for reconsideration and an administrative stay of all future compliance deadlines for the ELG rule. In August 2017, EPA granted petitions for reconsideration of the CCR rule.

Endangered Species Act

The federal 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 January 25, 2018, we employed 3,321 full-time employees, including 2,931 employees involved in active mining operations, 180 employees in other operations, and 179 corporate employees. Our work force is entirely union-free.

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 general partner, the Intermediate Partnership, 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, 2017 of $0.4 million from AHGP. Please read "Item 13—Certain Relationships and Related Transactions, and Director Independence—*Administrative Services*."

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 and investments;
- 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 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 10 – 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 general partner, without the consent of our unitholders, which will dilute your ownership interest in us and may increase the risk that we will not have sufficient available cash to maintain or increase our per unit distribution level.

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

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

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

As of December 31, 2017, AHGP owned 87,188,338 of our common units. AHGP also indirectly owns our general partner. AHGP has announced its intent to distribute our common units to the holders of its equity interests in the Simplification Transactions and those holders may dispose of some or all of these units. The sale or disposition of a substantial number of our common units by our existing unitholders 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 general partner and its owners could adversely affect our credit ratings and profile.

The credit and risk profile of our general partner or its owners may be factors in credit evaluations of us as a master limited partnership. This is because our 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 general partner or vote on our general partner's officers or directors. As of December 31, 2017, AHGP owned 66.7% of our outstanding units, a sufficient number to block any attempt to remove our general partner.

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

In addition, if our unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Our 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, 2017, AHGP owned approximately 66.7% of our outstanding units. Consequently, it is not currently possible for our 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 general partner and its affiliates, cannot be voted on any matter.

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

Our 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 general partner to sell or transfer all or part of their ownership interest in our general partner to a third party. The new owner or owners of our general partner would then be in a position to replace the directors and officers of our general partner and control the decisions made and actions taken by the Board of Directors and officers.

Unitholders may be required to sell their units to our 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 partner and its affiliates, our 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 general partner may assign this purchase right to any of its affiliates or to us.

Cost reimbursements due to our general partner 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 partner and its 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 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 18. 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 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.

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

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

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

Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates and which reduce the obligations to which our 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 partner to the limited partners. Our partnership agreement:

- permits our general partner to make a number of decisions in its "sole discretion." This entitles our 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 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 general partner may consider the interests of all parties involved, including its own. Unless our general partner has acted in bad faith, the action taken by our general partner shall not constitute a breach of its fiduciary duty; and
- provides that our general partner 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 partner 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 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 general partner to deduct from available 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 partner has conflicts of interest and limited fiduciary responsibilities, which may permit our general partner 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 partner and its affiliates, on the one hand, and us, on the other hand. As a result of these conflicts our general partner may favor its 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 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 partner's affiliates are not prohibited from engaging in other businesses or activities, including those in direct competition with us, except as provided in the omnibus agreement (please see "Item 13. Certain Relationships and Related Transactions, and Director Independence—Omnibus Agreement").
- Our 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 general partner determines whether to issue additional units or other equity securities in us.
- Our general partner determines which costs are reimbursable by us.
- Our general partner controls the enforcement of obligations owed to us by it.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

- Our 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 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. and globally 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 that affect demand for, or our ability to produce, coal;
- the proximity to and capacity of transportation facilities;
- competition from other coal suppliers;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- the effect of worldwide energy consumption, including the impact of technological advances on 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.

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. In addition, we face competition from foreign and domestic producers that sell their coal in the international coal markets. 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 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.

According to the most recent information from the Energy Information Administration, since 2000, coal's share of U.S. electricity production has fallen from 53% to 30%, while natural gas' share has increased from 16% to 32%.

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.

Future environmental regulation of GHG emissions also 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, to the extent implemented as originally finalized, the EPA's CPP could 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 several 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. 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 previously finalized an NSPS to regulate GHG emissions from new power plants; however, the EPA published notice in the federal register in April 2017 that the agency has initiated a review of the NSPS for new and modified fossil fuel fired power plants and that, following the review, the EPA will initiate reconsideration proceedings to suspend, revise or rescind this NSPS. 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, to the extent implemented as originally finalized, effectively prevents construction of new coal fired power plants. In August 2015, the EPA issued its final CPP rules that establish carbon pollution standards for existing power plants, called CO_2 emission performance rates. Judicial challenges led the U.S. Supreme Court to grant a stay in February 2016 of the implementation of the CPP before the Circuit Court even issued a decision. By its terms, this stay will remain in effect throughout the pendency of the appeals process including at the Circuit Court and the Supreme Court through any certiorari petition that may be granted. The Supreme Court's stay applies only to EPA's regulations for CO_2 emissions from existing power plants and will not affect EPA's standards for new power plants. It is not yet clear how either the Circuit Court or the Supreme Court will rule on the legality of the CPP. Additionally, in October 2017 EPA proposed to repeal the CPP,

although the final outcome of this action and the pending litigation regarding the CPP is uncertain at this time. In connection with this proposed repeal, EPA issued an ANPRM in December 2017 regarding emission guidelines to limit GHG emissions from existing electricity utility generating units. The ANPRM seeks comment regarding what the EPA should include in a potential new, existing-source regulation under the Clean Air Act of GHG emissions from electric utility generating units that it may propose. If the effort to repeal the rules is unsuccessful and the rules were upheld at the conclusion of this appellate process and were implemented in their current form, or if the ANPRM results in a different proposal to control GHG emissions from electric utility generating units, demand for coal would likely be further decreased, potentially significantly, and our business would be adversely impacted. 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 U.N. 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.

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, several major banks have enacted such policies. 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 more than 600 coal-fired electric generating units through 2030. These retirements and conversions amount to nearly 111,000 megawatts ("MW") or almost 35% of the 2010 total coal electric generating capacity. At the end of 2017 retirement and conversions affecting 69,000

MW, or approximately 22% 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 and other factors could lead to additional retirements and conversions and, thereby, additional reductions in the demand for coal.

We or our customers could be subject to 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 2017, we sold approximately 71.7% 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.

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.

While we did not have customers from which we derived 10% or more of our revenues in 2017, if we were to lose any of our significant 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. See "Item 3. Legal Proceedings."

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;
- seismic activities, ground failures, rock bursts or structural cave-ins or slides;
- 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, 2017, 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").

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.

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 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.

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.

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;
- future improvements in mining technology; 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.

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, 2017, our total long-term indebtedness outstanding was $502.4 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 an 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 after such distribution, we fail to meet a coverage test based on the ratio of our consolidated cash flow to our consolidated fixed charges.

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. Please see "Item 8. Financial Statements and Supplementary Data – Note 7. Long-Term Debt" for further discussion.

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, 2017, our total of such bonds was $268.7 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 19. Commitments and Contingencies" for further discussion.

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

We have indirect investments in oil and gas mineral interests and gas compression services in the continental U.S. Consequently, the value of the investments as well as any resulting cash flows, may fluctuate with changes in the market and prices for oil and natural gas. Since we began these investments in late 2014, the oil and natural gas industry has experienced significant fluctuations in commodity prices driven by a global supply/demand imbalance for oil and an oversupply of natural gas in the U.S. If commodity prices decline to lower levels, 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 Partnerships and Kodiak, please read "Item 8. Financial Statements and Supplementary Data—Note 11. Investments."

Terrorist attacks or cyber-incidents could result in information theft, data corruption, operational disruption and/or financial loss.

Like most companies, we have become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications and services, to operate our businesses, to process and record financial and operating data, communicate with our business partners, analyze mine and mining information, estimate quantities of coal reserves, as well as other activities related to our businesses. Strategic targets, such as energy-related assets, may be at greater risk of future terrorist or cyber-attacks than other targets in the U.S. Deliberate attacks on, or security breaches in, our systems or infrastructure, or the systems or infrastructure of third parties, or cloud-based applications could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery, difficulty in completing and settling transactions, challenges in maintaining our books and records, environmental damage, communication interruptions, other operational disruptions and third-party liability. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, results of operations and cash flows. Further, as cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents.

Risks Related to Our Proposed Simplification Transactions

The completion of the Simplification Transactions is subject to conditions.

The Simplification Agreement contains conditions, some of which are beyond the parties' control, that, if not satisfied or waived, may delay the closing of the Simplification Transactions or result in the Simplification Transactions not occurring. We cannot predict with certainty when and whether any of the conditions to the completion of the Simplification Transactions will be satisfied. Any delay in completing the Simplification Transactions could increase our cost or cause us not to realize, or delay realization of, some or all of the benefits that we expect to achieve from the Simplification Transactions. If the Simplification Transactions are not completed, we and AHGP will have incurred substantial expenses for which no ultimate benefit will have been received by either company. In addition, if the Simplification Agreement is terminated under specified circumstances, either we or AHGP will be required to pay certain expenses of the other party.

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") were to treat 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 taxable income at the corporate tax rate, 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.

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 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 applied 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. From time to time, members of Congress have proposed and considered such substantive changes to the existing federal income tax laws that affect us or all publicly traded partnerships. For example, recently enacted legislation repealed Section 199, which, prior to its repeal, entitled our unitholders to a deduction equal to a specified percentage of our qualified production activities income that was allocated to such unitholder. In addition, although there is no current legislative proposal, a prior legislative proposal would have eliminated 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.

Further, on January 24, 2017, final regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. (the "Final Regulations") were published in the Federal Register. The Final Regulations are effective as of January 19, 2017, and apply to taxable years beginning on or after January 19, 2017. We do not believe the Final Regulations affect our ability to be treated as a partnership for federal income tax purposes.

However, 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 similar or future legislative changes could negatively impact the amount of our unit distributions and the value of an investment in our units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our units.

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

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions that we take. 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 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 our cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Pursuant to the Bipartisan Budget Act of 2015, for taxable years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us. To the extent possible under the new rules,

our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties and interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to pay taxes, penalties and interest, our cash available for distribution to our unitholders may be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

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

You will be required to pay federal income taxes and, in some cases, state and local income taxes, on your share of our taxable income, whether or not you receive cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability 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.

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

Investment in our units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our units.

Non-U.S. Unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). Income allocated to our unitholders

and any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a Non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a Non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit.

The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a Non-U.S. unitholder's sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interests in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-U.S. unitholders should consult a tax advisor before investing in our units.

We treat each purchaser of our units as having the same tax benefits without regard to the units actually 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 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 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 (the "Allocation Date"), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do 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 are no specific rules governing the U.S. federal income tax consequence 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 to the short seller 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 consult a tax advisor to determine whether it is advisable 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 recognized 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.

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

In past years, members of Congress have 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.

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, even if you do not live in any of those jurisdictions. 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.

ITEM 2. PROPERTIES

Coal Reserves

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, 2017, we had approximately 1.67 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, 2017 about our coal operations:

Operations	Mine Type (1)	Heat Content (BTUs per pound)	Pounds S02 per MMBTU <1.2	1.2-2.5	>2.5	Total	Classification Proven	Probable	Reserve Assignment Assigned	Unassigned	Reserve Control Owned	Leased
			(tons in millions)									
Illinois Basin Operations												
Dotiki (KY)	U	12,200	—	—	80.6	80.6	52.5	28.1	36.8	43.8	28.8	51.8
Warrior (KY)	U	12,500	—	—	96.4	96.4	72.9	23.5	76.1	20.3	23.8	72.6
Hopkins (KY)	U	12,000	—	—	13.9	13.9	9.7	4.2	—	13.9	2.9	11.0
	S	11,500	—	—	7.8	7.8	7.8	—	7.8	—	7.8	—
River View (KY)	U	11,500	—	—	166.4	166.4	108.4	58.0	166.4	—	37.3	129.1
Henderson/Union (KY)	U	11,400	—	5.7	495.3	501.0	168.2	332.8	—	501.0	90.8	410.2
Onton (KY)	U	11,750	—	—	40.3	40.3	22.6	17.7	40.3	—	0.2	40.1
Sebree (KY)	U	11,400	—	—	8.6	8.6	3.1	5.5	—	8.6	3.9	4.7
Hamilton County (IL)	U	11,650	—	—	559.3	559.3	243.0	316.3	147.1	412.2	53.3	506.0
Gibson (North) (IN, IL)	U	11,500	0.1	8.0	14.5	22.6	17.5	5.1	22.6	—	0.3	22.3
Gibson (South) (IN)	U	11,500	0.9	19.5	45.2	65.6	56.3	9.3	65.6	—	18.0	47.6
Region Total			1.0	33.2	1,528.3	1,562.5	762.0	800.5	562.7	999.8	267.1	1,295.4
Appalachia Operations												
MC Mining (KY)	U	12,900	2.9	0.5	1.7	5.1	4.4	0.7	2.9	2.2	0.1	5.0
Mettiki (MD)	U	13,200	—	1.6	3.8	5.4	5.2	0.2	5.4	—	—	5.4
Mettiki (WV)	U	13,200	—	8.2	8.2	16.4	11.0	5.4	10.5	5.9	2.4	14.0
Tunnel Ridge (WV)	U	12,600	—	—	83.6	83.6	33.8	49.8	83.6	—	—	83.6
Region Total			2.9	10.3	97.3	110.5	54.4	56.1	102.4	8.1	2.5	108.0
Total			3.9	43.5	1,625.6	1,673.0	816.4	856.6	665.1	1,007.9	269.6	1,403.4
% of Total			0.2%	2.6%	97.2%	100.0%	48.8%	51.2%	39.8%	60.2%	16.1%	83.9%

(1) U = Underground and S = Surface

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. We have historically obtained an outside audit of our reserve estimates and calculation methods every five years with the most recent audit being performed by Weir International Mining Consultants 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 2.9 million tons of reserves listed at MC Mining as <1.2 pounds of SO_2 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—2.9 million tons, Tunnel Ridge—17.4 million tons, Hamilton—33.3 million tons, Warrior—4.8 million tons, Dotiki—0.6 million tons, Onton—4.6 million tons, Gibson (North)—0.4 million tons, Gibson (South)—1.2 million tons, Elk Creek—-4.9 million tons and Pattiki—-53.5 million tons. The Henderson/Union Reserves account for the majority of our non-reserve coal deposits with 199.9 million tons. In addition, there are 17.3 million tons located near our Dotiki complex for total non-reserve coal deposits of 340.8 million tons.

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.

Mining Operations

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

Operations	Location	Tons Produced 2017	2016	2015	Transportation	Equipment
		(in millions)				
Illinois Basin Operations						
Dotiki	Kentucky	2.6	3.7	4.0	CSX, PAL, truck, barge	CM
Warrior	Kentucky	3.6	3.8	4.0	CSX, PAL, truck, barge	CM
Hopkins	Kentucky	—	0.4	2.9	CSX, PAL, truck, barge	CM, TS
River View	Kentucky	9.0	8.6	9.1	Barge	CM
Onton	Kentucky	—	—	1.8	Barge, truck	CM
Hamilton	Illinois	6.1	3.0	2.7	CSX, EVWR, NS, truck, barge	LW, CM
Pattiki	Illinois	—	1.9	2.4	CSX, EVWR, barge	CM
Gibson (North)	Indiana	—	—	2.2	CSX, NS, truck, barge	CM
Gibson (South)	Indiana	6.0	4.0	2.9	CSX, NS, truck, barge	CM
Region Total		27.3	25.4	32.0		
Appalachia Operations						
MC Mining	Kentucky	1.4	1.2	1.5	CSX, truck, barge	CM
Mettiki	WV, MD	2.1	2.0	2.1	CSX, truck	LW, CM
Tunnel Ridge	West Virginia	6.8	6.6	5.6	Barge, WLE, NS	LW, CM
Region Total		10.3	9.8	9.2		
TOTAL		37.6	35.2	41.2		

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

ITEM 3. LEGAL PROCEEDINGS

From time to time we are party to litigation matters incidental to the conduct of our business. We initiated litigation on January 15, 2015 alleging that a customer anticipatorily breached a coal supply contract when it notified us that it would not accept coal shipments under the contract after April 15, 2015. The contract obligated the customer to purchase more than 5.0 million tons during the period between April 16, 2015 and the end of the contract term on December 31, 2021. On February 18, 2018 we reached agreement with the customer and certain of its affiliates to settle the litigation. The agreement includes a $93 million payment to us and certain future coal supply commitments. In addition, we will acquire certain coal reserves for $2.0 million from an affiliate of the customer. As a result of certain costs related to this settlement, we expect to realize approximately $80 million from the recovery.

It is the opinion of management that the ultimate resolution of our pending litigation matters will not have a material adverse effect on our financial condition, results of operation or liquidity. However, we cannot assure you that disputes or litigation will not arise or that we will be able to resolve any such future disputes or litigation in a satisfactory manner. The information under "General Litigation" and "Other" in "Item 8. Financial Statements and Supplementary Data—Note 19. Commitments and Contingencies" is incorporated herein by this reference.

ITEM 4. MINE SAFETY DISCLOSURES

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

PART II

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

The common units representing limited partners' interests are listed on the NASDAQ Global Select Market under the symbol "ARLP." The common units began trading on August 20, 1999. On February 8, 2018, the closing market price for the common units was $18.40 per unit and there were 130,903,256 common units outstanding. There were approximately 32,648 record holders of common units at December 31, 2017.

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

	High	Low	Distributions Per Unit
1st Quarter 2016	$ 14.75	$ 9.95	$0.4375 (paid May 13, 2016)
2nd Quarter 2016	$ 16.85	$ 11.00	$0.4375 (paid August 12, 2016)
3rd Quarter 2016	$ 22.65	$ 15.50	$0.4375 (paid November 14, 2016)
4th Quarter 2016	$ 26.65	$ 21.40	$0.4375 (paid February 14, 2017)
1st Quarter 2017	$ 25.55	$ 20.25	$0.4375 (paid May 15, 2017)
2nd Quarter 2017	$ 23.45	$ 18.15	$0.50 (paid August 14, 2017)
3rd Quarter 2017	$ 21.30	$ 17.65	$0.505 (paid November 14, 2017)
4th Quarter 2017	$ 20.80	$ 17.60	$0.51 (paid February 14, 2018)

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

Under the quarterly incentive distribution provisions of the partnership agreement prior to the Exchange Transaction, MGP was entitled to receive 15% of the amount we distributed in excess of $0.1375 per unit, 25% of the amount we distributed in excess of $0.15625 per unit, and 50% of the amount we distributed in excess of $0.1875 per unit. Beginning with distributions declared for the three months ended June 30, 2017, payable in August 2017, we no longer make distributions with respect to IDRs.

Equity Compensation Plans

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

ITEM 6. SELECTED FINANCIAL DATA

Our historical financial data below were derived from our audited consolidated financial statements as of and for the years ended December 31, 2017, 2016, 2015, 2014 and 2013. Prior years results presented have been recast to reflect a reclassification of depreciation and depletion capitalized into coal inventory as adjustments to *Depreciation, depletion and amortization* rather than *Operating expenses (excluding depreciation, depletion and amortization)*.

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

	Year Ended December 31,				
	2017	2016	2015	2014	2013
Statements of Income					
Sales and operating revenues:					
Coal sales	$ 1,711.1	$ 1,861.8	$ 2,158.0	$ 2,208.6	$ 2,137.4
Transportation revenues	41.7	30.1	33.6	26.0	32.6
Other sales and operating revenues	43.4	39.6	82.1	66.1	35.5
Total revenues	1,796.2	1,931.5	2,273.7	2,300.7	2,205.5
Expenses:					
Operating expenses (excluding depreciation, depletion and amortization)	1,095.2	1,124.8	1,386.8	1,383.4	1,398.8
Transportation expenses	41.7	30.1	33.6	26.0	32.6
Outside coal purchases	—	1.5	0.3	—	2.0
General and administrative	61.8	72.6	67.5	72.5	63.7
Depreciation, depletion and amortization	269.0	336.5	324.0	274.6	264.9
Asset impairment	—	—	100.1	—	—
Total operating expenses	1,467.7	1,565.5	1,912.3	1,756.5	1,762.0
Income from operations	328.5	366.0	361.4	544.2	443.5
Interest expense (net of interest capitalized)	(39.4)	(30.7)	(31.2)	(33.6)	(27.0)
Interest income	0.1	—	1.5	1.7	1.0
Equity investment income (loss)	13.9	3.5	(49.0)	(16.7)	(24.4)
Cost investment income	6.4	—	—	—	—
Acquisition gain, net	—	—	22.5	—	—
Debt extinguishment loss	(8.1)	—	—	—	—
Other income	3.0	0.7	1.0	1.6	1.8
Income before income taxes	304.4	339.5	306.2	497.2	394.9
Income tax expense	0.2	—	—	—	1.4
Net income	304.2	339.5	306.2	497.2	393.5
Less: Net income attributable to noncontrolling interest	(0.6)	(0.1)	—	—	—
Net income attributable to Alliance Resource Partners, L.P. ("Net Income of ARLP")	$ 303.6	$ 339.4	$ 306.2	$ 497.2	$ 393.5
General Partners' interest in Net Income of ARLP	$ 21.9	$ 80.9	$ 146.3	$ 138.3	$ 121.4
Limited Partners' interest in Net Income of ARLP	$ 281.7	$ 258.5	$ 159.9	$ 358.9	$ 272.1
Basic and diluted net income of ARLP per limited partner unit (1) (2)	$ 2.80	$ 3.39	$ 2.11	$ 4.77	$ 3.63
Distributions paid per limited partner unit	$ 1.88	$ 1.9875	$ 2.6625	$ 2.4725	$ 2.2825
Weighted-average number of units outstanding-basic and diluted	98,707,696	74,354,162	74,174,389	74,044,417	73,904,384
Balance Sheet Data:					
Working capital (3)	$ (8.0)	$ (50.2)	$ (108.2)	$ (80.0)	$ 109.4
Total assets	2,219.4	2,193.0	2,361.3	2,285.1	2,121.9
Long-term obligations (4)	473.0	485.0	658.6	606.9	848.4
Total liabilities	1,067.9	1,099.6	1,372.0	1,270.0	1,270.7
Partners' capital	$ 1,151.5	$ 1,093.4	$ 989.3	$ 1,015.1	$ 851.2
Other Operating Data:					
Tons sold	37.8	36.7	40.2	39.7	38.8
Tons produced	37.6	35.2	41.2	40.7	38.8
Coal sales per ton sold (5)	$ 45.24	$ 50.76	$ 53.62	$ 55.59	$ 55.04
Cost per ton sold (6)	$ 28.95	$ 30.71	$ 34.46	$ 34.82	$ 36.07
Other Financial Data:					
Net cash provided by operating activities	$ 556.1	$ 703.5	$ 716.3	$ 739.2	$ 704.7
Net cash used in investing activities	(244.8)	(191.8)	(355.9)	(441.2)	(426.0)
Net cash used in financing activities	(344.4)	(505.4)	(351.6)	(367.0)	(213.3)
EBITDA (7)	612.7	706.7	659.9	803.7	685.9
Adjusted EBITDA (7)	620.8	706.7	737.5	803.7	685.9
Maintenance capital expenditures (8)	$ 140.0	$ 93.3	$ 236.3	$ 236.3	$ 222.4

(1) Diluted earnings per unit ("EPU") gives effect to all dilutive potential common units outstanding during the period using the treasury stock method. Diluted EPU excludes all dilutive units calculated under the treasury stock method

if their effect is anti-dilutive. For the years ended December 31, 2017, 2016, 2015, 2014 and 2013, long-term incentive plan ("LTIP"), Supplemental Executive Retirement Plan ("SERP") and Directors' compensation units of 1,466,404, 922,386, 734,171, 798,701 and 682,746, respectively, were considered anti-dilutive.

(2) As a result of the Exchange Transaction, net income beginning with the second quarter of 2017 was not allocated to incentive distribution rights and the related general partner interests exchanged; however, additional net income in a corresponding amount was allocated to limited partner interests. Please read "Item 8. Financial Statements and Supplementary Data—Note 12. Net Income of ARLP Per Limited Partner Unit" for more information on the impact of the Exchange Transaction on basic and diluted net income of ARLP per limited partner unit, including a table presenting basic and diluted net income of ARLP per limited partner unit on a pro forma basis as if the Exchange Transaction had taken place on January 1, 2015.

(3) Working capital is impacted by current maturities of long-term debt. For information regarding long-term debt, please read "Item 8. Financial Statements and Supplementary Data—Note 7. Long-Term Debt."

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

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

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

(7) EBITDA and Adjusted EBITDA are financial measures not calculated in accordance with generally accepted accounting principles ("GAAP"). EBITDA is defined as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes and depreciation, depletion and amortization. Adjusted EBITDA is EBITDA modified for certain items that may not reflect the trend of future results, such as asset impairments, gains and losses from acquisition-valuation related accounting and debt extinguishment losses.

EBITDA is used as a supplemental financial measure by management and by external users of our financial statements such as investors, commercial banks, research analysts and others. We believe that the presentation of EBITDA provides useful information to investors regarding our performance and results of operations because EBITDA, when used in conjunction with related GAAP financial measures, (i) provides additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provides investors with the financial analytical framework upon which we base financial, operational, compensation and planning decisions and (iii) presents a measurement that investors, rating agencies and debt holders have indicated is useful in assessing us and our results of operations.

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

EBITDA and Adjusted EBITDA should not be considered as alternatives to net income attributable to ARLP, net income, income from operations, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. EBITDA and Adjusted EBITDA are not intended to represent cash flow and do not represent the measure of cash available for distribution. Our method of computing EBITDA and Adjusted EBITDA may not be the same method used to compute similar measures reported by other companies, or EBITDA and Adjusted EBITDA may be computed differently by us in different contexts (e.g., public reporting versus computation under financing agreements).

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

	Year Ended December 31,				
	2017	2016	2015	2014	2013
			(in thousands)		
Cash flows provided by operating activities	$ 556,116	$ 703,544	$ 716,342	$ 739,201	$ 704,652
Non-cash compensation expense	(12,326)	(13,885)	(12,631)	(11,250)	(8,896)
Asset retirement obligations	(3,793)	(3,769)	(3,192)	(2,730)	(3,004)
Coal inventory adjustment to market	(449)	—	(1,952)	(377)	(2,811)
Equity investment income (loss)	13,860	3,543	(49,046)	(16,648)	(24,441)
Distributions received from investments	(13,939)	(2,719)	—	—	—
Paid-in-kind distributions received from cost investment	6,398	—	—	—	—
Net gain (loss) on sale of property, plant and equipment	696	76	1	4,409	(3,475)
Valuation allowance of deferred tax assets	3,339	1,365	(1,557)	(1,636)	(3,483)
Other	(6,212)	(3,300)	(6,388)	5,151	6,251
Net effect of working capital changes	37,640	(8,808)	66,159	55,659	(6,392)
Interest expense, net	39,291	30,659	29,694	31,913	26,082
Income tax expense	210	13	21	—	1,396
Adjusted EBITDA	620,831	706,719	737,451	803,692	685,879
Asset impairment	—	—	(100,130)	—	—
Acquisition gain, net	—	—	22,548	—	—
Debt extinguishment loss	(8,148)	—	—	—	—
EBITDA	612,683	706,719	659,869	803,692	685,879
Depreciation, depletion and amortization	(268,981)	(336,509)	(323,983)	(274,566)	(264,911)
Interest expense, net	(39,291)	(30,659)	(29,694)	(31,913)	(26,082)
Income tax expense	(210)	(13)	(21)	—	(1,396)
Net income	304,201	339,538	306,171	497,213	393,490
Net (income) loss attributable to noncontrolling interests	(563)	(140)	27	16	—
Net income attributable to ARLP	$ 303,638	$ 339,398	$ 306,198	$ 497,229	$ 393,490

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

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

General

The following discussion of our financial condition and results of operations should be read in conjunction with the historical financial statements and notes thereto included in Item 8. Financial Statements and Supplementary Data where you can find more detailed information in "Note 1. Organization and Presentation" and "Note 2. Summary of Significant Accounting Policies" regarding the basis of presentation supporting the following financial information.

Executive Overview

We are a diversified producer and marketer of coal primarily to major U.S. utilities and industrial users and were the first such producer and marketer in the nation to be a publicly traded master limited partnership. We are currently the second-largest coal producer in the eastern U.S. In 2017, we produced and sold 37.6 million and 37.8 million tons of coal, respectively. The coal we sold in 2017 was approximately 25.4% low-sulfur coal, 39.9% medium-sulfur coal and 34.7% high-sulfur coal. Based on market expectations, we classify low-sulfur coal as coal with a sulfur content of less than 1.5%, medium-sulfur coal as coal with a sulfur content of 1.5% to 3%, and high-sulfur coal as coal with a sulfur content of greater than 3%. The BTU content of our coal ranges from 11,400 to 13,200.

We operate eight underground mining complexes in Illinois, Indiana, Kentucky, Maryland and West Virginia, as well as a coal-loading terminal on the Ohio River at Mt. Vernon, Indiana. In addition, we own equity interests in various oil and gas mineral interests and gas compression services in various geographic locations within producing basins in the continental U.S. At December 31, 2017, we had approximately 1.67 billion tons of proven and probable coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. We believe we control adequate reserves to implement our currently contemplated mining plans. Please see "Item 1. Business—Mining Operations" for further discussion of our mines.

On July 19, 2017, Alliance Minerals purchased $100 million of Series A-1 Preferred Interests from Kodiak, a privately-held company providing large-scale, high-utilization gas compression assets to customers operating primarily in the Permian Basin. On July 31, 2015, Hamilton acquired the remaining equity interests of White Oak, from White Oak Finance Inc. and other parties. Prior to the acquisition we leased coal reserves to White Oak and owned and operated certain surface facilities at White Oak's mining complex. For more information on the White Oak Acquisition, please read "Item 8. Financial Statements and Supplementary Data—Note 3. Acquisitions."

In 2017, approximately 80.0% of our sales tonnage was purchased by U.S. electric utilities, with the balance sold to third-party resellers and industrial consumers. Although many utility customers recently have appeared to favor a shorter-term contracting strategy, in 2017, approximately 71.7% of our sales tonnage was sold under long-term contracts. Our long-term contracts contribute to our stability and profitability by providing greater predictability of sales volumes and sales prices. In 2017, approximately 85.9% of our medium- and high-sulfur coal was sold to utility plants with installed pollution control devices. These devices, also known as scrubbers, eliminate substantially all emissions of sulfur dioxide.

As discussed in more detail in "Item 1A. Risk Factors," our results of operations could be impacted by prices for items that are used in coal production such as steel, electricity and other supplies, unforeseen geologic conditions or mining and processing equipment failures and unexpected maintenance problems, and by the availability or reliability of transportation for coal shipments. Moreover, the regulatory environment in which we operate has grown increasingly stringent as a result of legislation and initiatives pursued during the years prior to the current Trump administration. Additionally, our results of operations could be impacted by our ability to obtain and renew permits necessary for our operations, secure or acquire coal reserves, or find replacement buyers for coal under contracts with comparable terms to existing contracts. As outlined in "Item 1. Business—Regulation and Laws," a variety of measures taken by regulatory agencies in the U.S. and abroad in response to the perceived threat from climate change attributed to GHG emissions could substantially increase compliance costs for us and our customers and reduce demand for coal, which could materially and adversely impact our results of operations. For additional information regarding some of the risks and uncertainties that affect our business and the industry in which we operate, see "Item 1A. Risk Factors."

As discussed above, on February 22, 2018, our Board of Directors and the board of directors of AHGP's general partner approved the Simplification Agreement, pursuant to which AHGP would become a wholly owned subsidiary of

us. For more information regarding the Simplification Agreement, please see "Item 1. Business – Simplification Transactions."

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

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

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

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

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

- *Illinois Basin* reportable segment is comprised of multiple operating segments, including currently operating mining complexes (a) Webster County Coal's Dotiki mining complex, (b) Gibson County Coal's mining complex, which includes the Gibson North and Gibson South mines, (c) Warrior's mining complex, (d) River View's mining complex and (e) the Hamilton mining complex. The Gibson North mine has been idled since the fourth quarter of 2015 in response to market conditions but is expected to resume production in 2018.

  The Illinois Basin reportable segment also includes White County Coal's Pattiki mining complex, Hopkins County Coal's mining complex, which includes the Elk Creek mine, the Pleasant View surface mineable reserves and the Fies underground project, Sebree's mining complex, which includes the Onton mine, Steamport and certain reserves, CR Services, LLC, CR Machine Shop, LLC, certain properties and equipment of Alliance Resource Properties, ARP Sebree, LLC, ARP Sebree South, LLC and UC Coal, LLC and its subsidiaries, UC Mining, LLC, and UC Processing, LLC. The Pattiki mine ceased production in December 2016. The Elk Creek mine depleted its reserves in March 2016 and ceased production on April 1, 2016. Our Onton mine has been idled since the fourth quarter of 2015 in response to market conditions. UC Coal, LLC equipment assets acquired in 2015 continue to be deployed as needed at various Illinois Basin operating mines.

- *Appalachia* reportable segment is comprised of multiple operating segments, including the Mettiki mining complex, the Tunnel Ridge mining complex and the MC Mining mining complex. The Mettiki mining complex includes Mettiki (WV)'s Mountain View mine and Mettiki (MD)'s preparation plant.

- *Other and Corporate* includes marketing and administrative activities, Alliance Service, Inc. ("ASI") and its subsidiaries included in the Matrix Group, ASI's ownership of aircraft, our Mt. Vernon dock activities, Alliance Coal's coal brokerage activity, Mid-America Carbonates, LLC's ("MAC") manufacturing and sales (primarily to our mines) of rock dust, certain of Alliance Resource Properties' land and mineral interest activities, Pontiki Coal, LLC's ("Pontiki") legacy workers' compensation and pneumoconiosis liabilities, Wildcat Insurance, which assists

the ARLP Partnership with its insurance requirements, Alliance Minerals, and its affiliate, Cavalier Minerals, both of which hold equity investments in various AllDale Partnerships, Alliance Mineral's investment in Kodiak, AROP Funding, LLC ("AROP Funding") and our new subsidiary formed on March 30, 2017, Alliance Resource Finance Corporation ("Alliance Finance"). Please read "Item 8. Financial Statements and Supplementary Data—Note 7. Long-Term Debt", "—Note 10. Variable Interest Entities" and "—Note 11. Investments" for more information on AROP Funding, Alliance Finance, Alliance Minerals, Cavalier Minerals, the AllDale Partnerships and Kodiak.

How We Evaluate Our Performance

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

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

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

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

EBITDA. We define EBITDA (a non-GAAP financial measure) as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes and depreciation, depletion and amortization. EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others. We believe that the presentation of EBITDA provides useful information to investors regarding our performance and results of operations because EBITDA, when used in conjunction with related GAAP financial measures, (i) provides additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provides investors with the financial analytical framework upon which we base financial, operational, compensation and planning decisions and (iii) presents a measurement that investors, rating agencies and debt holders have indicated is useful in assessing us and our results of operations.

Segment Adjusted EBITDA. We define Segment Adjusted EBITDA (a non-GAAP financial measure) as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes, depreciation, depletion and amortization, asset impairment, acquisition gain, net, debt extinguishment loss and general and administrative expenses. Management therefore is able to focus solely on the evaluation of segment operating profitability as it relates to our revenues and operating expenses, which are primarily controlled by our segments.

Analysis of Historical Results of Operations

2017 Compared with 2016

We reported net income attributable to ARLP of $303.6 million for 2017 compared to $339.4 million for 2016. The decrease of $35.8 million was due to lower coal sales price realizations offset in part by increased sales volumes, decreased operating expenses, reduced depreciation, depletion and amortization and increased income from our oil and gas investments. Total revenues decreased to $1.80 billion in 2017 compared to $1.93 billion in 2016 as the anticipated reduction in coal sales prices more than offset increased sales volumes and other sales and operating revenues. Even though sales and production volumes increased for 2017, operating expenses were lower compared to 2016, reflecting our initiatives to shift production to lower-cost operations. The favorable production cost mix and lower selling expenses in 2017 significantly lowered operating expenses per ton sold compared to 2016. Results presented for 2016 have been recast to reflect a reclassification of depreciation and depletion capitalized into coal inventory as an adjustment to depreciation, depletion and amortization rather than operating expenses.

As a result of the Exchange Transaction, net income beginning with the second quarter of 2017 was not allocated to incentive distribution rights and the related general partner interests exchanged; however, additional net income, in a corresponding amount, was allocated to limited partner interests. We reported earnings per basic and diluted limited partner unit of $2.80 in 2017 compared to $3.39 in 2016. On a pro forma basis, as if the Exchange Transaction had taken place on January 1, 2016, basic and diluted net income of ARLP per limited partner unit ("Pro Forma EPU") in 2017 would have been $2.27 compared to $2.54 in 2016, reflecting the decline in net income attributable to ARLP as discussed above. Please read "Item 8. Financial Statements and Supplementary Data—Note 12. Net Income of ARLP Per Limited Partner Unit" for more information on the impact of the Exchange Transaction on earnings per basic and diluted limited partner unit, including a table providing a reconciliation of Pro Forma EPU amounts to net income of ARLP.

	December 31,		December 31,	
	2017	2016	2017	2016
	(in thousands)		(per ton sold)	
Tons sold	37,824	36,680	N/A	N/A
Tons produced	37,609	35,244	N/A	N/A
Coal sales	$ 1,711,114	$ 1,861,788	$ 45.24	$ 50.76
Operating expenses and outside coal purchases	$ 1,095,167	$ 1,126,362	$ 28.95	$ 30.71

Coal sales. Coal sales decreased $150.7 million or 8.1% to $1.71 billion for 2017 from $1.86 billion for 2016. The decrease was attributable to lower average coal sales prices, which reduced coal sales by $208.7 million, partially offset by the benefit of increased tons sold, which contributed $58.0 million in additional coal sales. Average coal sales prices decreased $5.52 per ton sold in 2017 to $45.24 compared to $50.76 per ton sold in 2016, primarily due to the expiration of higher-priced legacy contracts, partially offset by higher price realizations at our Mettiki mine from its participation in the metallurgical coal markets in 2017 and improved prices at our MC Mining mine. Sales and production volumes rose to 37.8 million tons sold and 37.6 million tons produced in 2017 compared to 36.7 million tons sold and 35.2 million tons produced in 2016, primarily due to strong performances at the Hamilton, Gibson South, Mettiki, MC Mining and Tunnel Ridge mines.

Operating expenses and outside coal purchases. Operating expenses and outside coal purchases decreased 2.8% to $1.10 billion for 2017 from $1.13 billion for 2016 primarily as a result of the previously discussed favorable production cost mix. On a per ton basis, operating expenses and outside coal purchases decreased 5.7% to $28.95 per ton sold from $30.71 per ton sold in 2016, due primarily to increased sales and production volumes and our previously discussed initiatives to shift production to lower-cost operations. The most significant operating expense variances by category are discussed below:

- Labor and benefit expenses per ton produced, excluding workers' compensation, decreased 13.2% to $9.24 per ton in 2017 from $10.65 per ton in 2016. This decrease of $1.41 per ton was primarily attributable to lower labor and benefit costs per ton due to fewer employees resulting in part from our increased mix of lower-cost production as well as lower health care benefit expenses; and

- Production taxes and royalty expenses decreased $0.49 per produced ton sold in 2017 compared to 2016 primarily as a result of lower excise taxes per ton resulting from a favorable state production mix, increased export sales and lower average coal sales prices.

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

- Material and supplies expenses per ton produced increased 1.9% to $9.76 per ton in 2017 from $9.58 per ton in 2016. The increase of $0.18 per ton produced resulted primarily from increases of $0.27 per ton for contract labor used in the mining process and $0.12 per ton for roof support, partially offset by the increased mix of lower-cost production and a related decrease of $0.10 per ton for power and fuel used in the mining process; and

- Maintenance expenses per ton produced increased 7.7% to $3.34 per ton in 2017 from $3.10 per ton in 2016. The increase of $0.24 per ton produced was primarily due to increased maintenance expenses at several mines in both reportable segments due in part to the use of surplus equipment from our idled mines.

Other sales and operating revenues. Other sales and operating revenues were principally comprised of Mt. Vernon transloading revenues, Matrix Design sales, other outside services and administrative services revenue from affiliates. Other sales and operating revenues increased to $43.4 million in 2017 from $39.6 million in 2016. The increase of $3.8 million was primarily due to increased mining technology product sales by Matrix Design and increased transloading revenues from Mt. Vernon, partially offset in comparison to 2016 by proceeds of coal supply contract buy-outs received in 2016.

General and administrative. General and administrative expenses for 2017 decreased to $61.8 million compared to $72.5 million in 2016. The decrease of $10.7 million was primarily due to lower incentive compensation expenses.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense decreased to $269.0 million for 2017 compared to $336.5 million for 2016 primarily as a result of the depletion of reserves at our Elk Creek mine in the first quarter of 2016, closure of the Pattiki mine in the fourth quarter of 2016, volume reductions at our Dotiki and Warrior mines, the use of surplus equipment from our idled mines and ongoing capital reduction initiatives at all of our operations.

Interest expense. Interest expense, net of capitalized interest, increased to $39.4 million in 2017 from $30.7 million in 2016 primarily due to interest incurred under our Senior Notes issued in April 2017, offset in part by reduced borrowings under our revolving credit facility and the payment of our Term Loan and Series B Senior Notes. Interest payable under our Senior Notes, revolving credit facility, Term Loan and Series B Senior Notes is discussed below under "–Debt Obligations."

Equity investment income. Equity investment income increased to $13.9 million in 2017 from $3.5 million in 2016 due to increased income from our investments in the AllDale Partnerships.

Cost investment income. Distributions of additional preferred interests received from our new Kodiak investment contributed $6.4 million of cost investment income to 2017.

Debt extinguishment loss. We recognized a debt extinguishment loss of $8.1 million in 2017 to reflect a make-whole payment incurred to repay our Series B Senior Notes in May 2017.

Transportation revenues and expenses. Transportation revenues and expenses were $41.7 million and $30.1 million for 2017 and 2016, respectively. The increase of $11.6 million was primarily attributable to increased tonnage for which we arrange third-party transportation at certain mines and an increase in average third-party transportation rates in 2017. The cost of third-party transportation services are passed through to our customers.

Segment Information. Our 2017 Segment Adjusted EBITDA decreased 12.4% to $682.6 million from 2016 Segment Adjusted EBITDA of $779.2 million. Segment Adjusted EBITDA, tons sold, coal sales, other sales and operating revenues and Segment Adjusted EBITDA Expense by segment are as follows:

	Year Ended December 31,			
	2017	2016	Increase (Decrease)	
		(in thousands)		
Segment Adjusted EBITDA				
Illinois Basin	$ 391,426	$ 552,284	$ (160,858)	(29.1)%
Appalachia	234,124	191,487	42,637	22.3 %
Other and Corporate	65,810	46,339	19,471	42.0 %
Elimination	(8,769)	(10,862)	2,093	19.3 %
Total Segment Adjusted EBITDA (1)	$ 682,591	$ 779,248	$ (96,657)	(12.4)%
Tons sold				
Illinois Basin	27,026	26,912	114	0.4 %
Appalachia	10,783	9,734	1,049	10.8 %
Other and Corporate	1,636	1,865	(229)	(12.3)%
Elimination	(1,621)	(1,831)	210	11.5 %
Total tons sold	37,824	36,680	1,144	3.1 %
Coal sales				
Illinois Basin	$ 1,078,255	$ 1,306,241	$ (227,986)	(17.5)%
Appalachia	616,305	534,796	81,509	15.2 %
Other and Corporate	74,973	86,174	(11,201)	(13.0)%
Elimination	(58,419)	(65,423)	7,004	10.7 %
Total coal sales	$ 1,711,114	$ 1,861,788	$ (150,674)	(8.1)%
Other sales and operating revenues				
Illinois Basin	$ 1,638	$ 7,686	$ (6,048)	(78.7)%
Appalachia	3,622	3,404	218	6.4 %
Other and Corporate	54,070	46,216	7,854	17.0 %
Elimination	(15,924)	(17,752)	1,828	10.3 %
Total other sales and operating revenues	$ 43,406	$ 39,554	$ 3,852	9.7 %
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 688,468	$ 761,644	$ (73,176)	(9.6)%
Appalachia	385,802	346,712	39,090	11.3 %
Other and Corporate	83,490	89,594	(6,104)	(6.8)%
Elimination	(65,573)	(72,313)	6,740	9.3 %
Total Segment Adjusted EBITDA Expense (1)	$ 1,092,187	$ 1,125,637	$ (33,450)	(3.0)%

(1) For a definition of Segment Adjusted EBITDA and Segment Adjusted EBITDA Expense and related reconciliations to comparable GAAP financial measures, please see below under "—Reconciliation of non-GAAP "Segment Adjusted EBITDA" to GAAP "net income" and reconciliation of non-GAAP "Segment Adjusted EBITDA Expense" to GAAP "Operating Expenses." Results presented for Segment Adjusted EBITDA and Segment Adjusted EBITDA Expense for 2016 have been recast to reflect a reclassification of depreciation and depletion capitalized into coal inventory as adjustments to depreciation, depletion and amortization rather than operating expenses.

Illinois Basin – Segment Adjusted EBITDA decreased 29.1% to $391.4 million in 2017 from $552.3 million in 2016. The decrease of $160.9 million was primarily attributable to lower coal sales, which decreased 17.5% to $1.08 billion in 2017 from $1.31 billion in 2016, partially offset by decreased expenses resulting from a favorable production mix. The coal sales decrease of $228.0 million primarily reflects lower average coal sales prices of $39.90 per ton in 2017 compared to $48.54 per ton in 2016, primarily resulting from the expiration of higher-priced legacy contracts. Lower sales prices were partially offset by increased tons sold, which increased slightly to 27.0 million tons in 2017 from 26.9 million tons in 2016. Higher sales volumes resulted from strong performances at the Gibson South and Hamilton mines, offset in part by the previously mentioned depletion of reserves at our Elk Creek mine in the 2016 first quarter, the closure of the Pattiki

mine in the 2016 fourth quarter and reduced sales at our Dotiki mine. Segment Adjusted EBITDA Expense decreased 9.6% to $688.5 million in 2017 from $761.6 million in 2016 and Segment Adjusted EBITDA Expense per ton decreased $2.83 per ton sold to $25.47 compared to $28.30 per ton sold in 2016, primarily due to a significant increase in low-cost longwall production from the Hamilton mine, increased production at our Gibson South operation and a related reduced mix of sales volumes from our higher cost mines, as well as reduced selling expenses, lower health care benefit expenses and certain cost decreases described above under "–Operating expenses and outside coal purchases."

Appalachia – Segment Adjusted EBITDA increased 22.3% to $234.1 million in 2017 from $191.5 million in 2016. The increase of $42.6 million was primarily attributable to increased coal sales, which rose 15.2% to $616.3 million in 2017 compared to $534.8 million in 2016, partially offset by higher Segment Adjusted EBITDA Expense. The increase of $81.5 million in coal sales resulted from higher sales volumes across the region, which increased 10.8% to 10.8 million tons sold in 2017 compared to 9.7 million tons sold in 2016, and higher average coal sales prices of $57.16 per ton in 2017 compared to $54.94 per ton in 2016. Higher price realizations in 2017 were a result of sales from our Mettiki mine into the metallurgic coal export market and improved prices at our MC Mining mine. Segment Adjusted EBITDA Expense increased 11.3% to $385.8 million in 2017 from $346.7 million in 2016 due to increased sales volumes. Segment Adjusted EBITDA Expense per ton increased slightly to $35.78 per ton compared to $35.62 per ton sold in 2016, primarily due to an increased sales mix of higher-cost Mettiki production in 2017 and reduced recoveries from our Tunnel Ridge mine.

Other and Corporate – Segment Adjusted EBITDA increased by $19.5 million to $65.8 million in 2017 compared to $46.3 million in 2016. The increase was primarily attributable to higher equity investment income from the AllDale Partnerships, distributions of additional preferred interests received from Kodiak and increased mining technology product sales by Matrix Design. In 2017, Segment Adjusted EBITDA Expense decreased to $83.5 million for 2017 compared to $89.6 million for 2016 primarily as a result of decreased coal brokerage activity.

Elimination – Segment Adjusted EBITDA Expense eliminations decreased in 2017 to $65.6 million from $72.3 million in 2016 and coal sales eliminations decreased to $58.4 million from $65.4 million in 2016, reflecting decreased intercompany coal sales brokerage activity.

2016 Compared with 2015

We reported net income attributable to ARLP of $339.4 million for 2016 compared to $306.2 million for 2015, an increase of $33.2 million. Comparative results between the years reflect in part the negative net impact in 2015 of $77.6 million of certain large non-cash items ("Non-Cash Items") described below and $48.5 million of equity investment loss related to White Oak also in 2015. Net income in 2016 was negatively impacted by reduced revenues compared to 2015 resulting from planned reductions in coal sales and production volumes, lower coal sales prices, lower other sales and operating revenues due to the absence of coal royalty and surface facilities revenues from White Oak in 2016, offset in part by reduced operating expenses in 2016. Lower operating expenses during 2016 primarily reflect decreased sales volumes and a favorable production cost mix resulting from our initiative to shift production to lower-cost per ton operations. Lower volumes in 2016 resulted from idling our Onton and Gibson North mines in the fourth quarter of 2015 and the planned depletion of reserves at our Elk Creek mine in the first quarter of 2016, partially offset by additional volumes from our Tunnel Ridge and Gibson South operations and the Hamilton mine acquired in the White Oak Acquisition. The Non-Cash Items in 2015 included asset impairments of $100.1 million offset in part by a net gain of $22.5 million related to final business combination accounting for the White Oak Acquisition. For more information on the White Oak Acquisition, please read "Item 8. Financial Statements and Supplementary Data—Note 3. Acquisitions." For more information on the 2015 non-cash asset impairments, please read "Item 8. Financial Statements and Supplementary Data—Note 4. Long-Lived Asset Impairments." Results presented for 2016 and 2015 have been recast to reflect a reclassification of depreciation and depletion capitalized into coal inventory as an adjustment to depreciation, depletion and amortization rather than operating expenses.

	December 31,		December 31,	
	2016	2015	2016	2015
	(in thousands)		(per ton sold)	
Tons sold	36,680	40,247	N/A	N/A
Tons produced	35,244	41,178	N/A	N/A
Coal sales	$ 1,861,788	$ 2,158,006	$ 50.76	$ 53.62
Operating expenses and outside coal purchases	$ 1,126,362	$ 1,387,110	$ 30.71	$ 34.46

Coal sales. Coal sales decreased $296.2 million or 13.7% to $1.86 billion for 2016 from $2.16 billion for 2015. The decrease was attributable to a volume variance of $191.2 million resulting from reduced tons sold as discussed above and a price variance of $105.0 million due to lower average coal sales prices. Average coal sales prices decreased $2.86 per ton sold in 2016 to $50.76 compared to $53.62 per ton sold in 2015, primarily due to lower-priced legacy contracts at our Hamilton mine inherited in the White Oak Acquisition and lower average prices at certain mines, particularly at our Gibson South, Dotiki, Tunnel Ridge and MC Mining operations, as a result of challenging market conditions.

Operating expenses and outside coal purchases. Operating expenses and outside coal purchases decreased 18.8% to $1.13 billion for 2016 from $1.39 billion for 2015 primarily as a result of the previously discussed reductions to coal production volumes and a favorable production cost mix. On a per ton basis, operating expenses and outside coal purchases decreased 10.9% to $30.71 per ton sold from $34.46 per ton sold in 2015, due primarily to the lower-cost production mix and higher productivity from our Tunnel Ridge and Gibson South mines. Operating expenses were impacted by various other factors, the most significant of which are discussed below:

- Labor and benefit expenses per ton produced, excluding workers' compensation, decreased 7.8% to $10.65 per ton in 2016 from $11.55 per ton in 2015. This decrease of $0.90 per ton was primarily attributable to the increased mix of lower-cost production discussed above and reduced overtime in response to market conditions;

- Material and supplies expenses per ton produced decreased 14.8% to $9.58 per ton in 2016 from $11.25 per ton in 2015. The decrease of $1.67 per ton produced resulted primarily from the increased mix of lower-cost production discussed above and related decreases of $0.77 per ton for roof support, $0.47 per ton for contract labor used in the mining process and $0.24 per ton for certain ventilation expenses partially offset by increases of $0.22 per ton for equipment rentals primarily due to equipment leases assumed in the White Oak Acquisition and $0.15 per ton for environmental and reclamation expenses;

- Maintenance expenses per ton produced decreased 21.1% to $3.10 per ton in 2016 from $3.93 per ton in 2015. The decrease of $0.83 per ton produced was primarily due to production variances at certain mines discussed above; and

- Production taxes and royalties expenses incurred as a percentage of coal sales prices and volumes decreased $0.39 per produced ton sold in 2016 compared to 2015 primarily as a result of lower excise taxes per ton resulting from a favorable state production mix and lower average coal sales prices discussed above;

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

- Operating expenses were increased by a 1.4 million ton inventory reduction and related inventory cost adjustments in 2016 as compared to a 1.0 million ton inventory increase and related inventory cost adjustments in 2015.

Other sales and operating revenues. Other sales and operating revenues were principally comprised of Mt. Vernon transloading revenues, Matrix Design sales, other outside services and administrative services revenue from affiliates and, in 2015, surface facility services and coal royalty revenues received from White Oak prior to the White Oak Acquisition in July 2015. Other sales and operating revenues decreased to $39.6 million in 2016 from $82.1 million in 2015. The decrease of $42.5 million was primarily due to the absence of coal royalty and surface facilities revenues from White Oak in 2016.

General and administrative. General and administrative expenses for 2016 increased to $72.5 million compared to $67.5 million in 2015. The increase of $5.0 million was primarily due to higher incentive compensation expenses.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense ("DD&A") for 2016 increased to $336.5 million compared to $324.0 million in 2015. The increase of $12.5 million was primarily due to increases in DD&A associated with our Pattiki mine, which ceased production in December 2016 and the acquisition of the Hamilton mine in July 2015, partially offset by the previously discussed volume reductions at our Onton, Gibson North and Elk Creek mines.

Asset impairment. In 2015, we recorded $100.1 million of impairment charges comprised of a $66.9 million impairment related to the idling of our Onton mine, a $19.5 million impairment at the MC Mining complex, primarily due to lower coal sales prices, and a $13.7 million impairment due to the surrender in 2015 of leases of undeveloped coal reserves and related property. No asset impairments were recorded in 2016.

Interest expense. Interest expense, net of capitalized interest, decreased slightly to $30.7 million in 2016 from $31.2 million in 2015 primarily due to the repayment of our Series A senior notes in June 2015 offset in part by additional interest incurred under capital lease obligations. Interest payable under our senior notes, term loan, revolving credit facility and capital lease financings is discussed below under "–Debt Obligations."

Equity investment income (loss). Equity investment income (loss) for 2016 includes Cavalier Minerals' equity method investments in AllDale Minerals. In addition to AllDale Minerals, 2015 also includes our equity method investment in White Oak. For 2016, we recognized equity investment income of $3.5 million compared to equity investment loss of $49.0 million for 2015. As discussed above, as a result of the White Oak Acquisition in July 2015, we no longer account for the Hamilton mine financial results as an equity method investment in our consolidated financials, but now consolidate Hamilton in our financial results. Thus, the change in equity investment income (loss) was primarily due to the elimination of equity losses related to White Oak as well as an increase in equity income from AllDale Minerals.

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

Transportation revenues and expenses. Transportation revenues and expenses were $30.1 million and $33.6 million for 2016 and 2015, respectively. The decrease of $3.5 million was primarily attributable to a decrease in average transportation rates in 2016, partially offset by increased tonnage for which we arrange transportation at certain mines. The cost of transportation services are passed through to our customers.

Segment Information. Our 2016 Segment Adjusted EBITDA decreased 3.2% to $779.2 million from 2015 Segment Adjusted EBITDA of $804.9 million. Segment Adjusted EBITDA, tons sold, coal sales, other sales and operating revenues and Segment Adjusted EBITDA Expense by segment are as follows:

	Year Ended December 31,			
	2016	2015	Increase (Decrease)	
	(in thousands)			
Segment Adjusted EBITDA				
Illinois Basin	$ 552,284	$ 604,808	$ (52,524)	(8.7)%
Appalachia	191,487	186,518	4,969	2.7 %
Other and Corporate	46,339	26,189	20,150	76.9 %
Elimination	(10,862)	(12,580)	1,718	13.7 %
Total Segment Adjusted EBITDA (1)	$ 779,248	$ 804,935	$ (25,687)	(3.2)%
Tons sold				
Illinois Basin	26,912	30,801	(3,889)	(12.6)%
Appalachia	9,734	9,439	295	3.1 %
Other and Corporate	1,865	2,813	(948)	(33.7)%
Elimination	(1,831)	(2,806)	975	34.7 %
Total tons sold	36,680	40,247	(3,567)	(8.9)%
Coal sales				
Illinois Basin	$ 1,306,241	$ 1,571,014	$ (264,773)	(16.9)%
Appalachia	534,796	573,453	(38,657)	(6.7)%
Other and Corporate	86,174	133,498	(47,324)	(35.4)%
Elimination	(65,423)	(119,959)	54,536	45.5 %
Total coal sales	$ 1,861,788	$ 2,158,006	$ (296,218)	(13.7)%
Other sales and operating revenues				
Illinois Basin	$ 7,686	$ 43,856	$ (36,170)	(82.5)%
Appalachia	3,404	11,136	(7,732)	(69.4)%
Other and Corporate	46,216	47,007	(791)	(1.7)%
Elimination	(17,752)	(19,869)	2,117	10.7 %
Total other sales and operating revenues	$ 39,554	$ 82,130	$ (42,576)	(51.8)%
Segment Adjusted EBITDA Expense				
Illinois Basin	$ 761,644	$ 961,611	$ (199,967)	(20.8)%
Appalachia	346,712	398,071	(51,359)	(12.9)%
Other and Corporate	89,594	153,720	(64,126)	(41.7)%
Elimination	(72,313)	(127,247)	54,934	43.2 %
Total Segment Adjusted EBITDA Expense (1)	$ 1,125,637	$ 1,386,155	$ (260,518)	(18.8)%

(1) For a definition of Segment Adjusted EBITDA and Segment Adjusted EBITDA Expense and related reconciliations to comparable GAAP financial measures, please see below under "—Reconciliation of non-GAAP "Segment Adjusted EBITDA" to GAAP "net income" and reconciliation of non-GAAP "Segment Adjusted EBITDA Expense" to GAAP "Operating Expenses." Results presented for Segment Adjusted EBITDA and Segment Adjusted EBITDA Expense for 2016 and 2015 have been recast to reflect a reclassification of depreciation and depletion capitalized into coal inventory as adjustments to depreciation, depletion and amortization rather than operating expenses.

Illinois Basin – Segment Adjusted EBITDA decreased 8.7% to $552.3 million in 2016 from $604.8 million in 2015, a decrease of $52.5 million. Segment Adjusted EBITDA in 2016 was negatively impacted by reduced revenues compared to 2015 resulting from planned reductions in coal sales and production volumes, lower coal sales prices, lower other sales and operating revenues due to the absence of coal royalty and surface facilities revenues from White Oak in 2016, offset in part by reduced operating expenses in 2016. Comparative results between the years also reflect the negative impact in 2015 of $48.5 million of equity investment loss related to White Oak prior to the White Oak Acquisition in July 2015. Coal sales decreased 16.9% to $1.31 billion compared to $1.57 billion in 2015. The coal sales decrease of $264.8 million

primarily reflects the previously discussed reduction of coal sales and production volumes at our Onton, Gibson North and Elk Creek mines, partially offset by additional volumes from our Gibson South operation and the Hamilton mine acquired in the White Oak Acquisition. Also impacting 2016 were lower average coal sales prices which decreased 4.8% to $48.54 per ton sold compared to $51.01 per ton sold in 2015 as a result of challenging market conditions and lower-priced legacy contracts at the Hamilton mine inherited in the White Oak Acquisition. Segment Adjusted EBITDA Expense decreased 20.8% to $761.6 million in 2016 from $961.6 million in 2015 due to reduced production and sales volumes as discussed above. Segment Adjusted EBITDA Expense per ton decreased $2.92 per ton sold to $28.30 in 2016 from $31.22 per ton sold in 2015, primarily as a result of a favorable production cost mix in 2016 due to reducing production from higher-cost per ton operations and improved recoveries at our Gibson South, River View and Warrior mines, as well as certain cost decreases described above under "–Operating expenses and outside coal purchases."

Appalachia – Segment Adjusted EBITDA increased 2.7% to $191.5 million for 2016 from $186.5 million in 2015. The increase of $5.0 million was primarily attributable to increased tons sold and reduced operating expenses partially offset by lower average coal sales prices of $54.94 per ton sold during 2016 compared to $60.76 per ton sold in 2015. Coal sales decreased 6.7% to $534.8 million in 2016 compared to $573.5 million in 2015. The decrease of $38.7 million was primarily due to lower average coal sales prices at our MC Mining and Tunnel Ridge mines. Segment Adjusted EBITDA Expense decreased 12.9% to $346.7 million in 2016 from $398.1 million in 2015 and Segment Adjusted EBITDA Expense per ton decreased $6.55 per ton sold to $35.62 compared to $42.17 per ton sold in 2015, primarily due to a favorable production cost mix resulting from an additional 1.0 million tons being produced from Tunnel Ridge in 2016 compared to 2015 and a reduction in volumes from our higher cost Appalachia mines. Segment Adjusted EBITDA Expense per ton also benefited from fewer longwall move days and lower roof support expenses, lower selling expenses across the region, and certain other cost decreases described above under "–Operating expenses and outside coal purchases."

Other and Corporate – In 2016, Segment Adjusted EBITDA increased $20.2 million compared to 2015 primarily as a result of increased margins on both safety equipment sales by Matrix Design and coal brokerage sales, as well as an increase in equity income from AllDale Minerals and a reduction in workers' compensation and pneumoconiosis accruals related to Pontiki which sold most of its assets in May 2014. In 2016, coal sales decreased $47.3 million and Segment Adjusted EBITDA Expense decreased $64.1 million compared to 2015. These decreases primarily resulted from reduced intercompany coal brokerage activity.

Elimination – Segment Adjusted EBITDA Expense eliminations decreased in 2016 to $72.3 million from $127.2 million in 2015 and coal sales eliminations decreased to $65.4 million from $120.0 million, respectively, primarily reflecting reduced intercompany coal brokerage activity.

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

Segment Adjusted EBITDA (a non-GAAP financial measure) is defined as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes, depreciation, depletion and amortization, asset impairment, acquisition gain, net, debt extinguishment loss and general and administrative expenses. Segment Adjusted EBITDA is a key component of consolidated EBITDA, which is used as a supplemental financial measure by management and by external users of our financial statements such as investors, commercial banks, research analysts and others. We believe that the presentation of EBITDA provides useful information to investors regarding our performance and results of operations because EBITDA, when used in conjunction with related GAAP financial measures, (i) provides additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provides investors with the financial analytical framework upon which we base financial, operational, compensation and planning decisions and (iii) presents a measurement that investors, rating agencies and debt holders have indicated is useful in assessing us and our results of operations.

Segment Adjusted EBITDA is also used as a supplemental financial measure by our management for reasons similar to those stated in the previous explanation of EBITDA. In addition, the exclusion of corporate general and administrative expenses, which are discussed above under "—Analysis of Historical Results of Operations," from consolidated Segment Adjusted EBITDA allows management to focus solely on the evaluation of segment operating profitability as it relates to our revenues and operating expenses, which are primarily controlled by our segments. Results presented for Segment Adjusted EBITDA for 2016 and 2015 have been recast to reflect a reclassification of depreciation and depletion capitalized into coal inventory as adjustments to depreciation, depletion and amortization rather than operating expenses.

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

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Consolidated Segment Adjusted EBITDA	$ 682,591	$ 779,248	$ 804,935
General and administrative	(61,760)	(72,529)	(67,484)
Depreciation, depletion and amortization	(268,981)	(336,509)	(323,983)
Asset impairment	—	—	(100,130)
Interest expense, net	(39,291)	(30,659)	(29,694)
Acquisition gain, net	—	—	22,548
Debt extinguishment loss	(8,148)	—	—
Income tax expense	(210)	(13)	(21)
Net income	$ 304,201	$ 339,538	$ 306,171

Segment Adjusted EBITDA Expense (a non-GAAP financial measure) includes operating expenses, coal purchases and other income. Transportation expenses are excluded as these expenses are passed through to our customers and, consequently, we do not realize any gain or loss on transportation revenues. Segment Adjusted EBITDA Expense is used as a supplemental financial measure by our management to assess the operating performance of our segments. Segment Adjusted EBITDA Expense is a key component of Segment Adjusted EBITDA in addition to coal sales and other sales and operating revenues. The exclusion of corporate general and administrative expenses from Segment Adjusted EBITDA Expense allows management to focus solely on the evaluation of segment operating performance as it primarily relates to our operating expenses. Results presented for Segment Adjusted EBITDA Expense for 2016 and 2015 have been recast to reflect a reclassification of depreciation and depletion capitalized into coal inventory as adjustments to depreciation, depletion and amortization rather than operating expenses

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

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Segment Adjusted EBITDA Expense	$ 1,092,187	$ 1,125,637	$ 1,386,155
Outside coal purchases	—	(1,514)	(327)
Other income	2,980	725	955
Operating expenses (excluding depreciation, depletion and amortization)	$ 1,095,167	$ 1,124,848	$ 1,386,783

Ongoing Acquisition Activities

Consistent with our business strategy, from time to time we engage in discussions with potential sellers regarding our possible acquisitions of certain assets and/or companies of the sellers. For more information on acquisitions, please read "Item 8. Financial Statements and Supplementary Data—Note 3. Acquisitions."

Liquidity and Capital Resources

Liquidity

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

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

We own equity interests in the AllDale Partnerships for the purchase of oil and gas mineral interests in various geographic locations within producing basins in the continental U.S. and plan to make similar additional equity investments in the future. As of December 31, 2017, we had provided funding of $163.4 million to the AllDale Partnerships. On July 19, 2017, we purchased $100 million of Series A-1 Preferred Interests from Kodiak, a privately-held company providing large-scale, high-utilization gas compression assets to customers operating primarily in the Permian Basin. This structured investment provides us with a quarterly cash or payment-in-kind return. In 2018, we expect investments of approximately $30.0 million for existing commitments related to our AllDale Partnerships and Kodiak investments. For more information on transactions with the AllDale Partnerships and Kodiak, please read "Item 8. Financial Statements and Supplementary Data—Note 10. Variable Interest Entities" and "Note 11. Investments."

On September 22, 2011, we entered into a series of transactions with White Oak to support development of the White Oak longwall mining operation (now known as the Hamilton mine) including the purchase of preferred equity interests. On July 31, 2015 ("White Oak Acquisition Date"), we paid $50.0 million to acquire the remaining equity interest in White Oak and assumed control of the mine. Prior to the White Oak Acquisition Date, we had funded $422.6 million to White Oak under various agreements inclusive of the preferred equity interest purchases. In conjunction with the acquisition of White Oak, we assumed $93.5 million of debt which was extinguished in the fourth quarter of 2015 and replaced with a $100 million equipment sale-leaseback arrangement. For more information on this sale-leaseback arrangement, please read "Item 8. Financial Statements and Supplementary Data—Note 19. Commitments and Contingencies." In 2015, we paid $20.5 million to Patriot Coal Corporation to acquire various assets, including certain mining equipment and reserves. We also paid $5.5 million in 2015 to acquire the remaining equity interest in MAC. For more information on our acquisitions, please read "Item 8. Financial Statements and Supplementary Data—Note 3. Acquisitions."

Cash Flows

Cash provided by operating activities was $556.1 million for 2017 compared to $703.5 million for 2016. The decrease in cash provided by operating activities was primarily due to a decrease in net income adjusted for non-cash items, a large decrease in coal inventories in 2016 compared to a nominal change in 2017 and an increase in prepaid expenses and other assets in 2017 compared to a decrease in prepaid expenses and other assets in 2016. These decreases were offset in part by a favorable working capital change in accounts payable in 2017 compared to 2016.

Net cash used in investing activities was $244.8 million for 2017 compared to $191.8 million for 2016. The increase in cash used in investing activities was primarily attributable to the funding of our new cost investment in Kodiak in 2017 and increased capital expenditures for mine infrastructure and equipment at various mines in 2017 compared to 2016. These increases were partially offset by decreased purchases of equity investments and the lack of customer contract buy-outs both in 2017 compared to 2016.

Net cash used in financing activities was $344.4 million for 2017 compared to $505.4 million for 2016. The decrease in cash used in financing activities was primarily attributable to proceeds received from the issuance of our Senior Notes, as defined below, and decreased payments under the Term Loan, as defined below. These decreases in cash used were partially offset by repayment of the Series B Senior Notes, as defined below, increased overall net payments on the securitization and revolving credit facilities, payment of debt issuance and extinguishment costs and no proceeds received from sales-leaseback transactions in 2017.

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

The following table provides details regarding our contractual cash obligations as of December 31, 2017:

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(in thousands)		
Long-term debt	$ 502,400	$ 72,400	$ —	$ 30,000	$ 400,000
Future interest obligations[1]	224,603	31,436	62,694	60,528	69,945
Operating leases	17,259	10,067	7,192	—	—
Capital leases[2]	92,080	32,378	57,819	1,883	—
Purchase obligations for capital projects	64,325	64,325	—	—	—
Reclamation obligations[3]	244,597	3,850	887	1,256	238,604
Workers' compensation and pneumoconiosis benefit[3]	249,590	9,585	18,524	14,563	206,918
	$ 1,394,854	$ 224,041	$ 147,116	$ 108,230	$ 915,467

(1) Interest on variable-rate, long-term debt was calculated using rates effective at December 31, 2017 for the remaining term of outstanding borrowings.

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

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

Off-Balance Sheet Arrangements

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

We use a combination of surety bonds and letters of credit to secure our financial obligations for reclamation, workers' compensation and other obligations as follows as of December 31, 2017:

	Reclamation Obligation	Workers' Compensation Obligation	Other	Total
		(in millions)		
Surety bonds	$ 172.8	$ 84.2	$ 11.7	$ 268.7
Letters of credit	—	5.0	8.1	13.1

Capital Expenditures

Capital expenditures increased to $145.1 million in 2017 compared to $91.1 million in 2016. See our discussion of "Cash Flows" above concerning the increase in capital expenditures.

We currently project average estimated annual maintenance capital expenditures over the next five years of approximately $4.72 per ton produced. Our anticipated total capital expenditures, including maintenance capital expenditures, for 2018 are estimated in a range of $220.0 million to $240.0 million. Management anticipates funding 2018 capital requirements with our December 31, 2017 cash and cash equivalents of $6.8 million, cash flows from operations and investments, borrowings under revolving credit and securitization facilities and cash provided from the issuance of debt or equity. We will continue to have significant capital requirements over the long term, which may require us to incur debt or seek additional equity capital. The availability and cost of additional capital will depend upon prevailing market conditions, the market price of our common units and several other factors over which we have limited control, as well as our financial condition and results of operations.

Insurance

Effective October 1, 2017, we renewed our annual property and casualty insurance program. Our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance. Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased reinsurance for the program in the standard market. The maximum limit in the commercial property program is $100.0 million per occurrence, excluding a $1.5 million deductible for property damage, a 75, 90 or 120 day waiting period for underground business interruption depending on the mining complex and an additional $10.0 million overall aggregate deductible. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future.

Debt Obligations

Credit Facility. On January 27, 2017, our Intermediate Partnership entered into a Fourth Amended and Restated Credit Agreement (the "Credit Agreement") with various financial institutions for a revolving credit facility and term loan (the "Credit Facility"). The Credit Facility replaced the $250 million term loan ("Replaced Term Loan") and $700 million revolving credit facility ("Replaced Revolving Credit Facility") extended to the Intermediate Partnership on May 23, 2012 (the "Replaced Credit Agreement") by various banks and other lenders that would have expired on May 23, 2017.

The Credit Agreement provided for a $776.5 million revolving credit facility, reducing to $494.75 million on May 23, 2017, including a sublimit of $125 million for the issuance of letters of credit and a sublimit of $15.0 million for swingline borrowings (the "Revolving Credit Facility"), and for a term loan with a remaining principal balance of $50.0 million (the "Term Loan"). The outstanding revolver balance and term loan balance under the Replaced Credit Agreement were considered advanced under the Credit Facility on January 27, 2017. On April 3, 2017, we entered into an amendment to the Credit Agreement (the "Amendment") to (a) extend the termination date of the Revolving Credit Facility as to $461.25 million of the $494.75 million of commitments to May 23, 2021, (b) eliminate the Cavalier Condition and the Senior Notes Condition (both as defined in the Credit Agreement) and (c) effectuate certain other changes. We incurred debt issuance costs in 2017 of $9.2 million in connection with the Credit Agreement. These debt issuance costs are deferred and amortized as a component of interest expense over the term of the Credit Facility.

The Credit Agreement is guaranteed by all of the material direct and indirect subsidiaries of our Intermediate Partnership, and is secured by substantially all of the Intermediate Partnership's assets. The Term Loan principal balance of $50.0 million was paid in full in May 2017.

Borrowings under the Credit Facility bear interest, at the option of the Intermediate Partnership, at either (i) the Base Rate at the greater of three benchmarks or (ii) a Eurodollar Rate, plus margins for (i) or (ii), as applicable, that fluctuate depending upon the ratio of Consolidated Debt to Consolidated Cash Flow (each as defined in the Credit Agreement). The interest rate, with applicable margin, under the Credit Facility was 4.49% as of December 31, 2017. At December 31, 2017, we had $8.1 million of letters of credit outstanding with $456.7 million available for borrowing under the Revolving Credit Facility. We currently incur an annual commitment fee of 0.35% on the undrawn portion of the Revolving Credit Facility. We utilize the Revolving Credit Facility, as appropriate, for working capital requirements, capital expenditures and investments, scheduled debt payments and distribution payments.

The Credit Agreement contains various restrictions affecting our Intermediate Partnership and its subsidiaries including, among other things, incurrence of additional indebtedness and liens, sale of assets, investments, mergers and consolidations and transactions with affiliates, in each case subject to various exceptions, and the payment of cash distributions by our Intermediate Partnership if such payment would result in a certain fixed charge coverage ratio (as defined in the Credit Agreement). The Amendment lowered this fixed charge ratio from less than 1.25 to 1.0 to 1.15 to 1.0 for each rolling four-quarter period and further limited the Intermediate Partnership's ability to incur certain unsecured debt. See "Item 8. Financial Statements and Supplementary Data—Note 10 – Variable Interest Entities" for further discussion of restrictions on the cash available for distribution. The Amendment raised the debt to cash flow ratio from 2.25 to 1.0 to 2.50 to 1.0 and also removed the requirement for the Intermediate Partnership to remain in control of a certain amount of mineable coal reserves relative to its annual production. The Credit Agreement requires the Intermediate Partnership maintain (a) a debt to cash flow ratio of not more than 2.5 to 1.0 and (b) a cash flow to interest expense ratio of not less than 3.0 to 1.0, in each case, during the four most recently ended fiscal quarters. The debt to cash flow ratio and cash flow to interest expense ratio were 0.91 to 1.0 and 16.1 to 1.0, respectively, for the trailing twelve months ended December 31, 2017. We were compliant with the covenants of the Credit Agreement as of December 31, 2017.

Series B Senior Notes. On January 27, 2017, the Intermediate Partnership also amended the 2008 Note Purchase Agreement dated June 26, 2008, for $145.0 million of Series B Senior Notes which bore interest at 6.72% and were due to mature on June 26, 2018 with interest payable semi-annually (the "Series B Senior Notes"). The amendment provided for certain modifications to the terms and provisions of the Note Purchase Agreement, including granting liens on substantially all of the Intermediate Partnership's assets to secure its obligations under the Note Purchase Agreement on an equal basis with the obligations under the Credit Agreement. The amendment also modified certain covenants to align them with the applicable covenants in the Credit Agreement. As discussed below, we repaid the Series B Senior Notes in May 2017.

Senior Notes. On April 24, 2017, the Intermediate Partnership and Alliance Finance (as co-issuer), a wholly owned subsidiary of the Intermediate Partnership, issued an aggregate principal amount of $400.0 million of senior unsecured notes due 2025 ("Senior Notes") in a private placement to qualified institutional buyers. The Senior Notes have a term of eight years, maturing on May 1, 2025 (the "Term") and accrue interest at an annual rate of 7.5%. Interest is payable semi-annually in arrears on each May 1 and November 1, commencing on November 1, 2017. The indenture governing the Senior Notes contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of distributions or similar restricted payments, undertaking transactions with affiliates and limitations on asset sales. At any time prior to May 1, 2020, the issuers of the Senior Notes may redeem up to 35% of the aggregate principal amount of the Senior Notes with the net cash proceeds of one or more equity offerings at a redemption price equal to 107.5% of the principal amount redeemed, plus accrued and unpaid interest, if any, to the redemption date. The issuers of the Senior Notes may also redeem all or a part of the notes at any time on or after May 1, 2020, at redemption prices set forth in the indenture governing the Senior Notes. At any time prior to May 1, 2020, the issuers of the Senior Notes may redeem the Senior Notes at a redemption price equal to the principal amount of the Senior Notes plus a "make-whole" premium, plus accrued and unpaid interest, if any, to the redemption date. The net proceeds from issuance of the Senior Notes and cash on hand were used to repay the Revolving Credit Facility, Term Loan and Series B Senior Notes (including a make-whole payment of $8.1 million). We incurred discount and debt issuance costs of $7.3 million in connection with issuance of the Senior Notes. These costs are deferred and are currently being amortized as a component of interest expense over the Term.

Accounts Receivable Securitization. On December 5, 2014, certain direct and indirect wholly owned subsidiaries of our Intermediate Partnership entered into a $100.0 million accounts receivable securitization facility ("Securitization Facility"). Under the Securitization Facility, certain subsidiaries sell trade receivables on an ongoing basis to our Intermediate Partnership, which then sells the trade receivables to AROP Funding, a wholly owned bankruptcy-remote special purpose subsidiary of our Intermediate Partnership, which in turn borrows on a revolving basis up to $100.0 million secured by the trade receivables. After the sale, Alliance Coal, as servicer of the assets, collects the receivables on behalf of AROP Funding. The Securitization Facility bears interest based on a Eurodollar Rate. In November 2017, we extended the term of the Securitization Facility to January 2018. It was renewed in January 2018 and now matures in January 2019. At December 31, 2017, we had $72.4 million outstanding under the Securitization Facility.

Cavalier Credit Agreement. On October 6, 2015, Cavalier Minerals (see "Item 8. Financial Statements and Supplementary Data—Note 10 – Variable Interest Entities") entered into a credit agreement (the "Cavalier Credit Agreement") with Mineral Lending, LLC ("Mineral Lending") for a $100.0 million line of credit (the "Cavalier Credit Facility"). Mineral Lending is an entity owned by (a) ARH II, (b) an entity owned by an officer of ARH who is also a director of ARH II ("ARH Officer") and (c) foundations established by the President and Chief Executive Officer of MGP and Kathleen S. Craft. There is no commitment fee under the facility. Borrowings under the Cavalier Credit Facility bear interest at a one month LIBOR rate plus 6.0% with interest payable quarterly. Repayment of the principal balance begins following the first fiscal quarter after the earlier of the date on which the aggregate amount borrowed exceeds $90.0 million or December 31, 2017, in quarterly payments of an amount equal to the greater of $1.3 million initially, escalated to $2.5 million after two years, or fifty percent of Cavalier Minerals' excess cash flow. The Cavalier Credit Facility matures September 30, 2024, at which time all amounts then outstanding are required to be repaid. To secure payment of the facility, Cavalier Minerals pledged all of its partnership interests, owned or later acquired, in AllDale Minerals. Cavalier Minerals may prepay the Cavalier Credit Facility at any time in whole or in part subject to terms and conditions described in the Cavalier Credit Agreement. As of December 31, 2017, Cavalier Minerals had not drawn on the Cavalier Credit Facility. Alliance Minerals has the right to require Cavalier Minerals to draw the full amount available under the Cavalier Credit Facility and distribute the proceeds to the members of Cavalier Minerals, including Alliance Minerals.

Other. We also have an agreement with a bank to provide additional letters of credit in an amount of $5.0 million to maintain surety bonds to secure certain asset retirement obligations and our obligations for workers' compensation benefits. At December 31, 2017, we had $5.0 million in letters of credit outstanding under this agreement.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the U.S. The preparation of our consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts and disclosures in the consolidated financial statements. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances. We discuss these estimates and judgments with the audit committee of the MGP Board of Directors ("Audit Committee") periodically. Actual results may differ from these estimates. We have provided a description of all significant accounting policies in the notes to our consolidated financial statements. The following critical accounting policies are materially impacted by judgments, assumptions and estimates used in the preparation of our consolidated financial statements:

Business Combinations and Goodwill

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

In the 2015 acquisitions of White Oak and MAC, we were required to value the previously held equity interests just prior to acquisition and record a gain or loss if fair value was determined to be different from our carrying value. We re-measured our equity investment immediately prior to the White Oak acquisition using a discounted cash flow model which resulted in a loss of $52.3 million. The assumptions used in the determination of the fair value include projected financial information, forward coal price curves and a risk adjusted discount rate. When valuing the previously held equity investment in MAC, a market approach was used to determine that the carrying value of the investment was equal to the fair value resulting in no gain or loss being recorded.

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

The only indefinite-lived intangible that the Partnership has is goodwill. At December 31, 2017, the Partnership had $136.4 million in goodwill. Goodwill is not amortized, but subject to annual reviews on November 30th for impairment at a reporting unit level. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed or operated. A reporting unit is an operating segment or a component that is one level below an operating segment. We have assessed the reporting unit definitions and determined that at December 31, 2017, the Hamilton reporting unit and the MAC reporting unit are the appropriate reporting units for testing goodwill impairment related to the White Oak and MAC acquisitions.

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

sales volumes are critical assumptions used in our discounted cash flow analysis. There were no impairments of goodwill during 2017 or 2016. In future periods, it is reasonably possible that a variety of circumstances could result in an impairment of our goodwill.

A discounted cash flow analysis requires us to make various judgmental assumptions about sales, operating margins, capital expenditures, working capital and coal sales prices. Assumptions about sales, operating margins, capital expenditures and coal sales prices are based on our budgets, business plans, economic projections, and anticipated future cash flows. In determining the fair value of our reporting units, we were required to make significant judgments and estimates regarding the impact of anticipated economic factors on our business. The forecast assumptions used in the period ended December 31, 2017 make certain assumptions about future pricing, volumes and expected maintenance capital expenditures. Assumptions are also made for a "normalized" perpetual growth rate for periods beyond the long range financial forecast period.

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

Coal Reserve Values

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

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

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

Workers' Compensation and Pneumoconiosis (Black Lung) Benefits

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. We generally provide for these claims through self-insurance programs. Workers' compensation laws also compensate survivors of workers who suffer employment related deaths. Our liability for traumatic injury claims is the estimated present value of current workers' compensation benefits, based on our actuary estimates. Our actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including claim development patterns, mortality, medical costs and interest rates. See "Item 8. Financial Statements and Supplementary Data—Note 17. Accrued Workers' Compensation and Pneumoconiosis Benefits" for additional discussion. We had accrued liabilities

for workers' compensation of $54.4 million and $48.1 million for these costs at December 31, 2017 and 2016, respectively. A one-percentage-point reduction in the discount rate would have increased operating expense by approximately $3.6 million at December 31, 2017.

Coal mining companies are subject to CMHSA, as amended, and various state statutes for the payment of medical and disability benefits to eligible recipients related to coal worker's pneumoconiosis, or black lung. We provide for these claims through self-insurance programs. Our pneumoconiosis benefits liability is calculated using the service cost method based on the actuarial present value of the estimated pneumoconiosis benefits obligation. Our actuarial calculations are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and discount rates. We had accrued liabilities of $74.9 million and $65.0 million for the pneumoconiosis benefits at December 31, 2017 and 2016, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2017 by approximately $2.8 million. Under the service cost method used to estimate our pneumoconiosis benefits liability, actuarial gains or losses attributable to changes in actuarial assumptions, such as the discount rate, are amortized over the remaining service period of active miners.

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

Defined Benefit Plan

Eligible employees at certain of our mining operations participate in the Alliance Coal, LLC and Affiliates Pension Plan for Coal Employees (the "Pension Plan") that we sponsor. The Pension Plan is closed to new participants and effective January 31, 2017 participants within the Pension Plan are no longer receiving benefit accruals for service. All participants can participate in enhanced benefits provisions under the profit sharing and savings plan. The benefit formula for the Pension Plan is a fixed dollar unit based on years of service. The funded status of our pension benefit plan is recognized separately in our consolidated balance sheets as either an asset or liability. The funded status is the difference between the fair value of plan assets and the plan's benefit obligation. Unrecognized actuarial gains and losses and unrecognized prior service costs and credits are deferred and recorded in accumulated other comprehensive income until amortized as a component of net periodic benefit cost. Unrecognized actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the market-related value of plan assets are amortized over the participants' average remaining future years of service. The calculation of our net periodic benefit cost (pension expense) and benefit obligation (pension liability) associated with our Pension Plan requires the use of a number of assumptions including expected return on assets, discount rates, mortality assumptions, employee turnover rates and retirement dates. Changes in these assumptions can result in materially different pension expense and pension liability amounts. In addition, actual experiences can differ materially from the assumptions. Significant assumptions used in calculating pension expense and pension liability are shown in "Item 8. Financial Statements and Supplementary Data—Note 13. Employee Benefit Plans" and as follows:

- Our expected long-term rate of return assumption is based on broad equity and bond indices, the investment goals and objectives, the target investment allocation and on the average annual total return for each asset class. Our expected long-term rate of return used to determine our pension liability was 7.0% at December 31, 2017 and 2016. Our expected long-term rate of return used to determine our pension expense was 7.0% and 7.5% for the years ended December 31, 2017 and 2016, respectively. The expected long-term rate of return used to determine our pension liability is based on a 1.5% active management premium in addition to an asset allocation assumption of:

As of December 31, 2017	Asset allocation assumption
Equity securities	62%
Fixed income securities	33%
Real estate	5%
	100%

- Our expected long-term rate of return is based on the anticipated return for each investment group. Additionally, we base our determination of pension expense on a smoothed market-related valuation of assets equal to the fair value of assets, which immediately recognizes all investment gains or losses. The actual return on plan assets was 18.0% and 5.9% for the years ended December 31, 2017 and 2016, respectively. Lowering the expected long-term rate of return assumption by 1.0% (from 7.0% to 6.0%) at December 31, 2016 would have increased our pension expense for the year ended December 31, 2017 by approximately $0.7 million; and

- Our weighted-average discount rate used to determine our pension liability was 3.54% and 4.06% at December 31, 2017 and 2016, respectively. Our weighted-average discount rate used to determine our pension expense was 4.06% and 4.27% at December 31, 2017 and 2016, respectively. The discount rate that we utilize for determining our future pension obligation is based on a review of currently available high-quality fixed-income investments that receive one of the two highest ratings given by a recognized rating agency. We have historically used the average monthly yield for December of an A-rated utility bond index as the primary benchmark for establishing the discount rate. Lowering the discount rate assumption by 0.5% (from 4.06% to 3.56%) at December 31, 2016 would not have materially increased our pension expense for the year ended December 31, 2017.

Long-Lived Assets

We review the carrying value of long-lived assets and certain identifiable intangibles whenever events or changes in circumstances indicate that the carrying amount may not be recoverable based upon estimated undiscounted future cash flows. Long-lived assets and certain intangibles are not reviewed for impairment unless an impairment indicator is noted. Several examples of impairment indicators include:

- A significant decrease in the market price of a long-lived asset;
- A significant adverse change in the extent or manner in which a long-lived asset is being used or in its physical condition;
- A significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset, including an adverse action of assessment by a regulator;
- An accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- A current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset; or
- A current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. The term more likely that not refers to a level of likelihood that is more than 50 percent.

The above factors are not all inclusive, and management must continually evaluate whether other factors are present that would indicate a long-lived asset may be impaired. If there is an indication that carrying amount of an asset may not be recovered, the asset is monitored by management where changes to significant assumptions are reviewed. Individual assets are grouped for impairment review purposes based on the lowest level for which there is identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a by-mine basis. The amount of impairment is measured by the difference between the carrying value and the fair value of the asset. The fair value of impaired assets is typically determined based on various factors, including the present values of expected future cash flows using a risk adjusted discount rate, the marketability of coal properties and the estimated fair value of assets that could be sold or used at other operations. We recorded an asset impairment of $100.1 million in 2015 (see "Item 8. Financial Statements and Supplementary Data—Note 4. Long-Lived Asset Impairments"). No impairment charges were recorded in 2017 or 2016.

Equity Method Investments

We evaluate equity method investments for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such investments may have experienced an other-than-temporary decline in value. We continue to monitor our equity method investments for any indications that the carrying value may have experienced an other-than-temporary decline in value. When evidence of a loss in value has occurred, we compare our estimate of the fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred.

We generally estimate the fair value of our investments using an income approach where significant judgments and assumptions include expected future cash flows and the appropriate discount rate. A discounted cash flow analysis under the income approach requires us to make various judgmental assumptions about the investee, such as the investee's sales, operating margins, capital expenditures and expected distributions. Assumptions about sales, operating margins, capital expenditures and expected distributions are based on the investee's business plans, economic projections and anticipated future cash flows.

If the estimated fair value is less than the carrying value and we consider the decline in value to be other-than-temporary, the excess of the carrying value over the fair value is recognized in the consolidated financial statements as an impairment charge. Events or changes in circumstances that may be indicative of an other-than-temporary decline in value may include:

- Evidence of the lack of ability to recover the carrying amount of the investment;
- The inability to sustain an earnings capacity to justify the carrying amount;
- The current fair value of the investment is less than the carrying amount; or
- Other investors cease to provide support thus reducing their financial commitment to the investee.

As of December 31, 2017, we determined that no impairment indicators exist for any of our equity method investments.

Mine Development Costs

Mine development costs are capitalized until production, other than production incidental to the mine development process, commences and are amortized on a units of production method based on the estimated proven and probable reserves. Mine development costs represent costs incurred in establishing access to mineral reserves and include costs associated with sinking or driving shafts and underground drifts, permanent excavations, roads and tunnels. The end of the development phase and the beginning of the production phase takes place when construction of the mine for economic extraction is substantially complete. Our estimate of when construction of the mine for economic extraction is substantially complete is based upon a number of factors, such as expectations regarding the economic recoverability of reserves, the type of mine under development, and completion of certain mine requirements, such as ventilation. Coal extracted during the development phase is incidental to the mine's production capacity and is not considered to shift the mine into the production phase. At December 31, 2017 and December 31, 2016, there were no capitalized development costs associated with mines in the development phase. All past capitalized development costs are associated with mines that shifted to the production phase and thus, these costs are being amortized. We believe that the carrying value of the past development costs will be recovered. At December 31, 2015, capitalized mine development costs representing the carrying value of development costs attributable to properties where we had not reached the production stage of mining operations totaled $5.9 million.

Asset Retirement Obligations

SMCRA and similar state statutes require that mined property be restored in accordance with specified standards and an approved reclamation plan. A liability is recorded for the estimated cost of future mine asset retirement and closing procedures on a present value basis when incurred or acquired and a corresponding amount is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to permanently sealing portals at underground mines and to reclaiming the final pits and support surface acreage for both our underground mines and past surface mines. Examples of these types of costs, common to both types of mining, include, but are not limited to, removing or covering refuse piles and settling ponds, water treatment obligations, and dismantling preparation plants, other facilities and roadway infrastructure. Accrued liabilities of $130.6 million and $125.7 million for these costs are recorded at December 31, 2017 and 2016, respectively. See "Item 8. Financial Statements and Supplementary Data—Note 16. Asset Retirement Obligations" for additional information. The liability for asset retirement and closing procedures is sensitive to changes in cost estimates and estimated mine lives. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free interest rate.

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

On at least an annual basis, we review our entire asset retirement obligation liability and make necessary adjustments for permit changes approved by state authorities, changes in the timing of reclamation activities, and revisions to cost estimates and productivity assumptions, to reflect current experience. Adjustments to the liability associated with these assumptions resulted in an increase of $2.2 million and a decrease of $1.4 million for the year ended December 31, 2017 and 2016, respectively. The adjustments to the liability for the year ended December 31, 2017 were primarily attributable to the net impact of overall general changes in inflation and discount rates, current estimates of the costs and scope of remaining reclamation work, reclamation work completed and fluctuations in projected mine life estimates, as well as by increased expansion and disturbances of refuse sites primarily at our Hamilton and River View mines.

While the precise amount of these future costs cannot be determined with certainty, we have estimated the costs and timing of future asset retirement obligations escalated for inflation, then discounted and recorded at the present value of those estimates. Discounting resulted in reducing the accrual for asset retirement obligations by $114.0 million and $110.7 million at December 31, 2017 and 2016. We estimate that the aggregate undiscounted cost of final mine closure is approximately $244.6 million at December 31, 2017. If our assumptions differ from actual experiences, or if changes in the regulatory environment occur, our actual cash expenditures and costs that we incur could be materially different than currently estimated.

Contingencies

We are currently involved in certain legal proceedings. Our estimates of the probable costs and probability of resolution of these claims are based upon a number of assumptions, which we have developed in consultation with legal counsel involved in the defense of these matters and based upon an analysis of potential results, assuming a combination of litigation and settlement strategies. Based on known facts and circumstances, we believe the ultimate outcome of these outstanding lawsuits, claims and regulatory proceedings will not have a material adverse effect on our financial condition, results of operations or liquidity. However, if the results of these matters were different from management's current opinion and in amounts greater than our accruals, then they could have a material adverse effect.

Universal Shelf

In February 2015, we filed with the SEC a universal shelf registration statement allowing us to issue from time to time an indeterminate amount of debt or equity securities ("2015 Registration Statement"). At February 23, 2018, we had not utilized any amounts available under the 2015 Registration Statement. We currently intend to file with the SEC a new universal shelf registration statement prior to the expiration of the 2015 Registration Statement.

Related–Party Transactions

See "Item 8. Financial Statements and Supplementary Data—Note 18. Related-Party Transactions" for a discussion of our related-party transactions.

Accruals of Other Liabilities

We had accruals for other liabilities, including current obligations, totaling $287.7 million and $264.2 million at December 31, 2017 and 2016, respectively. These accruals were chiefly comprised of workers' compensation benefits, pneumoconiosis benefits, and costs associated with asset retirement obligations. These obligations are self-insured except for certain excess insurance coverage for workers' compensation. The accruals of these items were based on estimates of future expenditures based on current legislation, related regulations and other developments. Thus, from time to time, our results of operations may be significantly affected by changes to these liabilities. Please see "Item 8. Financial Statements and Supplementary Data—Note 16. Asset Retirement Obligations" and "Note 17. Accrued Workers' Compensation and Pneumoconiosis Benefits."

Inflation

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

New Accounting Standards

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

Other Information

White Oak IRS Notice

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

We have significant long-term coal supply agreements as evidenced by approximately 71.7% of our sales tonnage being sold under long-term contracts in 2017. Most of the long-term coal supply agreements are subject to price adjustment provisions, which periodically permit an increase or decrease in the contract price, typically to reflect changes in specified indices or changes in production costs resulting from regulatory changes, or both. For additional discussion of coal supply agreements, please see "Item 1. Business—Coal Marketing and Sales" and "Item 8. Financial Statements and Supplementary Data—Note 20. Concentration of Credit Risk and Major Customers." As of February 15, 2018, our nominal commitment under long-term contracts was approximately 34.7 million tons in 2018, 13.6 million tons in 2019, 8.5 million tons in 2020 and 1.3 million tons in 2021. Please read "Item 3. Legal Proceedings."

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

Credit Risk

In 2017, approximately 80.0% of our sales tonnage was purchased by electric utilities. Therefore, our credit risk is primarily with domestic electric power generators. Our policy is to independently evaluate each customer's creditworthiness prior to entering into transactions and to constantly monitor outstanding accounts receivable against established credit limits. When deemed appropriate by our credit management department, we will take steps to reduce our credit exposure to customers that do not meet our credit standards or whose credit has deteriorated. These steps may include obtaining letters of credit or cash collateral, requiring prepayments for shipments or establishing customer trust accounts held for our benefit in the event of a failure to pay.

Exchange Rate Risk

Almost all of our transactions are denominated in U.S. dollars, and as a result, we do not have material exposure to currency exchange-rate risks.

Interest Rate Risk

Borrowings under the Credit Facility, Securitization Facility and Cavalier Credit Agreement are at variable rates and, as a result, we have interest rate exposure. Historically, our earnings have not been materially affected by changes in interest rates. We do not utilize any interest rate derivative instruments related to our outstanding debt. We had $30.0

million in borrowings under the Credit Facility and $72.4 million in borrowings under the Securitization Facility at December 31, 2017. A one percentage point increase in the interest rates related to the Credit Facility and Securitization Facility would result in an annualized increase in interest expense of $1.0 million, based on borrowing levels at December 31, 2017. With respect to our fixed-rate borrowings, we had $400.0 million in borrowings under our Senior Notes at December 31, 2017. A one percentage point increase in interest rates would result in a decrease of approximately $27.0 million in the estimated fair value of these borrowings.

The table below provides information about our market sensitive financial instruments and constitutes a "forward-looking statement." The fair values of long-term debt are estimated using discounted cash flow analyses, based upon our incremental borrowing rates for similar types of borrowing arrangements as of December 31, 2017 and 2016.

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

Expected Maturity Dates as of December 31, 2017	2018	2019	2020	2021	2022	Thereafter	Total	Fair Value December 31, 2017
				(in thousands)				
Fixed rate debt	$ —	$ —	$ —	$ —	$ —	$ 400,000	$ 400,000	$ 438,142
Weighted-average interest rate	7.50 %	7.50 %	7.50 %	7.50 %	7.50 %	7.50 %		
Variable rate debt	$ 72,400	$ —	$ —	$ 30,000	$ —	$ —	$ 102,400	$ 103,005
Weighted-average interest rate (1)	4.33 %	4.49 %	4.49 %	4.49 %	—	—		

Expected Maturity Dates as of December 31, 2016	2017	2018	2019	2020	2021	Thereafter	Total	Fair Value December 31, 2016
				(in thousands)				
Fixed rate debt	$ —	$ 145,000	$ —	$ —	$ —	$ —	$ 145,000	$ 154,449
Weighted-average interest rate	6.72 %	6.72 %	—	—	—	—		
Variable rate debt	$ 150,000	$ —	$ 255,000	$ —	$ —	$ —	$ 405,000	$ 405,060
Weighted-average interest rate (2)	2.98 %	3.37 %	3.37 %	—	—	—		

(1) Interest rate of variable rate debt equal to the rate effective at December 31, 2017, held constant for the remaining term of the outstanding borrowing.

(2) Interest rate of variable rate debt equal to the rate elected by us as of December 31, 2016 adjusted for estimated increase of 95 basis points under the Credit Agreement, held constant for the remaining term of the outstanding borrowing.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

The Board of Directors of Alliance Resource Management GP, LLC
and the Partners of Alliance Resource Partners, L.P.

Opinion on the Financial Statements
We have audited the accompanying consolidated balance sheets of Alliance Resource Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, cash flows, and partners' capital for each of the three years in the period ended December 31, 2017, and the related notes and financial statement schedule listed in the Index at Item 15(a)(2) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the consolidated financial position of the Partnership at December 31, 2017 and 2016, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 23, 2018 expressed an unqualified opinion thereon.

Basis for Opinion
These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Partnership's auditor since 2011.

Tulsa, Oklahoma
February 23, 2018

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2017 AND 2016
(In thousands, except unit data)

	December 31,	
	2017	**2016**
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 6,756	$ 39,782
Trade receivables	181,671	152,032
Other receivables	146	279
Due from affiliates	165	271
Inventories, net	60,275	61,051
Advance royalties, net	4,510	1,207
Prepaid expenses and other assets	28,117	22,050
Total current assets	281,640	276,672
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment, at cost	2,934,188	2,920,988
Less accumulated depreciation, depletion and amortization	(1,457,532)	(1,335,145)
Total property, plant and equipment, net	1,476,656	1,585,843
OTHER ASSETS:		
Advance royalties, net	39,660	29,372
Equity investments	147,964	138,817
Cost investments	106,398	—
Goodwill	136,399	136,399
Other long-term assets	30,654	25,939
Total other assets	461,075	330,527
TOTAL ASSETS	$ 2,219,371	$ 2,193,042
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 96,958	$ 64,055
Due to affiliates	771	906
Accrued taxes other than income taxes	20,336	18,273
Accrued payroll and related expenses	35,751	41,576
Accrued interest	5,005	316
Workers' compensation and pneumoconiosis benefits	10,729	9,897
Current capital lease obligations	28,613	27,196
Other current liabilities	19,071	14,778
Current maturities, long-term debt, net	72,400	149,874
Total current liabilities	289,634	326,871
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities, net	415,937	399,446
Pneumoconiosis benefits	71,875	62,822
Accrued pension benefit	45,317	42,070
Workers' compensation	46,694	40,400
Asset retirement obligations	126,750	125,266
Long-term capital lease obligations	57,091	85,540
Other liabilities	14,587	17,203
Total long-term liabilities	778,251	772,747
Total liabilities	1,067,885	1,099,618
PARTNERS' CAPITAL:		
Alliance Resource Partners, L.P. ("ARLP") Partners' Capital:		
Limited Partners - Common Unitholders 130,704,217 and 74,375,025 units outstanding, respectively	1,183,219	1,400,202
General Partners' interest	14,859	(273,788)
Accumulated other comprehensive loss	(51,940)	(38,540)
Total ARLP Partners' Capital	1,146,138	1,087,874
Noncontrolling interest	5,348	5,550
Total Partners' Capital	1,151,486	1,093,424
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 2,219,371	$ 2,193,042

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015
(In thousands, except unit and per unit data)

	Year Ended December 31,		
	2017	2016	2015
SALES AND OPERATING REVENUES:			
Coal sales	$ 1,711,114	$ 1,861,788	$ 2,158,006
Transportation revenues	41,700	30,111	33,597
Other sales and operating revenues	43,406	39,554	82,130
Total revenues	1,796,220	1,931,453	2,273,733
EXPENSES:			
Operating expenses (excluding depreciation, depletion and amortization)	1,095,167	1,124,848	1,386,783
Transportation expenses	41,700	30,111	33,597
Outside coal purchases	—	1,514	327
General and administrative	61,760	72,529	67,484
Depreciation, depletion and amortization	268,981	336,509	323,983
Asset impairment	—	—	100,130
Total operating expenses	1,467,608	1,565,511	1,912,304
INCOME FROM OPERATIONS	328,612	365,942	361,429
Interest expense (net of interest capitalized of $551, $358 and $695, respectively)	(39,385)	(30,669)	(31,153)
Interest income	94	10	1,459
Equity investment income (loss)	13,860	3,543	(49,046)
Cost investment income	6,398	—	—
Acquisition gain, net	—	—	22,548
Debt extinguishment loss	(8,148)	—	—
Other income	2,980	725	955
INCOME BEFORE INCOME TAXES	304,411	339,551	306,192
INCOME TAX EXPENSE	210	13	21
NET INCOME	304,201	339,538	306,171
LESS: NET LOSS (INCOME) ATTRIBUTABLE TO NONCONTROLLING INTEREST	(563)	(140)	27
NET INCOME ATTRIBUTABLE TO ALLIANCE RESOURCE PARTNERS, L.P. ("NET INCOME OF ARLP")	$ 303,638	$ 339,398	$ 306,198
GENERAL PARTNERS' INTEREST IN NET INCOME OF ARLP	$ 21,904	$ 80,911	$ 146,338
LIMITED PARTNERS' INTEREST IN NET INCOME OF ARLP	$ 281,734	$ 258,487	$ 159,860
BASIC AND DILUTED NET INCOME OF ARLP PER LIMITED PARTNER UNIT	$ 2.80	$ 3.39	$ 2.11
DISTRIBUTIONS PAID PER LIMITED PARTNER UNIT	$ 1.88	$ 1.9875	$ 2.6625
WEIGHTED-AVERAGE NUMBER OF UNITS OUTSTANDING – BASIC AND DILUTED	98,707,696	74,354,162	74,174,389

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015
(In thousands)

	Year Ended December 31,		
	2017	**2016**	**2015**
NET INCOME	$ 304,201	$ 339,538	$ 306,171
OTHER COMPREHENSIVE INCOME (LOSS):			
Defined benefit pension plan			
Prior service cost	—	(1,498)	—
Amortization of prior service cost (1)	186	—	—
Net actuarial loss	(6,610)	(2,589)	(863)
Amortization of net actuarial loss (1)	3,054	2,952	3,354
Total defined benefit pension plan adjustments	(3,370)	(1,135)	2,491
Pneumoconiosis benefits			
Net actuarial loss	(7,938)	(205)	(750)
Amortization of net actuarial gain (1)	(2,092)	(2,643)	(451)
Total pneumoconiosis benefits adjustments	(10,030)	(2,848)	(1,201)
OTHER COMPREHENSIVE INCOME (LOSS)	(13,400)	(3,983)	1,290
COMPREHENSIVE INCOME	290,801	335,555	307,461
Less: Comprehensive (income) loss attributable to noncontrolling interest	(563)	(140)	27
COMPREHENSIVE INCOME ATTRIBUTABLE TO ARLP	$ 290,238	$ 335,415	$ 307,488

(1) Amortization of prior service cost and actuarial gain or loss is included in the computation of net periodic benefit cost (see Notes 13 and 17 for additional details).

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015
(In thousands)

	Year Ended December 31,		
	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 304,201	$ 339,538	$ 306,171
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	268,981	336,509	323,983
Non-cash compensation expense	12,326	13,885	12,631
Asset retirement obligations	3,793	3,769	3,192
Coal inventory adjustment to market	449	—	1,952
Equity investment (income) loss	(13,860)	(3,543)	49,046
Distributions received from investments	13,939	2,719	—
Paid-in-kind distributions received from cost investment	(6,398)	—	—
Net gain on sale of property, plant and equipment	(696)	(76)	(1)
Asset impairment	—	—	100,130
Acquisition gain, net	—	—	(22,548)
Valuation allowance of deferred tax assets	(3,339)	(1,365)	1,557
Debt extinguishment loss	8,148	—	—
Other	6,212	3,300	6,388
Changes in operating assets and liabilities:			
Trade receivables	(29,639)	(29,157)	64,412
Other receivables	133	417	422
Inventories, net	(1,449)	44,948	(21,898)
Prepaid expenses and other assets	(6,067)	17,023	(3,403)
Advance royalties, net	(13,591)	(2,464)	(6,915)
Accounts payable	25,499	(15,140)	(41,534)
Due to/from affiliates	(29)	696	(11,114)
Accrued taxes other than income taxes	2,063	2,652	(4,287)
Accrued payroll and related benefits	(5,825)	4,545	(24,527)
Pneumoconiosis benefits	(159)	447	2,808
Workers' compensation	(4,371)	(6,427)	(2,491)
Other	(4,205)	(8,732)	(17,632)
Total net adjustments	251,915	364,006	410,171
Net cash provided by operating activities	556,116	703,544	716,342
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(145,088)	(91,056)	(212,797)
Increase (decrease) in accounts payable and accrued liabilities	7,404	(4,402)	(3,021)
Proceeds from sale of property, plant and equipment	2,139	1,165	2,062
Contributions to equity investments	(20,688)	(76,797)	(64,540)
Purchase of cost investment	(100,000)	—	—
Distributions received from investments in excess of cumulative earnings	11,462	3,313	444
Payments for acquisitions of businesses, net of cash acquired	—	(1,011)	(74,953)
Payment for acquisition of customer contracts	—	(23,000)	—
Advances/loans to affiliate	—	—	(7,300)
Other	—	—	4,190
Net cash used in investing activities	(244,771)	(191,788)	(355,915)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under securitization facility	100,000	44,600	6,500
Payments under securitization facility	(127,600)	(27,700)	(23,400)
Payments on term loan	(50,000)	(156,250)	(108,502)
Borrowings under revolving credit facilities	215,486	140,000	543,000
Payments under revolving credit facilities	(440,486)	(270,000)	(308,000)
Borrowings under long-term debt	400,000	—	—
Payment on long-term debt	(145,000)	—	(205,000)
Proceeds on capital lease transactions	—	33,881	100,000
Payments on capital lease obligations	(27,071)	(24,456)	(4,312)
Payment of debt issuance costs	(16,487)	(101)	—
Payment for debt extinguishment	(8,148)	—	—
Contributions to consolidated company from affiliate noncontrolling interest	251	3,014	2,147
Net settlement of employee withholding taxes on vesting of Long-Term Incentive Plan	(2,988)	(1,336)	(2,719)
Cash contributions by General Partners	1,105	1,047	1,595
Distributions paid to Partners	(240,812)	(247,915)	(346,799)
Other	(2,621)	(189)	(6,107)
Net cash used in financing activities	(344,371)	(505,405)	(351,597)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(33,026)	6,351	8,830
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	39,782	33,431	24,601
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 6,756	$ 39,782	$ 33,431

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015
(In thousands, except unit data)

	Number of Limited Partner Units	Limited Partners' Capital	General Partners' Capital (Deficit)	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Partners' Capital
Balance at January 1, 2015	74,060,634	$ 1,310,517	$ (260,088)	$ (35,847)	$ 465	$ 1,015,047
Comprehensive income:						
Net income (loss)	—	159,860	146,338	—	(27)	306,171
Actuarially determined long-term liability adjustments	—	—	—	1,290	—	1,290
Total comprehensive income	—	—	—	—	—	307,461
Issuance of units to participants in deferred compensation plans (Note 14)	128,150	(2,719)	—	—	—	(2,719)
Common unit-based compensation	—	12,631	—	—	—	12,631
Distributions on common unit-based compensation	—	(2,627)	—	—	—	(2,627)
General Partners contributions (Note 12)	—	—	1,595	—	—	1,595
Contributions to consolidated company from affiliate noncontrolling interest (Note 10)	—	—	—	—	2,147	2,147
Distributions to Partners	—	(197,444)	(146,728)	—	—	(344,172)
Balance at December 31, 2015	74,188,784	1,280,218	(258,883)	(34,557)	2,585	989,363
Comprehensive income:						
Net income	—	258,487	80,911	—	140	339,538
Actuarially determined long-term liability adjustments	—	—	—	(3,983)	—	(3,983)
Total comprehensive income	—	—	—	—	—	335,555
Issuance of units to participants in deferred compensation plans (Note 14)	186,241	(1,336)	—	—	—	(1,336)
Common unit-based compensation	—	13,885	—	—	—	13,885
Distributions on common unit-based compensation	—	(3,355)	—	—	—	(3,355)
General Partners contributions (Note 12)	—	—	1,047	—	—	1,047
Contributions to consolidated company from affiliate noncontrolling interest (Note 10)	—	—	—	—	3,014	3,014
Distributions from consolidated company to affiliate noncontrolling interest (Note 10)	—	—	—	—	(189)	(189)
Distributions to Partners	—	(147,697)	(96,863)	—	—	(244,560)
Balance at December 31, 2016	74,375,025	1,400,202	(273,788)	(38,540)	5,550	1,093,424
Comprehensive income:						
Net income	—	281,734	21,904	—	563	304,201
Actuarially determined long-term liability adjustments	—	—	—	(13,400)	—	(13,400)
Total comprehensive income	—	—	—	—	—	290,801
Issuance of units to participants in deferred compensation plans (Note 14)	222,011	(2,988)	—	—	—	(2,988)
Issuance of units to MGP in Exchange Transaction	56,100,000	14,171	(14,171)	—	—	—
Issuance of units to SGP in Exchange Transaction	7,181	(320,838)	320,838	—	—	—
Exchange Transaction fees	—	(1,605)	—	—	—	(1,605)
Common unit-based compensation	—	12,326	—	—	—	12,326
Distributions on common unit-based compensation	—	(3,248)	—	—	—	(3,248)
General Partners contributions (Note 12)	—	—	1,105	—	—	1,105

Contributions to consolidated company from affiliate noncontrolling interest (Note 10)	—	—	—	—	251	251
Distributions from consolidated company to affiliate noncontrolling interest (Note 10)	—	—	—	—	(1,016)	(1,016)
Distributions to Partners	—	(196,535)	(41,029)	—	—	(237,564)
Balance at December 31, 2017	130,704,217	$ 1,183,219	$ 14,859	$ (51,940)	$ 5,348	$1,151,486

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015

1. ORGANIZATION AND PRESENTATION

Significant Relationships Referenced in Notes to Consolidated Financial Statements

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

Organization

ARLP is a Delaware limited partnership listed on the NASDAQ Global Select Market under the ticker symbol "ARLP." ARLP was formed in May 1999 to acquire, upon completion of ARLP's initial public offering on August 19, 1999, certain coal production and marketing assets of Alliance Resource Holdings, Inc., a Delaware corporation ("ARH"), consisting of substantially all of ARH's operating subsidiaries, but excluding ARH. ARH is owned by Joseph W. Craft III, the President and Chief Executive Officer and a Director of MGP, and Kathleen S. Craft. SGP, a Delaware limited liability company, is owned by ARH. SGP owns 20,641,168 common units of AHGP's 59,863,000 outstanding common units, 7,181 common units of ARLP and, prior to the Exchange Transaction discussed below, owned a 0.01% special general partner interest in both ARLP and the Intermediate Partnership.

We are managed by MGP, a Delaware limited liability company and the sole general partner of ARLP. MGP holds a non-economic general partner interest in ARLP, a 1.0001% managing general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal. AHGP is a Delaware limited partnership that was formed to become the owner and controlling member of MGP. AHGP completed its initial public offering ("AHGP IPO") on May 15, 2006. AHGP owns directly and indirectly 87,188,338 common units of ARLP's 130,704,217 outstanding common units as of December 31, 2017. AHGP indirectly owns 100% of the members' interest of MGP. ARLP and its consolidated subsidiaries represent virtually all the net assets and operations of AHGP. See discussions below regarding MGP's and AHGP's change of ownership in ARLP effective with the Exchange Transaction on July 28, 2017.

The Delaware limited partnership, limited liability companies and corporation that comprise our subsidiaries are as follows: Intermediate Partnership; Alliance Coal; Alliance Design Group, LLC ("Alliance Design"); Alliance Land, LLC; Alliance Minerals, LLC ("Alliance Minerals"); Alliance Resource Properties; Alliance Resource Finance Corporation ("Alliance Finance"); AROP Funding, LLC ("AROP Funding"); ARP Sebree, LLC ("ARP Sebree"); ARP Sebree South, LLC ("ARP Sebree South"); Alliance WOR Properties, LLC; Alliance Service, Inc. ("ASI"); Backbone Mountain, LLC; CR Services, LLC ("CR Services"); CR Machine Shop, LLC ("CR Machine Shop"); Excel Mining, LLC; Gibson County Coal, LLC ("Gibson County Coal"); Hamilton County Coal, LLC ("Hamilton"); Hopkins County Coal, LLC ("Hopkins County Coal"); Matrix Design Group, LLC ("Matrix Design"); Matrix Design International, LLC; Matrix Design Africa (PTY) LTD; MC Mining, LLC ("MC Mining"); Mettiki Coal, LLC ("Mettiki (MD)"); Mettiki Coal (WV), LLC ("Mettiki (WV)"); Mid-America Carbonates, LLC ("MAC"); Mt. Vernon Transfer Terminal, LLC ("Mt. Vernon"); Penn Ridge Coal,

LLC ("Penn Ridge"); Pontiki Coal, LLC ("Pontiki"); River View Coal, LLC ("River View"); Rough Creek Mining, LLC; Sebree Mining, LLC ("Sebree"); Steamport, LLC; Tunnel Ridge, LLC ("Tunnel Ridge"); UC Coal, LLC ("UC Coal"); UC Mining, LLC ("UC Mining"); UC Processing, LLC ("UC Processing"); Warrior Coal, LLC ("Warrior"); Webster County Coal, LLC ("Webster County Coal"); White County Coal, LLC ("White County Coal"); WOR Land 6, LLC and Wildcat Insurance, LLC ("Wildcat Insurance").

Exchange Transaction

In 2017, the board of directors of our general partner ("Board of Directors") and its conflicts committee ("Conflicts Committee") unanimously approved a transaction to simplify our partnership structure and on July 28, 2017, MGP contributed to ARLP all of its incentive distribution rights ("IDRs") and its 0.99% managing general partner interest in ARLP in exchange for 56,100,000 ARLP common units and a non-economic general partner interest in ARLP. In conjunction with this transaction and on the same economic basis as MGP, SGP also contributed to ARLP its 0.01% general partner interests in both ARLP and the Intermediate Partnership in exchange for 7,181 ARLP common units (collectively the "Exchange Transaction"). In connection with the Exchange Transaction, ARLP amended its partnership agreement to reflect, among other things, cancellation of the IDRs and the economic general partner interest in ARLP and issuance of a non-economic general partner interest to MGP. MGP is the sole general partner of ARLP following the Exchange Transaction, and no control, management or governance changes otherwise occurred.

The Exchange Transaction constituted an exchange of equity interests between entities under common control and not a transfer of a business. Therefore, the exchange resulted in a reclassification, as of the date of the Exchange Transaction, of a $306.7 million deficit capital balance from the *General Partners' interest* line item to the *Limited Partners - Common Unitholders* line item in our consolidated balance sheets. The reclassification amounts represented the carrying value of the exchanged interests, which included the SGP's deficit balance associated with its prior special general partner interests in ARLP and the Intermediate Partnership, partially offset, by MGP's capital balance associated with its prior managing general partner interest in ARLP. The SGP deficit balance primarily resulted from contribution and assumption agreements associated with the formation of the ARLP Partnership in 1999.

Simultaneously with the Exchange Transaction discussed above, MGP became a wholly owned subsidiary of MGP II, LLC ("MGP II") which is owned 100% directly and indirectly by AHGP and was created in connection with the Exchange Transaction. As of December 31, 2017, MGP II held the 56,100,000 ARLP common units discussed above.

Presentation

The consolidated financial statements include the accounts and operations of the ARLP Partnership and present our financial position as of December 31, 2017 and 2016, and results of our operations, comprehensive income, cash flows and changes in partners' capital for each of the three years in the period ended December 31, 2017. All of our intercompany transactions and accounts have been eliminated.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

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

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

***Consolidation*—**The consolidated financial statements present the consolidated financial position, results of operations and cash flows of ARLP, the Intermediate Partnership (a subsidiary of ARLP and a variable interest entity of which ARLP is the primary beneficiary), Alliance Coal (a subsidiary of the Intermediate Partnership and a variable interest entity of which the Intermediate Partnership is the primary beneficiary) and other directly and indirectly wholly- and majority-owned subsidiaries of the Intermediate Partnership and Alliance Coal. The Intermediate Partnership, Alliance Coal and their wholly- and majority-owned subsidiaries represent virtually all the net assets of the ARLP Partnership. MGP's interests in both Alliance Coal and the Intermediate Partnership are reported as general partner interest in the ARLP Partnership. MGP's previous 0.99% managing general partner interest and IDR in ARLP and SGP's previous 0.01% interest in both ARLP and the Intermediate Partnership, all held prior to the Exchange Transaction, are also reported with the general partner interest in ARLP. All intercompany transactions and accounts have been eliminated. See Note 10 – Variable Interest Entities for more information regarding ARLP's consolidation of the Intermediate Partnership and Alliance Coal. See Note 9 – Distributions of Available Cash for more information regarding MGP's IDR in ARLP. See Note 1 – Organization and Presentation for more information regarding the Exchange Transaction.

***Fair Value Measurements*—**We apply fair value measurements to certain assets and liabilities. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Fair value is based upon assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and risks inherent in valuation techniques and inputs to valuations. Fair value measurements assume that the transaction occurs in the principal market for the asset or liability or, in the absence of a principal market, the most advantageous market for the asset or liability (the market for which the reporting entity would be able to maximize the amount received or minimize the amount paid). Valuation techniques used in our fair value measurements are based upon observable and unobservable inputs. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect our own market assumptions.

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

- Level 1 – Quoted prices for identical assets and liabilities in active markets that we have the ability to access at the measurement date.
- Level 2 – Quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model derived valuations whose inputs are observable or whose significant value drivers are observable.
- Level 3 – Unobservable inputs for the asset or liability including situations where there is little, if any, market activity for the asset or liability.

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

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

***Cash Management*—**The cash flows from operating activities section of our consolidated statements of cash flows reflects adjustments for $14.0 million and $10.6 million representing book overdrafts at December 31, 2017 and 2015. We did not have material book overdrafts at December 31, 2016.

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

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

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

***Goodwill*—**Goodwill represents the excess of cost over the fair value of net assets of acquired businesses. Goodwill is not amortized, but instead is evaluated for impairment periodically. We evaluate goodwill for impairment annually on November 30th, or more often if events or circumstances indicate that goodwill might be impaired. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed or operated. A reporting unit is an operating segment or a component that is one level below an operating segment. There were no impairments of goodwill during 2017 or 2016.

***Property, Plant and Equipment*—**Expenditures which extend the useful lives of existing plant and equipment assets are capitalized. Interest costs associated with major asset additions are capitalized during the construction period. Maintenance and repairs that do not extend the useful life or increase productivity of the asset are charged to operating expense as incurred. Exploration expenditures are charged to operating expense as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves. Land, machinery and equipment under capital lease agreements are capitalized and amortized over the useful lives of the assets given that in each case, ownership transfers at the end of the lease term. Preparation plants and processing facilities are depreciated using the units-of-production method. Other plant and equipment assets are depreciated principally using the straight-line method over the estimated useful lives of the assets, ranging from 1 to 22 years, limited by the remaining estimated life of each mine. Depreciable lives for the mining equipment range from 1 to 22 years. Depreciable lives for buildings, office equipment and improvements range from 1 to 24 years. Gains or losses arising from retirements are included in operating expenses. Depletable lives for mineral rights, assuming current production expectations, range from 1 to 22 years. Depletion of mineral rights is provided on the basis of tonnage mined in relation to estimated recoverable tonnage, which equals estimated proven and probable reserves. Therefore, our mineral rights are depleted based on only proven and probable reserves derived in accordance with Industry Guide 7. At December 31, 2017 and 2016, land and mineral rights include $34.5 million and $34.4 million, respectively, representing the carrying value of coal reserves attributable to properties where we or a third party to which we lease reserves are not currently engaged in mining operations or leasing to third parties, and therefore, the coal reserves are not currently being depleted. We believe that the carrying value of these reserves will be recovered. Our accounting for operating leases not currently capitalized is expected to change upon the adoption of Accounting Standards Update ("ASU") 2016-02, *Leases (Topic 842)* ("ASU 2016-02"), as discussed below under *New Accounting Standards Issued and Not Yet Adopted*.

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

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

***Intangibles*—**Intangibles subject to amortization include contracts with covenants not to compete, customer contracts acquired from other parties and mining permits. Intangibles other than customer contracts are amortized on a straight-line basis over their useful life. Intangibles for customer contracts are amortized on a per unit basis over the terms of the contracts. Amortization expense attributable to intangibles was $10.5 million, $18.1 million and $15.1 million for the years ending December 31, 2017, 2016 and 2015, respectively. Our intangibles are included in *Prepaid expenses and*

other assets, *Other long-term assets*, *Other current liabilities* and *Other liabilities* on our consolidated balance sheets at December 31, 2017 and 2016. Our intangibles at December 31 are summarized as follows:

	December 31, 2017			December 31, 2016		
	Original Cost	Accumulated Amortization	Intangibles, Net	Original Cost	Accumulated Amortization	Intangibles, Net
	(in thousands)					
Non-compete agreements	$ 9,697	$ (7,378)	$ 2,319	$ 14,542	$ (10,974)	$ 3,568
Customer contracts and other, net	48,970	(36,462)	12,508	54,978	(33,300)	21,678
Mining permits	1,500	(178)	1,322	1,500	(104)	1,396
Total	$ 60,167	$ (44,018)	$ 16,149	$ 71,020	$ (44,378)	$ 26,642

Amortization expense attributable to intangible assets is estimated as follows:

Year Ended December 31,	(in thousands)
2018	$ 6,918
2019	7,737
2020	391
2021	74
2022	74
Thereafter	955

Investments—Our investments and ownership interests in which we do not have a controlling financial interest are accounted for under either the cost method of accounting if we do not have the ability to exercise significant influence over the entity, or under the equity method of accounting if we have the ability to exercise significant influence over the entity.

Historical cost is used to account for investments accounted for under the cost method and distributions received on those investments are recorded as income unless those distributions are considered a return on investment in which case the historical cost is reduced. Our cost method investment includes Kodiak Gas Services, LLC ("Kodiak"). See Note 11 – Investments for further discussion of this cost method investment.

Investments accounted for under the equity method are initially recorded at cost, and the difference between the basis of our investment and the underlying equity in the net assets of the joint venture at the investment date, if any, is amortized over the lives of the related assets that gave rise to the difference. In the event our ownership entitles us to a disproportionate sharing of income or loss, our equity investment income or loss is allocated based on the hypothetical liquidation at book value ("HLBV") method of accounting.

Under the HLBV method, equity investment income or loss is allocated based on the difference between our claim on the net assets of the equity method investee at the end and beginning of the period, with consideration of certain eliminating entries regarding differences of accounting for various related-party transactions, after taking into account contributions and distributions, if any. Our share of the net assets of the equity method investee is calculated as the amount we would receive if the equity method investee were to liquidate all of its assets at net book value and distribute the resulting cash to creditors, other investors and us according to the respective priorities. None of our current equity investments use the HLBV method. Our last use of this method was in 2015 for our equity method investment in White Oak Resources LLC ("White Oak").

Our equity method investments include AllDale Minerals, LP ("AllDale I"), and AllDale Minerals II, LP ("AllDale II") (collectively "AllDale Minerals"), both held by our affiliate Cavalier Minerals JV, LLC ("Cavalier Minerals") and additionally, we have an equity method investment in AllDale Minerals III, LP ("AllDale III") which is held through our subsidiary, Alliance Minerals. AllDale III, together with AllDale Minerals is considered the "AllDale Partnerships." During 2015, our equity method investments also included White Oak prior to our acquisition of its remaining equity interests on July 31, 2015. See Note 11 – Investments for further discussion of these equity method investments. For discussion of the White Oak acquisition, see Note 3 – Acquisitions.

We review our investments and ownership interests accounted for under both the equity method of accounting and the cost method of accounting for impairment whenever events or changes in circumstances indicate a loss in the value of the investment may be other-than-temporary.

***Advance Royalties, net*—**Rights to coal mineral leases are often acquired and/or maintained through advance royalty payments. Where royalty payments represent prepayments recoupable against future production, they are recorded as an asset, with amounts expected to be recouped within one year classified as a current asset. As mining occurs on these leases, the royalty prepayments are charged to operating expenses. We assess the recoverability of royalty prepayments based on estimated future production. We have recorded a $6.1 million and $6.2 million allowance against these prepayments as of December 31, 2017 and 2016, respectively. Royalty prepayments estimated to be nonrecoverable are expensed. Our *Advance royalties, net* at December 31 are summarized as follows:

	2017	2016
	(in thousands)	
Advance royalties, affiliates (see Note 18 – Related-Party Transactions)	$ 32,993	$ 19,820
Advance royalties, third-parties	11,177	10,759
Total advance royalties, net	$ 44,170	$ 30,579

***Asset Retirement Obligations*—**The majority of our operations are governed by various state statutes and the Federal Surface Mining Control and Reclamation Act of 1977, which establish reclamation and mine closing standards. These regulations require, among other things, restoration of property in accordance with specified standards and an approved reclamation plan. We record a liability for the fair value of the estimated cost of future mine asset retirement and closing procedures, escalated for inflation then discounted, on a present value basis in the period incurred or acquired and a corresponding amount is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to permanently sealing portals at underground mines and to reclaiming the final pits and support surface acreage for both our underground mines and past surface mines. Examples of these types of costs, common to both types of mining, include, but are not limited to, removing or covering refuse piles and settling ponds, water treatment obligations, and dismantling preparation plants, other facilities and roadway infrastructure. Accounting for asset retirement obligations also requires depreciation of the capitalized asset retirement cost and accretion of the asset retirement obligation over time. The depreciation is generally determined on a units-of-production basis and accretion is generally recognized over the life of the producing assets. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free interest rate. Federal and state laws require bonds to secure our obligations to reclaim lands used for mining and are typically renewable on a yearly basis. See Note 16 – Asset Retirement Obligations for more information.

***Pension Benefits*—**The funded status of our pension benefit plan is recognized separately in our consolidated balance sheets as either an asset or liability. The funded status is the difference between the fair value of plan assets and the plan's benefit obligation. Pension obligations and net periodic benefit costs are actuarially determined and impacted by various assumptions and estimates including expected return on assets, discount rates, mortality assumptions, employee turnover rates and retirement dates. We evaluate our assumptions periodically and make adjustments to these assumptions and the recorded liability as necessary (See Note 13 – Employee Benefit Plans).

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

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

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

Workers' Compensation and Pneumoconiosis (Black Lung) Benefits—We are liable for workers' compensation benefits for traumatic injuries and benefits for black lung disease (or pneumoconiosis). Both traumatic claims and pneumoconiosis benefits are covered through our self-insured programs. In addition, certain of our mine operating entities are liable under state statutes and the Federal Coal Mine Health and Safety Act of 1969, as amended, to pay pneumoconiosis benefits to eligible employees and former employees and their dependents.

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. Workers' compensation laws also compensate survivors of workers who suffer employment related deaths. Our liability for traumatic injury claims is the estimated present value of current workers' compensation benefits, based on our actuarial estimates. Our actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including claim development patterns, mortality, medical costs and interest rates.

Our pneumoconiosis benefits liability is calculated using the service cost method based on the actuarial present value of the estimated pneumoconiosis obligation. Our actuarial calculations are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and discount rates. Actuarial gains or losses are amortized over the remaining service period of active miners. See Note 17 – Accrued Workers' Compensation and Pneumoconiosis Benefits for more information on Workers' Compensation and Pneumoconiosis Benefits.

Revenue Recognition—Revenues from coal sales are recognized when title passes to the customer as the coal is shipped. Some coal supply agreements provide for price adjustments based on variations in quality characteristics of the coal shipped. In certain cases, a customer's analysis of the coal quality is binding and the results of the analysis are received on a delayed basis. In these cases, we estimate the amount of the quality adjustment and adjust the estimate to actual when the information is provided by the customer. Historically, such adjustments have not been material. Non-coal sales revenues primarily consist of transloading fees, administrative service revenues from our affiliates, mine safety services and products, royalties and throughput fees earned from White Oak prior to July 31, 2015 as disclosed in Note 3 – Acquisitions, other coal contract fees and other handling and service fees. Transportation revenues are recognized in connection with us incurring the corresponding costs of transporting coal to customers through third-party carriers for which we are directly reimbursed through customer billings. As discussed below, we do not expect the new revenue recognition standard introduced by ASU 2014-09, *Revenue from Contracts with Customers* ("ASU 2014-09") will result in a material change to our pattern of revenue recognition when it becomes effective.

Common Unit-Based Compensation—We have the Long-Term Incentive Plan ("LTIP") for certain employees and officers of MGP and its affiliates who perform services for us. The LTIP awards are grants of non-vested "phantom" or notional units, also referred to as "restricted units", which upon satisfaction of time and performance based vesting requirements, entitle the LTIP participant to receive ARLP common units. Annual grant levels and vesting provisions for designated participants are recommended by the President and Chief Executive Officer of MGP, subject to review and approval of the compensation committee of our general partner ("Compensation Committee"). Vesting of all grants outstanding is subject to the satisfaction of certain financial tests, which management currently believes is probable. Grants issued to LTIP participants are expected to cliff vest on January 1st of the third year following issuance of the grants. We account for forfeitures of non-vested LTIP grants as they occur. We expect to settle the non-vested LTIP grants by delivery of ARLP common units, except for the portion of the grants that will satisfy tax withholding obligations of the LTIP participants. As provided under the distribution equivalent rights provisions of the LTIP and the terms of the LTIP awards, all non-vested grants include contingent rights to receive quarterly distributions in cash or at the discretion of the Compensation Committee, in lieu of cash, phantom units credited to a bookkeeping account with value, equal to the cash distributions we make to unitholders during the vesting period.

We utilize the Supplemental Executive Retirement Plan ("SERP") to provide deferred compensation benefits for certain officers and key employees. All allocations made to participants under the SERP are made in the form of "phantom" ARLP units and SERP distributions will be settled in the form of ARLP common units. The SERP is administered by the Compensation Committee.

Our directors participate in the MGP Amended and Restated Deferred Compensation Plan for Directors ("Deferred Compensation Plan"). Pursuant to the Deferred Compensation Plan, for amounts deferred either automatically or at the election of the director, a notional account is established and credited with notional common units of ARLP, described in the Deferred Compensation Plan as "phantom" units. Distributions from the Deferred Compensation Plan will be settled in the form of ARLP common units.

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

The fair value of restricted common unit grants under the LTIP, SERP and the Deferred Compensation Plan are determined on the grant date of the award and recognized as compensation expense on a pro rata basis for LTIP and SERP awards, as appropriate, over the requisite service period. Compensation expense is fully recognized on the grant date for quarterly distributions credited to SERP accounts and Deferred Compensation Plan awards. The corresponding liability is classified as equity and included in limited partners' capital in the consolidated financial statements (See Note 14 – Compensation Plans).

Income Taxes—We are not a taxable entity for federal or state income tax purposes; the tax effect of our activities accrues to the unitholders. Although publicly traded partnerships as a general rule will be taxed as corporations, we qualify for an exemption because at least 90% of our income consists of qualifying income, as defined in Section 7704 (c) of the Internal Revenue Code. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. Individual unitholders have different investment bases depending upon the timing and price of acquisition of their partnership units. Furthermore, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, differs from the accounting followed in our consolidated financial statements. Accordingly, the aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder's tax attributes in our partnership is not available to us. Our subsidiaries, ASI and Wildcat Insurance, are subject to federal and state income taxes. A valuation allowance is established if it is more likely than not that a deferred tax asset will not be realized. The Tax Cuts and Jobs Act of 2017 signed into law on December 22, 2017 is not expected to have a material impact on our consolidated financial statements.

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

Variable Interest Entity ("VIE")—VIEs are primarily entities that lack sufficient equity to finance their activities without additional financial support from other parties or whose equity holders, as a group, lack one or more of the following characteristics: (a) direct or indirect ability to make decisions, (b) obligation to absorb expected losses or (c) right to receive expected residual returns. A VIE must be evaluated quantitatively and qualitatively to determine the primary beneficiary, which is the reporting entity that has (a) the power to direct activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. The primary beneficiary is required to consolidate the VIE for financial reporting purposes.

To determine a VIE's primary beneficiary, we perform a qualitative assessment to determine which party, if any, has the power to direct activities of the VIE and the obligation to absorb losses and/or receive its benefits. This assessment involves identifying the activities that most significantly impact the VIE's economic performance and determine whether it, or another party, has the power to direct those activities. When evaluating whether we are the primary beneficiary of a VIE, we perform a qualitative analysis that considers the design of the VIE, the nature of our involvement and the variable interests held by other parties. See Note 10 – Variable Interest Entities for further information.

New Accounting Standards Issued and Adopted– In January 2017, the Financial Accounting Standards Board (the "FASB") issued ASU 2017-04, *Intangibles–Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* ("ASU 2017-04"). The ASU simplifies the subsequent measurement of goodwill by eliminating the need for an entity to determine the implied fair value of goodwill to calculate an impairment charge. Under the new guidance an entity compares the fair value of the reporting unit containing the goodwill to its carrying value and records any excess carrying value as an impairment charge. This new standard is applied prospectively and is effective for annual and interim periods beginning after December 15, 2019; however, early adoption is permitted. We have early adopted this new standard and will apply the guidance to any future goodwill impairment assessments. The adoption of ASU 2017-04 did not have a material impact on our consolidated financial statements.

In March 2016, the FASB issued ASU 2016-09, *Compensation–Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* ("ASU 2016-09"). ASU 2016-09 simplifies the accounting for several aspects of share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, flexibility in the accounting for forfeitures and classification on the statement of cash flows. ASU 2016-09 was effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods, with early adoption permitted. The adoption of ASU 2016-09 did not have a material impact on our consolidated financial statements.

In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 330): Simplifying the Measurement of Inventory* ("ASU 2015-11"). ASU 2015-11 simplifies the subsequent measurement of inventory. It replaces the current lower of cost or market test with the lower of cost or net realizable value test. Net realizable value is defined as the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The new standard was applied prospectively and was effective for annual reporting periods beginning after December 15, 2016 and interim periods within those annual periods, with early adoption permitted. The adoption of ASU 2015-11 did not have a material impact on our consolidated financial statements.

New Accounting Standards Issued and Not Yet Adopted– In March 2017, the FASB issued ASU 2017-07, *Compensation–Retirement Benefits (Topic 715)* ("ASU 2017-07"). ASU 2017-07 requires that an employer disaggregate the service cost component from the other components of net benefit cost. It also provides explicit guidance on how to present the service cost component and the other components of net benefit cost in the income statement and allows only the service cost component of net benefit cost to be eligible for capitalization. The new guidance will be applied retroactively to all periods presented. ASU 2017-07 is effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. We do not anticipate ASU 2017-07 will have a material impact on our consolidated financial statements.

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments* ("ASU 2016-13"). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments to require the use of a new forward-looking "expected loss" model that generally will result in earlier recognition of allowances for losses. The new standard will require disclosure of significantly more information related to these items. ASU 2016-13 is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, with early adoption permitted for the fiscal year beginning after December 15, 2018, including interim periods. We are currently evaluating the effect of adopting ASU 2016-13, but do not anticipate it will have a material impact on our consolidated financial statements.

In February 2016, the FASB issued ASU 2016-02 which increases transparency and comparability among organizations by requiring lessees to record right-to-use assets and corresponding lease liabilities on the balance sheet and disclosing key information about lease arrangements. The new guidance will classify leases as either finance or operating (similar to current standard's "capital" or "operating" classification), with classification affecting the pattern of income recognition in the statement of income. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted.

We have developed an assessment team to determine the effect of adopting ASU 2016-02. As part of the assessment process, we have reached out to various business units to begin the education process regarding the new standard, compile a population of leases, and assess systems and internal controls. We continue to monitor closely the activities of the FASB and various non-authoritative groups with respect to implementation issues that could affect our evaluation.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments - Overall (Subtopic 825-10), Recognition and Measurement of Financial Assets and Financial Liabilities* ("ASU 2016-01"). ASU 2016-01 will require entities to measure equity investments at fair value and recognize any changes in fair value in net income. The guidance removes the cost method of accounting for equity investments without a readily determinable fair value but provides a new measurement alternative where entities may choose to measure those investments at cost, less any impairment, plus or minus any changes resulting from observable price changes in transactions for the same issuer. ASU 2016-01 is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. We do not anticipate ASU 2016-01 will have a material impact on our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09 which is a new revenue recognition standard that provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the new standard is as follows:

An entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.

ASU 2014-09 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2017.

We developed an assessment team to determine the effect of adopting ASU 2014-09. As part of our assessment process, we applied the five-step analysis outlined in the new standard to certain contracts representative of the majority of our coal sales contracts and determined that our pattern of recognition is consistent between both the new and existing standards. We also reviewed the expanded disclosure requirements under the new standard and have determined the additional information to be disclosed. In addition, we reviewed our business processes, systems and internal controls over financial reporting to support the new recognition and disclosure requirements under the new standard.

We do not expect that the adoption of the new standard will have a material impact on our consolidated financial statements, but will require expanded disclosures including presenting, by type and by segment, revenues for all periods presented and expected revenues by year for performance obligations that are unsatisfied or partially unsatisfied as of the date of presentation. We have elected the modified retrospective transition method which allows a cumulative effect adjustment to equity as of the date of adoption. Because we do not anticipate a change in our pattern of revenue recognition, we anticipate that the transition will not have a material impact on our consolidated financial statements.

3. ACQUISITIONS

White Oak Resources

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

	(in thousands)
Cash on hand	$ 50,000
Contingent consideration	14,800
Settlement of pre-existing relationships	124,379
Previously held equity-method investment	121,155
Total consideration transferred	$ 310,334

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

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

Prior to the Hamilton Acquisition Date, we accounted for our 40% interest in White Oak as an equity method investment (See Note 11 – Investments). The acquisition date fair value of the previous equity interest was $121.2 million and is included in the measurement of the consideration transferred. We re-measured our equity investment immediately

prior to the Hamilton Acquisition using a discounted cash flow model which resulted in a loss of $52.3 million ("Re-measurement Loss") which is recorded in the line item *Acquisition gain, net* in our consolidated statements of income. The assumptions used in the determination of the fair value include projected financial information, forward coal price curves, and a risk adjusted discount rate. The assumptions used in this fair value measurement are not observable in active markets and therefore represents a Level 3 fair value measurement.

In connection with the Hamilton Acquisition, we settled our pre-existing relationships with White Oak which included existing account balances of $49.6 million. The settlement of pre-existing relationships also included, under business combination accounting, a $74.8 million net gain for above-market terms associated with pre-existing contractual agreements which were comprised of coal leases, a coal handling and preparation agreement, a coal supply agreement, export marketing and transportation agreements and certain debt agreements. The net gain of $74.8 million associated with the settlement of the net above-market terms is recorded in the line item *Acquisition gain, net* in our consolidated statements of income partially offset by the Re-measurement Loss of $52.3 million discussed above, which nets to $22.5 million. These settlements of account balances and settlements of net above-market terms are included in the measurement of consideration transferred for the Hamilton Acquisition. As part of the settlement of these agreements, we considered the rates at which a market participant would enter into these agreements and recognized gains for the above-market rates and losses for the below-market rates contained in the various agreements. We developed a discounted cash flow model to determine the fair value of each of these agreements at market rates and compared the valuations to similar models using the contractual rates of the agreements to determine our gains or losses. The assumptions used in these valuation models include processing rates, royalty rates, transportation rates, marketing rates, forward coal price curves, interest rates, projected financial information and risk-adjusted discount rates. These fair value measurements were based on the previously discussed assumptions which are not observable in active markets and therefore represent Level 3 fair value measurements.

The following table summarizes the fair value allocation of assets acquired and liabilities assumed at the Hamilton Acquisition Date:

	(in thousands)
Cash and cash equivalents	$ 3,125
Trade receivables	3,018
Prepaid expenses	3,942
Inventories	7,240
Other current assets	9,456
Property, plant and equipment	299,214
Advance royalties	3,349
Deposits	6,981
Other assets	12,829
Total identifiable assets acquired	349,154
Accounts payable	(31,181)
Accrued expenses	(20,987)
Deferred revenue	(517)
Current maturities, long-term debt	(29,529)
Long-term debt, excluding current maturities	(63,973)
Other long-term liabilities	(12,175)
Asset retirement obligations	(12,484)
Total liabilities assumed	(170,846)
Net identifiable assets acquired	$ 178,308
Goodwill	132,026
Net assets acquired	$ 310,334

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

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

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

We determined the fair value of cash and cash equivalents, trade receivables, prepaid expenses, advanced royalties, deposits, accounts payable, accrued expenses, and deferred revenue approximated White Oak's carrying value given the highly liquid and short-term nature of these assets and liabilities. We determined the fair value of inventories, property, plant and equipment (inclusive of mineral interests), and mining permits using a market approach. The market approach included the development of an entity-wide value using discounted cash flows and allocating the entity-wide value back to the underlying assets based on observed market prices. We have recorded the fair value of the above- and below-market components of customer contracts acquired as assets and liabilities. We determined these fair values through comparison of the terms in the contracts against projected coal prices. We also evaluated the acquired asset retirement obligation to determine the cost to fulfill the obligation and applied an appropriate discount rate to determine the fair value. The assumptions used in these fair value measurements are not observable in active markets and thus represent Level 3 fair value measurements. We determined the fair value of the long-term debt acquired through comparison of similar debt instruments and interest rates in active markets, and thus the assumptions used for the long-term debt represent Level 2 fair value measurements. (See Note 2 – Summary of Significant Accounting Policies – Fair Value Measurements for more information regarding fair value hierarchy levels.)

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

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

The following represents the pro forma revenue and net income for the year ended December 31, 2015 as if Hamilton had been included in the consolidated results of the Partnership since January 1, 2015. These amounts have been calculated after applying the Partnership's accounting. Additionally, the Partnership's results have been adjusted to remove the effect of its equity investment in White Oak and the pre-existing relationships that it had in White Oak.

	(in thousands)
Total revenues	
As reported	$ 2,273,733
Pro forma	2,337,380
Net income	
As reported	$ 306,171
Pro forma	295,219

Patriot Coal Corporation

On December 31, 2014 (the "Initial Closing Date"), we entered into asset purchase agreements with Patriot Coal Corporation ("Patriot") regarding certain assets relating to two of Patriot's western Kentucky mining operations, including certain coal sales agreements, unassigned coal reserves and underground mining equipment and infrastructure. Both of

the mining operations – the former Dodge Hill and Highland mining operations – were closed by Patriot in late 2014 prior to entering into these asset purchase agreements. Also on December 31, 2014, Patriot affiliates entered into agreements to sell other assets from Highland to a third party. Additional details of the transactions are discussed below.

On the Initial Closing Date, our subsidiary, Alliance Coal acquired the rights to certain coal supply agreements from an affiliate of Patriot for approximately $21.0 million. Of the $21.0 million purchase price, $9.3 million was paid into escrow subject to obtaining certain assignment consents. In February 2015, $7.5 million of the escrowed amount was released to Patriot for a consent received and $1.8 million was returned to Alliance Coal as a result of a consent not received, reducing our purchase price to $19.2 million. The acquired agreements provided for delivery of a total of approximately 5.1 million tons of coal from 2015 through 2017. Revenues generated by these contracts during 2015 were $130.5 million.

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

The mining and reserve assets acquired from Patriot described above are located in Union and Henderson Counties, Kentucky. The mining equipment, spare parts and underground infrastructure that we acquired from Patriot has been and is continuing to be dispersed to our existing operations in the Illinois Basin region in accordance with their highest and best use. Our purchase price of $19.2 million and $20.5 million paid on the Initial Closing Date and the Acquisition Date, respectively, described above was financed using existing cash on hand. In addition, our purchase price was increased by $8.3 million, comprising $2.1 million cash paid prior to the Acquisition Date related to the transaction and an agreement to pay approximately $6.2 million additional consideration, which was satisfied as of December 31, 2015.

In conjunction with our acquisitions on the Acquisition Date, WKY CoalPlay, LLC ("WKY CoalPlay"), a related party, acquired approximately 39.1 million tons of proven and probable medium/high-sulfur owned coal reserves located in Henderson and Union Counties, Kentucky from Central States Coal Reserves of Kentucky, LLC, a subsidiary of Patriot, for $25.0 million and in turn leased those reserves to us. See Note 18 – Related-Party Transactions for further information on our lease terms with WKY CoalPlay.

The fair value of the acquired tangible and intangible assets and assumed liabilities are based on discounted cash flow projections and estimated replacement cost valuation techniques. We used an estimate of replacement cost based on comparable market prices to value the acquired equipment and utilized discounted cash flows to value intangible assets and reserves. Key assumptions used in the valuations included projections of future cash flows, estimated weighted-average cost of capital, and internal rates of return. Due to the unobservable nature of these inputs, these estimates are considered Level 3 fair value measurements.

The following table summarizes the consideration transferred from us to Patriot and the fair value allocation of assets acquired and liabilities assumed as valued at the Acquisition Date:

	(in thousands)
Consideration transferred	$ 47,874
Recognized amounts of net tangible and intangible assets acquired and liabilities assumed:	
Inventories	1,994
Property, plant and equipment, including mineral rights and leased equipment	32,029
Customer contracts, net	19,193
Asset retirement obligation	(2,255)
Other liabilities	(3,087)
Net tangible and intangible assets acquired	$ 47,874

Intangible assets related to coal supply agreements, represented as "Customer contracts, net" in the table above, are reflected in the *Prepaid expenses and other assets* line item in our consolidated balance sheet at December 31, 2016. Amortization expense was recognized based on the weighted-average term of the contracts, ranging from 1 to 3 years, on a per unit basis.

MAC

In March 2006, White County Coal and Alexander J. House entered into a limited liability company agreement to form MAC. MAC was formed to engage in the development and operation of a rock dust mill and to manufacture and sell rock dust. White County Coal initially invested $1.0 million in exchange for a 50% equity interest in MAC. Our equity investment in MAC was $1.6 million at December 31, 2014. Effective on January 1, 2015, we purchased the remaining 50% equity interest in MAC from Mr. House for $5.5 million cash paid at closing. In conjunction with the acquisition, we assumed $0.2 million of liabilities and $7.3 million in assets, net of cash acquired, including $4.2 million of goodwill which is reflected in Other and Corporate in our segment presentation (Note 21 – Segment Information) and is included in the *Goodwill* line item in our consolidated balance sheets.

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for business combinations and goodwill.

4. LONG-LIVED ASSET IMPAIRMENTS

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

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

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

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

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for asset impairments.

5. INVENTORIES

Inventories consist of the following at December 31:

	2017	2016
	(in thousands)	
Coal	$ 22,825	$ 29,242
Supplies (net of reserve for obsolescence of $5,149 and $4,940, respectively)	37,450	31,809
Total inventories, net	$ 60,275	$ 61,051

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for inventories.

6. PROPERTY, PLANT AND EQUIPMENT

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

	2017	2016
	(in thousands)	
Mining equipment and processing facilities	$ 1,847,037	$ 1,854,001
Land and mineral rights	449,152	439,236
Buildings, office equipment and improvements	310,167	304,696
Construction and mine development in progress	47,223	26,025
Mine development costs	280,609	297,030
Property, plant and equipment, at cost	2,934,188	2,920,988
Less accumulated depreciation, depletion and amortization	(1,457,532)	(1,335,145)
Total property, plant and equipment, net	$ 1,476,656	$ 1,585,843

At December 31, 2017 and 2016, there were no capitalized development costs associated with mines in the development phase. All past capitalized development costs are associated with mines that shifted to the production phase and thus, these costs are being amortized. We believe that the carrying value of the past development costs will be recovered.

Equipment leased by us under lease agreements which are determined to be capital leases are stated at an amount equal to the present value of the minimum lease payments during the lease term, less accumulated amortization. Equipment under capital leases totaling $140.9 million included in mining equipment is amortized on the straight-line method over the shorter of its useful life or the related lease term. The provision for amortization of leased properties is included in depreciation, depletion and amortization expense. Accumulated amortization related to our capital leases was $55.6 million, $34.2 million and $7.1 million as of December 31, 2017, 2016 and 2015, respectively, and amortization expense was $24.9 million, $27.2 million and $5.7 million for the years ended December 31, 2017, 2016 and 2015, respectively. For information regarding long-lived asset impairments please see Note 4 – Long-Lived Asset Impairments. See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for property, plant and equipment.

7. LONG-TERM DEBT

Long-term debt consists of the following at December 31:

	Principal		Unamortized Discount and Debt Issuance Costs	
	2017	2016	2017	2016
	(in thousands)			
Revolving Credit facility	$ 30,000	$ 255,000	$ (7,356)	$ (453)
Senior notes	400,000	—	(6,707)	—
Series B senior notes	—	145,000	—	(101)
Term loan	—	50,000	—	(126)
Securitization facility	72,400	100,000	—	—
	502,400	550,000	(14,063)	(680)
Less current maturities	(72,400)	(150,000)	—	126
Total long-term debt	$ 430,000	$ 400,000	$ (14,063)	$ (554)

Credit Facility. On January 27, 2017, our Intermediate Partnership entered into a Fourth Amended and Restated Credit Agreement (the "Credit Agreement") with various financial institutions for a revolving credit facility and term loan (the "Credit Facility"). The Credit Facility replaced the $250 million term loan ("Replaced Term Loan") and $700 million revolving credit facility ("Replaced Revolving Credit Facility") extended to the Intermediate Partnership on May 23, 2012 (the "Replaced Credit Agreement") by various banks and other lenders that would have expired on May 23, 2017.

The Credit Agreement provided for a $776.5 million revolving credit facility, reducing to $494.75 million on May 23, 2017, including a sublimit of $125 million for the issuance of letters of credit and a sublimit of $15.0 million for swingline borrowings (the "Revolving Credit Facility"), and for a term loan with a remaining principal balance of $50.0 million (the "Term Loan"). The outstanding revolver balance and term loan balance under the Replaced Credit Agreement were considered advanced under the Credit Facility on January 27, 2017. On April 3, 2017, we entered into an amendment to the Credit Agreement (the "Amendment") to (a) extend the termination date of the Revolving Credit Facility as to $461.25 million of the $494.75 million of commitments to May 23, 2021, (b) eliminate the Cavalier Condition and the Senior Notes Condition (both as defined in the Credit Agreement) and (c) effectuate certain other changes. We incurred debt issuance costs in 2017 of $9.2 million in connection with the Credit Agreement. These debt issuance costs are deferred and amortized as a component of interest expense over the term of the Credit Facility.

The Credit Agreement is guaranteed by all of the material direct and indirect subsidiaries of our Intermediate Partnership, and is secured by substantially all of the Intermediate Partnership's assets. The Term Loan principal balance of $50.0 million was paid in full in May 2017.

Borrowings under the Credit Facility bear interest, at the option of the Intermediate Partnership, at either (i) the Base Rate at the greater of three benchmarks or (ii) a Eurodollar Rate, plus margins for (i) or (ii), as applicable, that fluctuate depending upon the ratio of Consolidated Debt to Consolidated Cash Flow (each as defined in the Credit Agreement). The interest rate, with applicable margin, under the Credit Facility was 4.49% as of December 31, 2017. At December 31, 2017, we had $8.1 million of letters of credit outstanding with $456.7 million available for borrowing under the Revolving Credit Facility. We currently incur an annual commitment fee of 0.35% on the undrawn portion of the Revolving Credit Facility. We utilize the Revolving Credit Facility, as appropriate, for working capital requirements, capital expenditures and investments, scheduled debt payments and distribution payments.

The Credit Agreement contains various restrictions affecting our Intermediate Partnership and its subsidiaries including, among other things, restrictions on incurrence of additional indebtedness and liens, sale of assets, investments, mergers and consolidations and transactions with affiliates, in each case subject to various exceptions, and the payment of cash distributions by our Intermediate Partnership if such payment would result in a certain fixed charge coverage ratio (as defined in the Credit Agreement). The Amendment lowered this fixed charge ratio from less than 1.25 to 1.0 to 1.15 to 1.0 for each rolling four-quarter period and further limited the Intermediate Partnership's ability to incur certain unsecured debt. See Note 10 – Variable Interest Entities for further discussion of restrictions on the cash available for distribution. The Amendment raised the debt to cash flow ratio from 2.25 to 1.0 to 2.50 to 1.0 and also removed the requirement for the Intermediate Partnership to remain in control of a certain amount of mineable coal reserves relative to its annual production. The Credit Agreement requires the Intermediate Partnership to maintain (a) a debt to cash flow

ratio of not more than 2.5 to 1.0 and (b) a cash flow to interest expense ratio of not less than 3.0 to 1.0, in each case, during the four most recently ended fiscal quarters. The debt to cash flow ratio and cash flow to interest expense ratio were 0.91 to 1.0 and 16.1 to 1.0, respectively, for the trailing twelve months ended December 31, 2017. We were in compliance with the covenants of the Credit Agreement as of December 31, 2017.

Series B Senior Notes. On January 27, 2017, the Intermediate Partnership also amended the 2008 Note Purchase Agreement dated June 26, 2008, for $145.0 million of Series B Senior Notes which bore interest at 6.72% and were due to mature on June 26, 2018 with interest payable semi-annually (the "Series B Senior Notes"). The amendment provided for certain modifications to the terms and provisions of the Note Purchase Agreement, including granting liens on substantially all of the Intermediate Partnership's assets to secure its obligations under the Note Purchase Agreement on an equal basis with the obligations under the Credit Agreement. The amendment also modified certain covenants to align them with the applicable covenants in the Credit Agreement. As discussed below, we repaid the Series B Senior Notes in May 2017.

Senior Notes. On April 24, 2017, the Intermediate Partnership and Alliance Finance (as co-issuer), a wholly owned subsidiary of the Intermediate Partnership, issued an aggregate principal amount of $400.0 million of senior unsecured notes due 2025 ("Senior Notes") in a private placement to qualified institutional buyers. The Senior Notes have a term of eight years, maturing on May 1, 2025 (the "Term") and accrue interest at an annual rate of 7.5%. Interest is payable semi-annually in arrears on each May 1 and November 1, commencing on November 1, 2017. The indenture governing the Senior Notes contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of distributions or similar restricted payments, undertaking transactions with affiliates and limitations on asset sales. At any time prior to May 1, 2020, the issuers of the Senior Notes may redeem up to 35% of the aggregate principal amount of the Senior Notes with the net cash proceeds of one or more equity offerings at a redemption price equal to 107.5% of the principal amount redeemed, plus accrued and unpaid interest, if any, to the redemption date. The issuers of the Senior Notes may also redeem all or a part of the notes at any time on or after May 1, 2020, at redemption prices set forth in the indenture governing the Senior Notes. At any time prior to May 1, 2020, the issuers of the Senior Notes may redeem the Senior Notes at a redemption price equal to the principal amount of the Senior Notes plus a "make-whole" premium, plus accrued and unpaid interest, if any, to the redemption date. The net proceeds from issuance of the Senior Notes and cash on hand were used to repay the Revolving Credit Facility, Term Loan and Series B Senior Notes (including a make-whole payment of $8.1 million). We incurred discount and debt issuance costs of $7.3 million in connection with issuance of the Senior Notes. These costs are deferred and are currently being amortized as a component of interest expense over the Term.

Accounts Receivable Securitization. On December 5, 2014, certain direct and indirect wholly owned subsidiaries of our Intermediate Partnership entered into a $100.0 million accounts receivable securitization facility ("Securitization Facility"). Under the Securitization Facility, certain subsidiaries sell trade receivables on an ongoing basis to our Intermediate Partnership, which then sells the trade receivables to AROP Funding, a wholly owned bankruptcy-remote special purpose subsidiary of our Intermediate Partnership, which in turn borrows on a revolving basis up to $100.0 million secured by the trade receivables. After the sale, Alliance Coal, as servicer of the assets, collects the receivables on behalf of AROP Funding. The Securitization Facility bears interest based on a Eurodollar Rate. In November 2017, we extended the term of the Securitization Facility to January 2018. It was renewed in January 2018 and now matures in January 2019. At December 31, 2017, we had $72.4 million outstanding under the Securitization Facility.

Cavalier Credit Agreement. On October 6, 2015, Cavalier Minerals (see Note 10 – Variable Interest Entities) entered into a credit agreement (the "Cavalier Credit Agreement") with Mineral Lending, LLC ("Mineral Lending") for a $100.0 million line of credit (the "Cavalier Credit Facility"). Mineral Lending is an entity owned by (a) Alliance Resource Holdings II, Inc. ("ARH II", the parent of ARH), (b) an entity owned by an officer of ARH who is also a director of ARH II ("ARH Officer") and (c) foundations established by the President and Chief Executive Officer of MGP and Kathleen S. Craft. There is no commitment fee under the facility. Borrowings under the Cavalier Credit Facility bear interest at a one month LIBOR rate plus 6.0% with interest payable quarterly. Repayment of the principal balance begins following the first fiscal quarter after the earlier of the date on which the aggregate amount borrowed exceeds $90.0 million or December 31, 2017, in quarterly payments of an amount equal to the greater of $1.3 million initially, escalated to $2.5 million after two years, or fifty percent of Cavalier Minerals' excess cash flow. The Cavalier Credit Facility matures September 30, 2024, at which time all amounts then outstanding are required to be repaid. To secure payment of the facility, Cavalier Minerals pledged all of its partnership interests, owned or later acquired, in AllDale Minerals. Cavalier Minerals may prepay the Cavalier Credit Facility at any time in whole or in part subject to terms and conditions described in the Cavalier Credit Agreement. As of December 31, 2017, Cavalier Minerals had not drawn on the Cavalier Credit Facility. Alliance

Minerals has the right to require Cavalier Minerals to draw the full amount available under the Cavalier Credit Facility and distribute the proceeds to the members of Cavalier Minerals, including Alliance Minerals.

Other. We also have an agreement with a bank to provide additional letters of credit in an amount of $5.0 million to maintain surety bonds to secure certain asset retirement obligations and our obligations for workers' compensation benefits. At December 31, 2017, we had $5.0 million in letters of credit outstanding under this agreement.

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

Year Ended December 31,	(in thousands)
2018	$ 72,400
2019	—
2020	—
2021	30,000
2022	—
Thereafter	400,000
	$ 502,400

8. FAIR VALUE MEASUREMENTS

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

	December 31, 2017			December 31, 2016		
	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
	(in thousands)					
Measured on a recurring basis:						
Contingent consideration	$ —	$ —	$ 6,800	$ —	$ —	$ 9,700
Additional disclosures:						
Long-term debt	—	541,147	—	—	559,509	—
Total	$ —	$ 541,147	$ 6,800	$ —	$ 559,509	$ 9,700

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

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

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

The estimated fair value of the contingent consideration arrangement is based on a probability-weighted discounted cash flow model. The assumptions in the model include a risk-adjusted discount rate, forward coal sale price curves, cost of debt and probabilities of meeting certain contractual threshold coal sales prices (See Note 3 – Acquisitions). The decrease in fair value was primarily a result of changes in forward coal sale prices and is recorded in *Operating expenses (excluding depreciation, depletion and amortization)* in our consolidated income statement. The fair value measurement is based on significant inputs not observable in active markets and thus represents a Level 3 fair value measurement under the fair value hierarchy.

9. DISTRIBUTIONS OF AVAILABLE CASH

We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined in the partnership agreement as all cash and cash equivalents on hand at the end of each quarter less reserves established by MGP in its reasonable discretion for future cash requirements. These reserves are retained to provide for the conduct of our business, the payment of debt principal and interest and to provide funds for future distributions. These reserves are also considered in our review of certain VIEs discussed in Note 10 – Variable Interest Entities.

Prior to the Exchange Transaction in July 2017 (See Note 1 – Organization and Presentation), as quarterly distributions of available cash exceeded certain target distribution levels, MGP received distributions based on specified increasing percentages of the available cash that exceeded the target distribution levels. The target distribution levels were based on the amounts of available cash from our operating surplus distributed for a given quarter that exceeded the minimum quarterly distribution ("MQD") and common unit arrearages, if any. The MQD was defined as $0.125 per unit ($0.50 per unit on an annual basis).

Under the previous quarterly IDR provisions of our partnership agreement, MGP was entitled to receive 15% of the amount we distributed in excess of $0.1375 per unit, 25% of the amount we distributed in excess of $0.15625 per unit, and 50% of the amount we distributed in excess of $0.1875 per unit. During the years ended December 31, 2017, 2016 and 2015, we paid to MGP incentive distributions of $37.6 million, $92.0 million and $139.8 million, respectively. The following table summarizes the quarterly per unit distribution paid during the respective quarter:

	Year		
	2017	2016	2015
First Quarter	$ 0.4375	$ 0.6750	$ 0.6500
Second Quarter	$ 0.4375	$ 0.4375	$ 0.6625
Third Quarter	$ 0.5000	$ 0.4375	$ 0.6750
Fourth Quarter	$ 0.5050	$ 0.4375	$ 0.6750

On January 26, 2018, we declared a quarterly distribution of $0.51 per unit, totaling approximately $67.3 million (including distributions to MGP with respect to its general partner interest in the Intermediate Partnership), on all our common units outstanding, which was paid on February 14, 2018, to all unitholders of record on February 7, 2018.

10. VARIABLE INTEREST ENTITIES

Cavalier Minerals

On November 10, 2014, our subsidiary, Alliance Minerals, and Bluegrass Minerals Management, LLC ("Bluegrass Minerals") entered into a limited liability company agreement (the "Cavalier Agreement") to create Cavalier Minerals, which was formed to indirectly acquire oil and gas mineral interests, initially through its 71.7% noncontrolling ownership interest in AllDale I and subsequently through its 72.8% noncontrolling ownership interest in AllDale II. Bluegrass Minerals is owned and controlled by the ARH Officer discussed in Note 7 – Long-Term Debt and is Cavalier Minerals' managing member. Alliance Minerals and Bluegrass Minerals initially committed funding of $48.0 million and $2.0 million, respectively, to Cavalier Minerals, and Cavalier Minerals committed funding of $49.0 million to AllDale I. On October 6, 2015, Alliance Minerals and Bluegrass Minerals committed to fund an additional $96.0 million and $4.0 million, respectively, to Cavalier Minerals, and Cavalier Minerals committed to fund $100.0 million to AllDale II. Contributions in 2017 sufficiently completed funding to Cavalier Minerals for these commitments. Cavalier Minerals is not expected to call on further funding of these commitments from Alliance Minerals and Bluegrass Minerals.

Contributions made from Alliance Minerals and Bluegrass Minerals to Cavalier Minerals for each period presented are as follows:

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Alliance Minerals			
Beginning cumulative commitment fulfilled	$ 137,077	$ 63,498	$ 11,520
Capital contributions - Cash	6,035	72,334	51,552
Capital contributions - Net AllDale Minerals' distributions received by Cavalier Minerals (1)	—	1,245	426
Ending cumulative commitment fulfilled	143,112	137,077	63,498
Remaining commitment	888	6,923	80,502
Total committed	$ 144,000	$ 144,000	$ 144,000
Bluegrass Minerals			
Beginning cumulative commitment fulfilled	$ 5,712	$ 2,646	$ 480
Capital contributions - Cash	251	3,014	2,148
Capital contributions - Net AllDale Minerals' distributions received by Cavalier Minerals (1)	—	52	18
Ending cumulative commitment fulfilled	5,963	5,712	2,646
Remaining commitment	37	288	3,354
Total committed	$ 6,000	$ 6,000	$ 6,000

(1) Represents distributions received from AllDale Minerals net of distributions reinvested and payments to Bluegrass Minerals for administration expense.

In accordance with the Cavalier Agreement, Bluegrass Minerals is entitled to receive an incentive distribution from Cavalier Minerals equal to 25% of all distributions (including in liquidation) after all members have recovered their investment. The incentive distributions are reduced by certain distributions received by Bluegrass Minerals or its owner from AllDale Minerals Management, LLC ("AllDale Minerals Management"), the managing member of AllDale Minerals. Distributions paid to Alliance Minerals and Bluegrass Minerals from Cavalier Minerals for each period presented are as follows:

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Alliance Minerals	$ 24,385	$ 4,546	$ —
Bluegrass Minerals	1,016	189	—

Alliance Minerals' ownership interest in Cavalier Minerals at December 31, 2017 and 2016 was 96%. The remainder of the equity ownership is held by Bluegrass Minerals. We have consolidated Cavalier Minerals' financial results as we concluded that Cavalier Minerals is a VIE and we are the primary beneficiary because neither Bluegrass Minerals nor Alliance Minerals individually has both the power and the benefits related to Cavalier Minerals and we are most closely aligned with Cavalier Minerals through our substantial equity ownership. Bluegrass Minerals' equity ownership of Cavalier Minerals is accounted for as noncontrolling ownership interest in our consolidated balance sheets. In addition, earnings attributable to Bluegrass Minerals are recognized as noncontrolling interest in our consolidated statements of income.

WKY CoalPlay

On November 17, 2014, SGP Land, LLC ("SGP Land"), a wholly owned subsidiary of SGP, and two limited liability companies ("Craft Companies") owned by irrevocable trusts established by the President and Chief Executive Officer of MGP entered into a limited liability company agreement to form WKY CoalPlay. WKY CoalPlay was formed, in part, to purchase and lease coal reserves. WKY CoalPlay is managed by the ARH Officer discussed in Note 7 – Long-Term Debt, who is also an employee of SGP Land and trustee of the irrevocable trusts owning the Craft Companies. In December 2014

and February 2015, we entered into various coal reserve leases with WKY CoalPlay. See Note 18 – Related-Party Transactions for further information on our lease terms with WKY CoalPlay.

We have concluded that WKY CoalPlay is a VIE because of our ability to exercise options to acquire reserves under lease with WKY CoalPlay (Note 18 – Related-Party Transactions), which is not within the control of the equity holders and, if it occurs, could potentially limit the expected residual return to the owners of WKY CoalPlay. We do not have any economic or governance rights related to WKY CoalPlay and our options that provide us with a variable interest in WKY CoalPlay's reserve assets do not give us any rights that constitute power to direct the primary activities that most significantly impact WKY CoalPlay's economic performance. SGP Land has the sole ability to replace the manager of WKY CoalPlay at its discretion and therefore has power to direct the activities of WKY CoalPlay. Consequently, we concluded that SGP Land is the primary beneficiary of WKY CoalPlay.

White Oak

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

These protective and participating rights did not provide us the ability to unilaterally direct any of the primary activities of White Oak that most significantly impacted its economic performance and thus, we were not the primary beneficiary for consolidation purposes. Consequentially, we accounted for our Series A Units investment as an equity investment. See Note 11 – Investments for further information.

Alliance Coal and the Intermediate Partnership

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

The Intermediate Partnership holds a 99.999% non-managing interest and MGP holds the 0.001% managing member interest in Alliance Coal. To determine whether Alliance Coal is a VIE, we considered that since Alliance Coal is structured as the equivalent of a limited partnership with the non-managing member 1) not having the ability to remove its managing member and 2) not participating significantly in the operational decisions, Alliance Coal represents a VIE.

We determined that neither the MGP nor the Intermediate Partnership have both the power and the benefits related to Alliance Coal. We then considered which of the two was most closely aligned with Alliance Coal and thus would be designated the primary beneficiary of Alliance Coal for consolidation purposes. We determined that the Intermediate Partnership was most closely aligned with Alliance Coal and is the primary beneficiary. We based our determination of alignment on 1) the purpose and design of Alliance Coal which is to a) be the operating subsidiary of the Intermediate Partnership and b) distribute all of its available cash to the Intermediate Partnership such that the Intermediate Partnership can pay its partners and debt obligations, 2) AHGP's common control over both the Intermediate Partnership and MGP, as discussed in Note 1 – Organization and Presentation, to achieve the aforementioned purpose and design and 3) the Intermediate Partnership's debt funding for Alliance Coal for capital expenditures, operations and other purposes as needed and related risks and collateral requirements in the debt arrangements.

ARLP holds a 98.9899% limited partnership interest and a 0.01% general partner interest in the Intermediate Partnership and MGP holds the 1.0001% managing general partner interest in the Intermediate Partnership. To determine whether the Intermediate Partnership is a VIE, we considered that since the Intermediate Partnership is structured as a

limited partnership with the limited partner 1) not having the ability to remove its managing general partner and 2) not participating significantly in the operational decisions, the Intermediate Partnership represents a VIE.

We determined that neither the MGP nor ARLP have both the power and the benefits related to Intermediate Partnership. We then considered which of the two was most closely aligned with the Intermediate Partnership and thus would be designated the primary beneficiary of the Intermediate Partnership for consolidation purposes. We determined that ARLP was most closely aligned with the Intermediate Partnership and is the primary beneficiary. We based our determination of alignment on 1) the purpose and design of the Intermediate Partnership which is to (a) be the operating subsidiary to ARLP and (b) distribute all of its available cash to ARLP to pay its partners and 2) AHGP's common control over ARLP, MGP and the Intermediate Partnership, as discussed in Note 1 – Organization and Presentation, to achieve the aforementioned purpose and design.

The effect of the partnership agreements of ARLP and the Intermediate Partnership and the operating agreement of Alliance Coal (collectively the "Agreements") is that on a quarterly basis 100% of available cash from our operations must be distributed by ARLP to its partners (apart from certain nominal distributions from the Intermediate Partnership and Alliance Coal to MGP). Available cash is determined as defined in the Agreements and represents all cash with the exception of cash reserves (i) for the proper conduct of the business including reserves for future capital expenditures and for anticipated credit needs of the Partnership Group, (ii) to comply with debt obligations or (iii) to provide funds for certain subsequent distributions. MGP, as the managing member of Alliance Coal and the managing general partner of the Intermediate Partnership, is responsible for distributing this cash to ARLP so it can meet its distribution requirements. As discussed in Note 7 – Long-Term Debt, the Intermediate Partnership's debt covenants place additional restrictions on distributions to ARLP by limiting cash available for distribution from the Intermediate Partnership based on various debt covenants pertaining to the most recent preceding quarter. MGP does not have the ability, without the consent of the limited partners, to amend the Agreements.

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for variable interest entities.

11. INVESTMENTS

AllDale Minerals

In November 2014, Cavalier Minerals (see Note 10 – Variable Interest Entities) was created to indirectly purchase, through its equity investments in AllDale Minerals, oil and gas mineral interests in various geographic locations within producing basins in the continental U.S. In February 2017, Alliance Minerals, which is included in our Other and Corporate category (see Note 21 – Segment Information), committed to directly (rather than through Cavalier Minerals) invest $30.0 million in AllDale III which was created for similar investment purposes. We account for our ownership interest in the income or loss of the AllDale Partnerships as equity method investments. We record equity income or loss based on the AllDale Partnerships' individual distribution structures. The changes in our aggregate equity method investment in the AllDale Partnerships for each of the periods presented were as follows:

	Year Ended December 31,		
	2017	2016	2015
	(in thousands)		
Beginning balance	$ 138,817	$ 64,509	$ 11,257
Contributions	20,688	76,797	54,290
Equity investment income (loss)	13,860	3,543	(594)
Distributions received	(25,401)	(6,032)	(444)
Ending balance	$ 147,964	$ 138,817	$ 64,509

Kodiak

On July 19, 2017, Alliance Minerals purchased $100 million of Series A-1 Preferred Interests from Kodiak, a privately-held company providing large-scale, high-utilization gas compression assets to customers operating primarily in the Permian Basin. This structured investment provides us with a quarterly cash or payment-in-kind return. Our ownership interests in Kodiak are senior to all other Kodiak equity interests and subordinate only to Kodiak's senior secured debt facility. We account for our ownership interests in Kodiak as a cost method investment. It is not practicable to estimate

the fair value of our investment in Kodiak because of the lack of a quoted market price for our ownership interests. The changes in our investment in Kodiak for the year ended December 31, 2017 were as follows:

	Year Ended December 31, 2017
	(in thousands)
Beginning balance	$ —
Contributions	100,000
Payment-in-kind distributions received	6,398
Ending balance	$ 106,398

White Oak

On September 22, 2011, we entered into a series of transactions ("Initial Transactions") with White Oak to support development of a longwall mining operation, which we assumed control of in July 2015 through our acquisition of the remaining equity interests in White Oak (see Note 3 - Acquisitions). The Initial Transactions featured several components, including an equity investment in White Oak, the acquisition and lease-back of certain coal reserves and surface rights, a loan and a coal handling and preparation agreement, pursuant to which we constructed and operated Hamilton's preparation plant and other surface facilities. Our previous equity investment income or loss from White Oak is reflected in our Illinois Basin reportable segment and was recorded under the hypothetical-liquidation-at-book-value method of accounting due to the preferences to which we were entitled with respect to distributions. See Note 10 – Variable Interest Entities regarding our determination to account for White Oak as an equity investment prior to the Hamilton Acquisition.

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

	January 1, 2015 to July 31, 2015
	(in thousands)
Total revenues	$ 108,256
Gross loss	(2,919)
Loss from operations	(38,148)
Net loss	(69,075)

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for equity investments.

12. NET INCOME OF ARLP PER LIMITED PARTNER UNIT

We utilize the two-class method in calculating basic and diluted earnings per unit ("EPU"). Net income of ARLP is allocated to the general partners and limited partners in accordance with their respective partnership percentages, after giving effect to any special income or expense allocations, including incentive distributions to our general partner, MGP. As discussed above in Note 1 – Organization and Presentation under *Exchange Transaction*, on July 28, 2017, MGP contributed to ARLP all of its IDRs and its general partner interest in ARLP in exchange for 56,100,000 ARLP common units and a non-economic general partner interest in ARLP. In conjunction with this transaction and on the same economic basis as MGP, SGP also contributed to ARLP its 0.01% general partner interests in both ARLP and the Intermediate Partnership in exchange for 7,181 ARLP common units. In connection with the Exchange Transaction, ARLP amended its partnership agreement to reflect, among other things, cancellation of the IDRs and the economic general partner interest in ARLP and issuance of a non-economic general partner interest to MGP. As of December 31, 2017, as a result of the transactions, ARLP has 130,704,217 common units outstanding. Under the IDR provisions of our partnership agreement prior to the Exchange Transaction, MGP was entitled to receive 15% of the amount we distributed in excess of $0.1375 per unit, 25% of the amount we distributed in excess of $0.15625 per unit, and 50% of the amount we distributed in excess of $0.1875 per unit. Beginning with distributions declared for the three months ended June 30, 2017, we no longer make distributions with respect to the IDRs.

Outstanding awards under our LTIP and phantom units in notional accounts under our SERP and the Deferred Compensation Plan include rights to nonforfeitable distributions or distribution equivalents and are therefore considered participating securities. As such, we allocate undistributed and distributed earnings to these outstanding awards in our calculation of EPU. The following is a reconciliation of net income of ARLP used for calculating basic and diluted earnings per unit and the weighted-average units used in computing EPU for the years ended December 31, 2017, 2016 and 2015, respectively:

	Year Ended December 31,		
	2017	2016	2015
	(in thousands, except per unit data)		
Net income of ARLP	$ 303,638	$ 339,398	$ 306,198
Adjustments:			
MGP's priority distributions (1)	(19,216)	(76,636)	(144,576)
General partners' equity ownership (1)	(3,688)	(5,275)	(3,262)
General partners' special allocation of certain general and administrative expenses (2)	1,000	1,000	1,500
Limited partners' interest in net income of ARLP	281,734	258,487	159,860
Less:			
Distributions to participating securities	(4,339)	(3,391)	(3,493)
Undistributed earnings attributable to participating securities	(1,026)	(3,281)	—
Net income of ARLP available to limited partners	$ 276,369	$ 251,815	$ 156,367
Weighted-average limited partner units outstanding – basic and diluted	98,708	74,354	74,174
Basic and diluted net income of ARLP per limited partner unit (3)	$ 2.80	$ 3.39	$ 2.11

(1) Amounts for 2017 reflect the impact of the Exchange Transaction eliminating second, third and fourth quarter distributions that would have been paid for the IDRs and the 0.99% general partner interest in ARLP, both of which were held by MGP prior to the Exchange Transaction. MGP maintained its 1.0001% general partner interest in the Intermediate Partnership and thus continues to receive the Intermediate Partnership quarterly distribution notwithstanding the Exchange Transaction. Because the Exchange Transaction occurred prior to the record date for ARLP's second quarter distributions, all of the second, third and fourth quarter earnings less the Intermediate Partnership's general partner interest were allocated to ARLP's limited partners. The Exchange Transaction also converted SGP's nominal general partnership interest for its second, third and fourth quarter earnings and subsequent distributions to the limited partner interest.

(2) An affiliated entity controlled by Mr. Craft made capital contributions of $1.0 million each year during 2017 and 2016 and $1.5 million during 2015 to AHGP for the purpose of funding certain general and administrative expenses. Upon AHGP's receipt of each contribution, it contributed the same to its subsidiary MGP, our general partner, which in turn contributed the same to our subsidiary, Alliance Coal. As provided under our partnership agreement, we made special allocations to MGP of certain general and administrative expenses equal to its contributions. Net income of ARLP allocated to the limited partners was not burdened by this expense.

(3) Diluted EPU gives effect to all potentially dilutive common units outstanding during the period using the treasury stock method. Diluted EPU excludes all potentially dilutive units calculated under the treasury stock method if their effect is anti-dilutive. For the year ended December 31, 2017, 2016 and 2015, the combined total of LTIP, SERP and Deferred Compensation Plan units of 1,466,404, 922,386, and 734,171, respectively, were considered anti-dilutive under the treasury stock method.

On a pro forma basis, as if the Exchange Transaction had taken place on January 1, 2015, the reconciliation of net income of ARLP to basic and diluted earnings per unit and the weighted-average units used in computing EPU for the years ended December 31, 2017, 2016 and 2015 are as follows:

	Year Ended December 31,		
	2017	2016	2015
	(in thousands, except per unit data)		
Net income of ARLP	$ 303,638	$ 339,398	$ 306,198
Adjustments:			
General partners' equity ownership	(3,036)	(3,397)	(3,063)
General partners' special allocation of certain general and administrative expenses (1)	1,000	1,000	1,500
Limited partners' interest in net income of ARLP	301,602	337,001	304,635
Less:			
Distributions to participating securities	(4,339)	(3,391)	(3,493)
Undistributed earnings attributable to participating securities	(701)	(1,594)	—
Net income of ARLP available to limited partners (2)	$ 296,562	$ 332,016	$ 301,142
Weighted-average limited partner units outstanding – basic and diluted (2)	130,681	130,461	130,282
Pro forma basic and diluted net income of ARLP per limited partner unit (3)	$ 2.27	$ 2.54	$ 2.31

(1) An affiliated entity controlled by Mr. Craft made capital contributions of $1.0 million each year during 2017 and 2016 and $1.5 million during 2015 to AHGP for the purpose of funding certain general and administrative expenses. Upon AHGP's receipt of each contribution, it contributed the same to its subsidiary MGP, our general partner, which in turn contributed the same to our subsidiary, Alliance Coal. As provided under our partnership agreement, we made special allocations to MGP of certain general and administrative expenses equal to its contributions. Net income of ARLP allocated to the limited partners was not burdened by this expense.

(2) The pro forma amounts presented above reflect net income allocations as if distributions had been made for all periods presented based on the limited and general partner interests outstanding as a result of the Exchange Transaction. Accordingly, the Adjustment - General partners' equity ownership line item above no longer includes the (a) IDR distributions to MGP, (b) general partner interest distributions from ARLP to MGP and SGP and (c) general partner distributions from the Intermediate Partnership to SGP. Pro forma amounts above also reflect weighted average units outstanding as if the issuance of 56,107,181 ARLP common units in the Exchange Transaction applied to all periods presented.

(3) Diluted EPU gives effect to all potentially dilutive common units outstanding during the period using the treasury stock method. Diluted EPU excludes all potentially dilutive units calculated under the treasury stock method if their effect is anti-dilutive. For the year ended December 31, 2017, 2016 and 2015, the combined total of LTIP, SERP and Deferred Compensation Plan units of 1,466,404, 922,386 and 734,171, respectively, were considered anti-dilutive under the treasury stock method.

13. EMPLOYEE BENEFIT PLANS

Defined Contribution Plans—Our eligible employees currently participate in a defined contribution profit sharing and savings plan ("PSSP") that we sponsor. The PSSP covers all regular full-time employees. PSSP participants may elect to make voluntary contributions to this plan up to a specified amount of their compensation. We make matching contributions based on a percent of an employee's eligible compensation and also make an additional non-matching contribution. Our contribution expense for the PSSP was approximately $18.7 million, $18.2 million and $22.6 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Defined Benefit Plan—Eligible employees at certain of our mining operations participate in a defined benefit plan (the "Pension Plan") that we sponsor. The Pension Plan is currently closed to new applicants and effective January 31, 2017, participants within the Pension Plan are no longer receiving benefit accruals for service. The amendment did not materially affect pension benefits accrued prior to January 31, 2017. All participants can participate in enhanced benefits provisions under the PSSP. The benefit formula for the Pension Plan is a fixed-dollar unit based on years of service.

The following sets forth changes in benefit obligations and plan assets for the years ended December 31, 2017 and 2016 and the funded status of the Pension Plan reconciled with the amounts reported in our consolidated financial statements at December 31, 2017 and 2016, respectively:

	2017	2016
	(dollars in thousands)	
Change in benefit obligations:		
Benefit obligations at beginning of year	$ 113,482	$ 107,476
Service cost	—	2,205
Interest cost	4,587	4,493
Actuarial loss	13,501	901
Benefits paid	(4,272)	(3,091)
Plan amendments	—	1,498
Benefit obligations at end of year	127,298	113,482
Change in plan assets:		
Fair value of plan assets at beginning of year	71,412	68,445
Employer contribution	2,971	2,608
Actual return on plan assets	11,870	3,450
Benefits paid	(4,272)	(3,091)
Fair value of plan assets at end of year	81,981	71,412
Funded status at the end of year	$ (45,317)	$ (42,070)
Amounts recognized in balance sheet:		
Non-current liability	$ (45,317)	$ (42,070)
Amounts recognized in accumulated other comprehensive income consists of:		
Prior service cost	$ (1,312)	$ (1,498)
Net actuarial loss	(41,979)	(38,424)
	$ (43,291)	$ (39,922)
Weighted-average assumptions to determine benefit obligations as of December 31,		
Discount rate	3.54%	4.06%
Expected rate of return on plan assets	7.00%	7.00%
Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31,		
Discount rate	4.06%	4.27%
Expected return on plan assets	7.00%	7.50%

The actuarial loss component of the change in benefit obligation in 2017 was primarily attributable to a decrease in the discount rate compared to December 31, 2016 and updated retirement and withdrawal rates, offset in part by improved life expectancies. The actuarial loss component of the change in benefit obligation in 2016 was primarily attributable to a decrease in the discount rate compared to December 31, 2015, offset in part by improved life expectancies and updated retirement and withdrawal rate estimates.

The expected long-term rate of return used to determine our pension liability is based on a 1.5% active management premium in addition to an asset allocation assumption of:

As of December 31, 2017	Asset allocation assumption
Equity securities	62%
Fixed income securities	33%
Real estate	5%
	100%

The actual return on plan assets was 18.0% and 5.9% for the years ended December 31, 2017 and 2016, respectively.

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Components of net periodic benefit cost:			
Service cost	$ —	$ 2,205	$ 2,473
Interest cost	4,587	4,493	4,296
Expected return on plan assets	(4,978)	(5,138)	(5,590)
Amortization of prior service cost	186	—	—
Amortization of net loss	3,054	2,952	3,354
Net periodic benefit cost	$ 2,849	$ 4,512	$ 4,533

	2017	2016
	(in thousands)	
Other changes in plan assets and benefit obligation recognized in accumulated other comprehensive loss:		
Prior service cost	$ —	$ (1,498)
Net actuarial loss	(6,610)	(2,589)
Reversal of amortization item:		
Prior service cost	186	—
Net actuarial loss	3,054	2,952
Total recognized in accumulated other comprehensive loss	(3,370)	(1,135)
Net periodic benefit cost	(2,849)	(4,512)
Total recognized in net periodic benefit cost and accumulated other comprehensive loss	$ (6,219)	$ (5,647)

Estimated future benefit payments as of December 31, 2017 are as follows:

Year Ended December 31,	(in thousands)
2018	$ 4,238
2019	4,651
2020	5,053
2021	5,420
2022	5,696
2023-2027	32,329
	$ 57,387

We expect to contribute $3.8 million to the Pension Plan in 2018. The estimated net actuarial loss and prior service cost for the Pension Plan that will be amortized from AOCL into net periodic benefit cost during the 2018 fiscal year is $3.8 million and $0.2 million, respectively.

The Compensation Committee has appointed an investment manager with full investment authority with respect to Pension Plan investments subject to investment guidelines and compliance with ERISA or other applicable laws. The investment manager employs a series of asset allocation strategy phases to glide the portfolio risk commensurate with both plan characteristics and market conditions. The objective of the allocation policy is to reach and maintain fully funded status. The total portfolio allocation will be adjusted as the funded ratio of the Pension Plan changes and market conditions warrant. The target allocation includes investments in equity and fixed income commingled investment funds. Total account performance is reviewed at least annually, using a dynamic benchmark approach to track investment performance. General asset allocation guidelines at December 31, 2017 are as follows:

	Percentage of Total Portfolio		
	Minimum	Target	Maximum
Equity securities	45%	62%	80%
Fixed income securities	10%	33%	55%
Real estate	0%	5%	10%

Equity securities include domestic equity securities, developed international securities, emerging markets equity securities and real estate investment trust. Fixed income securities include domestic and international investment grade fixed income securities, high yield securities and emerging markets fixed income securities. Fixed income futures may also be utilized within the fixed income securities asset allocation.

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

	December 31, 2017	December 31, 2016
	(in thousands)	
Cash and cash equivalents (a)	$ 1,439	$ 1,137
Commingled investment funds measured at net asset value (b):		
Equities - U.S. large-cap	26,031	21,082
Equities - U.S. small-cap	6,120	6,531
Equities - International developed markets	15,015	11,074
Equities - International emerging markets	6,528	4,614
Fixed income - Investment grade	13,546	16,823
Fixed income - High yield	4,325	4,543
Real estate	3,754	4,259
Other	5,223	1,349
Total	$ 81,981	$ 71,412

(a) Cash and cash equivalents represents a Level 1 fair value measurement. See Note 2 – Summary of Significant Accounting Policies – Fair Value Measurements for more information regarding the definitions of fair value hierarchy levels.

(b) Investments measured at fair value using the net asset value per share (or its equivalent) have not been classified within the fair value hierarchy. The fair values of all commingled investment funds are determined based on the net asset values per unit of each of the funds. The net asset values per unit represent the aggregate value of the fund's assets at fair value less liabilities, divided by the number of units outstanding.

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for pension benefits.

14. COMPENSATION PLANS

Long-Term Incentive Plan

We have the LTIP for certain employees and officers of MGP and its affiliates who perform services for us. The LTIP awards are grants of non-vested "phantom" or notional units, also referred to as "restricted units", which upon satisfaction of time and performance based vesting requirements, entitle the LTIP participant to receive ARLP common units. Annual

grant levels and vesting provisions for designated participants are recommended by the President and Chief Executive Officer of MGP, subject to review and approval of the Compensation Committee. Vesting of all grants outstanding is subject to the satisfaction of certain financial tests, which management currently believes is probable. Grants issued to LTIP participants are expected to cliff vest on January 1st of the third year following issuance of the grants. We account for forfeitures of non-vested LTIP grants as they occur. We expect to settle the non-vested LTIP grants by delivery of ARLP common units, except for the portion of the grants that will satisfy tax withholding obligations of LTIP participants. As provided under the distribution equivalent rights ("DERs") provisions of the LTIP and the terms of the LTIP awards, all non-vested grants include contingent rights to receive quarterly distributions in cash or at the discretion of the Compensation Committee, in lieu of cash, phantom units credited to a bookkeeping account with value, equal to the cash distributions we make to unitholders during the vesting period.

A summary of non-vested LTIP grants as of and for the years ended December 31, 2017, 2016 and 2015 is as follows:

	Number of units	Weighted average grant date fair value per unit	Intrinsic value (in thousands)
Non-vested grants at January 1, 2015	843,340	$ 37.16	$ 36,306
Granted	303,165	37.18	
Vested (1)	(202,778)	38.85	
Forfeited	(3,934)	36.49	
Non-vested grants at December 31, 2015	939,793	36.80	12,678
Granted	960,992	12.38	
Vested (1)	(284,272)	31.51	
Forfeited	(11,765)	26.39	
Non-vested grants at December 31, 2016	1,604,748	23.19	36,027
Granted	475,310	23.17	
Vested (1)	(350,516)	40.73	
Forfeited	(35,516)	20.01	
Non-vested grants at December 31, 2017	1,694,026	19.62	33,372

(1) During the years ended December 31, 2017, 2016 and 2015, we issued 222,011, 176,319, and 128,150, respectively, unrestricted common units to the LTIP participants. The remaining vested units were settled in cash to satisfy the individual statutory minimum tax obligations of the LTIP participants.

For the years ended December 31, 2017, 2016 and 2015, our LTIP expense was $11.0 million, $12.7 million and $11.2 million, respectively. The total obligation associated with the LTIP as of December 31, 2017 and 2016 was $21.8 million and $25.1 million, respectively, and is included in the partners' capital *Limited partners-common unitholders* line item in our consolidated balance sheets. As of December 31, 2017, there was $11.4 million in total unrecognized compensation expense related to the non-vested LTIP grants that are expected to vest. That expense is expected to be recognized over a weighted-average period of 1.1 years.

On January 24, 2018, the Compensation Committee determined that the vesting requirements for the 2015 grants of 290,706 restricted units (which was net of 12,459 forfeitures) had been satisfied as of January 1, 2018. As a result of this vesting, on February 8, 2018, we issued 191,858 unrestricted common units to the LTIP participants. The remaining units were settled in cash to satisfy tax withholding obligations of the LTIP participants. On January 24, 2018, the Compensation Committee also authorized additional grants of 526,305 restricted units, of which 511,305 units were granted.

After consideration of the January 1, 2018 vesting and subsequent issuance of 191,858 common units, approximately 2.1 million units remain available under the LTIP for issuance in the future, assuming all grants issued in 2018, 2017 and 2016 and currently outstanding are settled with common units, without reduction for tax withholding, and no future forfeitures occur and DERs continue being paid in cash versus additional phantom units.

Supplemental Executive Retirement Plan and Directors Deferred Compensation Plan

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

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

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

A summary of SERP and Deferred Compensation Plan activity as of and for the years ended December 31, 2017, 2016 and 2015 is as follows:

	Number of units	Weighted average grant date fair value per unit	Intrinsic value (in thousands)
Phantom units outstanding as of January 1, 2015	368,981	$ 34.02	$ 15,885
Granted	60,160	21.38	
Phantom units outstanding as of December 31, 2015	429,141	32.25	5,789
Granted	74,799	16.31	
Issued	(9,922)	33.76	
Phantom units outstanding as of December 31, 2016	494,018	29.77	11,091
Granted	67,766	20.38	
Phantom units outstanding as of December 31, 2017	561,784	28.64	11,067

Total SERP and Deferred Compensation Plan expense was $1.4 million, $1.2 million and $1.3 million for the years ended December 31, 2017, 2016 and 2015, respectively. As of December 31, 2017 and 2016, the total obligation associated with the SERP and Deferred Compensation Plan was $16.1 million and $14.7 million, respectively, and is included in the partners' capital *Limited partners-common unitholders* line item in our consolidated balance sheets. On February 8, 2018, we issued 7,181 ARLP common units to a participant under the SERP. Units issued to this participant were net of units settled in cash to satisfy tax withholding obligations.

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for unit-based compensation.

15. SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Cash Paid For:			
Interest	$ 31,692	$ 29,274	$ 30,438
Income taxes	$ 210	$ 10	$ 21
Non-Cash Activity:			
Accounts payable for purchase of property, plant and equipment	$ 15,636	$ 8,232	$ 12,634
Assets acquired by capital lease	$ —	$ 37,089	$ 99,543
Market value of common units vested in Long-Term Incentive Plan and Deferred Compensation Plan before minimum statutory tax withholding requirements	$ 8,149	$ 3,642	$ 7,389
Acquisition of businesses:			
Fair value of assets assumed, net of cash acquired	$ —	$ 1,011	$ 519,384
Contingent consideration	—	—	(20,907)
Settlement of pre-existing relationships	—	—	(124,379)
Previously held equity-method investment	—	—	(122,764)
Cash paid, net of cash acquired	—	(1,011)	(74,953)
Fair value of liabilities assumed	$ —	$ —	$ 176,381

16. ASSET RETIREMENT OBLIGATIONS

The majority of our operations are governed by various state statutes and the Federal Surface Mining Control and Reclamation Act of 1977, which establish reclamation and mine closing standards. These regulations require, among other things, restoration of property in accordance with specified standards and an approved reclamation plan.

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

	Year Ended December 31,	
	2017	2016
	(in thousands)	
Beginning balance	$ 125,701	$ 123,685
Accretion expense	3,793	3,769
Payments	(1,046)	(379)
Allocation of liability associated with acquisitions, mine development and change in assumptions	2,152	(1,374)
Ending balance	$ 130,600	$ 125,701

For the year ended December 31, 2017, the allocation of liability associated with acquisition, mine development and change in assumptions was a net increase of $2.2 million. This increase was attributable to the net impact of increased expansion and disturbances of refuse sites primarily at the Hamilton and River View mines, offset in part by overall changes in inflation and discount rates, current estimates of the costs and scope of remaining reclamation work, reclamation work completed and fluctuations in projected mine life estimates.

For the year ended December 31, 2016, the allocation of liability associated with acquisition, mine development and change in assumptions was a net decrease of $1.4 million. This decrease was primarily attributable to the net impact of overall general changes in inflation and discount rates, current estimates of the costs and scope of remaining reclamation work, reclamation work completed and fluctuations in projected mine life estimates, offset in part by increased expansion and disturbances of refuse sites primarily at the Warrior and Gibson County Coal mines.

The impact of discounting our estimated cash flows resulted in reducing the accrual for asset retirement obligations by $114.0 million and $110.7 million at December 31, 2017 and 2016, respectively. Estimated payments of asset retirement obligations as of December 31, 2017 are as follows:

Year Ended December 31,	(in thousands)
2018	$ 3,850
2019	454
2020	433
2021	—
2022	1,256
Thereafter	238,604
Aggregate undiscounted asset retirement obligations	244,597
Effect of discounting	(113,997)
Total asset retirement obligations	130,600
Less: current portion	(3,850)
Asset retirement obligations	$ 126,750

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining and are typically renewable on a yearly basis. As of December 31, 2017 and 2016, we had approximately $172.9 million and $171.8 million, respectively, in surety bonds outstanding to secure the performance of our reclamation obligations.

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for asset retirement obligations.

17. ACCRUED WORKERS' COMPENSATION AND PNEUMOCONIOSIS BENEFITS

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

The following is a reconciliation of the changes in workers' compensation liability (including current and long-term liability balances) at December 31, 2017 and 2016:

	2017	2016
	(in thousands)	
Beginning balance	$ 48,131	$ 54,558
Accruals increase	17,066	10,450
Payments	(10,769)	(10,415)
Interest accretion	1,681	1,967
Valuation gain	(1,670)	(8,429)
Ending balance	$ 54,439	$ 48,131

The discount rate used to calculate the estimated present value of future obligations for workers' compensation was 3.22%, 3.52% and 3.63% at December 31, 2017, 2016 and 2015, respectively.

The 2017 valuation gain was primarily attributable to favorable changes in claims development partially offset by the decrease in the discount rate used to calculate the estimated present value of future obligations. The 2016 valuation gain was primarily attributable to favorable changes in claims development partially offset by the decrease in the discount rate used to calculate the estimated present value of future obligations.

As of December 31, 2017 and 2016, we had $89.2 million and $89.1 million, respectively, in surety bonds and letters of credit outstanding to secure workers' compensation obligations.

We limit our exposure to traumatic injury claims by purchasing a high deductible insurance policy that starts paying benefits after deductibles for the particular claim year have been met. Our workers' compensation liability above is presented on a gross basis and does not include our expected receivables on our insurance policy. Our receivables for traumatic injury claims under this policy as of December 31, 2017 are $9.0 million and are included in *Other long-term assets* on our consolidated balance sheet.

The following is a reconciliation of the changes in pneumoconiosis benefit obligations at December 31, 2017 and 2016:

	2017	2016
	(in thousands)	
Benefit obligations at beginning of year	$ 64,988	$ 61,693
Service cost	2,255	2,578
Interest cost	2,555	2,506
Actuarial loss	7,938	205
Benefits and expenses paid	(2,877)	(1,994)
Benefit obligations at end of year	$ 74,859	$ 64,988

The following is a reconciliation of the changes in the pneumoconiosis benefit obligation recognized in AOCL for the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2015
	(in thousands)		
Net actuarial loss	$ (7,938)	$ (205)	$ (750)
Reversal of amortization item:			
Net actuarial gain	(2,092)	(2,643)	(451)
Total recognized in accumulated other comprehensive loss	$ (10,030)	$ (2,848)	$ (1,201)

The discount rate used to calculate the estimated present value of future obligations for pneumoconiosis benefits was 3.49%, 3.97% and 4.16% at December 31, 2017, 2016 and 2015, respectively.

	2017	2016	2015
		(in thousands)	
Amount recognized in accumulated other comprehensive loss consists of:			
Net actuarial loss (gain)	$ 8,648	$ (1,382)	$ (4,230)

The actuarial loss component of the change in benefit obligations in 2017 was primarily attributable to the decrease in the discount rate used to calculate the estimated present value of the future obligations, an increase in the assumed future medical benefits, and closure of a state fund which historically shared indemnity costs on state pneumoconiosis claims. The actuarial loss component of the change in benefit obligations in 2016 was primarily attributable to the decrease in the discount rate used to calculate the estimated present value of the future obligations which was partially offset by favorable claims development changes.

Summarized below is information about the amounts recognized in the accompanying consolidated balance sheets for pneumoconiosis and workers' compensation benefits at December 31, 2017 and 2016:

	2017	2016
	(in thousands)	
Workers' compensation claims	$ 54,439	$ 48,131
Pneumoconiosis benefit claims	74,859	64,988
Total obligations	129,298	113,119
Less current portion	(10,729)	(9,897)
Non-current obligations	$ 118,569	$ 103,222

Both the pneumoconiosis benefit and workers' compensation obligations were unfunded at December 31, 2017 and 2016.

The pneumoconiosis benefit and workers' compensation expense consists of the following components for the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2015
		(in thousands)	
Service cost	$ 2,255	$ 2,578	$ 3,081
Interest cost	2,555	2,506	2,094
Net amortization	(2,092)	(2,643)	(451)
Total pneumoconiosis expense	2,718	2,441	4,724
Workers' compensation expense	12,215	9,063	9,759
Total expense	$ 14,933	$ 11,504	$ 14,483

See Note 2 – Summary of Significant Accounting Policies for more information on our accounting policy for workers' compensation and pneumoconiosis benefits.

18. RELATED-PARTY TRANSACTIONS

We have continuing related-party transactions with MGP and its affiliates. The Board of Directors and its Conflicts Committee review our related-party transactions that involve a potential conflict of interest between our general partner or its affiliates and ARLP or its subsidiaries or another partner to determine that such transactions are fair and reasonable to ARLP. As a result of these reviews, the Board of Directors and the Conflicts Committee approved each of the transactions described below that had such potential conflict of interest as fair and reasonable to ARLP.

White Oak—On September 22, 2011, we entered into the Initial Transactions (See Note 11 – Investments) with White Oak and related entities to support development of a longwall mining operation. The Initial Transactions and subsequent transactions with White Oak involved several components, including an equity investment containing certain distribution and liquidation preferences, the acquisition and lease-back of certain reserves and surface rights which generated royalties of $11.4 million in 2015, a coal handling and services agreement which generated throughput revenues of $28.2 million in 2015, a coal supply agreement, export marketing and transportation agreements and certain debt agreements. On July 31, 2015, we purchased the remaining equity interests in White Oak. See Note 3 – Acquisitions for a detailed discussion of this acquisition.

In addition to the agreements discussed above, White Oak also had agreements with our subsidiaries for the purchase of various services and products, including for coal handling services provided by our Mt. Vernon transloading facility. For the year ended December 31, 2015, we recorded revenues of $4.6 million, for services and products provided by Mt. Vernon and Matrix Design to White Oak, which are included in Other sales and operating revenues on our consolidated statements of income.

Affiliate Royalty Agreements

The following table summarizes advanced royalties outstanding and related payments and recoupments under our affiliate royalty agreements:

	SGP	WKY CoalPlay				
		Towhead Coal	Webster Coal	Henderson Coal	WKY CoalPlay	
	Tunnel Ridge	Henderson & Union Counties, KY	Webster County, KY	Henderson County, KY	Henderson & Union Counties, KY	Total
	Acquired 2005	Acquired December 2014	Acquired December 2014	Acquired December 2014	Acquired February 2015	
			(in thousands)			
As of January 1, 2015	$ 10,706	$ —	$ —	$ —	$ —	$ 10,706
Payments	3,000	3,598	2,568	2,522	2,131	13,819
Recoupment	(8,293)	—	(42)	—	—	(8,335)
As of December 31, 2015	5,413	3,598	2,526	2,522	2,131	16,190
Payments	3,000	3,598	2,568	2,522	2,131	13,819
Recoupment	(8,413)	(1)	(1,775)	—	—	(10,189)
As of December 31, 2016	—	7,195	3,319	5,044	4,262	19,820
Payments	6,000	3,598	2,568	2,522	2,131	16,819
Recoupment	(3,000)	(109)	(531)	—	(6)	(3,646)
As of December 31, 2017	$ 3,000	$ 10,684	$ 5,356	$ 7,566	$ 6,387	$ 32,993

SGP—In January 2005, we acquired Tunnel Ridge from ARH. In connection with this acquisition, we assumed a coal lease with SGP. Under the terms of the lease, Tunnel Ridge has paid SGP and will continue to pay SGP an annual minimum royalty of $3.0 million until the earlier of January 1, 2033 or the exhaustion of the mineable and merchantable leased coal. In December 2016, Tunnel Ridge had recouped all past annual advances and made the first earned royalty payment to SGP, which was nominal. During 2017, Tunnel Ridge incurred $7.2 million in earned royalties of which $0.8 million was payable to SGP in January 2018 and paid its annual minimum of $3.0 million to SGP in January 2017 which was fully recouped by March 2017. Tunnel Ridge also paid the $3.0 million annual minimum due on January 1, 2018 in late December 2017 which will be fully recouped by March 2018.

WKY CoalPlay—In February 2015, WKY CoalPlay entered into a coal lease agreement with Alliance Resource Properties regarding coal reserves located in Henderson and Union Counties, Kentucky. The lease has an initial term of 20 years and provides for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of $2.1 million. All annual minimum royalty payments are recoupable from future earned royalties. Alliance Resource Properties also was granted an option to acquire the leased reserves at any time during a three-year period beginning in February 2018 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in these reserves taking into account payments previously made under the lease (See Note 10 - Variable Interest Entities).

In December 2014, WKY CoalPlay's subsidiaries, Towhead Coal Reserves, LLC ("Towhead Coal"), Webster Coal Reserves, LLC ("Webster Coal"), and Henderson Coal Reserves, LLC ("Henderson Coal") entered into coal lease agreements with Alliance Resource Properties. The leases with Towhead Coal and Henderson Coal have initial terms of 20 years and provide for earned royalty payments of 4.0% of the coal sales price to both and annual minimum royalty payments of $3.6 million and $2.5 million, respectively. The lease with Webster Coal has an initial term of 7 years and provides for earned royalty payments of 4.0% of the coal sales price and annual minimum royalty payments of $2.6 million. All annual minimum royalty payments for each agreement are recoupable from future earned royalties related to their respective agreements. Each agreement grants Alliance Resource Properties an option to acquire the leased reserves at any time during a three-year period beginning in December 2017 for a purchase price that would provide WKY CoalPlay a 7.0% internal rate of return on its investment in the reserves taking into account payments previously made under the leases (See Note 10 – Variable Interest Entities).

SGP Land—In 2001, SGP Land, as successor in interest to an unaffiliated third party, entered into an amended mineral lease with MC Mining. Under the terms of the lease, MC Mining was required to pay an annual minimum royalty of $0.3 million until $6.0 million of cumulative annual minimum and/or earned royalty payments had been paid. The cumulative annual minimum lease requirement of $6.0 million was met in 2015. MC Mining paid to SGP Land earned royalties of $0.6 million in each of the years ended December 31, 2017 and 2016 and $1.9 million in the year ended December 31, 2015.

Cavalier Minerals– As discussed in Note 10 – Variable Interest Entities, Alliance Minerals has a limited partnership interest in Cavalier and we consolidate Cavalier Minerals which holds limited partner interests in the AllDale Minerals entities, which were created to purchase oil and gas mineral interests in various geographical locations within producing basins in the continental U.S. See Note 11 - Investments for information on payments made and distributions received.

Mineral Lending– See Note 7 - Long-Term Debt for discussion of the Cavalier Credit Agreement and Mineral Lending.

19. COMMITMENTS AND CONTINGENCIES

Commitments—We lease buildings and equipment under operating lease agreements that provide for the payment of both minimum and contingent rentals. We also have a noncancelable lease with SGP and a noncancelable lease with a third party for equipment under a capital lease obligation. In 2015, we acquired equipment and other assets under operating and capital lease agreements as a result of the Hamilton and Patriot acquisitions (See Note 3 – Acquisitions). Future minimum lease payments are as follows:

		Other Operating Leases		
Year Ending December 31,	**Capital Lease**	**Affiliate**	**Others**	**Total**
		(in thousands)		
2018	$ 32,378	$ 240	$ 9,827	$ 10,067
2019	48,953	—	5,826	5,826
2020	8,866	—	1,366	1,366
2021	966	—	—	—
2022	917	—	—	—
Thereafter	—	—	—	—
Total future minimum lease payments	$ 92,080	$ 240	$ 17,019	$ 17,259
Less: amount representing interest	(6,376)			
Present value of future minimum lease payments	85,704			
Less: current portion	(28,613)			
Long-term capital lease obligation	$ 57,091			

Rental expense (including rental expense incurred under operating lease agreements) was $16.1 million, $17.0 million and $11.7 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Contractual Commitments—In connection with planned capital projects, we have contractual commitments of approximately $64.3 million at December 31, 2017. As of December 31, 2017, we had $1.3 million in commitments to purchase coal from external production sources in 2018.

In February 2017, Alliance Minerals committed to invest $30.0 million in AllDale III. As of December 31, 2017, Alliance Minerals had a remaining commitment to AllDale III of $15.6 million. For more information on Alliance Minerals and AllDale III, see Note 11 – Investments.

On October 29, 2015, we entered into a sale-leaseback transaction whereby we sold certain mining equipment for $100.0 million and concurrently entered into a lease agreement for the sold equipment with a four-year term. Under the lease agreement, we will pay an initial monthly rent of $1.9 million. A balloon payment equal to 20% of the equipment cost is due at the end of the lease term. As a result of this transaction, we recognized a deferred gain of $5.0 million which is being amortized over the lease term. On June 29, 2016, we entered into various sale-leaseback transactions for certain mining equipment and received $33.9 million in proceeds. The lease agreements have terms ranging from three to four

years with initial monthly rentals totaling $0.7 million. Balloon payments equal to 20% of the equipment cost under lease are due at the end of each lease term. As a result of this transaction, we recognized a deferred loss of $7.9 million which is being amortized over the life of the equipment. We have recognized these sales-leaseback transactions as capital leases and included future payments within future minimum lease payments presented above.

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

Other—Effective October 1, 2017, we renewed our annual property and casualty insurance program. Our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance. Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased reinsurance for the program in the standard market. The maximum limit in the commercial property program is $100.0 million per occurrence, excluding a $1.5 million deductible for property damage, a 75, 90 or 120 day waiting period for underground business interruption depending on the mining complex and an additional $10.0 million overall aggregate deductible. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future.

20. CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS

We have significant long-term coal supply agreements, some of which contain prospective price adjustment provisions designed to reflect changes in market conditions, labor and other production costs and, in the infrequent circumstance when the coal is sold other than free on board the mine, changes in transportation rates. For the year ended December 31, 2017, we had no customer from which total revenues including transportation revenues were at least ten percent of our total revenues, and therefore considered to be a major customer. For the years ended December 31, 2016 and 2015, the Illinois Basin and Appalachia segments as well as Other and Corporate had total revenues from major customers as follows:

	Year Ended December 31,	
	2016	2015
	(in thousands)	
Customer A	$ 253,465	$ 343,483
Customer B	241,255	305,048
Customer C	265,642	312,150

Trade accounts receivable from these customers totaled approximately $42.5 million and $48.4 million at December 31, 2016 and 2015, respectively. Our bad debt experience has historically been insignificant. Financial conditions of our customers could result in a material change to our bad debt expense in future periods. The coal supply agreements with these major customers expire in 2018 for customer A, and 2020 for customers B and C.

21. SEGMENT INFORMATION

We operate in the eastern U.S. as a producer and marketer of coal to major utilities and industrial users. We aggregate multiple operating segments into two reportable segments, Illinois Basin and Appalachia, and we have an "all other" category referred to as Other and Corporate. Our reportable segments correspond to major coal producing regions in the eastern U.S. Similar economic characteristics for our operating segments within each of these two reportable segments generally include coal quality, geology, coal marketing opportunities, mining and transportation methods and regulatory issues.

The Illinois Basin reportable segment is comprised of multiple operating segments, including currently operating mining complexes (a) Webster County Coal's Dotiki mining complex, (b) Gibson County Coal's mining complex, which includes the Gibson North (currently idled) and Gibson South mines, (c) Warrior's mining complex, (d) River View's mining complex and (e) the Hamilton mining complex. The Gibson North mine was idled in the fourth quarter of 2015 in response to market conditions but is expected to resume production in 2018.

The Illinois Basin reportable segment also includes White County Coal's Pattiki mining complex, Hopkins County Coal's mining complex, which includes the Elk Creek mine, the Pleasant View surface mineable reserves and the Fies underground project, Sebree's mining complex, which includes the Onton mine, Steamport and certain reserves, CR Services, CR Machine Shop, certain properties and equipment of Alliance Resource Properties, ARP Sebree, ARP Sebree South and UC Coal and its subsidiaries, UC Mining and UC Processing. The Pattiki mine ceased production in December 2016. The Elk Creek mine depleted its reserves in March 2016 and ceased production on April 1, 2016. Our Onton mine has been idled since the fourth quarter of 2015 in response to market conditions. UC Coal equipment assets acquired in 2015 continue to be deployed as needed at various Illinois Basin operating mines.

The Appalachia reportable segment is comprised of multiple operating segments, including the Mettiki mining complex, the Tunnel Ridge mining complex and the MC Mining mining complex. The Mettiki mining complex includes Mettiki (WV)'s Mountain View mine and Mettiki (MD)'s preparation plant.

Other and Corporate includes marketing and administrative activities, ASI and its subsidiaries, Matrix Design and Alliance Design Group, LLC (collectively Matrix Design and Alliance Design are referred to as the "Matrix Group"), ASI's ownership of aircraft, our Mt. Vernon dock activities, Alliance Coal's coal brokerage activity, MAC (see Note 3 – Acquisitions), certain of Alliance Resource Properties' land and mineral interest activities, Pontiki's prior workers' compensation and pneumoconiosis liabilities, Wildcat Insurance, Alliance Minerals, and its affiliate, Cavalier Minerals (see Note 10 – Variable Interest Entities), both of which hold equity investments in various AllDale Partnerships (see Note 11 – Investments), AROP Funding and our new subsidiary formed March 30, 2017, Alliance Finance (both discussed in Note 7 – Long-Term Debt). On July 19, 2017, Alliance Minerals purchased $100 million of Series A-1 Preferred Interests from Kodiak (see Note 11 – Investments).

Reportable segment results as of and for the years ended December 31, 2017, 2016 and 2015 are presented below.

	Illinois Basin	Appalachia	Other and Corporate	Elimination (1)	Consolidated
			(in thousands)		
Year Ended December 31, 2017					
Revenues - Outside	$ 1,059,381	$ 623,720	$ 113,119	$ —	$ 1,796,220
Revenues - Intercompany	56,097	2,321	15,924	(74,342)	—
Total revenues (2)	1,115,478	626,041	129,043	(74,342)	1,796,220
Segment Adjusted EBITDA Expense (3)	688,468	385,802	83,490	(65,573)	1,092,187
Segment Adjusted EBITDA (4)	391,426	234,124	65,810	(8,769)	682,591
Total assets	1,429,078	470,892	506,437	(187,036)	2,219,371
Capital expenditures	94,252	48,358	2,478	—	145,088
Year Ended December 31, 2016					
Revenues - Outside	$ 1,275,543	$ 541,108	$ 114,802	$ —	$ 1,931,453
Revenues - Intercompany	61,617	3,806	17,752	(83,175)	—
Total revenues (2)	1,337,160	544,914	132,554	(83,175)	1,931,453
Segment Adjusted EBITDA Expense (3)	761,644	346,712	89,594	(72,313)	1,125,637
Segment Adjusted EBITDA (4)	552,284	191,487	46,339	(10,862)	779,248
Total assets	1,460,924	480,745	404,153	(152,780)	2,193,042
Capital expenditures (5)	52,505	36,213	2,338	—	91,056
Year Ended December 31, 2015					
Revenues - Outside	$ 1,527,596	$ 584,962	$ 161,175	$ —	$ 2,273,733
Revenues - Intercompany	108,621	11,337	19,869	(139,827)	—
Total revenues (2)	1,636,217	596,299	181,044	(139,827)	2,273,733
Segment Adjusted EBITDA Expense (3)	961,611	398,071	153,720	(127,247)	1,386,155
Segment Adjusted EBITDA (4)	604,808	186,518	26,189	(12,580)	804,935
Total assets	1,694,044	517,972	263,817	(114,547)	2,361,286
Capital expenditures (5)	145,352	61,279	6,166	—	212,797

(1) The elimination column represents the elimination of intercompany transactions and is primarily comprised of sales from the Matrix Group and MAC to our mining operations, coal sales and purchases between operations within different segments, sales of receivables to AROP Funding and insurance premiums paid to Wildcat Insurance.

(2) Revenues included in the Other and Corporate column are primarily attributable to the Matrix Group revenues, Mt. Vernon transloading revenues, administrative service revenues from affiliates, MAC revenues, Wildcat Insurance revenues and brokerage coal sales.

(3) Segment Adjusted EBITDA Expense includes operating expenses, coal purchases and other income. Transportation expenses are excluded as these expenses are passed through to our customers and consequently we do not realize any gain or loss on transportation revenues. We review Segment Adjusted EBITDA Expense per ton for cost trends. Results presented for Segment Adjusted EBITDA Expense for the years ended December 31, 2016 and 2015 have been recast to reflect a reclassification of depreciation and depletion capitalized into coal inventory as adjustments to *Depreciation, depletion and amortization* rather than *Operating expenses (excluding depreciation, depletion and amortization)*.

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

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Segment Adjusted EBITDA Expense	$ 1,092,187	$ 1,125,637	$ 1,386,155
Outside coal purchases	—	(1,514)	(327)
Other income	2,980	725	955
Operating expenses (excluding depreciation, depletion and amortization)	$ 1,095,167	$ 1,124,848	$ 1,386,783

(4) Segment Adjusted EBITDA is defined as net income (prior to the allocation of noncontrolling interest) before net interest expense, income taxes, depreciation, depletion and amortization, asset impairment, net acquisition gain, debt extinguishment loss and general and administrative expenses. Management therefore is able to focus solely on the evaluation of segment operating profitability as it relates to our revenues and operating expenses, which are primarily controlled by our segments. Results presented for Segment Adjusted EBITDA for the years ended December 31, 2016 and 2015 have been recast to reflect a reclassification of depreciation and depletion capitalized into coal inventory as adjustments to *Depreciation, depletion and amortization* rather than *Operating expenses (excluding depreciation, depletion and amortization)*. Consolidated Segment Adjusted EBITDA is reconciled to net income as follows:

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Consolidated Segment Adjusted EBITDA	$ 682,591	$ 779,248	$ 804,935
General and administrative	(61,760)	(72,529)	(67,484)
Depreciation, depletion and amortization	(268,981)	(336,509)	(323,983)
Asset impairment	—	—	(100,130)
Interest expense, net	(39,291)	(30,659)	(29,694)
Acquisition gain, net	—	—	22,548
Debt extinguishment loss	(8,148)	—	—
Income tax expense	(210)	(13)	(21)
Net income	$ 304,201	$ 339,538	$ 306,171

(5) Capital expenditures shown above exclude the Hamilton Acquisition on July 31, 2015, the Patriot acquisition on February 3, 2015, the MAC acquisition on January 1, 2015 and the payment for acquisition of customer contracts in 2016 (see consolidated statements of cash flows).

22. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

A summary of our consolidated quarterly operating results in 2017 and 2016 is as follows:

	Quarter Ended			
	March 31, 2017	June 30, 2017 (1)	September 30, 2017	December 31, 2017
	(in thousands, except unit and per unit data)			
Revenues	$ 461,080	$ 398,720	$ 453,189	$ 483,231
Income from operations	107,532	78,760	64,828	77,492
Income before income taxes	105,038	63,356	61,431	74,586
Net income of ARLP	104,902	63,230	61,271	74,235
Basic and diluted net income of ARLP per limited partner unit	$ 1.10	$ 0.82	$ 0.52	$ 0.55
Weighted-average number of units outstanding – basic and diluted (2)	74,503,298	74,597,036	114,237,979	130,704,217

	Quarter Ended			
	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016
	(in thousands, except unit and per unit data)			
Revenues	$ 412,829	$ 439,150	$ 552,074	$ 527,400
Income from operations	54,847	90,361	96,431	124,303
Income before income taxes	47,299	82,717	89,831	119,704
Net income of ARLP	47,310	82,713	89,780	119,595
Basic and diluted net income of ARLP per limited partner unit	$ 0.36	$ 0.82	$ 0.91	$ 1.30
Weighted-average number of units outstanding – basic and diluted	74,291,114	74,375,025	74,375,025	74,375,025

(1) Our June 30, 2017 quarterly results were affected by a debt extinguishment loss of $8.1 million related to early repayment of our Series B Senior Notes in May 2017 (Note 7 – Long-Term Debt).

(2) Weighted-average number of units outstanding – basic and diluted were impacted by the Exchange Transaction in the quarters ended September 30, 2017 and December 31, 2017. See Note 1 – Organization and Presentation for more information regarding the Exchange Transaction.

23. SUBSEQUENT EVENTS

Other than those events described below and in Notes 7, 9 and 14, there were no subsequent events.

Simplification Transactions

On February 22, 2018, our Board of Directors and the board of directors of AHGP's general partner approved a simplification agreement (the "Simplification Agreement") pursuant to which, through a series of transactions (i) AHGP would become a wholly owned subsidiary of ARLP, (ii) all of the issued and outstanding AHGP common units would be canceled and converted into the right to receive all of the ARLP common units held by AHGP and its subsidiaries (collectively, the "Simplification Transactions") and (iii) MGP will remain the sole general partner of ARLP, and no control, management, or governance changes are otherwise expected to occur. The consummation of the Simplification Transactions is subject to the SEC declaring the effectiveness of a registration statement on Form S-4 under the Securities Act of 1933 to register the ARLP common units that will be distributed to former unitholders of AHGP and the affirmative vote or consent of the holders of a majority of the outstanding AHGP common units. Certain unitholders of AHGP that beneficially own a majority of the outstanding AHGP common units have entered into a unitholder support agreement pursuant to which such unitholders have agreed to execute a written consent approving the Simplification Agreement

within two business days after the registration statement on Form S-4 is declared effective by the SEC. We currently believe that the Simplification Transactions will not result in any gain or loss on our financial statements, but anticipate this will result in a change in reporting entity requiring us to recast our historical financial statements reflecting the resulting structure as if it had always been the structure for the periods covered by such financial statements.

Settlement of Litigation

On February 18, 2018 we reached agreement with a customer and certain of its affiliates to settle breach of contract litigation we initiated in January 2015. The agreement includes a $93.0 million payment to us and certain future coal supply commitments. In addition, we will acquire certain coal reserves for $2.0 million from an affiliate of the customer. As a result of certain costs related to this settlement, we expect to realize approximately $80 million from the recovery. We expect the settlement to be concluded in early March 2018. This is a non-recognized subsequent event for the 2017 fiscal year. Once the settlement is finalized, we will assess the accounting impact on future periods.

SCHEDULE II

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015

	Balance At Beginning of Year	Additions Charged to Income	Deductions	Balance At End of Year
		(in thousands)		
2017				
Allowance for doubtful accounts	$ —	$ —	$ —	$ —
2016				
Allowance for doubtful accounts	$ —	$ —	$ —	$ —
2015				
Allowance for doubtful accounts	$ —	$ —	$ —	$ —

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. We maintain controls and procedures designed to provide reasonable assurance that information required to be disclosed in the reports we file with the SEC is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Exchange Act) as of December 31, 2017. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that these controls and procedures are effective as of December 31, 2017.

Our management, including the Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls or our internal controls over financial reporting will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the ARLP Partnership have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that simple errors or mistakes can occur. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based, in part, upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our disclosure controls and internal controls and make modifications as necessary; our intent in this regard is that the disclosure controls and the internal controls will be maintained as systems change and conditions warrant.

Management's Annual Report on Internal Control over Financial Reporting. Management of the ARLP Partnership is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Exchange Act. The ARLP Partnership's internal control over financial reporting is designed to provide reasonable assurance to our management and Board of Directors of our general partner regarding the preparation and fair presentation of published financial statements. Our controls are designed to provide reasonable assurance that the ARLP Partnership's assets are protected from unauthorized use and that transactions are executed in accordance with established authorizations and properly recorded. The internal controls are supported by written policies and are complemented by a staff of competent business process owners and an internal auditor supported by competent and qualified external resources used to assist in testing the operating effectiveness of the ARLP Partnership's internal control over financial reporting. Management concluded that the design and operations of our internal controls over financial reporting at December 31, 2017 are effective and provide reasonable assurance the books and records accurately reflect the transactions of the ARLP Partnership.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control—Integrated Framework (2013)*. Based on its assessment, management concluded that, as of December 31, 2017, the ARLP Partnership's internal control over financial reporting

was effective based on those criteria, and management believes that we have no material internal control weaknesses in our financial reporting process.

Ernst & Young LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2017, as stated in their report that is included herein.

Changes in Internal Controls Over Financial Reporting. There has been no change in our internal controls over financial reporting (as defined in Rule 13a-15(f) or Rule 15d-15(f) of the Exchange Act) in the three months ended December 31, 2017 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

Report of Independent Registered Public Accounting Firm

The Board of Directors of Alliance Resource Management GP, LLC
and the Partners of Alliance Resource Partners, L.P.

Opinion on Internal Controls over Financial Reporting
We have audited Alliance Resource Partners, L.P. and subsidiaries' internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Alliance Resource Partners, L.P. and subsidiaries (the Partnership) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Partnership as of December 31, 2017 and 2016, and the related consolidated statements of income, comprehensive income, cash flows, and partners' capital for each of the three years in the period ended December 31, 2017, and the related notes and schedule listed in the Index at Item 15(a)(2) and our report dated February 23, 2018 expressed an unqualified opinion thereon.

Basis for Opinion
The Partnership's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 23, 2018

ITEM 9B. OTHER INFORMATION

On February 22, 2018, MGP entered into Amendment No. 1 (the "Amendment") to our partnership agreement. The Amendment is in response to changes to the Internal Revenue Code enacted by the Bipartisan Budget Act of 2015 (the "BBA") relating to changes in partnership audit and adjustment procedures. The Amendment makes certain revisions to our partnership agreement that facilitate MGP's obligations as the "Partnership Representative" under the BBA and, if possible and practical, provide MGP with the option of maintaining the current economic balance by which the partners during a reviewed year bear the economic burden associated with any adjustments for such year. For more information regarding the Amendment, please see the complete text of the Amendment, a copy of which is filed as Exhibit 3.9 to this Annual Report.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE OF THE GENERAL PARTNER

As is commonly the case with publicly traded limited partnerships, we are managed and operated by our general partner. The following table shows information for executive officers and members of the Board of Directors as of the date of the filing of this Annual Report on Form 10-K. Executive officers and directors are elected until death, resignation, retirement, disqualification, or removal.

Name	Age	Position With Our General Partner
Joseph W. Craft III	67	President, Chief Executive Officer and Director
Brian L. Cantrell	58	Senior Vice President and Chief Financial Officer
R. Eberley Davis	60	Senior Vice President, General Counsel and Secretary
Robert G. Sachse	69	Executive Vice President
Charles R. Wesley	63	Executive Vice President and Director
Timothy J. Whelan	55	Senior Vice President - Sales and Marketing of Alliance Coal, LLC
Thomas M. Wynne	61	Senior Vice President and Chief Operating Officer
Nick Carter	71	Director and Member of Audit, Compensation and Conflicts Committees
John P. Neafsey	78	Chairman of the Board and Member of Audit, Compensation and Conflicts* Committees
John H. Robinson	67	Director and Member of Audit, Compensation* and Conflicts Committees
Wilson M. Torrence	76	Director and Member of Audit* and Compensation Committees

* Indicates Chairman of Committee

Joseph W. Craft III has been President, Chief Executive Officer and a Director since August 1999 and has indirect majority ownership of our general partner. Mr. Craft also serves as President, Chief Executive Officer and Chairman of the Board of Directors of AGP, the general partner of AHGP. Previously Mr. Craft served as President of MAPCO Coal Inc. since 1986. During that period, he also was Senior Vice President of MAPCO Inc. and had previously been that company's General Counsel and Chief Financial Officer. He is a former Chairman and current Board member of the National Coal Council, a Board Member of the National Mining Association, and a Director and past Chairman of American Coalition for Clean Coal Electricity ("ACCCE"). Mr. Craft is a Director and Chairman of the Kentucky Chamber of Commerce and a Director and Executive Committee member of the U.S. Chamber of Commerce. He has been a Director of BOK Financial Corporation (NASDAQ: BOKF) since 2007 and chairman of its compensation committee since 2014. Mr. Craft holds a Bachelor of Science degree in Accounting and a Juris Doctorate degree from the University of Kentucky. Mr. Craft also is a graduate of the Senior Executive Program of the Alfred P. Sloan School of Management at Massachusetts Institute of Technology. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Craft should serve as a Director include his long history of significant involvement in the coal industry, his demonstrated business acumen and his exceptional leadership of the Partnership since its inception.

Brian L. Cantrell has been Senior Vice President and Chief Financial Officer since October 2003. Mr. Cantrell also serves as Senior Vice President and Chief Financial Officer of AGP, the general partner of AHGP. Prior to his current position, Mr. Cantrell was President of AFN Communications, LLC from November 2001 to October 2003 where he had previously served as Executive Vice President and Chief Financial Officer after joining AFN in September 2000. Mr. Cantrell's previous positions include Chief Financial Officer, Treasurer and Director with Brighton Energy, LLC from August 1997 to September 2000; Vice President—Finance of KCS Medallion Resources, Inc.; and Vice President—

Finance, Secretary and Treasurer of Intercoast Oil and Gas Company. Mr. Cantrell is a Certified Public Accountant and holds Master of Accountancy and Bachelor of Accountancy degrees from the University of Oklahoma.

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

Robert G. Sachse has been Executive Vice President since August 2000. Effective November 1, 2006, Mr. Sachse assumed responsibility for our coal marketing, sales and transportation functions. Mr. Sachse was also Vice Chairman of our general partner from August 2000 to January 2007. Mr. Sachse was Executive Vice President and Chief Operating Officer of MAPCO Inc. from 1996 to 1998 when MAPCO merged with The Williams Companies. Following the merger, Mr. Sachse had a two year non-compete consulting agreement with The Williams Companies. Mr. Sachse held various positions while with MAPCO Coal Inc. from 1982 to 1991, and was promoted to President of MAPCO Natural Gas Liquids in 1992. Mr. Sachse holds a Bachelor of Science degree in Business Administration from Trinity University and a Juris Doctorate degree from the University of Tulsa.

Charles R. Wesley has been a Director since January 2009 and Executive Vice President since March 2009. Mr. Wesley has served in a variety of capacities since joining the company in 1974, including as Senior Vice President—Operations from August 1996 through February 2009. Mr. Wesley is a former Chairman of the Board of Directors of the Kentucky Coal Association and also has served the industry as past President of the West Kentucky Mining Institute and National Mine Rescue Association Post 11, and as a director of the Kentucky Mining Institute. Mr. Wesley holds a Bachelor of Science degree in Mining Engineering from the University of Kentucky. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Wesley should serve as a Director include his long history of significant involvement in the coal industry, his successful leadership of the Partnership's operations, and his knowledge and technical expertise in all aspects of producing and marketing coal.

Timothy J. Whelan has been Senior Vice President - Sales and Marketing of Alliance Coal, LLC since May 2013. Since joining Alliance in September 2003, Mr. Whelan has held several positions with increasing responsibility, serving as Vice President – Sales prior to his current position. Mr. Whelan previously served in various business development positions for MAPCO Inc. and as Director, Power & Gas Origination for Williams Energy Marketing and Trading. Mr. Whelan has over 25 years of energy industry experience, and is a former board member of the American Coal Council and The Coal Institute. Mr. Whelan holds a Bachelor of Science degree in Finance from the University of Arkansas.

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

Nick Carter became a Director in April 2015. Mr. Carter is a member of the Audit, Compensation and Conflicts Committees. Mr. Carter retired as President and Chief Operating Officer of Natural Resource Partners L.P. (NYSE: NRP) on September 1, 2014, having served in such capacities since 2002 and in other roles for NRP or its affiliates since 1990. Prior to 1990, Mr. Carter held various positions with MAPCO Coal Corporation and was engaged in the private practice of law. Mr. Carter also serves on the board of directors, the audit committee and as chairman of the compensation committee of Community Trust Bancorp, Inc. (NASDAQ: CTBI). Mr. Carter previously served as chairman of the National Council of Coal Lessors for 12 years and as chairman of the West Virginia Chamber of Commerce. He also previously served as a board member of the West Virginia Coal Association, the Indiana Coal Council, the National Mining Association, and ACCCE. Mr. Carter has served as a board member of the Kentucky Coal Association for over 20 years and currently is its Treasurer. Mr. Carter holds Bachelor and Juris Doctorate degrees from the University of Kentucky and a Master of Business Administration degree from the University of Hawaii. The specific experience, qualifications,

attributes or skills that led to the conclusion Mr. Carter should serve as a Director include his extensive experience in the coal and energy industries and in senior corporate leadership.

John P. Neafsey has served as Chairman of the Board of Directors since June 1996. Mr. Neafsey is also Chairman of the Conflicts Committee and a member of the Audit and Compensation Committees. Mr. Neafsey is President of JN Associates, an investment consulting firm formed in 1993. Mr. Neafsey served as President and CEO of Greenwich Capital Markets from 1990 to 1993 and as a Director since its founding in 1983. Positions that Mr. Neafsey held during a 23-year career at The Sun Company include Director; Executive Vice President responsible for Canadian operations, Sun Coal Company and Helios Capital Corporation; Chief Financial Officer; and other executive and director positions with numerous subsidiary companies. He is or has been active in a number of organizations, including the following: former Director and Chairman of the audit committee for The West Pharmaceutical Services Company and former Chairman and a member of the audit and compensation committees of Constar, Inc., former Chairman and member of the audit and compensation committees of NES Rentals, Inc., Trustee Emeritus and Presidential Counselor, Cornell University, and Overseer of Cornell-Weill Medical Center. Mr. Neafsey holds a Bachelor of Science degree in Engineering and a Master of Business Administration degree from Cornell University. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Neafsey should serve as a Director include his extensive service in senior corporate leadership positions in both the energy and financial services industries, and his technical expertise, knowledge and experience with financial markets.

John H. Robinson became a Director in December 1999. Mr. Robinson is Chairman of the Compensation Committee and a member of the Audit and Conflicts Committees. Mr. Robinson is Chairman of Hamilton Ventures, LLC. From 2003 to 2004, he was Chairman of EPC Global, Ltd., an engineering staffing company. From 2000 to 2002, he was Executive Director of Amey plc, a British business process outsourcing company. Mr. Robinson served as Vice Chairman of Black & Veatch, Inc. from 1998 to 2000. He began his career at Black & Veatch in 1973 and was a General Partner and Managing Partner prior to becoming Vice Chairman when the firm incorporated. Mr. Robinson is a Director of Coeur Mining Corporation and a member of its executive and audit committees and chairman of its compensation committee, and he is a Director of the Federal Home Loan Bank of Des Moines, also serving on its mission, member and housing committee and its business operations and technology committee. Mr. Robinson is also a Director of Olsson Associates. He holds Bachelor and Master of Science degrees in Engineering from the University of Kansas and is a graduate of the Owner-President-Management Program at the Harvard Business School. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Robinson should serve as a Director include his significant experience in the engineering and consulting industries, his extensive service in senior corporate leadership positions in both industries and his familiarity with financial matters.

Wilson M. Torrence became a Director in January 2007. Mr. Torrence is Chairman of the Audit Committee and a member of the Compensation Committee. Mr. Torrence is also a Director and Chairman of the Audit Committee of AGP, the general partner of AHGP. Mr. Torrence retired from Fluor Corporation in 2006 as a Senior Vice President of Project Development and Investments and since that time has performed investment and business consulting services for various clients. Mr. Torrence was employed at Fluor from 1989 to 2006 where, among other roles, he was responsible for the global Project Investment and Structured Finance Group and served as Chairman of Fluor's Investment Committee. In that position, Mr. Torrence had executive responsibility for Fluor's global activities in developing and arranging third-party financing for some of Fluor's clients' construction projects. Prior to joining Fluor in 1989, Mr. Torrence was President and CEO of Combustion Engineering Corporation's Waste to Energy Division and, during that time, also served as Chairman of the Institute of Resource Recovery, a Washington-based industry advocacy organization. Mr. Torrence began his career at Mobil Oil Corporation, where he held several executive positions, including Assistant Treasurer of Mobil's International Marketing and Refining Division and Chief Financial and Planning Officer of Mobil Land Development Company. Mr. Torrence holds a Bachelor and a Master of Business Administration degree from Virginia Tech University. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Torrence should serve as a Director include his extensive experience in the construction and energy businesses, his senior corporate finance-related and other leadership positions and his participation in numerous financing transactions.

Board of Directors

The leadership structure of the Board of Directors has been consistent since the ARLP Partnership's inception. The President and Chief Executive Officer is a member of the Board of Directors, but is not its Chairman, and its Chairman is an independent Director. We believe this structure is appropriate for the Partnership because it allows for leadership of the Board of Directors that is independent of management, enhancing the effectiveness of the Board of Directors' oversight.

The Board of Directors generally administers its risk oversight function through the board as a whole. The President and Chief Executive Officer, who reports to the Board of Directors, and the other executives named above, who report to the President and Chief Executive Officer, have day-to-day risk management responsibilities. At the Board of Director's request, each of these executives attends the meetings of the Board of Directors, where the Board of Directors routinely receives reports on our financial results, the status of our operations and our safety performance, and other aspects of implementation of our business strategy, with ample opportunity for specific inquiries of management. In addition, management provides periodic reports of the Partnership's financial and operational performance to each member of the Board of Directors. The Audit Committee provides additional risk oversight through its quarterly meetings, where it receives a report from the Partnership's internal auditor, who reports directly to the Audit Committee, and reviews the Partnership's contingencies, significant transactions and subsequent events, among other matters, with management and our independent auditors.

The Board of Directors has selected as director nominees individuals with experience, skills and qualifications relevant to the business of the Partnership, such as experience in energy or related industries or with financial markets, expertise in mining, engineering or finance, and a history of service in senior leadership positions. The Board of Directors has not established a formal process for identifying director nominees, nor does it have a formal policy regarding consideration of diversity in identifying director nominees, but has endeavored to assemble a diverse group of individuals with the qualities and attributes required to provide effective oversight of the Partnership.

Audit Committee

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

Report of the Audit Committee

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

- filings with the SEC pursuant to the Securities Act of 1933 (the "Securities Act") and the Exchange Act (i.e., Forms 10-K, 10-Q, and 8-K);
- press releases and other communications by us to the public concerning earnings, financial condition and results of operations, including changes in distribution policies or practices affecting the holders of our units, if such review is not undertaken by the Board of Directors;
- systems of internal controls regarding finance and accounting that management and the Board of Directors have established; and
- auditing, accounting and financial reporting processes generally.

In fulfilling its oversight and other responsibilities, the Audit Committee met eight times during 2017. The Audit Committee's activities included, but were not limited to: (a) selecting the independent registered public accounting firm, (b) meeting periodically in executive session with the independent registered public accounting firm, (c) reviewing the Quarterly Reports on Form 10-Q for the three months ended March 31, June 30, and September 30, 2017, (d) performing a self-assessment of the committee, (e) reviewing the Audit Committee charter, and (f) reviewing the overall scope, plans and findings of our internal auditor. Based on the results of the annual self-assessment, the Audit Committee believes that it satisfied the requirements of its charter. The Audit Committee also reviewed and discussed with management and the

independent registered public accounting firm this Annual Report on Form 10-K, including the audited financial statements.

Our independent registered public accounting firm, Ernst & Young LLP, is responsible for expressing an opinion on the conformity of the audited financial statements with GAAP. The Audit Committee reviewed with Ernst & Young LLP its judgment as to the quality, not just the acceptability, of our accounting principles and such other matters as are required to be discussed with the Audit Committee under generally accepted auditing standards.

The Audit Committee discussed with Ernst & Young LLP the matters required to be discussed by Auditing Standard No. 16, *Communications with Audit Committees*. The Audit Committee received written disclosures and the letter from Ernst & Young LLP required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent accountant's communication with the Audit Committee regarding independence, and has discussed with Ernst & Young LLP its independence from management and the ARLP Partnership.

Based on the reviews and discussions referred to above, the Audit Committee recommended to the Board of Directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2017 for filing with the SEC.

Members of the Audit Committee:

Wilson M. Torrence, Chairman
Nick Carter
John P. Neafsey
John H. Robinson

Code of Ethics

We have adopted a code of ethics with which the President and Chief Executive Officer and the senior financial officers (including the principal financial officer and the principal accounting officer or controller) are expected to comply. The code of ethics is publicly available on our website under "Investor Relations" at www.arlp.com and is available in print without charge to any unitholder who requests it. Such requests should be directed to Investor Relations at (918) 295-7674. If any substantive amendments are made to the code of ethics or if there is a grant of a waiver, including any implicit waiver, from a provision of the code to the President and Chief Executive Officer, Chief Financial Officer, or Controller, we will disclose the nature of such amendment or waiver on our website or in a report on Form 8-K.

Communications with the Board

Unitholders or other interested parties can contact any director or committee of the Board of Directors by writing to them c/o Senior Vice President, General Counsel and Secretary, P.O. Box 22027, Tulsa, Oklahoma 74121-2027. Comments or complaints relating to our accounting, internal accounting controls or auditing matters will also be referred to members of the Audit Committee. The Audit Committee has procedures for (a) receipt, retention and treatment of complaints received by us regarding accounting, internal accounting controls, or auditing matters and (b) the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act, as amended, requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC initial reports of ownership and reports or changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms they file. Based upon a review of the copies of the forms furnished to us and written representations from certain reporting persons, we believe that during 2017 none of our officers and directors were delinquent with respect to any of the filing requirements under Rule 16(a).

Reimbursement of Expenses of our General Partner and its Affiliates

Our general partner does not receive any management fee or other compensation in connection with its management of us. Our general partner is reimbursed by us for all expenses incurred on our behalf. Please see "Item 13. Certain Relationships and Related Transactions, and Director Independence—*Administrative Services*."

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Introduction

The Compensation Committee oversees the compensation of our general partner's executive officers, including the President and Chief Executive Officer, our principal executive officer, the Senior Vice President and Chief Financial Officer, our principal financial officer, and the three most highly compensated executive officers in 2017, each of whom is named in the Summary Compensation Table (collectively, our "Named Executive Officers"). Our Named Executive Officers are employees of our operating subsidiary, Alliance Coal. Certain of our Named Executive Officers devote a portion of their time to the business of one or more related parties and, to the extent they do so, Alliance Coal is reimbursed for such services by those related parties pursuant to an administrative services agreement. Please see "Item 13—Certain Relationships and Related Transactions, and Director Independence—*Administrative Services*." We do not have employment agreements with any of our Named Executive Officers.

Compensation Objectives and Philosophy

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

Setting Executive Compensation

Role of the Compensation Committee

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

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

Role of Executive Officers

Each year, the President and Chief Executive Officer submits recommendations to the Compensation Committee for adjustments to the salary, bonuses and long-term equity incentive awards payable to our Named Executive Officers, excluding himself. The President and Chief Executive Officer bases his recommendations on his assessment of each executive's performance, experience, demonstrated leadership, job knowledge and management skills. The Compensation Committee considers the recommendations of the President and Chief Executive Officer as one factor in making compensation decisions regarding our Named Executive Officers. Historically, and in 2017, the Compensation Committee and the President and Chief Executive Officer have been substantially aligned on decisions regarding compensation of the Named Executive Officers. As executive officers are promoted or hired during the year, the President and Chief Executive Officer makes compensation recommendations to the Compensation Committee and works closely with the Compensation Committee to ensure that all compensation arrangements for executive officers are consistent with our compensation philosophy and are approved by the Compensation Committee. At the direction of the Compensation Committee, the President and Chief Executive Officer and the Senior Vice President, General Counsel and Secretary attend certain meetings of the Compensation Committee.

Use of Peer Group Comparisons

The Compensation Committee believes that it is important to review and compare our performance with that of peer companies in the coal industry, and reviews the composition of the peer group annually. The peer group for 2017 included Arch Coal, Inc., CNX Coal Resources LP, Consol Energy Inc., Contura Energy, Inc., Foresight Energy, L.P., Natural Resource Partners L.P., Peabody Energy Corporation, Warrior Met Coal, Inc., and Westmoreland Resource Partners, L.P. In assessing the competitiveness of our executive compensation program for 2017, the Compensation Committee, with the assistance of the President and Chief Executive Officer, collected and analyzed peer group proxy information and developed a comparative analysis of base salaries, short-term incentives, total cash compensation, long-term incentives and total direct compensation. The Compensation Committee uses the peer group data as a point of reference for comparative purposes, but it is not the determinative factor for the compensation of our Named Executive Officers. The Compensation Committee exercises discretion in determining the nature and extent of the use of comparative pay data.

Consideration of Equity Ownership

Mr. Craft, the President and Chief Executive Officer, is evaluated and treated differently with respect to compensation than our other Named Executive Officers. Mr. Craft and related entities own significant equity positions in AHGP, which owns MGP II and MGP and, as of December 31, 2017, 66.7% of ARLP's outstanding common units. Because of these ownership positions, the interests of Mr. Craft are directly aligned with those of our unitholders. Mr. Craft has not received an increase in base salary since 2002, has not received a bonus under our short-term incentive plan ("STIP") since 2005 and did not receive any grants of LTIP awards from 2005 through 2015. Beginning in February 2016, at Mr. Craft's request, his annual base salary was reduced to $1. On January 22, 2016, the Compensation Committee approved an LTIP award for Mr. Craft that will cliff vest on January 1, 2019 provided the vesting requirement for the 2016 awards is met.

Compensation Components

Overview

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

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

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

Each of our Named Executive Officers also receives supplemental retirement benefits through the SERP. In addition, all executive officers are entitled to customary benefits available to our employees generally, including group medical,

dental, and life insurance and participation in our profit sharing and savings plan ("PSSP"). Our PSSP is a defined contribution plan and includes an employer matching contribution of 75% on the first 3% of eligible compensation contributed by the employee, an employer non-matching contribution of 0.75% of eligible compensation, and an employer supplemental contribution of 5% of eligible compensation. The PSSP provides an additional means of attracting and retaining qualified employees by providing tax-advantaged opportunities for employees to save for retirement.

Base Salary

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

Annual Cash Incentive Bonus Awards

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

The performance target historically has been EBITDA-based, with items added or removed from the EBITDA calculation to ensure that the performance target reflects the operating results of our core business. (EBITDA is defined as net income of ARLP before net interest expense, income taxes, depreciation, depletion and amortization and net income attributable to noncontrolling interest.) The aggregate cash available for awards under the STIP each year is dependent on our actual financial results for the year compared to the annual performance target, and it increases in relationship to our EBITDA, as adjusted, exceeding the minimum threshold. The Compensation Committee may determine satisfactory results and adjust the size of the pay-out pool in its sole discretion. In 2017, the Compensation Committee approved a minimum financial performance target of $531.2 million in EBITDA from current operations, normalized by excluding any charges for unit-based and directors' compensation and affiliate contributions, if any. For 2017, we exceeded the minimum performance target.

Awards to our Named Executive Officers each year are determined by and in the discretion of the Compensation Committee. However, the Compensation Committee does not establish individual target payout amounts for the Named Executive Officers' STIP awards or otherwise communicate with the Named Executive Officers regarding their STIP awards or the payout amounts thereunder until the individual STIP awards are paid. As it does when reviewing base salaries, in determining individual awards under the STIP the Compensation Committee considers its assessment of the individual's performance, our financial performance, comparative compensation data of companies in our peer group and the recommendation of the President and Chief Executive Officer. The compensation expense associated with STIP awards is recognized in the year earned, with the cash awards payable in the first quarter of the following calendar year. Termination of employment of an executive officer for any reason prior to payment of a cash award will result in forfeiture of any right to the award, unless and to the extent waived by the Compensation Committee in its discretion.

The performance measure for the STIP in 2018 will be EBITDA for current operations, excluding charges for unit-based and directors' compensation and affiliate contributions, if any. As discussed above, the Compensation Committee may, in its discretion, make equitable adjustments to the performance criteria under the STIP and adjust the amount of the aggregate pay-out. The Compensation Committee believes the STIP performance criteria for 2018 will be reasonably difficult to achieve and therefore support our key compensation objectives discussed above.

Equity Awards under the LTIP

Equity compensation pursuant to the LTIP is a key component of our executive compensation program. Our LTIP is sponsored by Alliance Coal. Under the LTIP, grants may be made of either (a) restricted units or (b) options to purchase

common units, although to date, no grants of options have been made. The Compensation Committee has authority to determine the participants to whom restricted units are granted, the number of restricted units to be granted to each such participant, and the conditions under which the restricted units may become vested, including the duration of any vesting period. Annual grant levels for designated participants (including our Named Executive Officers) are recommended by our general partner's President and Chief Executive Officer, subject to review and approval by the Compensation Committee. Grant levels are intended to support the objectives of the comprehensive compensation package described above. The LTIP grants provide our Named Executive Officers with the opportunity to achieve a meaningful ownership stake in the Partnership, thereby assuring that their interests are aligned with our success. Even though Mr. Craft was not granted an award under the LTIP from 2005 through 2015, the Compensation Committee believes Mr. Craft's interests are directly aligned with the interests of our unitholders as a result of his ownership positions. In addition, as noted above, Mr. Craft was granted an LTIP award for 2016. There is no formula for determining the size of awards to any individual recipient and, as it does when reviewing base salaries and individual STIP payments, the Compensation Committee considers its assessment of the individual's performance, our financial performance, compensation levels at peer companies in the coal industry and the recommendation of the President and Chief Executive Officer. Amounts realized from prior grants, including amounts realized due to changes in the value of our common units, are not considered in setting grant levels or other compensation for our Named Executive Officers.

Restricted Units. Restricted units granted under the LTIP are "phantom" or notional units that upon vesting entitle the participant to receive an ARLP common unit. Restricted units granted under the LTIP vest at the end of a stated period from the grant date (which is currently approximately three years for all outstanding restricted units), provided we achieve an aggregate performance target for that period. However, if a grantee's employment is terminated for any reason prior to the vesting of any restricted units, those restricted units will be automatically forfeited, unless the Compensation Committee, in its sole discretion, determines otherwise. The number of units actually distributed upon satisfaction of the applicable vesting requirements is reduced to cover the minimum statutory income tax withholding requirement for each individual participant based upon the fair market value of the common units as of the date of distribution. At the Compensation Committee's discretion, grants of restricted units under the LTIP may include the contingent right to receive quarterly distributions in an amount equal to the cash distributions we make to unitholders during the vesting period ("DERs"). DERs are payable, in the discretion of the Compensation Committee, either in cash or in the form of additional Restricted Units credited to a book keeping account subject to the same vesting restrictions as the tandem award.

The performance target applicable to restricted unit awards under the LTIP is based on a normalized EBITDA measure, with that measure typically being similar to the STIP measure for the year of the grant. The target, however, requires achieving an aggregate performance level for the three-year period. We typically issue grants under the LTIP at the beginning of each year, with the exceptions of new employees who begin employment with us at some other time and job promotions that may occur at some other time. The compensation expense associated with LTIP grants is recognized over the vesting period in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 718, *Compensation — Stock Compensation*.

Our general partner's policy is to grant restricted units pursuant to the LTIP to serve as a means of incentive compensation for performance. Therefore, no consideration will be payable by the LTIP participants upon receipt of the common units. Common units to be delivered upon the vesting of restricted units may be common units we already own, common units we acquire in the open market or from any other person, newly issued common units, or any combination of the foregoing. If we issue new common units upon payment of the restricted units instead of purchasing them, the total number of common units outstanding will increase.

Grants for 2017 under the LTIP, made January 26, 2017, will cliff vest on January 1, 2020, provided we achieve a target level of aggregate EBITDA for current operations, excluding any charges for unit-based and directors' compensation and affiliate contributions, if any, for the period January 1, 2017 through December 31, 2019. Grants for 2018 under the LTIP, made January 24, 2018, will cliff vest on January 1, 2021, provided we achieve a target level of aggregate EBITDA for current operations, excluding any charges for unit-based and directors' compensation and affiliate contributions, if any, for the period January 1, 2018 through December 31, 2020. The LTIP provides the Compensation Committee with discretion to determine the conditions for vesting (as well as all other terms and conditions) associated with any award under the plan, and to amend any of those conditions so long as an amendment does not materially reduce the benefit to the participant. The Compensation Committee believes the performance-related vesting conditions of all outstanding awards under the LTIP will be reasonably difficult to satisfy and therefore support our key compensation objectives discussed above.

Unit Options. We have not made any grants of unit options. The Compensation Committee, in the future, may decide to make unit option grants to employees and directors on terms determined by the Compensation Committee.

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

Effect of a Change in Control. Upon a "change in control" as defined in the LTIP, all awards outstanding under the LTIP will automatically vest and become payable or exercisable, as the case may be, in full. Please see "Item 11. Executive Compensation—*Potential Payments Upon a Termination or Change of Control*."

Amendments and Termination. The Board of Directors or the Compensation Committee may, in its discretion, terminate the LTIP at any time with respect to any common units for which a grant has not previously been made. Except as required by the rules of the exchange on which the common units may be listed at that time, the Board of Directors or the Compensation Committee may alter or amend the LTIP in any manner from time to time; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the affected participant. In addition, the Board of Directors or the Compensation Committee may, in its discretion, establish such additional compensation and incentive arrangements as it deems appropriate to motivate and reward our employees.

Supplemental Executive Retirement Plan

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

Under the terms of the SERP, a participant is entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to his or her percentage allocation multiplied by the sum of the participant's base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year. A participant's cumulative notional phantom unit account balance earns the equivalent of common unit distributions, which are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant's termination from employment in ARLP common units equal to the number of phantom units then credited to the participant's account, less the number of units required to satisfy our tax withholding obligations. A participant in the SERP is not entitled to an allocation for the year in which his termination from employment occurs, except as described below.

A participant in the SERP, including any of our Named Executive Officers, is entitled to receive an allocation under the SERP for the year in which his employment is terminated only if such termination results from one of the following events:

(1) the participant's employment is terminated other than for "cause";

(2) the participant terminates employment for "good reason";

(3) a change of control of us or our general partner occurs and, as a result, the participant's employment is terminated (whether voluntary or involuntary);

(4) death of the participant;

(5) the participant attains (or has attained) retirement age of 65 years; or

(6) the participant incurs a total and permanent disability, which shall be deemed to occur if the participant is eligible to receive benefits under the terms of the long-term disability program we maintain.

This allocation for the year in which a participant's termination occurs shall equal the participant's eligible compensation for such year (including any severance amount, if applicable) multiplied by his percentage allocation under the SERP, reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year.

Other Compensation-Related Matters

Trading in Derivatives

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

Tax Deductibility of Compensation

The deduction limitations imposed under Section 162(m) of the Internal Revenue Code do not apply to compensation paid to our Named Executive Officers because we are a limited partnership and not a "corporation" within the meaning of Section 162(m).

Perquisites and Personal Benefits

The Partnership provides a limited amount of perquisites and personal benefits to the Named Executive Officers in keeping with the Compensation Committee's objectives to provide competitive compensation to motivate and reward executive officers for creating sustainable, capital-efficient growth in available cash. These perquisites and personal benefits typically include amounts for items such as tax preparation fees and social club dues, and are reviewed annually by the Compensation Committee.

Compensation Committee Report

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

Our Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis contained in this Annual Report on Form 10-K with management. Based on our Compensation Committee's review of and the discussions with management with respect to the Compensation Discussion and Analysis, our Compensation Committee recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2017.

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

Members of the Compensation Committee:

John H. Robinson, Chairman
Nick Carter
John P. Neafsey
Wilson M. Torrence

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

Summary Compensation Table

Name and Principal Position	Year	Salary (1)	Unit Awards (2)	Non-Equity Incentive Plan Compensation (3)	All Other Compensation (4)	Total
Joseph W. Craft III	2017	$ 1	$ —	$ —	$ 376,620	$ 376,621
President, Chief Executive	2016	32,197	972,511	—	356,682	1,361,390
Officer and Director	2015	341,267	—	—	478,458	819,725
Brian L. Cantrell,	2017	284,000	487,483	242,000	91,310	1,104,793
Senior Vice President –	2016	284,000	486,534	300,000	83,669	1,154,203
Chief Financial Officer	2015	289,462	499,239	218,600	96,941	1,104,242
R. Eberley Davis	2017	325,000	587,644	277,000	111,287	1,300,931
Senior Vice President,	2016	325,000	584,336	342,000	94,572	1,345,908
General Counsel and Secretary	2015	331,250	584,590	246,500	114,783	1,277,123
Robert G. Sachse	2017	200,000	613,196	271,000	139,301	1,223,497
Executive Vice President	2016	275,692	680,900	382,000	120,698	1,459,290
	2015	329,212	748,895	245,000	150,441	1,473,548
Thomas M. Wynne	2017	374,000	710,264	319,000	113,983	1,517,247
Senior Vice President and	2016	374,000	714,945	394,000	97,027	1,579,972
Chief Operating Officer	2015	381,192	708,023	285,300	103,191	1,477,706

(1) Certain of our Named Executive Officers devote a portion of their time to the business of one or more related parties and, to the extent they do so, the base salary of those executive officers is reimbursed to Alliance Coal by those related parties pursuant to an administrative services agreement. Please see "Item 1. Business—Employees—*Administrative Services Agreement*." In 2017, the percentage of base salary reimbursed to Alliance Coal was 5% for Mr. Craft, 6% for Mr. Cantrell and 9% for Mr. Davis. In 2016 and 2015, the percentage of base salary reimbursed to Alliance Coal was 5% for Mr. Craft, 4% for Mr. Cantrell and 8% for Mr. Davis.

(2) The Unit Awards represent the aggregate grant date fair value of equity awards granted (computed in accordance with FASB ASC 718) to each Named Executive Officer under the LTIP in the respective year. Please see "Item 11. Compensation Discussion and Analysis—Compensation Program Components—*Equity Awards under the LTIP*" for a description of the terms of the awards.

(3) Amounts represent the STIP bonus earned for the respective year. STIP payments are made in the first quarter of the year following the year in which they are earned. Other than this bonus, there were no other applicable bonuses earned or deferred associated with year 2017. Please see "Item 11. Compensation Discussion and Analysis—Compensation Program Components—*Annual Cash Incentive Bonus Awards*."

(4) For all Named Executive Officers, the amounts represent the sum of the (a) SERP phantom unit contributions valued at the market closing price of our common units on the date the phantom unit was granted, (b) profit sharing savings plan employer contribution and (c) perquisites in excess of $10,000. A reconciliation of the 2017 amounts shown is as follows:

	SERP	Profit Sharing Plan Employer Contribution	Perquisites (a)	Total
Joseph W. Craft III	$ 364,670	$ —	$ 11,950	$ 376,620
Brian L. Cantrell	59,546	21,600	10,164	91,310
R. Eberley Davis	89,687	21,600	—	111,287
Robert G. Sachse	103,639	16,000	19,662	139,301
Thomas M. Wynne	92,383	21,600	—	113,983

a) For Mr. Craft and Mr. Cantrell, perquisites and other personal benefits comprised of club dues of $11,950 and $10,164, respectively. For Mr. Sachse, perquisites and other personal benefits totaling $19,662 comprised of club dues of $16,472 and tax preparation fees of $3,190.

Grants of Plan-Based Awards Table

Name	Grant Date	Approved Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards Threshold (3)	Target (4)	Maximum (3)	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (5)	Target (6)	Maximum (5)	All Other Unit Awards: Number of Units (7)	Grant Date Fair Value of Unit Awards (8)
Joseph W. Craft III	February 3, 2017	February 3, 2017					—		—	$ —
	February 14, 2017	(1), (2)					—		3,567	82,754
	May 15, 2017	(1), (2)					—		3,774	86,236
	August 14, 2017	(1), (2)					—		5,232	95,484
	November 14, 2017	(1), (2)					—		5,416	100,196
	December 31, 2017	(2)					—		—	—
		February 9, 2018		$ —			—		—	—
				—			—		17,989	364,670
Brian L. Cantrell	February 3, 2017	February 3, 2017					20,967		—	487,483
	February 14, 2017	(1), (2)					—		318	7,378
	May 15, 2017	(1), (2)					—		336	7,678
	August 14, 2017	(1), (2)					—		466	8,505
	November 14, 2017	(1), (2)					—		482	8,917
	December 31, 2017	(2)					—		1,374	27,068
		February 9, 2018		242,000			—		—	—
				242,000			20,967		2,976	547,029
R. Eberley Davis	February 3, 2017	February 3, 2017					25,275		—	587,644
	February 14, 2017	(1), (2)					—		407	9,442
	May 15, 2017	(1), (2)					—		430	9,826
	August 14, 2017	(1), (2)					—		596	10,877
	November 14, 2017	(1), (2)					—		617	11,415
	December 31, 2017	(2)					—		2,443	48,127
		February 9, 2018		277,000			—		—	—
				277,000			25,275		4,493	677,331
Robert G. Sachse	February 3, 2017	February 3, 2017					26,374		—	613,196
	February 14, 2017	(1), (2)					—		525	12,180
	May 15, 2017	(1), (2)					—		555	12,682
	August 14, 2017	(1), (2)					—		770	14,053
	November 14, 2017	(1), (2)					—		797	14,745
	December 31, 2017	(2)					—		2,537	49,979
		February 9, 2018		271,000			—		—	—
				271,000			26,374		5,184	716,835
Thomas M. Wynne	February 3, 2017	February 3, 2017					30,549		—	710,264
	February 14, 2017	(1), (2)					—		419	9,721
	May 15, 2017	(1), (2)					—		443	10,123
	August 14, 2017	(1), (2)					—		614	11,206
	November 14, 2017	(1), (2)					—		635	11,748
	December 31, 2017	(2)					—		2,517	49,585
		February 9, 2018		319,000			—		—	—
				$ 319,000			30,549		4,628	$ 802,647

(1) In accordance with the provisions of the SERP, a participant's cumulative notional phantom unit account balance earns the equivalent of common unit distributions when we pay a distribution to our common unitholders, which is added to the account balance in the form of phantom units.

(2) These contributions are made in accordance with the SERP plan document that has been approved by the Compensation Committee. Therefore, these contributions are not separately approved by the Compensation Committee.

(3) Awards under our STIP are subject to a minimum financial performance target each year. However, determination of individual awards under the STIP is based upon an assessment of the Named Executive Officer's performance, comparative compensation data of companies in our peer group and recommendation of the President and Chief

Executive Officer. The STIP does not specify any threshold or maximum payout amounts. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Annual Cash Incentive Bonus Awards*" for additional information regarding the STIP awards.

(4) These amounts represent awards pursuant to our STIP. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Annual Cash Incentive Bonus Awards*" for additional information regarding the STIP awards.

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

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

(7) These awards are phantom units added to each Named Executive Officer's SERP notional account balance. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Supplemental Executive Retirement Plan*."

(8) We calculated the fair value of LTIP awards using a value of $23.25 per unit, the unit price applicable for 2017 grants. We calculated the fair value of SERP phantom unit awards using the market closing price on the date the phantom unit award was granted. Phantom units granted under the SERP vest on the date granted.

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

Annual Cash Incentive Bonus Awards

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

Long-Term Incentive Plan

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

Supplemental Executive Retirement Plan

Under the terms of the SERP, participants are entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to his or her percentage allocation multiplied by the sum of base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year. A participant's cumulative notional phantom unit account balance earns the equivalent of common unit distributions. The calculated distributions are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant's termination or death in ARLP common units equal to the number of phantom units then credited to the participant's account, subject to reduction of the number of units distributed to cover withholding obligations. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Supplemental Executive Retirement Plan*."

Salary and Bonus in Proportion to Total Compensation

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

Name	Year	Salary and Bonus ($)	Total Compensation ($)	Salary and Bonus as a % of Total Compensation
Joseph W. Craft III	2017	$ 1	$ 376,621	0.0%
	2016	32,197	1,361,390	2.4%
	2015	341,267	819,725	41.6%
Brian L. Cantrell	2017	284,000	1,104,793	25.7%
	2016	284,000	1,154,203	24.6%
	2015	289,462	1,104,242	26.2%
R. Eberley Davis	2017	325,000	1,300,931	25.0%
	2016	325,000	1,345,908	24.1%
	2015	331,250	1,277,123	25.9%
Robert G. Sachse	2017	200,000	1,223,497	16.3%
	2016	275,692	1,459,290	18.9%
	2015	329,212	1,473,548	22.3%
Thomas M. Wynne	2017	374,000	1,517,247	24.6%
	2016	374,000	1,579,972	23.7%
	2015	381,192	1,477,706	25.8%

Outstanding Equity Awards at 2017 Fiscal Year-End Table

Name	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights That Have Not Vested (1)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested (2)
Joseph W. Craft III	78,555	$ 1,547,534
Brian L. Cantrell	73,691	1,451,713
R. Eberley Davis	88,194	1,737,422
Robert G. Sachse	101,511	1,999,767
Thomas M. Wynne	107,337	2,114,539

(1) Amounts represent restricted units awarded under the LTIP that were not vested as of December 31, 2017. Subject to our achieving financial performance targets, the units vested, or will vest, as follows:

	January 1,		
Name	2018	2019	2020
Joseph W. Craft III	—	78,555	—
Brian L. Cantrell	13,424	39,300	20,967
R. Eberley Davis	15,719	47,200	25,275
Robert G. Sachse	20,137	55,000	26,374
Thomas M. Wynne	19,038	57,750	30,549

Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Equity Awards under the LTIP*." All grants of restricted units under the LTIP include the contingent right to receive quarterly cash distributions in an amount equal to the cash distributions we make to unitholders during the vesting period.

(2) Stated values are based on $19.70 per unit, the closing price of our common units on December 29, 2017, the final market trading day of 2017.

Units Vested Table for 2017

	Unit Awards	
Name	Number of Units Acquired on Vesting (1)	Value Realized on Vesting (1)
Joseph W. Craft III	—	$ —
Brian L. Cantrell	14,968	336,032
R. Eberley Davis	19,118	429,199
Robert G. Sachse	21,710	487,390
Thomas M. Wynne	21,118	474,099

(1) Amounts represent the number and value of restricted units granted under the LTIP that vested in 2017. All of these units vested on January 1, 2017 and are valued at $22.45 per unit, the closing price on December 30, 2016, the final

market trading day of 2016. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Equity Awards under the LTIP*."

Pension Benefits Table for 2017

Name	Plan Name	Number of Years Credited Service (1)	Present Value of Accumulated Benefit (2)	Payments During Last Fiscal Year
Joseph W. Craft III	SERP		$ 4,171,495	$ —
Brian L. Cantrell	SERP		398,019	—
R. Eberley Davis	SERP		523,173	—
Robert G. Sachse	SERP		663,240	—
Thomas M. Wynne	SERP		538,657	—

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

(2) Amounts represent the Named Executive Officer's cumulative notional account balance of phantom units valued at $19.70, the closing price of our common units on December 29, 2017, the final market trading day of 2017. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Supplemental Executive Retirement Plan*."

Narrative Discussion Relating to the Pension Benefits Table for 2017

Supplemental Executive Retirement Plan

Under the terms of the SERP, participants are entitled to receive on December 31 of each year an allocation of phantom units having a fair market value equal to their percentage allocation multiplied by the sum of base salary and cash bonus received that year, then reduced by any supplemental contribution that was made to our defined contribution PSSP for the participant that year. A participant's cumulative notional phantom unit account balance earns the equivalent of common unit distributions. The calculated distributions are added to the notional account balance in the form of additional phantom units. All amounts granted under the SERP vest immediately and are paid out upon the participant's termination or death in ARLP common units equal to the number of phantom units then credited to the participant's account, subject to reduction of the number of units distributed to cover withholding obligations. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Supplemental Executive Retirement Plan*."

Potential Payments Upon a Termination or Change of Control

Each of our Named Executive Officers is eligible to receive accelerated vesting and payment under the LTIP and the SERP upon certain terminations of employment or upon our change in control. Upon a "change of control," as defined in the LTIP, all awards outstanding under the LTIP will automatically vest and become payable or exercisable, as the case may be, in full. In this regard, all restricted periods shall terminate and all performance criteria, if any, shall be deemed to have been achieved at the maximum level. The LTIP defines a "change in control" as one of the following events: (1) any sale, lease, exchange or other transfer of all or substantially all of our assets or Alliance Coal's assets to any person other than a person who is our affiliate; (2) the consolidation or merger of Alliance Coal with or into another person pursuant to a transaction in which the outstanding voting interests of Alliance Coal are changed into or exchanged for cash, securities or other property, other than any such transaction where (a) the outstanding voting interests of Alliance Coal are changed into or exchanged for voting stock or interests of the surviving corporation or its parent and (b) the holders of the voting interests of Alliance Coal immediately prior to such transaction own, directly or indirectly, not less than a majority of the voting stock or interests of the surviving corporation or its parent immediately after such transaction; or (3) a person or group being or becoming the beneficial owner of more than 50% of all voting interests of Alliance Coal then outstanding.

The amounts each of our Named Executive Officers could receive under the SERP have been previously disclosed in "Item 11. Pension Benefits Table for 2017" and the amounts each of the Named Executive Officers could receive under

the LTIP have been previously disclosed in "Item 11. Outstanding Equity Awards at 2017 Fiscal Year-End Table", in each case assuming the triggering event occurred on December 31, 2017. In addition, if a Named Executive Officer's employment were terminated as a result of one of certain enumerated events, the Named Executive Officer would receive an amount based on an allocation for the year of termination. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Supplemental Executive Retirement Plan*" for additional information regarding the enumerated events and allocation determination. The exact amount that any Named Executive Officer would receive could only be determined with certainty upon an actual termination or change in control.

Director Compensation

The compensation of the directors of our general partner, MGP, is set by the Board of Directors upon recommendation of the Compensation Committee. Mr. Craft received no director compensation in 2017. The directors of MGP devote 100% of their time as directors of MGP to the business of the ARLP Partnership.

Director Compensation Table for 2017

Name	Fees earned or Paid in Cash ($)	Unit Awards ($) (3)(4)	Option Awards ($)(1)	Non-Equity Incentive Plan Compensation ($)(2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(1)	All Other Compensation ($)(1)	Total ($)
John P. Neafsey	$ —	$348,011	$ —	$ 25,000	$ —	$ —	$373,011
John H. Robinson	165,000	—	—	25,000	—	—	190,000
Wilson M. Torrence	92,500	12,260	—	25,000	—	—	129,760
Nick Carter	155,000	—	—	25,000	—	—	180,000
Charles R. Wesley	—	—	—	25,000	—	—	25,000

(1) Columns are not applicable.

(2) These amounts represent a discretionary payment to the directors as a result of the 2017 performance.

(3) Amounts represent the grant date fair value of equity awards in 2017 related to deferrals of annual retainer and distributions earned on deferred units (computed in accordance with FASB ASC 718, using the same assumptions as used for financial reporting purposes). Please see *Narrative to Director Compensation Table*, below.

(4) At December 31, 2017, each director had the following number of "phantom" ARLP common units credited to his notional account under the MGP's Amended and Restated Deferred Compensation Plan for Directors ("Deferred Compensation Plan"):

Name	Directors Deferred Compensation Plan (in Units)
John P. Neafsey	92,770
John H. Robinson	—
Wilson M. Torrence	7,028
Nick Carter	—

Please see "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" for information regarding our Directors' beneficial ownership of ARLP common units.

Narrative to Director Compensation Table

Compensation for our non-employee directors includes an annual cash retainer paid quarterly in advance on a pro rata basis. The annual retainer for calendar year 2017 was $155,000 for each director other than Mr. Torrence, and $77,500 for Mr. Torrence (who also served, and received additional compensation, as a director and chairman of the audit committee of AGP, the general partner of AHGP). Mr. Neafsey also was entitled to cash compensation of $38,750 for service as Chairman of the Board of Directors, Mr. Torrence also was entitled to cash compensation of $15,000 for service

as Chairman of the Audit Committee, and Mr. Robinson also was entitled to additional cash compensation of $10,000 for service as Chairman of the Compensation Committee. Directors have the option to defer all or part of their cash compensation pursuant to the Deferred Compensation Plan by completing an election form prior to the beginning of each calendar year. Only Mr. Neafsey elected to defer cash compensation in 2017 pursuant to the Deferred Compensation Plan, deferring all of his cash compensation for 2017 (including the annual retainer described above).

Pursuant to the Deferred Compensation Plan, a notional account is established for deferred amounts of cash compensation and credited with notional common units of ARLP, described in the plan as "phantom" units. The number of phantom units credited is determined by dividing the amount deferred by the average closing unit price for the ten trading days immediately preceding the deferral date. When quarterly cash distributions are made with respect to ARLP common units, an amount equal to such quarterly distribution is credited to the notional account as additional phantom units. Payment of accounts under the Deferred Compensation Plan will be made in ARLP common units equal to the number of phantom units then credited to the director's account.

Directors may elect to receive payment of the account resulting from deferrals during a plan year either (a) on the January 1 on or next following their separation from service as a director or (b) on the earlier of a specified January 1 or the January 1 on or next following their separation from service. The payment election must be made prior to each plan year; if no election is made, the account will be paid on the January 1 on or next following the director's separation from service. The Deferred Compensation Plan is administered by the Compensation Committee, and the Board of Directors may change or terminate the plan at any time; provided, however, that accrued benefits under the plan cannot be impaired.

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

The Board of Directors has established a recommendation that each non-employee director should attain within five years following such person's election to the Board of Directors, and thereafter maintain during service on the Board of Directors, ownership of equity of ARLP (including phantom equity ownership under the Deferred Compensation Plan) with an aggregate value of $220,000.

CEO Pay Ratio Disclosures

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, we are providing the following information about the relationship of the annual total compensation of our employees and the annual total compensation of Joseph W. Craft III, our Chief Executive Officer (our "CEO").

For 2017, our last completed fiscal year:

- The median of the annual total compensation of all employees of our company (other than the CEO) was $89,934.
- The annual total compensation of our CEO, as reported in the Summary Compensation Table was $376,621.
- Based on this information, for 2017 the ratio of the annual total compensation of our CEO to the median of the annual total compensation of all employees was reasonably estimated to be 4.2 to 1.

To identify the median of the annual total compensation of all our employees, as well as to determine the annual total compensation of our median employee and our CEO, we took the following steps:

- We determined that, as of December 31, 2017, our employee population consisted of approximately 3,321 individuals with the vast majority of these individuals located in the U.S. This population consisted of our full-time, part-time, and temporary employees, as we do not have seasonal workers.

- We used a consistently applied compensation measure to identify our median employee of comparing the amount of salary or wages reflected in our payroll records as reported to the Internal Revenue Service on Form W-2 for 2017.
- We identified our median employee by consistently applying this compensation measure to all of our employees included in our analysis. Since the vast majority of our employees, including our CEO, are located in the U.S., we did not make any cost of living adjustments in identifying the median employee.
- After we identified our median employee, we combined all of the elements of such employee's compensation for the 2017 year in accordance with the requirements of Item 402(c)(2)(x) of Regulation S-K, resulting in annual total compensation of $89,934, comprised of such employee's W-2 compensation of $82,324 and contributions in the amount of $7,610 that we made on the employee's behalf to our 401(k) plan for the 2017 year.
- With respect to the annual total compensation of our CEO, we used the amount reported in the "Total" column of our 2017 Summary Compensation Table.

Compensation Committee Interlocks and Insider Participation

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

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

The following table sets forth certain information as of February 8, 2018, regarding the beneficial ownership of common units held by (a) each director of our general partner, (b) each executive officer of our general partner identified in the Summary Compensation Table included in "Item 11. Executive Compensation" above, (c) all such directors and executive officers as a group, and (d) each person known by our general partner to be the beneficial owner of 5% or more of our common units. Our general partner is 100% directly owned by MGP II and MGP II is 100% indirectly owned by AHGP, both of which are reflected as a 5% common unitholder in the table below. Approximately 69% of the equity of AHGP is owned by certain parties (some of whom are current or former members of management) who may comprise a group under Rule 13d-5(b) of the Exchange Act as a result of being subject to a transfer restrictions agreement entered into in connection with the AHGP IPO. SGP is a wholly owned subsidiary of ARH, which is indirectly owned by Mr. Craft and Kathleen S. Craft. The address of each of AHGP, ARH, our general partner, SGP, and unless otherwise indicated in the footnotes to the table below, each of the directors and executive officers reflected in the table below is 1717 South Boulder Avenue, Suite 400, Tulsa, Oklahoma 74119. Unless otherwise indicated in the footnotes to the table below, the common units reflected as being beneficially owned by our general partner's directors and Named Executive Officers are held directly by such directors and officers. The percentage of common units beneficially owned is based on 130,903,256 common units outstanding as of February 8, 2018.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Directors and Executive Officers		
Joseph W. Craft III (1)	87,554,971	66.9%
Nick Carter	3,000	*
John P. Neafsey	51,604	*
John H. Robinson	18,462	*
Wilson M. Torrence	34,796	*
Charles R. Wesley III (2)	—	*
Brian L. Cantrell	108,361	*
R. Eberley Davis	79,407	*
Robert G. Sachse	118,210	*
Thomas M. Wynne	75,160	*
Timothy Whelan	20,223	*
All directors and executive officers as a group (11 persons)	88,064,194	67.3%
5% Common Unit Holders		
Alliance Holdings GP, L.P. (3)	87,188,338	66.6%
MGP II, LLC (3)	56,100,000	42.9%

* Less than one percent.

(1) The common units attributable to Mr. Craft consist of (i) 357,452 common units held directly by him, (ii) 2,000 common units held by his son, (iii) 31,088,338 common units held directly by AHGP, (iv) 56,100,000 common units held by MGP II, and (v) 7,181 common units held by SGP (indirectly owned by Mr. Craft and Kathleen S. Craft). Mr. Craft is Chairman of the Board of Directors, and through his ownership of C-Holdings, LLC, the sole owner of AGP, the general partner of AHGP, and he holds, directly or indirectly, or may be deemed to be the beneficial owner of, a majority of the outstanding common units of AHGP. AHGP, including its 100% indirectly owned subsidiary, MGP II, beneficially owned approximately 66.6% of our common units as of February 8, 2018. Mr. Craft disclaims beneficial ownership of the common units held by AHGP and MGP II except to the extent of his pecuniary interest therein.

(2) Mr. Wesley holds 2,912,500 common units of AHGP through trusts and other entities controlled by him and his spouse.

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

Equity Compensation Plan Information

Plan Category	Number of units to be issued upon exercise/vesting of outstanding options, warrants and rights as of December 31, 2017	Weighted-average exercise price of outstanding options, warrants and rights	Number of units remaining available for future issuance under equity compensation plans as of December 31, 2017
Equity compensation plans approved by unitholders:			
Long-Term Incentive Plan	1,694,026	N/A	2,531,064
Equity compensation plans not approved by unitholders:			
Supplemental Executive Retirement Plan	461,986	N/A	N/A
Deferred Compensation Plan for Directors	99,798	N/A	N/A

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

In addition to the related-party transactions discussed in "Item 8. Financial Statements and Supplementary Data—Note 18. Related-Party Transactions," ARLP has the following additional related-party transactions:

Certain Relationships

As of December 31, 2017, AHGP and its indirectly wholly owned subsidiary, MGP II combined, owned 87,188,338 common units representing 66.7% of our common units and MGP II owns MGP. MGP's ability, as general partner, to control us together with AHGP's direct and indirect ownership of 66.7% of our common units, effectively gives our general partner the ability to veto our actions and to control our management.

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

Related-Party Transactions

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

Administrative Services

On April 1, 2010, effective January 1, 2010, ARLP entered into an Administrative Services Agreement with our general partner, our Intermediate Partnership, AHGP and its general partner AGP, and ARH II. The Administrative Services Agreement superseded a similar agreement signed in connection with the AHGP IPO in 2006. Under the Administrative Services Agreement, certain employees, including some executive officers, provide administrative services for AHGP, AGP and ARH II and their respective affiliates. We are reimbursed for services rendered by our employees on behalf of these entities as provided under the Administrative Services Agreement. We billed and recognized administrative service revenue under this agreement for the year ended December 31, 2017 of $0.4 million from AHGP.

Our partnership agreement provides that our general partner and its affiliates be reimbursed for all direct and indirect expenses incurred or payments made on behalf of us, including, but not limited to, director fees and expenses, management's salaries and related benefits (including incentive compensation), and accounting, budgeting, planning,

treasury, public relations, land administration, environmental, permitting, payroll, benefits, disability, workers' compensation management, legal and information technology services. Our general partner may determine in its sole discretion the expenses that are allocable to us. Total costs billed to us by our general partner and its affiliates were approximately $0.9 million for the year ended December 31, 2017. The executive officers of our general partner are employees of and paid by Alliance Coal, and the reimbursement we pay to our general partner pursuant to the partnership agreement does not include any compensation expenses associated with them.

General Partner Contribution

During January 2017 and December 2017, an affiliated entity controlled by Mr. Craft contributed a total of $1.0 million to AHGP for the purpose of funding certain of our general and administrative expenses. Upon AHGP's receipt of this contribution, it contributed the same to its subsidiary MGP, our general partner, which in turn contributed the same to our subsidiary, Alliance Coal. As provided under our partnership agreement, we made a special allocation to our general partner of certain general and administrative expenses equal to the amount of its contribution.

JC Land

Our subsidiary, ASI, has a time-sharing agreement with Mr. Craft and Mr. Craft's affiliate, JC Land, LLC ("JC Land"), concerning their use of aircraft owned by ASI for purposes other than our business. In accordance with the provisions of that agreement, Mr. Craft and JC Land paid ASI $53,796 for the year ended December 31, 2017 for use of the aircraft. In addition, Alliance Coal has a time-sharing agreement with JC Land concerning Alliance Coal's use of an airplane owned by JC Land. In accordance with the provisions of that agreement, Alliance Coal paid JC Land $0.2 million for the year ended December 31, 2017 for use of the aircraft.

Effective August 1, 2013, Alliance Coal entered into an expense reimbursement agreement with JC Land regarding pilots hired by Alliance Coal to operate aircraft owned by ASI and JC Land. In accordance with the expense reimbursement agreement, JC Land reimburses Alliance Coal for a portion of the compensation expense for its pilots. JC Land paid us $0.2 million in 2017 pursuant to this agreement.

Omnibus Agreement

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

Director Independence

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

All members of the Audit Committee—Messrs. Torrence, Carter, Neafsey and Robinson—and all members of the Compensation Committee—Messrs. Robinson, Carter, Neafsey and Torrence—are independent directors as defined under

applicable NASDAQ and Exchange Act rules. Please see "Item 10. Directors, Executive Officers and Corporate Governance of the General Partner—Audit Committee" and "Item 11. Executive Compensation—Compensation Discussion and Analysis."

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The firm of Ernst & Young LLP is our independent registered public accounting firm. The following table sets forth fees paid to Ernst & Young LLP during the years ended December 31, 2017 and 2016:

	2017	2016
	(in thousands)	
Audit Fees (1)	$ 969	$ 1,068
Audit-related fees (2)	—	—
Tax fees (3)	205	325
All other fees	—	—
Total	$ 1,174	$ 1,393

(1) Audit fees consist primarily of the audit and quarterly reviews of the consolidated financial statements, but can also be related to statutory audits of subsidiaries required by governmental or regulatory bodies, attestation services required by statute or regulation, comfort letters, consents, assistance with and review of documents filed with the SEC, work performed by tax professionals in connection with the audit and quarterly reviews, and accounting and financial reporting consultations and research work necessary to comply with GAAP.

(2) Audit-related fees include fees related to acquisition due diligence and accounting consultations.

(3) Tax fees consist primarily of services rendered for tax compliance, tax advice, and tax planning.

The charter of the Audit Committee provides that the committee is responsible for the pre-approval of all auditing services and permitted non-audit services to be performed for us by our independent registered public accounting firm, subject to the requirements of applicable law. In accordance with such charter, the Audit Committee may delegate the authority to grant such pre-approvals to the Audit Committee chairman or a sub-committee of the Audit Committee, which pre-approvals are then reviewed by the full Audit Committee at its next regular meeting. Typically, however, the Audit Committee itself reviews the matters to be approved. The Audit Committee periodically monitors the services rendered by and actual fees paid to the independent registered public accounting firm to ensure that such services are within the parameters approved by the Audit Committee.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) (1) Financial Statements.

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

(a)(2) Financial Statement Schedule.

Schedule II—Valuation and Qualifying Accounts—Years ended December 31, 2017, 2016 and 2015, is set forth under Item 8. Financial Statements and Supplementary Data. All other schedules are omitted because they are not applicable or the information is shown in the financial statements or notes thereto.

(a)(3) and (c) The exhibits listed below are filed as part of this annual report.

		Incorporated by Reference				
Exhibit Number	**Exhibit Description**	**Form**	**SEC File No. and Film No.**	**Exhibit**	**Filing Date**	**Filed Herewith***
3.1	Fourth Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.	8-K	000-26823 17990766	3.2	07/28/2017	
3.2	Amended and Restated Agreement of Limited Partnership of Alliance Resource Operating Partners, L.P.	10-K	000-26823 583595	3.2	03/29/2000	
3.3	Amended and Restated Certificate of Limited Partnership of Alliance Resource Partners, L.P.	8-K	000-26823 17990766	3.6	07/28/2017	
3.4	Certificate of Limited Partnership of Alliance Resource Operating Partners, L.P.	S-1/A	333-78845 99669102	3.8	07/23/1999	
3.5	Certificate of Formation of Alliance Resource Management GP, LLC	S-1/A	333-78845 99669102	3.7	07/23/1999	
3.6	Second Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC	8-K	000-26823 17990766	3.3	07/28/2017	
3.7	Certificate of Formation of MGP II, LLC	8-K	000-26823 17990766	3.5	07/28/2017	
3.8	Amended and Restated Operating Agreement of MGP II, LLC	8-K	000-26823 17990766	3.4	07/28/2017	
3.9	Amendment No. 1 to the Fourth Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.					☑

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith*
		Form	SEC File No. and Film No.	Exhibit	Filing Date	
4.1	Form of Common Unit Certificate (Included as Exhibit A to the Second Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., included in this Exhibit Index as Exhibit 3.1).	8-K	000-26823 08763867	3.1	04/18/2008	
4.2	Indenture, dated as of April 24, 2017, by and among Alliance Resource Operating Partners, L.P. and Alliance Resource Finance Corporation, as issuers, Alliance Resource Partners, L.P., as parent, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee.	8-K	000-26823 17798539	4.1	04/24/2017	
4.3	Form of 7.500% Senior Note due 2025 (included in Exhibit 4.2).	8-K	000-26823 17798539	4.1	04/24/2017	
10.1	Note Purchase Agreement, dated as of August 16, 1999, among Alliance Resource GP, LLC and the purchasers named therein.	10-K	000-26823 583595	10.2	03/29/2000	
10.2	Amendment and Restatement of Letter of Credit Facility Agreement dated October 2, 2010.	10-Q	000-26823 11823116	10.1	05/09/2011	
10.3	Letter of Credit Facility Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association.	10-Q	000-26823 1782487	10.25	11/13/2001	
10.4	First Amendment to the Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association.	10-Q	000-26823 02827517	10.32	11/14/2002	
10.5	Promissory Note Agreement dated as of October 2, 2001, between Alliance Resource Partners, L.P. and Bank of the Lakes, N.A.	10-Q	000-26823 1782487	10.26	11/13/2001	
10.6	Guarantee Agreement, dated as of October 2, 2001, between Alliance Resource GP, LLC and Bank of the Lakes, N.A.	10-Q	000-26823 1782487	10.27	11/13/2001	
10.7	Contribution and Assumption Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC, Alliance Resource Partners, L.P., Alliance Resource Operating Partners, L.P. and the other parties named therein	10-K	000-26823 583595	10.3	03/29/2000	
10.8	Omnibus Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC and Alliance Resource Partners, L.P.	10-K	000-26823 583595	10.4	03/29/2000	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith*
		Form	SEC File No. and Film No.	Exhibit	Filing Date	
10.9(1)	Amended and Restated Alliance Coal, LLC 2000 Long-Term Incentive Plan	10-K	000-26823 04667577	10.17	03/15/2004	
10.10(1)	First Amendment to the Alliance Coal, LLC 2000 Long-Term Incentive Plan	10-K	000-26823 04667577	10.18	03/15/2004	
10.11(1)	Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 583595	10.12	03/29/2000	
10.12(1)	Alliance Coal, LLC Supplemental Executive Retirement Plan	S-8	333-85258 02595143	99.2	04/01/2002	
10.13(1)	Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors	S-8	333-85258 02595143	99.3	04/01/2002	
10.14	Guaranty by Alliance Resource Partners, L.P. dated March 16, 2012	10-Q	000-26823 12825281	10.3	05/09/2012	
10.15(2)	Base Contract for Purchase and Sale of Coal, dated March 16, 2012, between Seminole Electric Cooperative, Inc. and Alliance Coal, LLC	10-Q	000-26823 12825281	10.1	05/09/2012	
10.16(2)	Contract of Confirmation, effective March 16, 2012, between Seminole Electric Cooperative, Inc., Alliance Coal, LLC and Alliance Resource Partners, L.P.	10-Q/A	000-26823 12947715	10.2	07/05/2012	
10.17	Amended and Restated Charter for the Audit Committee of the Board of Directors dated February 23, 2009	10-K	000-26823 09647063	10.35	03/02/2009	
10.18	Second Amendment to the Omnibus Agreement dated May 15, 2006 by and among Alliance Resource Partners, L.P., Alliance Resource GP, LLC, Alliance Resource Management GP, LLC, Alliance Resource Holdings, Inc., Alliance Resource Holdings II, Inc., AMH-II, LLC, Alliance Holdings GP, L.P., Alliance GP, LLC and Alliance Management Holdings, LLC	10-Q	000-26823 061017824	10.1	08/09/2006	
10.19	Administrative Services Agreement dated May 15, 2006 among Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC, Alliance Resource Holdings II, Inc., Alliance Holdings GP, L.P. and Alliance GP, LLC	10-Q	000-26823 061017824	10.2	08/09/2006	
10.20(1)	First Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan	10-K	000-26823 07660999	10.50	03/01/2007	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith*
		Form	SEC File No. and Film No.	Exhibit	Filing Date	
10.21(1)	Second Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan	10-K	000-26823 08654096	10.50	02/29/2008	
10.22(1)	First Amendment to the Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 07660999	10.52	03/01/2007	
10.23(1)	Second Amendment to the Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 08654096	10.53	02/29/2008	
10.24	Note Purchase Agreement, 6.28% Senior Notes Due June 26, 2015, and 6.72% Senior Notes due June 26, 2018, dated as of June 26, 2008, by and among Alliance Resource Operating Partners, L.P. and various investors	8-K	000-26823 08928968	10.1	07/01/2008	
10.25	First Amendment, dated as of June 26, 2008, to the Note Purchase Agreement, dated August 16, 1999, 8.31% Senior Notes due August 20, 2014, by and among Alliance Resource Operating Partners, L.P. (as successor to Alliance Resource GP, LLC) and various investors	8-K	000-26823 08928968	10.2	07/01/2008	
10.26(1)	Third Amendment to the Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan	10-K	000-26823 09647063	10.52	03/02/2009	
10.27(1)	Amended and Restated Alliance Coal, LLC Supplemental Executive Retirement Plan dated as of January 1, 2011	10-K	000-26823 11645603	10.40	02/28/2011	
10.28(1)	Amended and Restated Alliance Resource Management GP, LLC Deferred Compensation Plan for Directors dated as of January 1, 2011	10-K	000-26823 11645603	10.42	02/28/2011	
10.29	Amendment No. 2 to Letter of Credit Facility Agreement between Alliance Resource Partners, L.P. and Bank of the Lakes, National Association, dated April 13, 2009	10-Q	000-26823 09811514	10.1	05/08/2009	
10.30(2)	Agreement for the Supply of Coal, dated August 20, 2009 between Tennessee Valley Authority and Alliance Coal, LLC	10-Q	000-26823 091164883	10.2	11/06/2009	
10.31	Amended and Restated Charter for the Compensation Committee of the Board of Directors dated February 23, 2010.	10-K	000-26823 10638795	10.49	02/26/2010	
10.32	Amended and Restated Administrative Services Agreement effective January 1, 2010, among Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC, Alliance Resource Holdings II, Inc., Alliance Resource Operating Partners, L.P., Alliance Holdings GP, L.P. and Alliance GP, LLC.	10-Q	000-26823 101000555	10.1	08/09/2010	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith*
		Form	SEC File No. and Film No.	Exhibit	Filing Date	
10.33	Uncommitted Line of Credit and Reimbursement Agreement dated April 9, 2010 between Alliance Resource Partners, L.P. and Fifth Third Bank.	10-Q	000-26823 101000555	10.2	08/09/2010	
10.34	Purchase and Sale Agreement, dated as of December 5, 2014, among Alliance Resource Operating Partners, L.P., as buyer and Alliance Coal, LLC, Gibson County Coal, LLC, Hopkins County Coal, LLC, Mettiki Coal (WV), LLC, Mt. Vernon Transfer Terminal, LLC, River View Coal, LLC, Sebree Mining, LLC, Tunnel Ridge, LLC and White County Coal, LLC, as originators	8-K	000-26823 141277053	10.1	12/10/2014	
10.35	Sale and Contribution Agreement, dated as of December 5, 2014, among Alliance Resource Operating Partners, L.P., as seller and AROP Funding, LLC, as buyer	8-K	000-26823 141277053	10.2	12/10/2014	
10.36	Receivables Financing Agreement, dated as of December 5, 2014, among Borrower, PNC Bank, National Association, as administrative agent as well as the letter of credit bank, the persons from time to time party thereto as lenders, the persons from time to time party thereto as letter of credit participants, and Alliance Coal, LLC, as initial servicer	8-K	000-26823 141277053	10.3	12/10/2014	
10.37	Performance Guaranty, dated as of December 5, 2014, by AROP in favor of PNC Bank, National Association, as administrative agent	8-K	000-26823 141277053	10.4	12/10/2014	
10.38	Master Lease Agreement, dated as of October 29, 2015, between Alliance Resource Operating Partners, L.P., Hamilton County Coal, LLC and White Oak Resources LLC, as lessees, and PNC Equipment Finance, LLC and the other lessors named therein.	8-K	000-26823 151198024	10.1	11/04/2015	
10.39(1)	The Amended and Restated Alliance Coal, LLC Long-Term Incentive Plan as amended by the Third Amendment and Fourth Amendment	10-K	000-26823 161460619	10.46	02/26/2016	
10.40	First Amendment to the Receivables Financing Agreement, dated as of December 4, 2015	10-Q	000-26823 161634229	10.1	05/10/2016	
10.41	Second Amendment to the Receivables Financing Agreement, dated as of February 24, 2016	10-Q	000-26823 161634229	10.2	05/10/2016	

Exhibit Number	Exhibit Description	Incorporated by Reference: Form	SEC File No. and Film No.	Exhibit	Filing Date	Filed Herewith*
10.42	Joinder Agreement, dated as of February 24, 2016, among Warrior Coal, LLC, Webster County Coal, LLC, White Oak Resources LLC and Hamilton County Coal, LLC, dated as of February 24, 2016	10-Q	000-26823 161634229	10.3	05/10/2016	
10.43	Fourth Amended and Restated Credit Agreement, dated as of January, 27, 2017, by and among Alliance Resource Operating Partners, L.P., as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto.	8-K	000-26823 17567534	10.1	02/02/2017	
10.44	First Amendment to Note Purchase Agreement, dated as of January 27, 2017, by and among Alliance Resource Operating Partners, L.P. and the subsidiary guarantors and various investors named therein.	8-K	000-26823 17567534	10.2	02/02/2017	
10.45	Third Amendment to the Receivables Financing Agreement, dated as of December 2, 2016	10-K	000-26823 17636362	10.45	02/24/2017	
10.46	Amendment No. 1 dated April 3, 2017 to the Fourth Amended and Restated Credit Agreement, dated as of January, 27, 2017, by and among Alliance Resource Operating Partners, L.P., as borrower, the initial lenders, initial issuing banks and swingline bank named therein, JPMorgan Chase Bank, N.A., as administrative agent, JPMorgan Chase Bank, N.A., Wells Fargo Securities, LLC and Citigroup Global Markets Inc. as joint lead arrangers, JPMorgan Chase Bank, N.A., Wells Fargo Securities, LLC, Citigroup Global Markets Inc., and BOKF, NA DBA Bank of Oklahoma as joint bookrunners, Wells Fargo Bank, National Association, Citibank, N.A., and BOKF, NA DBA Bank of Oklahoma as syndication agents, and the other institutions named therein as documentation agents.	8-K	000-26823 17750742	10.1	04/07/2017	
10.47	Fourth Amendment to the Receivables Financing Agreement, dated as of November 27, 2017					☑
10.48	Fifth Amendment to the Receivables Financing Agreement, dated as of January 17, 2018					☑
10.49	Contribution Agreement, dated as of July 28, 2017, by and among Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC, ARM GP Holdings, Inc., MGP II, LLC and Alliance Holdings GP, L.P.	8-K	000-26823 17990766	10.1	07/28/2017	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith*
		Form	SEC File No. and Film No.	Exhibit	Filing Date	
14.1	Code of Ethics for Principal Executive Officer and Senior Financial Officers	10-K	000-26823 13656028	14.1	03/01/2013	
21.1	List of Subsidiaries.					☑
23.1	Consent of Ernst & Young LLP.					☑
31.1	Certification of Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the general partner of Alliance Resource Partners, L.P., dated February 23, 2018, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					☑
31.2	Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the general partner of Alliance Resource Partners, L.P., dated February 23, 2018, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					☑
32.1	Certification of Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the general partner of Alliance Resource Partners, L.P., dated February 23, 2018, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					☑
32.2	Certification of Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the general partner of Alliance Resource Partners, L.P., dated February 23, 2018, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					☑
95.1	Federal Mine Safety and Health Act Information					☑
101	Interactive Data File (Form 10-K for the year ended December 31, 2017 filed in XBRL).					☑

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

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

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, in Tulsa, Oklahoma, on February 23, 2018.

ALLIANCE RESOURCE PARTNERS, L.P.

By: Alliance Resource Management GP, LLC
its general partner

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

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

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

Signature	Title	Date
/s/ Joseph W. Craft III Joseph W. Craft III	President, Chief Executive Officer, and Director (Principal Executive Officer)	February 23, 2018
/s/ Brian L. Cantrell Brian L. Cantrell	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 23, 2018
/s/ Nick Carter Nick Carter	Director	February 23, 2018
/s/ John P. Neafsey John P. Neafsey	Director	February 23, 2018
/s/ John H. Robinson John H. Robinson	Director	February 23, 2018
/s/ Wilson M. Torrence Wilson M. Torrence	Director	February 23, 2018
/s/ Charles R. Wesley Charles R. Wesley	Executive Vice President and Director	February 23, 2018

(Back To Top)

Section 2: EX-3.9 (EX-3.9)

Exhibit 3.9

AMENDMENT NO. 1
TO
FOURTH AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP
OF

ALLIANCE RESOURCE PARTNERS, L.P.

February 22, 2018

This Amendment No. 1 (this "**Amendment**") to the Fourth Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., a Delaware limited partnership (the "**Partnership**"), dated as of July 28, 2017 (the "**Partnership Agreement**"), is entered into as of the date hereof and is effective as of January 1, 2018 in accordance with Section 761(c) of the Code at the direction of Alliance Resource Management GP, LLC, a Delaware limited liability company, as the general partner of the Partnership (the "**General Partner**"), pursuant to authority granted to it in Section 13.1 of the Partnership Agreement. Capitalized terms used but not defined herein have the meanings ascribed to them in the Partnership Agreement.

RECITALS

WHEREAS, Section 9.3 and Section 9.4 of the Partnership Agreement currently provide as follows:

Section 9.3 **Tax Controversies**.

"(a) Subject to the provisions hereof, the Board of Directors shall designate one officer of the Partnership or the General Partner who is a Partner as the Tax Matters Partner (as defined in Section 6231(a)(7) of the Code as in effect prior to the enactment of the Bipartisan Budget Act of 2015), and the "partnership representative" (as defined in Section 6223 of the Code following the enactment of the Bipartisan Budget Act of 2015) and is authorized and required to represent the Partnership (at the Partnership's expense) in connection with all examinations of the Partnership's affairs by tax authorities, including resulting administrative and judicial proceedings, and to expend Partnership funds for professional services and costs associated therewith. In its capacity as "partnership representative," the General Partner shall exercise any and all authority of the "partnership representative" under the Code, including, without limitation, (i) binding the Partnership and its Partners with respect to tax matters and (ii) determining whether to make any available election under Section 6226 of the Code. Each Partner agrees to cooperate with the General Partner and to do or refrain from doing any or all things reasonably required by the General Partner to conduct such proceedings. Each Partner agrees that notice of or updates regarding tax controversies shall be deemed conclusively to have been given or made by the General Partner if the Partnership has either (a) filed the information for which notice is required with the Commission via its Electronic Data Gathering, Analysis and Retrieval system and such information is publicly available on such system or (b) made the information for which notice is required available on any publicly available website maintained by the Partnership, whether or not such Partner remains a Partner in the Partnership at the time such information is made publicly available. The General Partner may amend the provisions of this Agreement as determined

appropriate in order to minimize the potential U.S. federal and state or local income tax consequences to current and former Limited Partners, and for the proper administration of the Partnership, upon any amendment to the provisions of Subchapter C of Chapter 63 of Subtitle A of the Code, as enacted by the Bipartisan Budget Act of 2015, or the promulgation of regulations or publication of other administrative guidance thereunder."

Section 9.4 **Withholding; Tax Payments**.

"Notwithstanding any other provision of this Agreement, the General Partner is authorized to take any action that it determines in its discretion to be necessary or appropriate to cause the Partnership, the Intermediate Partnership and the Operating Subsidiary to comply with any withholding requirements established under the Code or any other federal, state or local law including, without limitation, pursuant to Sections 1441, 1442, 1445 and 1446 of the Code. To the extent that the Partnership is required or elects to withhold and pay over to any taxing authority any amount resulting from the allocation or distribution of income to any Partner or Assignee (including, without limitation, by reason of Section 1446 of the Code), the amount withheld may at the discretion of the General Partner be treated by the Partnership as a distribution of cash pursuant to Section 6.3 in the amount of such withholding from such Partner."

WHEREAS, the Bipartisan Budget Act of 2015 eliminates the concept of a "Tax Matters Partner," replaces it with the concept of a "Partnership Representative" and makes certain changes to the manner in which partnerships and their partners are audited and taxes may be assessed therefrom, each effective for tax years commencing after December 31, 2017;

WHEREAS, Section 9.2(c) of the Partnership Agreement provides the General Partner with the authority to determine whether the Partnership should make certain elections permitted by the Code;

WHEREAS, Section 13.1(c) of the Partnership Agreement provides that the General Partner, without the approval of any Partner or Assignee, may amend any provision of the Partnership Agreement to reflect a change that, in the sole discretion of the General Partner, is necessary or advisable to ensure that the Partnership, the Intermediate Partnership and the Operating Subsidiary will not be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;

WHEREAS, Section 13.1(d)(i) of the Partnership Agreement provides that the General Partner, without the approval of any Partner or Assignee, may amend any provision of the Partnership Agreement to reflect a change that, in the discretion of the General Partner, does not adversely affect the Limited Partners in any material respect;

WHEREAS, Section 13.1(d)(ii)(A) of the Partnership Agreement provides that the General Partner, without the approval of any Partner or Assignee, may amend any provision of the Partnership Agreement to reflect a change that, in the discretion of the General Partner, is necessary or advisable to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute (including the Delaware Act);

WHEREAS, Section 13.1(d)(iv) of the Partnership Agreement provides that the General Partner, without the approval of any Partner or Assignee, may amend any provision of the Partnership Agreement to reflect a change that, in the discretion of the General Partner, is required to effect the intent expressed in the provisions of the Partnership Agreement or is otherwise contemplated by the Partnership Agreement; and

WHEREAS, acting pursuant to the power and authority granted to it under Section 9.2(c), Section 13.1(c), Section 13.1(d)(i), Section 13.1(d)(ii)(A) and Section 13.1(d)(iv) of the Partnership Agreement, the General Partner has determined that the following amendment to the Partnership Agreement (A) is necessary and advisable to ensure that the Partnership, the Intermediate Partnership and the Operating Subsidiary will not be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes, (B) does not adversely affect the Limited Partners in any material respect, (C) is necessary and advisable to satisfy requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute (including the Delaware Act) and (D) and is required to effect the intent expressed in the provisions of the Partnership Agreement or is otherwise contemplated by the Partnership Agreement.

NOW, THEREFORE, the General Partner does hereby amend the Partnership Agreement as follows:

A. Amendment.

(1) Section 9.3 of the Partnership Agreement is hereby amended and restated to read in its entirety as follows:

Section 9.3 **Tax Controversies.**

(a) Subject to the provisions hereof, the Board of Directors shall designate one officer of the Partnership who is a partner or the General Partner as the Tax Matters Partner (as defined in Section 6231(a)(7) of the Code as in effect prior to the enactment of the Bipartisan Budget Act of 2015), and the Partnership Representative (as defined in Section 6223 of the Code following the enactment of the Bipartisan Budget Act of 2015 or under any applicable state or local law providing for an analogous capacity), and is authorized and required to represent the Partnership (at the Partnership's expense) in connection with all examinations of the Partnership's affairs by tax authorities, including resulting administrative and judicial proceedings, and to expend Partnership funds for professional services and costs associated therewith. In its capacity as Partnership Representative, the General Partner shall exercise any and all authority of the Partnership Representative under the Code, including, without limitation, (i) binding the Partnership and its Partners with respect to tax matters and (ii) determining whether to make any available election under Section 6226 of the Code or an analogous election under state or local law, which election permits the Partnership to pass any partnership adjustment through to the Persons who were Partners of the Partnership in the year to which the adjustment relates and irrespective of whether such Persons are Partners of the Partnership at the time such election is made. Each Partner agrees to cooperate with the General Partner and to do or refrain from doing any or all things reasonably required by

the General Partner in its capacity as Tax Matters Partner or Partnership Representative. For Partners that are not tax-exempt entities (as defined in Section 168 (h)(2) of the Code) and subject to the General Partner's discretion to seek modifications of an imputed underpayment, this cooperation includes (i) filing amended federal, state or local tax returns, paying any additional tax (including interest, penalties and other additions to tax), and providing the General Partner with an affidavit swearing to those facts (all within the requisite time periods), and (ii) providing any other information requested by the General Partner in order to seek modifications of an imputed underpayment. For Partners that are tax-exempt entities (as defined in Section 168(h)(2) of the Code) and subject to the General Partner's discretion to seek modifications of an imputed underpayment, this cooperation includes providing the General Partner with information necessary to establish the Partner's tax-exempt status. This agreement to cooperate applies irrespective of whether such Persons are Partners of the Partnership at the time of the requested cooperation.

(b) Each Partner agrees that notice of or updates regarding tax controversies shall be deemed conclusively to have been given or made by the General Partner if the Partnership has either (i) filed the information for which notice is required with the Commission via its Electronic Data Gathering, Analysis and Retrieval system and such information is publicly available on such system or (ii) made the information for which notice is required available on any publicly available website maintained by the Partnership, whether or not such Partner remains a Partner in the Partnership at the time such information is made publicly available. Notwithstanding anything herein to the contrary, nothing in this provision shall obligate the Partnership Representative to provide notice to the Partners other than as required by the Code.

(c) The General Partner may amend the provisions of this Agreement as it determines appropriate to satisfy any requirements, conditions, or guidelines set forth in any amendment to the provisions of Subchapter C of Chapter 63 of Subtitle F of the Code, any analogous provisions of the laws of any state or locality, or the promulgation of regulations or publication of other administrative guidance thereunder.

(2) Section 9.4 of the Partnership Agreement is hereby amended and restated to read in its entirety as follows:

Section 9.4 **Withholding and Other Tax Payments by the Partnership**.

(a) The General Partner may treat taxes paid by the Partnership on behalf of all or less than all of the Partners as a distribution of cash to such Partners, or a general expense of the Partnership, or as indemnifiable payments made by the Partnership on behalf of the Partners or former Partners (as provided in Section 9.4 (c)), as determined appropriate under the circumstances by the General Partner.

(b) Notwithstanding any other provision of this Agreement, the General Partner is authorized to take any action that it determines in its discretion to be necessary or appropriate to cause the Partnership, the Intermediate Partnership and

the Operating Subsidiary to comply with any withholding requirements established under the Code or any other federal, state or local law including, without limitation, pursuant to Sections 1441, 1442, 1445 and 1446 of the Code. To the extent that the Partnership is required or elects to withhold and pay over to any taxing authority any amount resulting from the allocation or distribution of income or from a distribution to any Partner or Assignee (including, without limitation, by reason of Section 1446 of the Code), the amount withheld may at the discretion of the General Partner be treated by the Partnership as a distribution of cash pursuant to Section 6.3 in the amount of such withholding from such Partner.

(c) If the Partnership pays an imputed underpayment under Section 6225 of the Code and/or any analogous provision of the laws of any state or locality, the General Partner may require that some or all of the Partners of the Partnership in the year to which the underpayment relates indemnify the Partnership for their allocable share of that underpayment (including interest, penalties and other additions to tax). This indemnification obligation shall not apply to a Partner to the extent that (i) the Partnership received a modification of the imputed underpayment under Section 6225(c)(2) of the Code (or any analogous provision of state or local law) due to the Partner's filing of amended tax returns and payment of any resulting tax (including interest, penalties and other additions to tax), (ii) the Partner is a tax-exempt entity (as defined in Section 168(h)(2) of the Code) and either the Partnership received a modification of the imputed underpayment under Section 6225(c)(3) of the Code (or any analogous provision of state or local law) because of such Partner's status as a tax-exempt entity or the Partnership did not make a good faith effort to obtain a modification of the imputed underpayment due to such Partner's status as a tax-exempt entity, or (iii) the Partnership received a modification of the imputed underpayment under Section 6225(c)(4)-(6) of the Code (or any analogous provision of state or local law) as a result of other information that was either provided by the Partner or otherwise available to the Partnership with respect to the Partner. This indemnification obligation imposed on Partners, including former Partners, applies irrespective of whether such Persons are Partners of the Partnership at the time the Partnership pays the imputed underpayment.

B. Ratification of Partnership Agreement. Except as expressly modified and amended herein, all of the terms and conditions of the Partnership Agreement shall remain in full force and effect.

C. General Authority. The appropriate officers of the General Partner are hereby authorized to make such clarifying and conforming changes as they deem necessary or appropriate and to interpret the Partnership Agreement to give effect to the intent and purpose of this Amendment.

D. Governing Law. This Amendment shall be construed in accordance with and governed by the laws of the State of Delaware, without regard to the principles of conflicts of laws.

E. Severability. Each provision of this Amendment shall be considered severable and if for any reason any provision or provisions herein are determined to be invalid, unenforceable or illegal

under any existing or future law, such invalidity, unenforceability or illegality shall not impair the operation of or affect those portions of this Amendment that are valid, enforceable and legal.

(Signature Page Follows)

IN WITNESS WHEREOF, the General Partner has executed this Amendment as of the date first set forth above.

GENERAL PARTNER:

ALLIANCE RESOURCE MANAGEMENT GP, LLC

By: /s/ R. Eberley Davis _____
Name:R. Eberley Davis
Title: Senior Vice President, General Counsel and Secretary

(Back To Top)

Section 3: EX-10.47 (EX-10.47)

Exhibit 10.47

EXECUTION VERSION

FOURTH AMENDMENT TO THE RECEIVABLES FINANCING AGREEMENT

This FOURTH AMENDMENT TO THE RECEIVABLES FINANCING AGREEMENT (this "Amendment"), dated as of November 27, 2017, is entered into by and among the following parties:

(i) AROP FUNDING, LLC, as Borrower;

(ii) ALLIANCE COAL, LLC, as initial Servicer; and

(iii) PNC BANK, NATIONAL ASSOCIATION ("PNC"), as LC Bank, LC Participant, Lender and Administrative Agent.

Capitalized terms used but not otherwise defined herein (including such terms used above) have the respective meanings assigned thereto in the Receivables Financing Agreement described below.

BACKGROUND

A. The parties hereto have entered into a Receivables Financing Agreement, dated as of December 5, 2014 (as amended, restated, supplemented or otherwise modified through to the date hereof, the "Receivables Financing Agreement").

B. The parties hereto desire to amend the Receivables Financing Agreement as set forth herein.

NOW, THEREFORE, with the intention of being legally bound hereby, and in consideration of the mutual undertakings expressed herein, each party to this Amendment hereby agrees as follows:

SECTION 1. Amendments to the Receivables Financing Agreement. The Receivables Financing Agreement is hereby amended by removing the reference to "December 2, 2017" in the definition of "Scheduled Termination Date" and inserting "January 17, 2018" in place thereof.

SECTION 2. Representations and Warranties of the Borrower and Servicer. The Borrower and the Servicer hereby represent and warrant to each of the parties hereto as of the date hereof as follows:

(a) *Representations and Warranties*. The representations and warranties made by it in the

Receivables Financing Agreement and each of the other Transaction Documents to which it is a party are true and correct as of the date hereof.

(b) *Enforceability*. The execution and delivery by it of this Amendment, and the performance of its obligations under this Amendment, the Receivables Financing Agreement (as amended hereby) and the other Transaction Documents to which it is a party are within its organizational powers and have been duly authorized by all necessary action on its part, and this Amendment, the Receivables Financing Agreement (as amended

hereby) and the other Transaction Documents to which it is a party are (assuming due authorization and execution by the other parties thereto) its valid and legally binding obligations, enforceable in accordance with its terms, except (x) the enforceability thereof may be limited by bankruptcy, insolvency, reorganization, moratorium or other similar laws from time to time in effect relating to creditors' rights, and (y) the remedy of specific performance and injunctive and other forms of equitable relief may be subject to equitable defenses and to the discretion of the court before which any proceeding therefor may be brought.

(c) *No Event of Default*. No Event of Default or Unmatured Event of Default has occurred and is continuing, or would occur as a result of this Amendment or the transactions contemplated hereby.

SECTION 3. Effect of Amendment; Ratification. All provisions of the Receivables Financing Agreement and the other Transaction Documents, as expressly amended and modified by this Amendment, shall remain in full force and effect. After this Amendment becomes effective, all references in the Receivables Financing Agreement (or in any other Transaction Document) to "this Receivables Financing Agreement", "this Agreement", "hereof", "herein" or words of similar effect referring to the Receivables Financing Agreement shall be deemed to be references to the Receivables Financing Agreement as amended by this Amendment. This Amendment shall not be deemed, either expressly or impliedly, to waive, amend or supplement any provision of the Receivables Financing Agreement other than as set forth herein. The Receivables Financing Agreement, as amended by this Amendment, is hereby ratified and confirmed in all respects.

SECTION 4. Conditions to Effectiveness. This Amendment shall become effective as of the date hereof upon the Administrative Agent's receipt of counterparts of this Amendment executed by each of the parties hereto.

SECTION 5. Severability. Any provisions of this Amendment which are prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

SECTION 6. Transaction Document. This Amendment shall be a Transaction Document for purposes of the Receivables Financing Agreement.

SECTION 7. Counterparts. This Amendment may be executed in any number of counterparts and by different parties on separate counterparts, each of which when so executed shall be deemed to be an original and all of which when taken together shall constitute but one and the same instrument. Delivery of an executed counterpart of a signature page to this Amendment by facsimile or e-mail transmission shall be effective as delivery of a manually executed counterpart hereof.

SECTION 8. GOVERNING LAW AND JURISDICTION.

(a) THIS AMENDMENT, INCLUDING THE RIGHTS AND DUTIES OF THE PARTIES HERETO, SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK (INCLUDING SECTIONS 5-1401 AND 5-1402 OF THE GENERAL OBLIGATIONS LAW OF THE STATE OF NEW YORK, BUT WITHOUT REGARD TO ANY OTHER CONFLICTS OF LAW PROVISIONS THEREOF, EXCEPT TO THE EXTENT THAT THE PERFECTION, THE EFFECT OF PERFECTION OR PRIORITY OF THE INTERESTS OF ADMINISTRATIVE AGENT OR ANY LENDER IN THE COLLATERAL IS GOVERNED BY THE LAWS OF A JURISDICTION OTHER THAN THE STATE OF NEW YORK).

(b) EACH PARTY HERETO HEREBY IRREVOCABLY SUBMITS TO (I) WITH RESPECT TO THE BORROWER AND THE SERVICER, THE EXCLUSIVE JURISDICTION, AND (II) WITH RESPECT TO EACH OF THE OTHER PARTIES HERETO, THE NON-EXCLUSIVE JURISDICTION, IN EACH CASE, OF ANY NEW YORK STATE OR FEDERAL COURT SITTING IN NEW YORK CITY, NEW YORK IN ANY ACTION OR PROCEEDING ARISING OUT OF OR RELATING TO THIS AMENDMENT, AND EACH PARTY HERETO HEREBY IRREVOCABLY AGREES THAT ALL CLAIMS IN RESPECT OF SUCH ACTION OR PROCEEDING (I) IF BROUGHT BY THE BORROWER, THE SERVICER OR ANY AFFILIATE THEREOF, SHALL BE HEARD AND DETERMINED, AND (II) IF BROUGHT BY ANY OTHER PARTY TO THIS AMENDMENT, MAY BE HEARD AND DETERMINED, IN EACH CASE, IN SUCH NEW YORK STATE COURT OR, TO THE EXTENT PERMITTED BY LAW, IN SUCH FEDERAL COURT. NOTHING IN THIS SECTION 8 SHALL AFFECT THE RIGHT OF THE ADMINISTRATIVE AGENT OR ANY OTHER CREDIT PARTY TO BRING ANY ACTION OR PROCEEDING AGAINST THE BORROWER OR THE SERVICER OR ANY OF THEIR RESPECTIVE PROPERTY IN THE COURTS OF OTHER JURISDICTIONS. EACH OF THE BORROWER AND THE SERVICER HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT IT MAY EFFECTIVELY DO SO, THE DEFENSE OF AN INCONVENIENT FORUM TO THE MAINTENANCE OF SUCH ACTION OR PROCEEDING. THE PARTIES HERETO AGREE THAT A FINAL JUDGMENT IN ANY SUCH ACTION OR PROCEEDING SHALL BE CONCLUSIVE AND MAY BE ENFORCED IN OTHER JURISDICTIONS BY SUIT ON THE JUDGMENT OR IN ANY OTHER MANNER PROVIDED BY LAW.

SECTION 9. Section Headings. The various headings of this Amendment are included for convenience only and shall not affect the meaning or interpretation of this Amendment, the Receivables Financing Agreement or any provision hereof or thereof.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF, the parties hereto have executed this Amendment by their duly authorized officers as of the date first above written.

AROP FUNDING, LLC

By: /s/ R. EBERLEY DAVIS
Name: R. Eberley Davis
Title: Senior Vice President, General Counsel and Secretary

ALLIANCE COAL, LLC,
as the Servicer

By: /s/ R. EBERLEY DAVIS
Name: R. Eberley Davis
Title: Senior Vice President, General Counsel and Secretary

PNC BANK, NATIONAL ASSOCIATION,
as Administrative Agent

By: /s/ MICHAEL BROWN
Name: Michael Brown
Title: Senior Vice President

PNC BANK, NATIONAL ASSOCIATION,
as LC Bank and as an LC Participant

By: /s/ MICHAEL BROWN
Name: Michael Brown
Title: Senior Vice President

PNC BANK, NATIONAL ASSOCIATION,
as a Lender

By: /s/ MICHAEL BROWN
Name: Michael Brown
Title: Senior Vice President

Reaffirmation of Performance Guaranty. By executing a counterpart to this Amendment, the Performance Guarantor hereby unconditionally reaffirms its obligations under the Performance Guaranty and acknowledges and agrees that such obligations continue in full force and effect (including, without limitation, with respect to the "Guaranteed Obligations", as defined in the Performance Guaranty), and the Performance Guaranty is hereby ratified and confirmed.

ALLIANCE RESOURCE OPERATING
PARTNERS, L.P., as Performance Guarantor

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

By: /s/ R. EBERLEY DAVIS
Name: R. Eberley Davis
Title: Senior Vice President, General Counsel and
Secretar

(Back To Top)

Section 4: EX-10.48 (EX-10.48)

Exhibit 10.48

EXECUTION VERSION

**FIFTH AMENDMENT TO THE
RECEIVABLES FINANCING AGREEMENT**

This FIFTH AMENDMENT TO THE RECEIVABLES FINANCING AGREEMENT (this "Amendment"), dated as of January 17, 2018, is entered into by and among the following parties:

(i) AROP FUNDING, LLC, as Borrower;

(ii) ALLIANCE COAL, LLC, as initial Servicer; and

(iii) PNC BANK, NATIONAL ASSOCIATION ("PNC"), as LC Bank, LC Participant, Lender and Administrative Agent.

Capitalized terms used but not otherwise defined herein (including such terms used above) have the respective meanings assigned thereto in the Receivables Financing Agreement described below.

BACKGROUND

A. The parties hereto have entered into a Receivables Financing Agreement, dated as of December 5, 2014 (as amended, restated, supplemented or otherwise modified through to the date hereof, the "Receivables Financing Agreement").

B. Concurrently herewith, the parties hereto are entering into an Amended and Restated Fee Letter (the "Fee Letter"), dated as of the date hereof.

C. Concurrently herewith, the parties thereto are entering into amendments to the Sale Agreements (the "Sale Agreement Amendments"), each dated as of the date hereof.

D. The parties hereto desire to amend the Receivables Financing Agreement as set forth herein.

NOW, THEREFORE, with the intention of being legally bound hereby, and in consideration of the mutual undertakings expressed herein, each party to this Amendment hereby agrees as follows:

SECTION 1. Amendments to the Receivables Financing Agreement. The Receivables Financing Agreement is hereby amended to incorporate the changes shown on the marked pages of the Receivables Financing Agreement attached hereto as Exhibit A.

SECTION 2. Representations and Warranties of the Borrower and Servicer. The Borrower and the Servicer hereby represent and warrant to each of the parties hereto as of the date hereof as follows:

(a) *Representations and Warranties*. The representations and warranties made by it in the Receivables Financing Agreement and each of the other Transaction Documents to which it is a party are true and correct as of the date hereof.

(b) *Enforceability*. The execution and delivery by it of this Amendment, and the performance of its obligations under this Amendment, the Receivables Financing Agreement (as amended hereby) and the other Transaction Documents to which it is a party are within its organizational powers and have been duly authorized by all necessary action on its part, and this Amendment, the Receivables Financing Agreement (as amended hereby) and the other Transaction Documents to which it is a party are (assuming due authorization and execution by the other parties thereto) its valid and legally binding obligations, enforceable in accordance with its terms, except (x) the enforceability thereof may be limited by bankruptcy, insolvency, reorganization, moratorium or other similar laws from time to time in effect relating to creditors' rights, and (y) the remedy of specific performance and injunctive and other forms of equitable relief may be subject to equitable defenses and to the discretion of the court before which any proceeding therefor may be brought.

(c) *No Event of Default*. No Event of Default or Unmatured Event of Default has occurred and is continuing, or would occur as a result of this Amendment or the transactions contemplated hereby.

SECTION 3. Effect of Amendment; Ratification. All provisions of the Receivables Financing Agreement and the other Transaction Documents, as expressly amended and modified by this Amendment, shall remain in full force and effect. After this Amendment becomes effective, all references in the Receivables Financing Agreement (or in any other Transaction Document) to "this Receivables Financing Agreement", "this Agreement", "hereof", "herein" or words of similar effect referring to the Receivables Financing Agreement shall be deemed to be references to the Receivables Financing Agreement as amended by this Amendment. This Amendment shall not be deemed, either expressly or impliedly, to waive, amend or supplement any provision of the Receivables Financing Agreement other than as set forth herein. The Receivables Financing Agreement, as amended by this Amendment, is hereby ratified and confirmed in all respects.

SECTION 4. Conditions to Effectiveness. This Amendment shall become effective as of the date hereof upon the Administrative Agent's receipt of:

(a) counterparts of this Amendment executed by each of the parties hereto;

(b) counterparts of the Fee Letter executed by each of the parties thereto;

(c) counterparts of the Sale Agreement Amendments executed by each of the parties thereto; and

(d) confirmation that the "Amendment Fee" has been paid in accordance with the Fee Letter.

SECTION 5. Severability. Any provisions of this Amendment which are prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

SECTION 6. Transaction Document. This Amendment shall be a Transaction Document for purposes of the Receivables Financing Agreement.

SECTION 7. Counterparts. This Amendment may be executed in any number of counterparts and by different parties on separate counterparts, each of which when so executed shall be deemed to be an original and all of which when taken together shall constitute but one and the same instrument. Delivery of an executed counterpart of a signature page to this Amendment by facsimile or e-mail transmission shall be effective as delivery of a manually executed counterpart hereof.

SECTION 8. GOVERNING LAW AND JURISDICTION.

(a) THIS AMENDMENT, INCLUDING THE RIGHTS AND DUTIES OF THE PARTIES HERETO, SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK (INCLUDING SECTIONS 5-1401 AND 5-1402 OF THE GENERAL OBLIGATIONS LAW OF THE STATE OF NEW YORK, BUT WITHOUT REGARD TO ANY OTHER CONFLICTS OF LAW PROVISIONS THEREOF, EXCEPT TO THE EXTENT THAT THE PERFECTION, THE EFFECT OF PERFECTION OR PRIORITY OF THE INTERESTS OF ADMINISTRATIVE AGENT OR ANY LENDER IN THE COLLATERAL IS GOVERNED BY THE LAWS OF A JURISDICTION OTHER THAN THE STATE OF NEW YORK).

(b) EACH PARTY HERETO HEREBY IRREVOCABLY SUBMITS TO (I) WITH RESPECT TO THE BORROWER AND THE SERVICER, THE EXCLUSIVE JURISDICTION, AND (II) WITH RESPECT TO EACH OF THE OTHER PARTIES HERETO, THE NON-EXCLUSIVE JURISDICTION, IN EACH CASE, OF ANY NEW YORK STATE OR FEDERAL COURT SITTING IN NEW YORK CITY, NEW YORK IN ANY ACTION OR PROCEEDING ARISING OUT OF OR RELATING TO THIS AMENDMENT, AND EACH PARTY HERETO HEREBY IRREVOCABLY AGREES THAT ALL CLAIMS IN RESPECT OF SUCH ACTION OR PROCEEDING (I) IF BROUGHT BY THE BORROWER, THE SERVICER OR ANY AFFILIATE THEREOF, SHALL BE HEARD AND DETERMINED, AND (II) IF BROUGHT BY ANY OTHER PARTY TO THIS AMENDMENT, MAY BE HEARD AND DETERMINED, IN EACH CASE, IN SUCH NEW YORK STATE COURT OR, TO THE EXTENT PERMITTED BY LAW, IN SUCH FEDERAL COURT. NOTHING IN THIS SECTION SHALL AFFECT THE RIGHT OF THE ADMINISTRATIVE AGENT OR ANY OTHER CREDIT PARTY TO BRING ANY ACTION OR PROCEEDING AGAINST THE BORROWER OR THE SERVICER OR ANY OF THEIR RESPECTIVE PROPERTY IN THE COURTS OF OTHER JURISDICTIONS. EACH OF THE BORROWER AND THE SERVICER HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT IT MAY EFFECTIVELY DO SO, THE DEFENSE OF AN INCONVENIENT FORUM TO THE MAINTENANCE OF SUCH ACTION OR PROCEEDING. THE PARTIES HERETO AGREE THAT A FINAL JUDGMENT IN ANY SUCH ACTION OR PROCEEDING SHALL BE CONCLUSIVE AND MAY BE ENFORCED IN OTHER JURISDICTIONS BY SUIT ON THE JUDGMENT OR IN ANY OTHER MANNER PROVIDED BY LAW.

SECTION 9. Section Headings. The various headings of this Amendment are included for convenience only and shall not affect the meaning or interpretation of this Amendment, the Receivables Financing Agreement or any provision hereof or thereof.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF, the parties hereto have executed this Amendment by their duly authorized officers as of the date first above written.

AROP FUNDING, LLC

By: /s/ R. EBERLEY DAVIS
Name: R. Eberley Davis
Title: Senior Vice President, General Counsel and Secretary

ALLIANCE COAL, LLC,
as the Servicer

By: /s/ R. EBERLEY DAVIS
Name: R. Eberley Davis
Title: Senior Vice President, General Counsel and Secretary

PNC BANK, NATIONAL ASSOCIATION,
as Administrative Agent

By: /s/ MICHAEL BROWN
Name: Michael Brown
Title: Senior Vice President

PNC BANK, NATIONAL ASSOCIATION,
as LC Bank and as an LC Participant

By: /s/ MICHAEL BROWN
Name: Michael Brown
Title: Senior Vice President

PNC BANK, NATIONAL ASSOCIATION,
as a Lender

By: /s/ MICHAEL BROWN
Name: Michael Brown
Title: Senior Vice President

Reaffirmation of Performance Guaranty. By executing a counterpart to this Amendment, the Performance Guarantor hereby unconditionally reaffirms its obligations under the Performance Guaranty and acknowledges and agrees that such obligations continue in full force and effect (including, without limitation, with respect to the "Guaranteed Obligations", as defined in the Performance Guaranty), and the Performance Guaranty is hereby ratified and confirmed.

ALLIANCE RESOURCE OPERATING
PARTNERS, L.P., as Performance Guarantor

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

By: /s/ R. EBERLEY DAVIS
Name: R. Eberley Davis
Title: Senior Vice President, General Counsel and Secretary

EXHIBIT A

(Receivables Financing Agreement)

rescinded or must otherwise be returned for any reason, such Capital shall be increased by the amount of such rescinded or returned distribution as though it had not been made.

"Capital Stock" means, with respect to any Person, any and all common shares, preferred shares, interests, participations, rights in or other equivalents (however designated) of such Person's capital stock, partnership interests, limited liability company interests, membership interests or other equivalent interests and any rights (other than debt securities convertible into or exchangeable for capital stock), warrants or options exchangeable for or convertible into such capital stock or other equity interests.

"Change in Control" means the occurrence of any of the following: (a) the Transferor ceases to own, directly, 100% of the issued and outstanding Capital Stock and other equity interests of Borrower free and clear of all Adverse Claims
(other than any Adverse Claim in favor of the Credit Agreement Administrative Agent (so long as such Person is then party to the No Petition Letter))

, (b) Parent ceases to own, directly or indirectly, 98% or more of the issued and outstanding Capital Stock or other equity interests of any Originator or the Servicer, (c) the managing general partner of the Parent shall at any time for any reason cease to be either the sole or managing general partner of Alliance Resource Partners, L.P. or (d) the AHGP Management Investors shall at any time for any reason cease to (i) possess the right, directly or indirectly, to elect or appoint a majority of the board of directors of the managing general partner of the Parent or (ii) control, directly or indirectly, the managing general partner of the Parent. Notwithstanding the foregoing, any transaction or series of transactions that result in (I) Alliance Holdings GP, L.P. merging with and into Alliance Resource Partners, L.P., with either Alliance Holdings GP, L.P. or Alliance Resource Partners, L.P. as the surviving entity, (II) Alliance Holdings GP, L.P. becoming a direct or indirect wholly-owned subsidiary of Alliance Resource Partners, L.P., (III) Alliance Resource Partners, L.P. merging with or into Alliance Holdings GP, L.P. or a Subsidiary thereof, with Alliance Holdings GP, L.P. or such Subsidiary as the surviving entity, or (IV) any exchange of incentive distribution rights in Alliance Resource Partners, L.P. and/or exchange of general partner interests in Alliance Resource Partners, L.P. or the Parent for common units of Alliance Resource Partners, L.P. (any such transaction described in clause (I) - (IV) above, a "Simplification Transaction"), shall not constitute a Change in Control hereunder regardless of whether or not, after giving effect to such Simplification Transaction, any of the events described in clauses (c) or (d) of the first sentence of this definition of Change in Control shall have occurred.

"Change in Law" means the occurrence, after the Closing Date (or with respect to any Lender, if later, the date on which such Lender becomes a Lender), of any of the following: (a) the adoption or taking effect of any law, rule, regulation or treaty, (b) any change in any law, rule, regulation or treaty or in the administration, interpretation, implementation or application thereof by any Governmental Authority or (c) the making or issuance of any request, rule, guideline or directive (whether or not having the force of law) by any Governmental Authority; provided that notwithstanding anything herein to the contrary, (x) the Dodd-Frank Wall Street Reform and Consumer Protection Act and all requests, rules, guidelines or directives thereunder or issued in connection therewith and (y) all requests, rules,

guidelines or directives promulgated by the Bank for International Settlements, the Basel Committee on Banking Supervision (or any successor or similar authority) or the United States or foreign regulatory authorities, in each case pursuant to the agreements reached by the Basel Committee on Banking Supervision in “Basel III: A Global

Regulatory Framework for More Resilient Banks and Banking Systems" (as amended, supplemented or otherwise modified or replaced from time to time), shall in each case be deemed to be a "Change in Law", regardless of the date enacted, adopted or issued.

"Closing Date" means December 5, 2014.

"Code" means the Internal Revenue Code of 1986, as amended, reformed or otherwise modified from time to time.

"Collateral" has the meaning set forth in Section 5.05(a).

"Collections" means, with respect to any Pool Receivable: (a) all funds that are received by any Originator, the Transferor, the Borrower, the Servicer or any other Person on their behalf in payment of any amounts owed in respect of such Pool Receivable (including purchase price, finance charges, interest and all other charges), or applied to amounts owed in respect of such Pool Receivable (including insurance payments and net proceeds of the sale or other disposition of repossessed goods or other collateral or property of the related Obligor or any other Person directly or indirectly liable for the payment of such Pool Receivable and available to be applied thereon), (b) all Deemed Collections, (c) all proceeds of all Related Security with respect to such Pool Receivable and (d) all other proceeds of such Pool Receivable.

"Commitment" means, with respect to any Lender, LC Participant or LC Bank, as applicable, the maximum aggregate amount which such Person is obligated to lend or pay hereunder on account of all Loans and all drawings under all Letters of Credit, on a combined basis, as set forth on Schedule I or in the Assumption Agreement or other agreement pursuant to which it became a Lender and/or LC Participant, as such amount may be modified in connection with any subsequent assignment pursuant to Section 14.03 or in connection with a reduction in the Facility Limit pursuant to Section 2.02(e) or an increase in Commitments pursuant to Section 2.02(h). If the context so requires, "Commitment" also refers to a Lender's obligation to make Loans, make Participation Advances and/or issue Letters of Credit hereunder in accordance with this Agreement.

"Concentration Percentage" means (i) for any Group AA Obligor, 30.00%, (ii) for any Group A Obligor, 17.50%, (iii) for any Group B Obligor, 15.00%, (iv) for any Group C Obligor, 12.50% and (v) for any Group D Obligor, 7.50%.

"Concentration Reserve" means, at any time of determination, an amount equal to: (a) the sum of the Aggregate Capital plus the LC Participation Amount on such date, multiplied by (b)(i) the Concentration Reserve Percentage on such date, divided by (ii) 100% minus the Concentration Reserve Percentage on such date.

"Concentration Reserve Percentage" means, at any time of determination, the largest of: (a) the sum of the five (5) largest Obligor Percentages of the Group D Obligors, (b) the sum of the three (3) largest Obligor Percentages of the Group C Obligors, (c) the sum of the two (2) largest Obligor Percentage of the Group B Obligors and (d) the largest Obligor Percentage of the Group A Obligors ; provided, that, for purposes of determining the Concentration Reserve Percentage, with respect to any Eligible Receivable supported by an Eligible Supporting Letter of Credit, the "Obligor" thereof (including for purposes of determining such Obligor's Obligor Percentage and

status as a Group A Obligor, Group B Obligor, Group C Obligor or Group D Obligor) shall be deemed to be the related Eligible Supporting Letter of Credit Provider; provided, further that if any Pool Receivable is partially supported by an Eligible Supporting Letter of Credit, then the "Obligor" thereof shall be deemed to be (i) with respect to the Unsupported Outstanding Balance of such Pool Receivable, the Obligor of such Pool Receivable and (ii) with respect to the Supported Outstanding Balance of such Pool Receivable, the related Eligible Supporting Letter of Credit Provider

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"Consolidated Cash Flow" means, as of any date of determination for any applicable period, the excess, if any, of (a) the sum of, without duplication, the amounts for such period, taken as a single accounting period, of (i) Consolidated Net Income for such period, plus (ii) to the extent deducted in the determination of Consolidated Net Income for such period, without duplication, (A) Consolidated Non-Cash Charges, (B) Consolidated Interest Expense and (C) Consolidated Income Tax Expense, over (b) the sum of, without duplication, the amounts for such period, taken as a single accounting period, of (i) any non-cash items increasing Consolidated Net Income for such period (x) to the extent that such items constitute reversals of Consolidated Non-Cash Charges for a previous period and which were included in the computation of Consolidated Cash Flow for such previous period pursuant to the provisions of the preceding clause (a) or (y) for unrealized gains under derivative instruments, and (ii) any cash charges for such period to the extent that such charges constituted non-cash items for a previous period and to the extent such charges are not otherwise included in the determination of Consolidated Net Income; provided that Consolidated Cash Flow shall be calculated, without duplication, after giving effect on a pro forma basis for such period, in all respects in accordance with GAAP, to any Transfer or Asset Acquisitions (including, without limitation any Asset Acquisition by the Parent or any Subsidiary of Parent giving rise to the need to determine Consolidated Cash Flow as a result of the Parent or one of its Subsidiaries (including any person that becomes a Subsidiary as result of any such Asset Acquisition) incurring, assuming or otherwise becoming liable for any debt) occurring during the period commencing on the first day of such period to and including the date of the transaction, as if such Transfer or Asset Acquisition occurred on the first day of such period.

"Consolidated Fixed Charges" means, with respect to the Parent and its Subsidiaries for any period, the sum of Consolidated Interest Expense plus cash distributions for such period, in each case, determined on a consolidated basis in accordance with GAAP.

"Consolidated Income Tax Expense" means, with respect to any period, all provisions for Federal, state, local and foreign income taxes of the Parent and its Subsidiaries for such period as determined on a consolidated basis in accordance with GAAP.

"Consolidated Interest Expense" means, as of any date of determination for any applicable period, the sum (without duplication) of the following (in each case, eliminating all offsetting debits and credits between the Parent and its Subsidiaries and all other items required to be eliminated in the course of the preparation of consolidated financial statements of the Parent and its Subsidiaries in accordance with GAAP): (a) all interest in respect of debt of the Parent and its Subsidiaries whether paid or accrued (including non-cash interest payments and imputed interest on capital lease obligations) deducted in determining Consolidated Net Income

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"Controlled Related Party" of a Borrower Indemnified Party or Servicer Indemnified Party means (1) any Affiliate of a Borrower Indemnified Party or Servicer Indemnified Party (as applicable), (2) the respective directors, officers, or employees of such Borrower Indemnified Party or Servicer Indemnified Party (as applicable) and its Affiliates and (3) the respective agents or representatives of such Borrower Indemnified Party or Servicer Indemnified Party (as applicable) and its Affiliates, in the case of this clause (3), acting on behalf of or at the instructions of such Borrower Indemnified Party or Servicer Indemnified Party (as applicable) or its Affiliates; provided, however, that no Covered Entity or Affiliate of a Covered Entity, or any director, officer, employee, agent or representative of any of the foregoing shall constitute a "Controlled Related Party".

"Covered Entity" shall mean (a) each of Borrower, the Servicer, the Transferor, each Originator, the Parent and each of Parent's Subsidiaries and (b) each Person that, directly or indirectly, is in control of a Person described in clause (a) above. For purposes of this definition, control of a Person shall mean the direct or indirect (x) ownership of, or power to vote, 25% or more of the issued and outstanding equity interests having ordinary voting power for the election of directors of such Person or other Persons performing similar functions for such Person, or (y) power to direct or cause the direction of the management and policies of such Person whether by ownership of equity interests, contract or otherwise.

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"Credit Agreement" means the ~~Third~~ _____ Amended and Restated Credit Agreement, dated as of ~~May 23,~~ January 27, 2017,

~~2012,~~ _____ among Parent, as borrower, the lenders from time to time party thereto, the letter of credit issuing banks from time to time party thereto and ~~JPMorgan Chase Bank, N.A., as administrative agent, swing line~~ the Credit Agreement Administrative Agent

~~lender and collateral agent~~ _____, as amended, restated, amended and restated, supplemented or otherwise modified from time to time.

"Credit Agreement Administrative Agent" means _____ JPMorgan Chase Bank, N.A., as administrative and/or collateral agent under the Credit Agreement.

agent _____

"Credit and Collection Policy" means, as the context may require, those receivables credit and collection policies and practices of the Originators in effect on the Closing Date and described in Exhibit E, as modified in compliance with this Agreement.

"Credit Extension" means the making of any Loan or the issuance of any Letter of Credit or any modification, extension or renewal of any Letter of Credit.

"Credit Party" means each Lender, the LC Bank, each LC Participant and the Administration Agent.

"Daily Report" means a report substantially in the form of Exhibit I-2.

"Days' Sales Outstanding" means, for any Fiscal Month, an amount computed as of the last day of such Fiscal Month equal to: (a) the average of the Outstanding Balance of all Pool Receivables as of the last day of each of the three most recent Fiscal Months ended on the last day of such Fiscal Month, divided by (b) (i) the aggregate initial Outstanding Balance of all Pool Receivables originated by the Originators during the three most recent Fiscal Months ended on the last day of such Fiscal Month, divided by (ii) 90.

"Dilution Horizon Ratio" means, for any Fiscal Month, the ratio (expressed as a percentage and rounded to the nearest 1/100th of 1%, with 5/1000th of 1% rounded upward) computed as of the last day of such Fiscal Month by dividing: (a) the aggregate initial Outstanding Balance of all Pool Receivables generated by the Originators during the most recent Fiscal Month, by (b) the Net Receivables Pool Balance as of the last day of such Fiscal Month.

"Dilution Ratio" means, for any Fiscal Month, the greater of (i) 0.50% and (ii) the ratio (expressed as a percentage and rounded to the nearest 1/100th of 1%, with 5/1000th of 1% rounded upward), computed as of the last day of each Fiscal Month by dividing: (a) the aggregate amount of Deemed Collections during such Fiscal Month (other than any Deemed Collections with respect to any Receivables that were both (I) generated by an Originator during such Fiscal Month and (II) written off the applicable Originator's or the Borrower's books as uncollectible during such Fiscal Month), by (b) the aggregate initial Outstanding Balance of all Pool Receivables generated by the Originators during the Fiscal Month that is one month prior to such Fiscal Month.

"Dilution Reserve" means, on any day, an amount equal to: (a) the Aggregate Capital plus the LC Participation Amount on such day, multiplied by (b) (i) the Dilution Reserve Percentage on such day, divided by (ii) 100% minus the Dilution Reserve Percentage on such day.

"Dilution Reserve Percentage" means, on any day, the product of (a) the Dilution Horizon Ratio, multiplied by (b) the sum of (i) 2.25 times the average of the Dilution Ratios for the twelve most recent Fiscal Months, plus (ii) the Dilution Volatility Component.

"Dilution Volatility Component" means, for any Fiscal Month, (a) the positive difference, if any, between: (i) the highest Dilution Ratio for any Fiscal Months during the twelve most recent Fiscal Month and (ii) the arithmetic average of the Dilution Ratios for such twelve months times (b) (i) the highest Dilution Ratio for any Fiscal Month during the twelve most recent Fiscal Months, divided by (ii) the arithmetic average of the Dilution Ratios for such twelve months.

"Dollars" and "$" each mean the lawful currency of the United States of America.

"Drawing Date" has the meaning set forth in Section 3.04(a).

"Eligible Assignee" means (i) any Lender or any of its Affiliates and (ii) any other financial institution approved by the Borrower, such approval not to be unreasonably withheld, conditioned or delayed.

"Eligible Foreign Obligor" means an Obligor (or with respect to any Receivable that is supported by an Eligible Supporting Letter of Credit, such Eligible Supporting Letter of Credit Provider) which is organized under the laws of any country (or with respect to an Eligible Supporting Letter of Credit Provider, the country in which the office from which it is obligated to make payment with respect to such Eligible Supporting Letter of Credit is located) (other than the United States) that is not a Sanctioned Country and that has a foreign currency rating of at least "BBB-" by S&P and "Baa3" by Moody's.

"Eligible Receivable" means, at any time of determination, a Pool Receivable:

(a) the Obligor of which is: (i) a resident of the United States of America or an Eligible Foreign Obligor

_____; (ii) not a federal governmental authority other than TVA; (iii) not a Sanctioned Person; (iv) not an Affiliate of the Borrower, the Parent, the Transferor, the Servicer or any Originator; (v) [Reserved]; (vi) not the Obligor with respect to Delinquent Receivables with an aggregate Outstanding Balance exceeding 25% of the aggregate Outstanding Balance of all such Obligor's Pool Receivables; and (vii) not a Material Supplier to any Originator or the Transferor or an Affiliate of such Material Supplier;

(b) for which an Insolvency Proceeding shall not have occurred with respect to the Obligor thereof or any other Person obligated thereon or owning any Related Security with respect thereto;

(c) that is denominated and payable only in U.S. dollars in the United States of America, and the Obligor with respect to which has been instructed to remit Collections in respect thereof directly to a Lock-Box or Lock-Box Account in the United States of America;

(d) that does not have a due date which is more than 60 days after the original invoice date of such Receivable;

(e) that arises under a Contract for the sale of goods or services in the ordinary course of the applicable Originator's business;

(f) that arises under a duly authorized Contract that is in full force and effect and that is a legal, valid and binding obligation of the related Obligor, enforceable against such Obligor in accordance with its terms;

(g) that has been sold by an Originator to the Transferor pursuant to the Purchase and Sale Agreement and sold or contributed by the Transferor to the Borrower pursuant to the Sale and Contribution Agreement, and with respect to which transfers all conditions precedent under the Sale Agreements have been met;

(h) that, together with any Contract related thereto, conforms in all material respects with all Applicable Laws (including any applicable laws relating to usury, truth in lending, fair credit billing, fair credit reporting, equal credit opportunity, fair debt collection practices and privacy);

(i) with respect to which all consents, licenses, approvals or authorizations of, or registrations or declarations with or notices to, any Governmental Authority or other Person required to be obtained, effected or given by an Originator in connection with the creation of such Receivable, the execution, delivery and performance by such Originator of the related Contract or the assignment thereof under the Purchase and Sale Agreement have been duly obtained, effected or given and are in full force and effect;

also obligated to perform under the contract and (iii) is not a transfer of an interest in or an assignment of a claim under a policy of insurance;

(u) which does not relate to the sale of any consigned goods or finished goods which have incorporated any consigned goods into such finished goods;

(v) if the Obligor of which is a Top Twenty-Five Obligor, in which no Originator or the Transferor (or any Affiliate of any of the foregoing) owes any amount to such Obligor (including as a result of such Obligor being a Supplier to such Person); provided, that only such portion of such Receivable to the extent subject to potential offset respecting any of the foregoing shall be deemed to be ineligible pursuant to this clause (v); and

(w) that satisfies all applicable requirements of clause (j) of Section 6.1 of the Purchase and Sale Agreement.

"Eligible Supporting Letter of Credit" means, with respect to any Pool Receivables of an Obligor, an unconditional (except for any draft or documentation required to be presented as a condition to drawings thereunder), irrevocable standby or commercial letter of credit, at all times in form and substance acceptable to the Administrative Agent in its sole discretion, issued or confirmed by an Eligible Supporting Letter of Credit Provider, which letter of credit (i) supports the payment of such Pool Receivables, (ii) names the Originator of such Pool Receivables as the sole beneficiary thereof and (iii) is payable in U.S. Dollars.

"Eligible Supporting Letter of Credit Provider" means a bank so designated in writing by the Administrative Agent to the Servicer (in the sole discretion of the Administrative Agent); provided, at any time after the long-term unsecured senior debt obligation of such bank is withdrawn or falls below a rating of (a) "BBB-" by S&P's on its long-term senior unsecured and uncredit-enhanced debt securities, or (b) "Baa3" by Moody's on its long-term senior unsecured and uncredit-enhanced debt securities, that the Administrative Agent may revoke (in the sole discretion) any such designation by written notice, which revocation shall be effective on the date so designated, and on such effective date, each letter of credit issued or confirmed by such bank shall cease to be an Eligible Supporting Letter of Credit.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time, and any rule or regulation issued thereunder.

"ERISA Affiliate" means, with respect to any Person, any corporation, trade or business which together with the Person is a member of a controlled group of corporations or a controlled group of trades or businesses and would be deemed a "single employer" within the meaning of Sections 414(b), (c), (m) of the Code or Section 4001(b) of ERISA.

"Euro-Rate" means, at any time of determination, with respect to any Lender, (i) if such Lender and the Borrower have agreed in writing that the Euro-Rate for such Lender will be determined based upon LMIR, then LMIR at such time or (ii) in all other cases, Adjusted LIBOR at such time. The Euro-Rate with respect to PNC shall be determined based upon LMIR unless otherwise agreed by PNC and the Borrower in writing.

"Euro-Rate Reserve Percentage" means, the maximum effective percentage in effect on such day as prescribed by the Board of Governors of the Federal Reserve System (or any successor) for determining the reserve requirements (including without limitation, supplemental, marginal,

and emergency reserve requirements) with respect to eurocurrency funding (currently referred to as "Eurocurrency Liabilities").

"Event of Default" has the meaning specified in Section 10.01.

"Excess Concentration" means, the sum, without duplication, of:

(a) the sum of the amounts calculated for each of the Obligors equal to the excess (if any) of (i) aggregate Outstanding Balance of the Eligible Receivables of such Obligor, over (ii) the product of (x) such Obligor's Concentration Percentage, multiplied by (y) the aggregate Outstanding Balance of all Eligible Receivables; plus

(b) the excess (if any) of (i) the aggregate Outstanding Balance of all Eligible Receivables , the Obligors of which are Eligible Foreign Obligors, over (ii) the product of (x) 3.50%, multiplied by (y) the aggregate Outstanding Balance of all Eligible Receivables; plus

(c) the excess (if any) of (i) the aggregate Outstanding Balance of all Eligible Receivables

that are In-Transit Receivables, over (ii) the product of (x) 7.5%, multiplied by (y) the aggregate Outstanding Balance of all Eligible Receivables; plus

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(e) the excess (if any) of (i) the aggregate Outstanding Balance of all Eligible Receivables that have not been billed, over (ii) the product of (x) 10.0%, multiplied by (y) the aggregate Outstanding Balance of all ;

Eligible Receivables

provided, that, for purposes of determining the "Excess Concentration" pursuant to clause (a) above, with respect to any Eligible Receivable supported by an Eligible Supporting Letter of Credit, the "Obligor" thereof shall be deemed to be the related Eligible Supporting Letter of Credit Provider, provided, further that, for purposes of determining the "Excess Concentration" pursuant to clause (b) above, with respect to any Eligible Receivable supported by an Eligible Supporting Letter of Credit, the "Obligor" thereof shall be deemed to be the related Eligible Supporting Letter of Credit Provider (and, with respect to any Eligible Receivable supported by an Eligible Supporting Letter of Credit, such Obligor shall be deemed to be organized under the laws of the country in which the office from which it is obligated to make payment with respect to such Eligible Supporting Letter of Credit is located) and provided, further that if any Pool Receivable is partially supported by an Eligible Supporting Letter of Credit, then the "Obligor" thereof shall be deemed to be (i) with respect to the Unsupported Outstanding Balance of such Pool Receivable, the Obligor of such Pool Receivable and (ii) with respect to the Supported Outstanding Balance of such Pool Receivable, the related Eligible Supporting Letter of Credit Provider.

"Exchange Act" means the Securities Exchange Act of 1934, as amended or otherwise modified from time to time.

"Federal Reserve Board" means the Board of Governors of the Federal Reserve System, or any entity succeeding to any of its principal functions.

"Fee Letter" has the meaning specified in Section 2.03(a).

"Fees" has the meaning specified in Section 2.03(a).

"Final Maturity Date" means the date that is one hundred eighty (180) days following the Scheduled Termination Date (as such date may be extended pursuant to Section 2.02(g)), or such earlier date on which the Loans become due and payable pursuant to Section 10.01.

"Final Payout Date" means the date on or after the Termination Date when (i) the Aggregate Capital and Aggregate Interest have been paid in full, (ii) the LC Participation Amount has been reduced to zero ($0) and no Letters of Credit issued hereunder remain outstanding and undrawn, (iii) all Borrower Obligations shall have been paid in full, (iv) all other amounts owing to the Credit Parties and any other Borrower Indemnified Party or Affected Person hereunder and under the other Transaction Documents have been paid in full and (v) all accrued Servicing Fees have been paid in full.

"Financial Officer" of any Person means, the chief executive officer, the chief financial officer, the chief accounting officer, the principal accounting officer, the controller, the treasurer or the assistant treasurer of such Person.

"Fiscal Month" means each calendar month.

"Fitch" means Fitch, Inc. and any successor thereto that is a nationally recognized statistical rating organization.

"Fixed Charge Ratio" means the ratio of (a) Consolidated Cash Flow minus (i) Consolidated Income Tax Expense, minus (ii) Maintenance Cap Ex to (b) Consolidated Fixed Charges of the Parent and its Subsidiaries for each rolling four-quarter period (*provided* that in calculating the Fixed Charge Ratio for any rolling four-quarter period from

(i) distributions made in the first quarter of such four-quarter period shall be excluded ~~form~~ ____ determining the Fixed Charge Ratio and (ii) all distributions declared or made in the current quarter when the calculation is being made (up to the time when the calculation is being made) shall be included in determining the Fixed Charge Ratio).

"GAAP" means generally accepted accounting principles in the United States of America, consistently applied.

"Governmental Acts" has the meaning set forth in Section 3.09.

"Governmental Authority" means the government of the United States of America or any other nation, or of any political subdivision thereof, whether state or local, and any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government (including any supra-national bodies such as the European Union or the European Central Bank).

(b) if the Base Rate is applicable to such Lender pursuant to Section 5.04, the Base Rate in effect on such day;

provided, however, that the "Interest Rate" for any day while an Event of Default has occurred and is continuing shall be an interest rate per annum equal to the sum of 2.00% per annum plus the greater of (i) the Base Rate in effect on such day and (ii) the Adjusted LIBOR with respect to such Lender for such Interest Period; provided, further, that no provision of this Agreement shall require the payment or permit the collection of Interest in excess of the maximum permitted by Applicable Law; and provided, further, however, that Interest for any Loan shall not be considered paid by any distribution to the extent that at any time all or a portion of such distribution is rescinded or must otherwise be returned for any reason.

"Interim Report" means each Daily Report and Weekly Report.

"In-Transit Receivable" means, at any time of determination, any Receivable arising in connection with the sale of any goods or merchandise that as of such time, have been shipped but not delivered to the related Obligor.

"Investment Company Act" means the Investment Company Act of 1940, as amended or otherwise modified from time to time.

"LC Bank" has the meaning set forth in the preamble to this Agreement.

"LC Collateral Account" means the account at any time designated as the LC Collateral Account established and maintained by the Administrative Agent (for the benefit of the LC Bank and the LC Participants), or such other account as may be so designated as such by the Administrative Agent.

"LC Fee Expectation" has the meaning set forth in Section 3.05(c).

"LC Limit" means $100,000,000. References to the unused portion of the LC Limit shall mean, at any time of determination, an amount equal to (x) the LC Limit at such time, minus (y) the LC Participation Amount.

"LC Participant" means each Lender.

"LC Participation Amount" means at any time of determination, the sum of the amounts then available to be drawn under all outstanding Letters of Credit.

"LC Request" means a letter in substantially the form of Exhibit A hereto executed and delivered by the Borrower to the Administrative Agent, the LC Bank and the Lenders pursuant to Section 3.02(a).

"LCR Security" means any commercial paper or security (other than equity securities issued to Parent or any Originator that is a consolidated subsidiary of Parent under generally accepted accounting principles) within the meaning of Paragraph __.32(e)(1)(viii) of the final rules titled Liquidity Coverage Ratio: Liquidity Risk Measurement Standards, 79 Fed. Reg. 197, 61440 et seq. (October 10, 2014).

"Notice Date" has the meaning set forth in Section 3.02(b).

"No-Petition Letter" means that certain Letter Agreement re Pledge of SPV Interests, entered into in connection with the Fifth Amendment to this Agreement, dated as of January 17, 2018, by and among the Credit Agreement Administrative Agent, the Administrative Agent and the other parties thereto.

"Obligor" means, with respect to any Receivable, the Person obligated to make payments pursuant to the Contract relating to such Receivable.

"Obligor Percentage" means, at any time of determination, for each Obligor, a fraction, expressed as a percentage, (a) the numerator of which is the aggregate Outstanding Balance of the Eligible Receivables of such Obligor less the amount (if any) then included in the calculation of the Excess Concentration with respect to such Obligor and (b) the denominator of which is the aggregate Outstanding Balance of all Eligible Receivables at such time.

"Order" has the meaning set forth in Section 3.10.

"Originator" and "Originators" have the meaning set forth in the Purchase and Sale Agreement, as the same may be modified from time to time by adding new Originators or removing Originators, in each case with the prior written consent of the Administrative Agent.

"Other Connection Taxes" means, with respect to any Affected Person, Taxes imposed as a result of a present or former connection between such Affected Person and the jurisdiction imposing such Tax (other than connections arising from such Affected Person having executed, delivered, become a party to, performed its obligations under, received payments under, received or perfected a security interest under, engaged in any other transaction pursuant to or enforced any Transaction Document, or sold or assigned an interest in any Loan or Transaction Document).

"Other Taxes" means any and all present or future stamp or documentary Taxes or any other excise or property Taxes, charges or similar levies or fees arising from any payment made hereunder or from the execution, delivery, filing, recording or enforcement of, or otherwise in respect of, this Agreement, the other Transaction Documents and the other documents or agreements to be delivered hereunder or thereunder, except any such Taxes that are Other Connection Taxes imposed with respect to any assignment or participation.

"Outstanding Balance" means, at any time of determination, with respect to any Receivable, the then outstanding principal balance thereof.

"Parent" means Alliance Resource Operating Partners, L.P., a Delaware limited partnership.

"Parent Revolving Facility" means the Parent's revolving credit facility under the Credit Agreement, as it may be extended, refinanced or refunded by some or all of the lenders thereunder.

"Parent Group" has the meaning set forth in Section 8.03(c).

"Reportable Compliance Event" shall mean that any Covered Entity becomes a Sanctioned Person, or is charged by indictment, criminal complaint or similar charging instrument, arraigned, or custodially detained in connection with any Anti-Terrorism Law or any predicate crime to any Anti-Terrorism Law, or has knowledge of facts or circumstances to the effect that it is reasonably likely that any aspect of its operations is in actual or probable violation of any Anti-Terrorism Law.

"Reportable Event" shall mean any reportable event as defined in Section 4043(c) of ERISA or the regulations issued thereunder with respect to a Pension Plan (other than a Pension Plan maintained by an ERISA Affiliate which is considered an ERISA Affiliate only pursuant to subsection (m) or (o) of Section 414 of the Code).

"Representatives" has the meaning set forth in Section 14.06(c).

"Required Capital Amount" means $12,000,000.

"Responsible Officer" of any Person means, any Financial Officer, any vice president, the secretary, the general counsel, or any other officer of such Person customarily performing functions similar to those performed by any of the above-designated officers or responsible for the administration of the obligations of such Person under the Transaction Documents and also, with respect to a particular matter any other officer to whom such matter is referred because of such officer's knowledge of and familiarity with the particular subject.

"S&P" means Standard & Poor's Rating Services, a Standard & Poor's Financial Services LLC business, and any successor thereto that is a nationally recognized statistical rating organization.

"Sale Agreements" means the Purchase and Sale Agreement and the Sale and Contribution Agreement.

"Sale and Contribution Agreement" means the Sale and Contribution Agreement, dated as of the Closing Date, among the Servicer, the Transferor and the Borrower, as such agreement may be amended, amended and restated, supplemented or otherwise modified from time to time.

"Sanctioned Country" means a country subject to a sanctions program maintained under any Anti-Terrorism Law.

"Sanctioned Person" means any individual person, group, regime, entity or thing listed or otherwise recognized as a specially designated, prohibited, sanctioned or debarred person, group, regime, entity or thing, or subject to any limitations or prohibitions (including but not limited to the blocking of property or rejection of transactions), under any Anti-Terrorism Law.

"Scheduled Termination Date" means January ~~17, 2018,~~ 16, 2019, as such date may be extended from time to time pursuant to Section 2.02(g).

"SEC" shall mean the U.S. Securities and Exchange Commission or any governmental agencies substituted therefor.

"Supported Outstanding Balance" means, for any Receivable at any time that is supported in whole or in part by an Eligible Supporting Letter of Credit, the lesser of (a) the Outstanding Balance of such Receivable and (b) the face amount of such Eligible Supporting Letter of Credit.

"Tax Benefit" has the meaning set forth in Section 5.03(k).

"Taxes" means any and all present or future taxes, levies, imposts, duties, deductions, charges or withholdings imposed by any Governmental Authority and all interest, penalties, additions to tax and any similar liabilities with respect thereto.

"Termination Date" means the earliest to occur of (a) the Scheduled Termination Date, (b) the date on which the "Termination Date" is declared or deemed to have occurred under Section 10.01 and (c) the date selected by the Borrower on which all Commitments have been reduced to zero pursuant to Section 2.02(e).

"Termination Event" means a "Termination Event" under any Sale Agreement.

"Top Twenty-Five Obligor" means, at any time of determination, the largest twenty-five Obligors based on Outstanding Balance of Receivables then in the Receivables Pool.

"Total Reserves" means, at any time of determination, the sum of: (a) the Yield Reserve, plus (b) the greater of (i) the sum of the Concentration Reserve plus the Minimum Dilution Reserve and (ii) the sum of the Loss Reserve plus the Dilution Reserve.

"Transaction Documents" means this Agreement, the Sale Agreements, the Lock-Box Agreements, the Fee the No-Petition Letter,

Letter, _____ each Subordinated Note, Demand Note, the Performance Guaranty and all other certificates, instruments, UCC financing statements, reports, notices, agreements and documents executed or delivered under or in connection with this Agreement, in each case as the same may be amended, supplemented or otherwise modified from time to time in accordance with this Agreement.

"Transfer" means, with respect to any person, any transaction in which such person sells, conveys, abandons, transfers, leases (as lessor), or otherwise disposes of any of its assets; provided, however, that "Transfer" shall not include (a) the granting of any liens permitted to be granted under the Credit Agreement, (b) any transfer of assets permitted pursuant to Section 5.02(d) of the Credit Agreement, (c) the making of any Restricted Payment (as defined in the Credit Agreement) permitted in the loan documentation relating to the Credit Agreement or (d) the making of any investments permitted in the loan documentation relating to the Credit Agreement.

"Transfer Restrictions Agreement" means that certain Transfer Restrictions Agreement, dated as of June 13, 2006, by and among Alliance Holdings GP, L.P., Alliance GP, LLC, C-Holdings, LLC, Joseph W. Craft III, Alliance Resource Holdings II, Inc., Alliance Resource Holdings, Inc., Alliance Resource GP, LLC and each other party named therein as a party thereto, as the same may be amended, modified or supplemented.

"Transferor" means the Parent.

"TVA" means Tennessee Valley Authority.

"UCC" means the Uniform Commercial Code as from time to time in effect in the applicable jurisdiction.

"Unmatured Event of Default" means an event that but for notice or lapse of time or both would constitute an Event of Default.

"Unsupported Outstanding Balance" means, for any Receivable at any time, (a) the then Outstanding Balance of such Receivable, less (b) the Supported Outstanding Balance for such Receivable.

"U.S. Tax Compliance Certificate" has the meaning set forth in Section 5.03(f)(ii)(B)(3).

"Volcker Rule" means Section 13 of the U.S. Bank Holding Company Act of 1956, as amended, and the applicable rules and regulations thereunder.

"Weekly Report" means a report substantially in the form of Exhibit I-1.

"Withdrawal Liability" shall mean liability to a Multiemployer Plan as a result of a complete or partial withdrawal from such Multiemployer Plan, as such terms are defined in Part I of Subtitle E of Title IV of ERISA.

"Yield Reserve" means, at any time of determination, an amount equal to the product of (i) the sum of the Aggregate Capital plus the LC Participation Amount on such date, multiplied by (ii) (x) the Yield Reserve Percentage on such date, divided by (y) 100% minus the Yield Reserve Percentage on such date.

"Yield Reserve Percentage" means, at any time of determination:

$$\frac{1.50 \times DSO \times (BR + SFR)}{360}$$

where:

BR = the Base Rate at such time;

DSO = Days' Sales Outstanding for the month most recently ended; and

SFR = the Servicing Fee Rate.

SECTION 1.02 Other Interpretative Matters. All accounting terms not specifically defined herein shall be construed in accordance with GAAP. All terms used in Article 9 of the UCC in the State of New York and not specifically defined herein, are used herein as defined in such Article 9. Unless otherwise expressly indicated, all references herein to "Article," "Section," "Schedule", "Exhibit" or "Annex" shall mean articles and sections of, and schedules, exhibits and annexes to,

this Agreement. For purposes of this Agreement, the other Transaction Documents and all such certificates and other documents, unless the context otherwise requires:

Borrower Indemnified Parties), the LC Bank and the LC Participants hereunder shall be paid or distributed to the Administrative Agent's Account. The Administrative Agent, upon its receipt in the Administrative Agent's Account of any such payments or distributions, shall distribute such amounts to the applicable Lenders, the LC Bank, LC Participants, Affected Persons and the Borrower Indemnified Parties ratably; provided that if the Administrative Agent shall have received insufficient funds to pay all of the above amounts in full on any such date, the Administrative Agent shall pay such amounts to the applicable Lenders, the LC Bank, the LC Participants, Affected Persons and the Borrower Indemnified Parties in accordance with the priority of payments set forth above, and with respect to any such category above for which there are insufficient funds to pay all amounts owing on such date, ratably (based on the amounts in such categories owing to each such Person) among all such Persons entitled to payment thereof.

(c) If and to the extent the Administrative Agent, any Credit Party, any Affected Person or any Borrower Indemnified Party shall be required for any reason to pay over to any Person any amount received on its behalf hereunder, such amount that is actually paid over shall be deemed not to have been so received but rather to have been retained by the Borrower and, accordingly, the Administrative Agent, such Credit Party, such Affected Person or such Borrower Indemnified Party, as the case may be, shall have a claim against the Borrower for such amount.

(d) For the purposes of this Section 4.01:

(i) if on any day the Outstanding Balance of any Pool Receivable is reduced or adjusted as a result of any defective, rejected, returned, repossessed or foreclosed goods or services, or any revision, cancellation, allowance, rebate, discount or other adjustment made by the Borrower, any Originator, the Transferor, the Servicer or any Affiliate of the Servicer, or any setoff or dispute between the Borrower or any Affiliate of the Borrower, the Transferor or any Affiliate of the Transferor, an Originator or any Affiliate of an Originator, or the Servicer or any Affiliate of the Servicer, and an Obligor, the Borrower shall be deemed to have received on such day a Collection of such Pool Receivable in the amount of such reduction or adjustment and shall immediately pay any and all such amounts in respect thereof to a Lock-Box Account (or as otherwise directed by the Administrative Agent at such time) for the benefit of the Credit Parties for application pursuant to Section 4.01(a);

(ii) if on any day any of the representations or warranties in Section 7.01 is not true with respect to any Pool Receivable, the Borrower shall be deemed to have received on such day a Collection of such Pool Receivable in full and shall immediately pay the amount of such deemed Collection to a Lock-Box Account (or as otherwise directed by the Administrative Agent at such time) for the benefit of the Credit Parties for application pursuant to Section 4.01(a) (Collections deemed to have been received pursuant to Section 4.01(d) are hereinafter sometimes referred to as "Deemed Collections");

(iii) except as provided in clauses (i) or (ii) above or otherwise required by Applicable Law or the relevant Contract, all Collections received from an Obligor (or Eligible Supporting Letter of Credit Provider)

_____ of any Receivable shall be applied to the

(z) Liquidity Coverage Ratio. The Borrower has not~~, does not and will not during the term of this Agreement (x) issue any obligations that (A) constitute asset-backed commercial paper, or (B) are securities required to be registered under the Securities Act of 1933 (the "33 Act") or that may be offered for sale under Rule 144A or a similar exemption from registration under the 33 Act or the rules promulgated thereunder, or (y) issue any other debt obligations or equity interests other than equity interests issued to the Parent, the Subordinated Notes or debt obligations substantially similar to the obligations of the Borrower under this Agreement that are (A) issued to other banks or asset-backed commercial paper conduits in privately negotiated transactions, and (B) subject to transfer restrictions substantially similar to the transfer restrictions set forth in this Agreement. The Borrower further represents and warrants that its assets and liabilities are consolidated with the assets and liabilities of Servicer for purposes of GAAP.~~
issued any LCR Securities, and the Borrower is a consolidated subsidiary of Parent under generally accepted accounting principles.

Notwithstanding any other provision of this Agreement or any other Transaction Document, the representations contained in this Section shall be continuing, and remain in full force and effect until the Final Payout Date.

SECTION 7.02. Representations and Warranties of the Servicer. The Servicer represents and warrants to each Credit Party as of the Closing Date, on each Settlement Date and on each day on which a Credit Extension shall have occurred:

(a) Organization and Good Standing. The Servicer is a duly organized and validly existing limited liability company in good standing under the laws of the State of Delaware, with the power and authority under its organizational documents and under the laws of the State of Delaware to own its properties and to conduct its business as such properties are currently owned and such business is presently conducted.

(b) Due Qualification. The Servicer is duly qualified to do business, is in good standing as a foreign entity and has obtained all necessary licenses and approvals in all jurisdictions in which the conduct of its business or the servicing of the Pool Receivables as required by this Agreement requires such qualification, licenses or approvals, except where the failure to do so could not reasonably be expected to have a Material Adverse Effect.

(c) Power and Authority; Due Authorization. The Servicer has all necessary power and authority to (i) execute and deliver this Agreement and the other Transaction Documents to which it is a party and (ii) perform its obligations under this Agreement and the other Transaction Documents to which it is a party and the execution, delivery and performance of, and the consummation of the transactions provided for in, this Agreement and the other Transaction Documents to which it is a party have been duly authorized by the Servicer by all necessary action.

(d) Binding Obligations. This Agreement and each of the other Transaction Documents to which it is a party constitutes legal, valid and binding obligations of the Servicer, enforceable against the Servicer in accordance with their respective terms, except (i) as such enforceability may be limited by applicable bankruptcy, insolvency, reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally and (ii) as such

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representatives to (A) examine and make copies of and abstracts from all books and records relating to the Pool Receivables or other Collateral, (B) visit the offices and properties of the Borrower for the purpose of examining such books and records and (C) discuss matters relating to the Pool Receivables, the other Collateral or the Borrower's performance hereunder or under the other Transaction Documents to which it is a party with any of the officers, directors, employees or independent public accountants of the Borrower having knowledge of such matters and (ii) without limiting the provisions of clause (i) above, during regular business hours, at the Borrower's expense, upon prior written notice from the Administrative Agent, permit certified public accountants or other auditors acceptable to the Administrative Agent to conduct a review of its books and records with respect to such Pool Receivables and other Collateral; provided, that the Borrower shall be required to reimburse the Administrative Agent for only one (1) such review pursuant to clause (ii) above in any twelve-month period, unless an Event of Default has occurred and is continuing.

(h) Payments on Receivables, Lock-Box Accounts. The Borrower (or the Servicer on its behalf) will, and will cause each Originator to, at all times, instruct all Obligors to deliver payments on the Pool Receivables to a Lock-Box Account or a Lock-Box. The Borrower (or the Servicer on its behalf) will, and will cause each Originator to, at all times, maintain such books and records necessary to identify Collections received from time to time on Pool Receivables and to segregate such Collections from other property of the Servicer, the Transferor and the Originators. If any payments on the Pool Receivables or other Collections are received by the Borrower, the Servicer, the Transferor or an Originator, it shall hold such payments in trust for the benefit of the Administrative Agent and the other Secured Parties and promptly (but in any event within two (2) Business Days after receipt) remit such funds into a Lock-Box Account.

The Borrower (or the Servicer on its behalf) will, unless otherwise agreed in writing by the Administrative Agent, instruct each Originator, in its capacity as the beneficiary (or prospective beneficiary) of an Eligible Supporting Letter of Credit, to instruct the related Eligible Supporting Letter of Credit Provider to make payments in respect of Eligible Supporting Letters of Credit issued (or confirmed by) such Eligible Supporting Letter of Credit Provider directly to a Lock-Box Account if the Servicer fails to do so and, if an Eligible Supporting Letter of Credit Provider fails to so deliver payments to a Lock-Box Account, the Borrower (or the Servicer on its behalf) will, unless otherwise agreed in writing by the Administrative Agent, use all reasonable efforts to cause the applicable Originator to cause such Eligible Supporting Letter of Credit Provider to deliver subsequent payments (if any) in respect of Eligible Supporting Letters of Credit issued (or confirmed by) such Eligible Supporting Letter of Credit Provider directly to a Lock-Box Account if the Servicer fails to do so.

The Borrower (or the Servicer on its behalf) will cause each Lock-Box Bank to comply with the terms of each applicable Lock-Box Agreement. The Borrower shall not permit funds other than (i) Collections on Pool Receivables and other Collateral and (ii) collections on Excluded Receivables, to be deposited into any Lock-Box Account. If such funds or any collections on Excluded Receivables are nevertheless deposited into any Lock-Box Account, the Borrower (or the Servicer on its behalf) will within two (2) Business Days of receipt identify and transfer such funds to the appropriate Person entitled to such funds. The Borrower will not, and will not permit the Servicer, the Transferor, any Originator or any other Person to commingle Collections or other funds to which the Administrative Agent or any

other Secured Party is entitled, with any other funds (other than the temporary commingling of Collections with collections on Excluded Receivables provided that such collections on Excluded Receivables are identified and removed from the applicable

(iii) The Borrower shall at all times be organized under the laws of the State of Delaware and shall not take any action to change its jurisdiction of organization.

(iv) The Borrower will not change its name, location, identity or corporate structure unless (x) the Borrower, at its own expense, shall have taken all action necessary or appropriate to perfect or maintain the perfection of the security interest under this Agreement (including, without limitation, the filing of all financing statements and the taking of such other action as the Administrative Agent may request in connection with such change or relocation) and (y) if requested by the Administrative Agent, the Borrower shall cause to be delivered to the Administrative Agent, an opinion, in form and substance satisfactory to the Administrative Agent as to such UCC perfection and priority matters as the Administrative Agent may request at such time.

(u) Anti-Money Laundering/International Trade Law Compliance. The Borrower will not become a Sanctioned Person. No Covered Entity, either in its own right or through any third party, will (a) have any of its assets in a Sanctioned Country or in the possession, custody or control of a Sanctioned Person in violation of any Anti-Terrorism Law; (b) do business in or with, or derive any of its income from investments in or transactions with, any Sanctioned Country or Sanctioned Person in violation of any Anti-Terrorism Law; (c) engage in any dealings or transactions prohibited by any Anti-Terrorism Law or (d) use the proceeds of any Credit Extension to fund any operations in, finance any investments or activities in, or, make any payments to, a Sanctioned Country or Sanctioned Person in violation of any Anti-Terrorism Law. The funds used to repay each Credit Extension will not be derived from any unlawful activity. The Borrower shall comply with all Anti-Terrorism Laws. The Borrower shall promptly following becoming aware of the same notify the Administrative Agent and each Lender in writing upon the occurrence of a Reportable Compliance Event.

(v) The Borrower has not used and will not use the proceeds of any Credit Extension to fund any operations in, finance any investments or activities in or make any payments to, a Sanctioned Person or a Sanctioned Country.

(w) Borrower's Net Worth. The Borrower shall not permit the Borrower's Net Worth to be less than the Required Capital Amount.

(x) Borrower's Tax Status. The Borrower will remain a wholly-owned subsidiary of a United States person (within the meaning of Section 7701(a)(30) of the Code) and not be subject to withholding under Section 1446 of the Code. No action will be taken that would cause the Borrower to be treated as an association taxable as a corporation or a publicly traded partnership taxable as a corporation for U.S. federal income tax purposes.

(y) Liquid Coverage Ratio. The Borrower shall not issue any LCR Security.

SECTION 8.02. Covenants of the Servicer. At all times from the Closing Date until the Final Payout Date:

(a) Financial Reporting. The Servicer will maintain a system of accounting established and administered in accordance with GAAP, and the Servicer shall furnish to the Administrative Agent, the LC Bank and each Lender:

representatives to (A) examine and make copies of and abstracts from all books and records relating to the Pool Receivables or other Collateral, (B) visit the offices and properties of the Servicer for the purpose of examining such books and records and (C) discuss matters relating to the Pool Receivables, the other Collateral or the Servicer's performance hereunder or under the other Transaction Documents to which it is a party with any of the officers, directors, employees or independent public accountants of the Servicer (provided that representatives of the Servicer are present during such discussions) having knowledge of such matters and (ii) without limiting the provisions of clause (i) above, during regular business hours, at the Servicer's expense, upon prior written notice from the Administrative Agent, permit certified public accountants or other auditors acceptable to the Administrative Agent to conduct a review of its books and records with respect to the Pool Receivables and other Collateral; provided, that the Servicer shall be required to reimburse the Administrative Agent for only one (1) such review pursuant to clause (ii) above in any twelve-month period unless an Event of Default has occurred and is continuing.

(f) Payments on Receivables, Lock-Box Accounts. The Servicer will at all times, instruct (or cause a Sub-Servicer to instruct) all Obligors to deliver payments on the Pool Receivables to a Lock-Box Account or a Lock-Box. The Servicer will, at all times, maintain such books and records necessary to identify Collections received from time to time on Pool Receivables and to segregate such Collections from other property of the Servicer, the Transferor and the Originators. If any payments on the Pool Receivables or other Collections are received by the Borrower (other than into a Lock-Box Account), the Servicer, the Transferor or an Originator, it shall hold such payments in trust for the benefit of the Administrative Agent and the other Secured Parties and promptly (but in any event within two (2) Business Days after receipt) remit such funds into a Lock -Box Account. The Servicer will (on behalf of the Borrower), unless otherwise agreed in writing by the Administrative Agent, instruct each Originator, in its capacity as the beneficiary of an Eligible Supporting Letter of Credit, to instruct each Eligible Supporting Letter of Credit Provider to make payments in respect of Eligible Supporting Letters of Credit issued (or confirmed by) such Eligible Supporting Letter of Credit Provider directly to a Lock-Box Account if the applicable Originator fails to do so and, if an Eligible Supporting Letter of Credit Provider fails to so deliver payments to a Lock-Box Account, the Servicer will, unless otherwise agreed in writing by the Administrative Agent, use all reasonable efforts to cause the applicable Originator to cause such Eligible Supporting Letter of Credit Provider to deliver subsequent payments (if any) in respect of Eligible Supporting Letters of Credit issued (or confirmed by) such Eligible Supporting Letter of Credit Provider directly to a Lock-Box Account if the applicable Originator fails to do so.

The Servicer shall not permit funds other than (i) Collections on Pool Receivables and other Collateral and (ii) collections on Excluded Receivables, to be deposited into any Lock-Box Account. If such funds or any collections on Excluded Receivables are nevertheless deposited into any Lock-Box Account, the Servicer will within two (2) Business Days of receipt identify and transfer such funds to the appropriate Person entitled to such funds. The Servicer will not, and will not permit the Borrower, any Originator or any other Person to commingle Collections or other funds to which the Administrative Agent or any other Secured Party is entitled, with any other funds (other than the temporary commingling of Collections with collections on Excluded Receivables provided that such collections on Excluded Receivables are identified and removed from the applicable Lock-Box Account within two (2) Business Days

following receipt thereof). The Servicer shall only add a Lock-Box Account (or a related Lock-Box), or a Lock-Box Bank to those listed on Schedule II to this Agreement, if the Administrative Agent has received notice of

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(Back To Top)

Section 5: EX-21.1 (EX-21.1)

EXHIBIT 21.1

LIST OF SUBSIDIARIES

First Tier Subsidiary:

Alliance Resource Operating Partners, L.P. (“AROP”) (98.9899% limited partner interest)

Second Tier Subsidiaries:

Alliance Coal, LLC (“Alliance Coal”) (AROP holds a 99.999% non-managing membership interest)
Alliance Minerals, LLC (“Alliance Minerals”) (AROP holds a 100% membership interest)
Alliance Resource Finance Corporation ("Alliance Finance") (AROP holds a 100% membership interest)
Alliance Resource Properties, LLC (“Alliance Resource Properties”) (AROP holds a 100% membership interest)
AROP Funding, LLC (AROP holds a 100% membership interest)
UC Coal, LLC (“UC Coal”) (AROP holds a 100% membership interest)
Wildcat Insurance, LLC (AROP holds a 100% membership interest)

Third Tier Subsidiaries: (Alliance Coal holds a 100% membership interest in (or holds 100% of the outstanding capital stock of) each of the following third-tier subsidiaries)

Alliance Design Group, LLC
Alliance Land, LLC
Alliance Service, Inc.
Backbone Mountain, LLC
CR Services, LLC
Excel Mining, LLC
Gibson County Coal, LLC
Hamilton County Coal, LLC
Hopkins County Coal, LLC
MC Mining, LLC
Mettiki Coal, LLC
Mettiki Coal (WV), LLC
Mid-America Carbonates, LLC
Mt. Vernon Transfer Terminal, LLC
Penn Ridge Coal, LLC
Pontiki Coal, LLC
River View Coal, LLC
Rough Creek Mining, LLC
Sebree Mining, LLC
Steamport, LLC
Tunnel Ridge, LLC
Warrior Coal, LLC
Webster County Coal, LLC
White County Coal, LLC

(Alliance Resource Properties holds a 100% membership interest in (or holds 100% of the outstanding capital stock of) each of the following third-tier subsidiaries)

ARP Sebree, LLC
ARP Sebree South, LLC
Alliance WOR Properties, LLC

(UC Coal holds a 100% membership interest in (or holds 100% of the outstanding capital stock of) each of the following third-tier subsidiaries)

UC Mining, LLC
UC Processing, LLC

Fourth Tier Subsidiaries:

CR Machine Shop, LLC (CR Services, LLC holds a 100% interest)
Matrix Design Group, LLC (Alliance Service, Inc. holds a 100% interest)
WOR Land 6, LLC (Alliance WOR Properties, LLC holds a 100% interest)

Fifth Tier Subsidiary:

Matrix Design International, LLC (Matrix Design Group, LLC holds a 100% interest)

Sixth Tier Subsidiary:

Matrix Design Africa (PTY) LTD (Matrix Design International, LLC holds a 100% interest)

All of the above entities are formed or incorporated, as the case may be, under the laws of the State of Delaware except for the following which are formed or incorporated in the following jurisdictions:

Wildcat Insurance, LLC – Oklahoma
Steamport, LLC – Kentucky
Matrix Design Africa (PTY) LTD – South Africa

(Back To Top)

Section 6: EX-23.1 (EX-23.1)

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-3 No. 333-202358) of Alliance Resource Partners, L.P.,

(2) Registration Statement (Form S-8 No. 333-165168) pertaining to the 2000 Long-Term Incentive Plan of Alliance Coal, LLC, and

(3) Registration Statement (Form S-8 No. 333-85258) pertaining to the Alliance Resource Management GP, LLC Long-Term Incentive Plan, the Supplemental Executive Retirement Plan and the Deferred Compensation Plan for Directors;

of our reports dated February 23, 2018, with respect to the consolidated financial statements and schedule of Alliance Resource Partners, L.P. and the effectiveness of internal control over financial reporting of Alliance Resource Partners, L.P. included in this Annual Report (Form 10-K) of Alliance Resource Partners, L.P. for the year ended December 31, 2017.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 23, 2018

(Back To Top)

Section 7: EX-31.1 (EX-31.1)

Exhibit 31.1

CERTIFICATION

I, Joseph W. Craft III certify that:

1. I have reviewed this Annual Report on Form 10-K of Alliance Resource Partners, L.P.;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
    b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusion about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this annual report based on such evaluation; and
    d. disclosed in this annual report any change in the registrant's internal control over financial reporting that occurred during the quarterly period ended December 31, 2017, that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2018

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

(Back To Top)

Section 8: EX-31.2 (EX-31.2)

Exhibit 31.2

CERTIFICATION

I, Brian L. Cantrell, certify that:

1. I have reviewed this Annual Report on Form 10-K of Alliance Resource Partners, L.P.;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the

circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
    b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusion about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this annual report based on such evaluation; and
    d. disclosed in this annual report any change in the registrant's internal control over financial reporting that occurred during the quarterly period ended December 31, 2017, that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2018

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

(Back To Top)

Section 9: EX-32.1 (EX-32.1)

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Alliance Resource Partners, L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Partnership.

By:/s/ Joseph W. Craft III
Joseph W. Craft III
President, Chief Executive Officer and Director
of Alliance Resource Management GP, LLC
(the general partner of Alliance Resource Partners, L.P.)

Date: February 23, 2018

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate document. A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

(Back To Top)

Section 10: EX-32.2 (EX-32.2)

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Alliance Resource Partners, L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brian L. Cantrell, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Partnership.

By:/s/ Brian L. Cantrell
Brian L. Cantrell
Senior Vice President and Chief Financial Officer
of Alliance Resource Management GP, LLC
(the general partner of Alliance Resource Partners, L.P.)

Date: February 23, 2018

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate document. A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

(Back To Top)

Section 11: EX-95.1 (EX-95.1)

EXHIBIT 95.1

Federal Mine Safety and Health Act Information

Our mining operations are subject to extensive and stringent compliance standards established pursuant to the Federal Mine Safety and Health Act of 1977, as amended by the Federal Mine Improvement and New Emergency Response Act of 2006 (as amended, the "Mine Act"). MSHA monitors and rigorously enforces compliance with these standards, and our mining operations are inspected frequently. Citations and orders are issued by MSHA under Section 104 of the Mine Act for violations of the Mine Act or any mandatory health or safety standard, rule, order or regulation promulgated under the Mine Act. A Section 104(a) "Significant and Substantial" or "S&S" citation is generally issued in a situation where the conditions created by the violation do not cause imminent danger, but in the opinion of the MSHA inspector could significantly and substantially contribute to the cause and effect of a mine safety or health hazard. During 2017, our mines were subject to 6,913 MSHA inspection days with an average of only 0.08 S&S citations written per inspection day.

The Mine Act has been construed as authorizing MSHA to issue citations and orders pursuant to the legal doctrine of strict liability, or liability without regard to fault. If, in the opinion of an MSHA inspector, a condition exists that violates the Mine Act or regulations promulgated thereunder, then a citation or order will be issued regardless of whether we had any knowledge of, or fault in, the existence of that condition. Many of the Mine Act standards include one or more subjective elements, so that issuance of a citation often depends on the opinions or experience of the MSHA inspector involved and the frequency of citations will vary from inspector to inspector.

If we disagree with the assertions of an MSHA inspector, we may exercise our right to challenge those findings by "contesting" the citation or order pursuant to the procedures established by the Mine Act and its regulations. During 2017, our operating subsidiaries contested approximately 10.8% of all citations and 26.9% of S&S citations issued by MSHA inspectors. These contest proceedings frequently result in the dismissal or modification of previously issued citations, substantial reductions in the penalty amounts originally assessed by MSHA, or both.

The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act") requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Mine Act. The following tables include information required by the Dodd-Frank Act for the twelve months ended December 31, 2017. The mine data retrieval system maintained by MSHA may show information that is different than what is provided herein. Any such difference may be attributed to the need to update that information on MSHA’s system and/or other factors.

Subsidiary Name / MSHA Identification Number [1]	Section 104 (a) S&S Citations[2]	Section 104(b) Orders [3]	Section 104 (d) Citations and Orders [4]	Section 110(b)(2) Violations [5]	Section 107(a) Orders [6]	Total Dollar Value of MSHA Assessments Proposed (in thousands) [7]
Illinois Basin Operations						
Webster County Coal, LLC (KY)						
1502132	113	-	-	-	-	$ 340.1
1511935	-	-	-	-	-	$ -
Warrior Coal, LLC (KY)						
1505230	-	-	-	-	-	$ -
1512083	-	-	-	-	-	$ -
1513514	-	-	-	-	-	$ -
1516460	-	-	-	-	-	$ -
1517216	94	-	-	-	-	$ 148.3
1517232	-	-	-	-	-	$ -
1517678	-	-	-	-	-	$ -
1517740	-	-	-	-	-	$ -
1517758	-	-	-	-	-	$ -
1514335	-	-	-	-	-	$ 1.2
Hopkins County Coal, LLC (KY)						
1502013	-	-	-	-	-	$ -
1517377	-	-	-	-	-	$ -
1517515	-	-	-	-	-	$ -
1518826	-	-	-	-	-	$ -
1517378	-	-	-	-	-	$ -
River View Coal, LLC (KY)						
1503178	2	-	-	-	-	$ 3.4
1519374	105	-	1	-	-	$ 175.9
White County Coal, LLC (IL)						
1102662	-	-	-	-	-	$ -
1103058	2	-	-	-	-	$ 15.4
Hamilton County Coal, LLC (IL)						
1103242	1	-	-	-	-	$ 1.0
1103203	98	-	5	-	-	$ 428.8
Gibson County Coal, LLC (IN)						
1202388	46	-	-	-	-	$ 97.8
1202215	2	-	-	-	-	$ 1.3
Sebree Mining, LLC (KY)						
1519264	-	-	-	-	-	$ -
1518547	-	-	-	-	-	$ 0.5
1518864	-	-	-	-	-	$ -
1517044	-	-	-	-	-	$ -
Appalachia Operations						
MC Mining, LLC (KY)						
1508079	-	-	-	-	-	$ -
1517733	-	-	-	-	-	$ 0.5
1519515	16	-	-	-	-	$ 31.9
Mettiki Coal, LLC (MD)						
1800621	-	-	-	-	-	$ -
1800671	-	-	-	-	-	$ 0.4
1800761	-	-	-	-	-	$ -
Mettiki Coal (WV), LLC						
4609028	18	-	-	-	-	$ 44.3
Tunnel Ridge, LLC (PA/WV)						
4608864	16	-	-	-	-	$ 41.2
Other						
4403236	-	-	-	-	-	$ -
4403255	-	-	-	-	-	$ -
4406630	-	-	-	-	-	$ -
4406867	-	-	-	-	-	$ -
1502709	-	-	-	-	-	$ -
Mid-America Carbonates, LLC (IL)						
1103176	-	-	-	-	-	$ 4.2

Subsidiary Name / MSHA Identification Number [1]	Total Number of Mining Related Fatalities	Received Notice of Pattern of Violations Under Section 104(e) (yes/no) [8]	Legal Actions Pending as of Last Day of Period	Legal Actions Initiated During Period	Legal Actions Resolved During Period
Illinois Basin Operations					
Webster County Coal, LLC (KY)					
1502132	-	No	7	16	14
1511935	-	No	-	-	-
Warrior Coal, LLC (KY)					
1505230	-	No	-	-	-
1512083	-	No	-	-	-
1513514	-	No	-	-	-
1516460	-	No	-	-	-
1517216	-	No	17	13	12
1517232	-	No	-	-	-
1517678	-	No	-	-	-
1517740	-	No	-	-	-
1517758	-	No	-	-	-
1514335	-	No	-	2	3
Hopkins County Coal, LLC (KY)					
1502013	-	No	-	-	-
1517377	-	No	-	-	-
1517515	-	No	-	-	-
1518826	-	No	-	-	17
1517378	-	No	-	-	-
River View Coal, LLC (KY)					
1503178	-	No	-	1	1
1519374	-	No	6	10	9
White County Coal, LLC (IL)					
1102662	-	No	-	-	-
1103058	-	No	-	3	15
Hamilton County Coal, LLC (IL)					
1103242	-	No	-	1	1
1103203	-	No	12	15	15
Gibson County Coal, LLC (IN)					
1202388	-	No	1	6	12
1202215	-	No	-	-	3
Sebree Mining, LLC (KY)					
1519264	-	No	-	-	-
1518547	-	No	-	1	8
1518864	-	No	-	-	-
1517044	-	No	-	-	-
Appalachia Operations					
MC Mining, LLC (KY)					
1508079	-	No	-	-	-
1517733	-	No	-	-	-
1519515	-	No	-	5	9
Mettiki Coal, LLC (MD)					
1800621	-	No	-	-	-
1800671	-	No	-	-	1
1800761	-	No	-	-	-
Mettiki Coal (WV), LLC					
4609028	-	No	-	-	1
Tunnel Ridge, LLC (PA/WV)					
4608864	-	No	1	3	3
Other					
4403236	-	No	-	-	-
4403255	-	No	-	-	-
4406630	-	No	-	-	-
4406867	-	No	-	-	-
Mid-America Carbonates, LLC (IL)					
1103176	-	No	1	2	2

The number of legal actions pending before the Federal Mine Safety and Health Review Commission as of December 31, 2017 that fall into each of the following categories is as follows:

Subsidiary Name / MSHA Identification Number [1]	*Contests of Citations and Orders*	*Contests of Proposed Penalties*	*Complaints for Compensation*	*Complaints of Discharge/ Discrimination /Interference*	*Applications for Temporary Relief*	*Appeals of Judges Rulings*
Illinois Basin Operations						
Webster County Coal, LLC (KY)						
1502132	-	7	-	-	-	-
1511935	-	-	-	-	-	-
Warrior Coal, LLC (KY)						
1505230	-	-	-	-	-	-
1512083	-	-	-	-	-	-
1513514	-	-	-	-	-	-
1516460	-	-	-	-	-	-
1517216	-	17	-	-	-	-
1517232	-	-	-	-	-	-
1517678	-	-	-	-	-	-
1517740	-	-	-	-	-	-
1517758	-	-	-	-	-	-
1514335	-	-	-	-	-	-
Hopkins County Coal, LLC (KY)						
1502013	-	-	-	-	-	-
1517377	-	-	-	-	-	-
1517515	-	-	-	-	-	-
1518826	-	-	-	-	-	-
1517378	-	-	-	-	-	-
River View Coal, LLC (KY)						
1503178	-	-	-	-	-	-
1519374	-	6	-	-	-	-
White County Coal, LLC (IL)						
1102662	-	-	-	-	-	-
1103058	-	-	-	-	-	-
Hamilton County Coal, LLC (IL)						
1103242	-	-	-	-	-	-
1103203	-	12	-	-	-	-
Gibson County Coal, LLC (IN)						
1202388	-	1	-	-	-	-
1202215	-	-	-	-	-	-
Sebree Mining, LLC (KY)						
1519264	-	-	-	-	-	-
1518547	-	-	-	-	-	-
1518864	-	-	-	-	-	-
1517044	-	-	-	-	-	-
Appalachia Operations						
MC Mining, LLC (KY)						
1508079	-	-	-	-	-	-
1517733	-	-	-	-	-	-
1519515	-	-	-	-	-	-
Mettiki Coal, LLC (MD)						
1800621	-	-	-	-	-	-
1800671	-	-	-	-	-	-
1800761	-	-	-	-	-	-
Mettiki Coal (WV), LLC						
4609028	-	-	-	-	-	-
Tunnel Ridge, LLC (PA/WV)						
4608864	-	1	-	-	-	-
Other						
4403236	-	-	-	-	-	-
4403255	-	-	-	-	-	-
4406630	-	-	-	-	-	-
4406867	-	-	-	-	-	-
Mid-America Carbonates, LLC (IL)						
1103176	-	1	-	-	-	-

(1) The statistics reported for each of our subsidiaries listed above are segregated into specific MSHA identification numbers.

(2) Mine Act section 104(a) S&S citations shown above are for alleged violations of mandatory health or safety standards that could significantly and substantially contribute to a coal mine health and safety hazard. It should be noted that, for purposes of this table, S&S citations that are included in another column, such as Section 104(d) citations, are not also included as Section 104(a) S&S citations in this column.

(3) Mine Act section 104(b) orders are for alleged failures to totally abate a citation within the time period specified in the citation.

(4) Mine Act section 104(d) citations and orders are for an alleged unwarrantable failure (*i.e.*, aggravated conduct constituting more than ordinary negligence) to comply with mandatory health or safety standards.

(5) Mine Act section 110(b)(2) violations are for an alleged "flagrant" failure (*i.e.*, reckless or repeated) to make reasonable efforts to eliminate a known violation of a mandatory safety or health standard that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury.

(6) Mine Act section 107(a) orders are for alleged conditions or practices which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated and result in orders of immediate withdrawal from the area of the mine affected by the condition.

(7) Amounts shown include assessments proposed by MSHA during the twelve months ended December 31, 2017 on all citations and orders, including those citations and orders that are not required to be included within the above chart.

(8) Mine Act section 104(e) written notices are for an alleged pattern of violations of mandatory health or safety standards that could significantly and substantially contribute to a coal mine safety or health hazard.

(Back To Top)