ALLIANCE RESOURCE PARTNERS LP
Form 10-K
February 22, 2019

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, 2018

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934

FOR THE TRANSITION PERIOD FROM ____________TO____________

COMMISSION FILE NO.: 0-26823

ALLIANCE RESOURCE PARTNERS, L.P.

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

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

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

(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES AND ZIP CODE)

(918) 295-7600

(REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE)

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

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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit 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 [ ] (Do not check if smaller reporting company)	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 $2,014,302,254 as of June 29, 2018, 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 22, 2019, 128,391,191 common units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: None

Table of Contents

TABLE OF CONTENTS

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 domestic and international coal markets and our ability to respond to such changes;
- legislation, regulations, and court decisions and interpretations thereof, both domestic and foreign, 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;
- recent action and the possibility of future action on trade made by United States and foreign governments;
- the effect of new tariffs and other trade measures;
- 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 & gas prices, which could, among other things, affect our investments in oil & gas mineral interests;
- our productivity levels and margins earned on our coal sales;
- decline in or change in 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, mine fires, mine floods or other interruptions;
- results of litigation, including claims not yet asserted;
- foreign currency fluctuations that could adversely affect the competitiveness of our coal abroad;

- 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;
- uncertainties in estimating and replacing our oil & gas reserves;
- uncertainties in the amount of oil & gas production due to the level of drilling and completion activity by the operators of our oil & gas properties;
- a loss or reduction of benefits from certain tax deductions and credits;

Table of Contents

- difficulty obtaining commercial property insurance, and risks associated with our participation 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 United States 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.

Table of Contents

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, it was also referred to as the managing general partner to distinguish them from SGP. Subsequent to the Exchange Transaction, SGP no longer holds any general partner interest.
- References to "SGP" mean Alliance Resource GP, LLC, ARLP's special general partner prior to the Exchange Transaction discussed below. SGP is indirectly wholly owned by Joseph W. Craft III, the Chairman, President and Chief Executive Officer ("CEO") of MGP, and Kathleen S. Craft, who are collectively referred to in such capacity as the "Owners of SGP." The Owners of SGP held approximately 34.48% of the outstanding AHGP common units prior to the Simplification Transactions 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.
- References to "AHGP" mean Alliance Holdings GP, L.P. individually and not on a consolidated basis as the parent company of MGP prior to the Simplification Transactions discussed below and as a wholly owned subsidiary of ARLP subsequent to the Simplification Transactions.

PART I

ITEM 1.BUSINESS

General

We are a diversified natural resource company that generates income from coal production and oil & gas mineral interests located in strategic producing regions across the United States. We are currently the second largest coal producer in the eastern United States with eight underground mining complexes in Illinois, Indiana, Kentucky, Maryland and West Virginia as well as a coal loading terminal in Indiana. We market our coal production to major domestic and international utilities and industrial users. We have grown historically primarily through expansion of our coal operations by adding and developing mines and coal reserves in these regions. In addition, we generate royalty income from mineral interests we own in premier oil & gas producing regions in the United States, primarily the Anadarko, Permian, Williston and Appalachian basins.

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 sole general partner, MGP, a Delaware limited liability company, which holds a non-economic general partner interest in ARLP. Prior to the Simplification Transactions, MGP was a wholly owned indirect subsidiary of AHGP. Alliance GP, LLC ("AGP"), which is indirectly wholly owned by Mr. Craft, was the general partner of AHGP prior to the Simplification Transactions and became the direct owner of MGP as a result of those transactions. See discussions under Partnership Simplification regarding changes in ownership of ARLP and MGP as a result of the Exchange Transaction and Simplification Transactions.

Simplification Transactions

On July 28, 2017, the conflicts committee ("Conflicts Committee") of the board of directors ("Board of Directors") of MGP and AGP's board of directors approved a transaction to simplify our partnership structure. Pursuant to that transaction, which closed on the same date, 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,

1

Table of Contents

SGP also contributed to ARLP its 0.01% general partner interest in both ARLP and the Intermediate Partnership in exchange for 28,141 ARLP common units collectively (the "Exchange Transaction").

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, among other things, through a series of transactions (the "Simplification 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 the ARLP common units held by AHGP and its subsidiaries,
iii. in exchange for a number of ARLP common units calculated pursuant to the Simplification Agreement, MGP's 1.0001% general partner interest in our Intermediate Partnership and MGP's 0.001% managing member interest in our subsidiary, Alliance Coal, would be contributed to us, and
iv. MGP would remain ARLP's sole general partner and would be a wholly owned subsidiary of AGP, and thus no control, management, or governance changes with respect to our business would occur.

The Simplification Agreement and the transactions contemplated thereby were approved by the written consent of approximately 68% of the holders of AHGP common units outstanding as of April 25, 2018, the record date for the consent solicitation. On May 31, 2018, ARLP, AHGP and the other parties to the Simplification Agreement completed the transactions contemplated by the Simplification Agreement.

As part of the Simplification Transactions, (i) each AHGP common unit that was issued and outstanding at the effective time of the Simplification Transactions was canceled and converted into the right to receive a portion of the ARLP common units held by AHGP and its subsidiaries, and (ii) SGP became the sole limited partner in AHGP. Each outstanding AHGP common unit, other than certain AHGP common units held by the Owners of SGP, converted into the right to receive approximately 1.4782 ARLP common units held by AHGP and its subsidiaries. The remaining AHGP common units held by the Owners of SGP were canceled and converted into the right to receive 29,188,997 ARLP common units which equaled (i) the product of the number of certain AHGP common units held by the Owners of SGP multiplied by 1.4782, minus (ii) 1,322,388 ARLP common units. In addition, ARLP issued 1,322,388 ARLP common units to the Owners of SGP in exchange for causing SGP to contribute to ARLP its remaining limited partner interest in AHGP, which included AHGP's indirect ownership of a 1.0001% general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal, resulting in an overall exchange ratio to the Owners of SGP equal to that of the other AHGP unitholders. Upon the issuance of ARLP common units to the Owners of SGP in exchange for the limited partner interest in AHGP, ARLP became a) the sole limited partner of AHGP and b) through AHGP, the indirect owner of a 1.0001% general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal.

AllDale I & II Acquisition

On January 3, 2019 (the "Acquisition Date"), ARLP acquired the general partner interests and all of the limited partner interests not owned by Cavalier Minerals JV, LLC ("Cavalier Minerals") in AllDale Minerals LP ("AllDale I") and AllDale Minerals II, LP ("AllDale II", and collectively with AllDale I, "AllDale I & II") for $176.0 million, which was funded with cash on hand and borrowings under our revolving credit facility (the "Acquisition"). ARLP indirectly owns a 96.0% non-managing member interest and a non-economic managing member interest in Cavalier Minerals. The Acquisition provides ARLP with diversified exposure to industry leading operators and is consistent with our general business strategy to pursue accretive acquisitions.

Kodiak Redemption

On January 26, 2019, Kodiak Gas Services, LLC ("Kodiak") provided notification that it intended to redeem our preferred interest for $135.0 million, which is inclusive of an early redemption premium. On February 8, 2019, we received the cash proceeds of the redemption.

Table of Contents

The following diagram depicts our organization and ownership as of January 3, 2019 (following the completion of the Acquisition):

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 SEC maintains a website that contains reports, proxy and information statements, and other information for issuers, including us. The public can obtain any documents that we file with the SEC at http://www.sec.gov.

Mining Operations

At December 31, 2018, we had approximately 1.7 billion tons of coal reserves in Illinois, Indiana, Kentucky, Maryland, Pennsylvania and West Virginia. 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. In 2018, we sold a record 40.4 million tons of coal and produced 40.3 million tons. The coal we sold in 2018 was approximately 28.1% low-sulfur coal, 40.1% medium-sulfur coal and 31.8% 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%. In 2018, approximately 68.2% of our tons sold were purchased by United States electric utilities and 27.8% were sold into the international markets through brokered transactions. The balance of our tons sold were to third-party resellers and industrial consumers. For tons sold to United

Table of Contents

States electric utilities, 100% were sold to utility plants with installed pollution control devices. The BTU content of our coal ranges from 11,400 to 13,200.

The following chart summarizes our coal production by region for the last five years.

	Year Ended December 31,				
Coal Regions	2018	2017	2016	2015	2014
	(tons in millions)				
Illinois Basin	29.9	27.3	25.4	32.0	30.9
Appalachia	10.4	10.3	9.8	9.2	9.8
Total	40.3	37.6	35.2	41.2	40.7

Table of Contents

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: Barge, Railroad
& Truck

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 & Truck

3. DOTIKI COMPLEX

Dotiki Mine

4. GIBSON COMPLEX

a. Gibson South Mine

b. Gibson North Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous

Miner
Coal Type: Low/Medium-Sulfur
Transportation: Barge, Railroad
& Truck

5. WARRIOR COMPLEX

Warrior Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Continuous

Miner
Coal Type: Medium/High-Sulfur
Transportation: Barge, Railroad,
& Truck

6. SEBREE COMPLEX
Onton Mine (Idled)

7. HENDERSON/UNION

RESERVES

Mining Type: Underground

Mining Access: Slope & Shaft
Mining Method: Continuous Miner
Coal Type: Medium/High-Sulfur

Transportation: Barge & Truck

Appalachian Operations:
8. MC MINING COMPLEX

a. Excel Mine No. 4
b. Excel Mine No. 5 (in development)

Mining Type: Underground

Mining Access: Slope & Shaft

Mining Method: Continuous

Miner

Coal Type: Low-Sulfur
Transportation: Barge, Railroad,

& Truck

9. TUNNEL RIDGE COMPLEX

Tunnel Ridge Mine
Mining Type: Underground

10. PENN RIDGE RESERVES
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Longwall

& Continuous Miner

Coal Type: High-Sulfur
Transportation: Barge & Railroad

11. 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:

12. MOUNT VERNON TRANSFER TERMINAL

Mining Type: Underground Mining Access: Slope & Shaft Mining Method: Continuous Miner Coal Type: Medium/High-Sulfur Transportation: Barge, Railroad & Truck	Mining Type: Underground Mining Access: Slope & Shaft Mining Method: Continuous Miner Coal Type: Medium/High-Sulfur Transportation: Barge & Truck	Mining Access: Slope & Shaft Mining Method: Longwall & Continuous Miner Coal Type: Medium/High-Sulfur Transportation: Barge & Railroad	Rail or Truck to Ohio River Barge Transloading Facility

Illinois Basin Operations

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois and southern Indiana. As of December 31, 2018, we had 2,331 employees, and we operate five active mining complexes in the Illinois Basin.

Hamilton Mining Complex. Our subsidiary, Hamilton County Coal, LLC ("Hamilton"), operates the Hamilton mine, located near the city of McLeansboro in Hamilton County, Illinois. The Hamilton mine 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, longwall mining began in October 2014 and we acquired complete ownership and control in 2015. Hamilton's preparation plant 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

Table of Contents

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.

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 United States. 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 medium/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 United States and state highways directly to customers or potentially 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 United States 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 also 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 December 2015 in response to market conditions but resumed production in May 2018. The Gibson North mine's preparation plant has throughput capacity of 700 tons of raw coal per hour. Production from the Gibson North mine is shipped by truck on United States and state highways or transported by rail on the CSX and NS railroads directly to customers or to various transloading facilities for barge delivery.

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's preparation plant 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 United States and state highways directly to customers or potentially to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries. In July 2018, Warrior completed the transition from the No. 11 seam to the No. 9 seam.

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 was operated by our subsidiary, Sebree Mining, LLC ("Sebree"). The Onton mine was idled in November 2015 in response to market conditions. For information regarding Onton's remaining coal reserves, please read "Item 2. Properties – Coal Reserves".

Alliance Resource Properties. Alliance Resource Properties and its subsidiaries own or control 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 Resources LLC the rights to approximately 309.6 million tons of proven and probable medium/high-sulfur coal reserves.

Other. In December 2014 and February 2015, WKY CoalPlay, LLC or its subsidiaries ("WKY CoalPlay"), which are related parties, entered into coal lease agreements with us regarding coal reserves located in Henderson and Union

Table of Contents

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 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. We are currently performing reclamation activities at the complex. For information regarding Pattiki's remaining coal reserves, please read "Item 2. Properties – Coal Reserves".

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 in April 2016. For information regarding Hopkins' remaining coal reserves, please read "Item 2. Properties – Coal Reserves".

Appalachian Operations

Our Appalachian mining operations are located in eastern Kentucky, Maryland and West Virginia. As of December 31, 2018, we had 881 employees, and we operate three mining complexes in Appalachia with one mine currently under development.

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 2018 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 United States and state highways directly to customers or to various docks on the Big Sandy River for barge deliveries. MC Mining's Excel Mine No. 4 is anticipated to deplete its reserves in 2020.

Our subsidiary, Excel, has begun development activity for MC Mining's Excel Mine No. 5 and currently anticipates deploying total capital of approximately $45.0 million to $50.0 million over the next 12 to 18 months. MC Mining controls the estimated 15 million tons of coal reserves assigned to the Excel Mine No. 5 and Excel will conduct all mining operations. The underground operation will utilize continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal with an expected annual production capacity of 1.3 million tons. MC

Mining plans to utilize its existing underground mining equipment and preparation plant to produce and process coal from the Excel Mine No. 5 and expects to ship coal produced from the mine to various transloading facilities on the Ohio River and the Big Sandy River for barge deliveries or directly to customers via the CSX railroad and by truck. We expect the development plan for the new Excel Mine No. 5 will provide a seamless transition from the current MC Mining operation.

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 with connections to the CSX and the NS railroads.

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)

Table of Contents

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.

Penn Ridge. Our subsidiary, Penn Ridge Coal, LLC ("Penn Ridge"), holds coal reserves in Washington County, Pennsylvania, estimated to include approximately 56.7 million tons of proven and probable high-sulfur coal in the Pittsburgh No. 8 seam. Development of the project is regulatory and market dependent, and its timing is open-ended pending obtaining all required regulatory approvals, sufficient coal sales commitments to support the project and final approval by the Board of Directors.

Royalty Operations

AllDale Partnerships

On November 10, 2014, Cavalier Minerals, in which Alliance Minerals, LLC ("Alliance Minerals") owns a 96.0% non-managing member interest, acquired a 71.7% limited partner interest in AllDale I and subsequently acquired a 72.8% limited partner interest in AllDale II. AllDale I & II were created to acquire oil & gas mineral interests in various geographic locations within producing basins in the continental United States. In February 2017, our subsidiary, Alliance Minerals, committed to directly invest $30.0 million in AllDale Minerals III, LP ("AllDale III") and as of December 31, 2018, Alliance Minerals had no remaining commitment to AllDale III. AllDale III was created to acquire oil & gas minerals in the same geographical locations as AllDale I & II. AllDale III, together with AllDale I & II are considered the ("AllDale Partnerships.")

As discussed in the AllDale I & II Acquisition section above, on January 3, 2019, ARLP acquired the AllDale I & II general partner interests and all of the limited partner interests in AllDale I & II not owned by Cavalier Minerals. As a result of the Acquisition and our previous investment held through Cavalier Minerals, ARLP now owns 100% of the general partner interests and approximately 97% of the limited partner interests in AllDale I & II. AllDale I & II control approximately 43,000 net royalty acres strategically positioned in the core of the Anadarko (SCOOP/STACK), Permian (Delaware and Midland), Williston (Bakken) and Appalachian basins. As of January 3, 2019, there were 3,823 gross producing wells generating production net to ARLP's interest of approximately 2,523 barrels of oil equivalent per day. In addition, there were 529 wells being drilled on ARLP's acreage and another 903 permitted well locations.

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 2018, the terminal loaded approximately 6.5 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 United States, 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 2018, 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 Matrix Design in September 2006.

Table of Contents

Compression Investment

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 February 8, 2019, Kodiak redeemed the preferred interests held by Alliance Minerals for $135.0 million cash which is inclusive of an early redemption premium.

Additional Services

We develop and market additional services in order to establish ourselves as the supplier of choice for our customers. Historically, and in 2018, outside revenues from these services were immaterial.

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 2018 approximately 69.1% and 68.9% 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 2019 to 2026. As of February 14, 2019, our nominal commitment under long-term contracts was approximately 17.3 million tons in 2019 and 17.2 million tons in 2020. 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.

The international coal market has been a substantial part of our business with indirect sales to end users in Europe, Africa, Asia, North America and South America. Our sales into the international coal market are considered exports and are made through brokered transactions. During the years ended December 31, 2018, 2017 and 2016, export tons represented approximately 27.8%, 17.4% and 4.5% of tons sold, respectively. We use the end usage point as the basis for attributing tons to individual countries. Because title to our export shipments typically transfers to our brokerage customers at a point that does not necessarily reflect the end usage point, we attribute export tons to the country with the end usage point, if known.

Reliance on Major Customers

During 2018, we derived approximately 10.9% of our total revenues from Louisville Gas and Electric Company. We did not derive 10.0% or more of our total revenues from any other individual customer during 2018. For more information about this customer, please read "Item 8. Financial Statement and Supplemental Data – Note 20 – Concentration of Credit Risk and Major Customers."

Competition

The coal industry is intensely competitive. The most important factors on which we compete are coal price, coal quality (including sulfur and heat content), transportation costs from the mine to the customer and the reliability and diversity of supply. We are currently the second largest coal producer in the eastern United States. 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.

In addition, we compete with companies that produce coal from one or more foreign countries. 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. We export a significant 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 global supply and demand, among others. Potential changes to international trade agreements, trade concessions or other political and economic arrangements may benefit coal producers operating in countries other than the United States. We may be adversely impacted on the basis of price or other factors with companies that in the future may benefit from favorable foreign trade policies or other arrangements. In addition, coal is sold internationally in United States dollars and, as a result, general economic conditions in foreign markets and changes in foreign currency exchange rates may provide our foreign competitors with a competitive advantage. If our competitors' currencies decline against the United States dollar or against foreign purchasers' local currencies, those competitors may be able to offer lower prices for coal to those purchasers. Furthermore, if the currencies of overseas purchasers were to significantly decline in value in comparison to the United States dollar, those purchasers may seek decreased prices for the coal we sell to them. Consequently, currency fluctuations could adversely affect the competitiveness of our coal in international markets, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Further, coal competes with other fuels such as natural gas, nuclear energy, petroleum and renewable energy sources for electrical power generation. Costs and other factors, such as safety and environmental considerations, have affected and may continue to affect the overall demand for coal as a fuel.

For additional information, please see "Item 1A. Risk Factors."

Transportation

Our coal is transported to our customers by barge, rail 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 41.1% of our 2018 sales volume was initially shipped from the mines by barge, 37.3% was shipped from the mines by rail and 21.6% was shipped from the mines by truck. 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 promptly remediate any identified condition. 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.

Table of Contents

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 United States 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 implemented 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. On July 9, 2018, MSHA published a request for information to solicit stakeholder comments, data, and information for the development of a framework to conduct a retrospective study on the impact of the final rule, as well as a request for information and data on engineering controls and best practices used by mine operators to lower miners' exposure to respirable coal dust. The comment period for this request for information will close on July 9, 2019. It is uncertain whether MSHA will present additional proposed rules, or revisions to the final rule, following the closing of the comment period for the current request for information.

Table of Contents

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, or if, 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. The comment period was reopened again in March 2018 and is scheduled to close in March 2019. 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.

In June 2018, MSHA published a request for information on Safety Improvement Technologies for Mobile Equipment at Surface Mines and for Belt Conveyors at Surface and Underground Mines. The comment period for the request for information closed on December 24, 2018. It is uncertain whether MSHA will present a proposed rule pertaining to safety improvement technologies for mobile equipment at surface mines or for belt conveyors at surface and underground mines.

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 levied a tax on coal sold 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. The coal we sell into international markets is generally not subject to this tax. 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. The Emergency Economic Stabilization Act of 2008 extended these rates through December 31, 2018. As of January 1, 2019, the excise tax rates have reverted to their original 1977 statutory levels of $0.50 per ton for underground-mined coal and $0.25 per ton for surface mined coal, but not to exceed 2% of the applicable sales price.

Table of Contents

Workers' Compensation and Black Lung

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. We generally self-insure this potential expense using our actuary estimates of the cost of present and future claims. In addition, 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 also 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. 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."

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.

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 Alliance Resource Holdings, Inc. ("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.

Table of Contents

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 United States 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 United States District Court for the District of Columbia. OSM reimplemented the 1983 SBZ rule. Subsequent attempts by OSM to issue a revised stream protection rule met with Congressional opposition, ultimately resulting in the passage of a resolution under the Congressional Review Act that revoked OSM's stream protection rule and prevents the agency from promulgating a substantially similar rule absent future legislation. Whether Congress will enact future legislation to require a new stream protection rule remains uncertain.

In December 2009, the United States Environmental Protection Agency ("EPA") issued proposed rules on coal combustion residues ("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.

Table of Contents

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 630 coal-fired electric generating units through 2030 in the United States.

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 2018, we sold 68.2% of our total tons to electric utilities in the United States, 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 United States 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 United States 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, the 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. In December 2018, the EPA determined that the CSAPR Update rule satisfies "good neighbor" obligations for the 2008 national ambient air quality standards ("NAAQS") for ground-level ozone. Litigation is pending 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 United States 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 the EPA's request to cancel oral arguments and ordered the case held in abeyance for an EPA review of the supplemental finding. In December 2018, the EPA issued a proposed Supplemental Cost Finding, as well as the CAA required "risk and technology review." 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 rule has forced 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. In March 2018, the D.C. Circuit affirmed the rule's startup and shutdown work practice standards but remanded a portion of the rule to reconsider the EPA's decision to adopt the 130 ppm carbon monoxide limits. 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 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, the 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. Various industry and state petitioners have filed challenges to the final rule 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 the 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, the 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, the EPA proposed to retain the current NAAQS for nitrogen oxides. The comment period for the proposal closed in September 2017. In June 2018, the EPA proposed to retain the existing sulfur oxide standards. The comment period for the proposal closed in August 2018. 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.

Table of Contents

- 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 prior 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. In June 2018, the EPA proposed to retain the existing sulfur oxide standards. The comment period for the proposal closed in August 2018.

- 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. In addition, there are proposals to modify the NSR program as a part of the Affordable Clean Energy ("ACE") rule which is subject to current pending litigation as discussed below. 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 United States could occur pursuant to future United States 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 United States 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 United States would withdraw from the Paris Agreement, which has a four year exit process. Future participation in the Paris Agreement by the United States 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. Others have announced their intent to increase the use of renewable energy sources, displacing coal and other fossil fuels. 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 United States 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 United States Supreme Court invalidated the EPA's position that power plants and other sources can be subject to permitting requirements based on their GHG emissions alone. For CO2 BACT to apply, CAA permitting must be triggered by another regulated pollutant (e.g., SO2).

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. CO2/MWh, which is equivalent to the carbon dioxide emitted by a natural gas combined cycle unit. In January 2014, the EPA formally published its re-proposed NSPS for carbon dioxide emissions from new power plants. The re-proposed rule requires an emissions standard of 1,100 lbs. CO2/MWh for new coal-fired power plants. To meet such a standard, new coal plants would be required to install carbon capture and storage ("CCS") technology. In August 2015, the EPA released final rules requiring newly constructed coal-fired steam electric generating units ("EGUs") to emit no more than 1,400 lbs CO2/MWh (gross) and be constructed with CCS to capture 16% of CO2 produced by an electric generating unit burning bituminous coal. At the same time, the EPA finalized GHG emissions regulations for modified and existing power plants. The rule for modified sources required reducing GHG emissions from any modified or reconstructed source and could limit the ability of generators to upgrade coal-fired power plants thereby reducing the demand for coal. 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 United States 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. In December 2018, the EPA re-proposed the NSPS with a standard reflecting the performance of currently demonstrated supercritical technologies with an emission limit of 1,900 lbs. CO2/MWh for large units (heat input greater than 2,000 MMBtu/hour) and subcritical technologies with an emission limit of 2,000 lbs. CO2/MWh for small units. 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 United States 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 the EPA's regulations for CO_2 emissions from existing power plants and will not affect the 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 the 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, the 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. In August 2018, the EPA proposed the ACE rule to replace the CPP with a rule that utilizes heat rate improvement measures as the "best system of emission reduction". The ACE rule adopts new implementing regulations under the CAA to clarify the roles of the EPA and the states, including an extension of the deadline for state plans and EPA approvals; and, the rule revises the NSR permitting program to provide EGUs the opportunity to make efficiency improvements without triggering NSR permit requirements. The EPA's attempts to replace the CPP with the ACE rule are currently subject to litigation, and we cannot predict the final outcome.

Notwithstanding the ACE rule, 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. Several states have announced their intent to have renewable energy comprise 100% of their electric generation portfolio. 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 United States 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 United States 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; however, the potential remains for CEQ to issue similar guidance in the future.

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 is expected to rejoin RGGI and the recently elected governors of Pennsylvania and Virginia have expressed interest in joining RGGI.

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 United States 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

Table of Contents

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. Also, recently activist shareholders have made attempts to pressure large financial institutions to restrict access to capital for the fossil fuel industry.

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 United States 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 United States 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 United States 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 United States 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. In June 2018, the EPA Administrator issued

Table of Contents

a memorandum directing the EPA's Office of Water to promulgate draft regulations eliminating the use of the EPA's Section 404 authority before a Section 404 permit application has been filed, or after a permit has been issued. To date, the EPA has not issued a proposed rule.

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 CWA. A 2015 rulemaking by the EPA to revise the standard was stayed nationwide by the United States 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, the EPA has promulgated a final rule that extends the applicability date of the 2015 rule for another two years in order to allow the 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, the 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 the 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. In December 2018, the EPA issued a proposed rule to revise the definition "to increase CWA program predictability and consistency by increasing clarity as to the scope of 'waters of the United States' federally regulated under the Act." Litigation surrounding these developments is ongoing and we cannot predict the outcome at this time.

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.

Table of Contents

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. The 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 United States 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, the 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, the EPA granted petitions for reconsideration and an administrative stay of all future compliance deadlines for the ELG rule. In August 2017, the EPA granted petitions for reconsideration of the CCR rule. In July 2018, the EPA published a final rule to revise requirements and extend the deadlines from the 2015 rule. In August 2018, the DC Circuit issued a decision that imposed additional restrictions and addressed all remaining issues in the litigation on the 2015 CCR rule. This court decision could make it more difficult for the EPA to reform the 2015 rule.

Endangered Species Act

The federal ESA and counterpart state legislation protect species threatened with possible extinction. The United States 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.

Regulation of the Oil & Gas Industry

Oil, natural gas and NGL exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. While we are not the operator for oil & gas activities associated with our mineral interests, these laws and regulations have the potential to impact production on our properties, including requirements to:

- obtain permits to conduct regulated activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- restrict the types, quantities and concentration of materials that can be released into the environment in the performance of drilling and production activities;
- initiate investigatory and remedial measures to mitigate pollution from former or current operations, such as restoration of drilling pits and plugging of abandoned wells; and

Table of Contents

· apply specific health and safety criteria addressing worker protection.

Failure to comply with environmental laws and regulations may result in the assessment of administrative, civil and criminal sanctions, including monetary penalties, the imposition of strict, joint and several liability, investigatory and remedial obligations and the issuance of injunctions limiting or prohibiting some or all of the operations on our properties. Moreover, these laws, rules and regulations may restrict the rate of oil, natural gas and NGL production below the rate that would otherwise be possible. The regulatory burden on the oil & gas industry increases the cost of doing business in the industry and consequently affects profitability. The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly construction, drilling, water management, completion, emission or discharge limits or waste handling, disposal or remediation obligations could increase the cost to our operators of developing our properties. Moreover, accidental releases or spills may occur in the course of operations on our properties, causing our operators to incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. Increased costs or operating restrictions on our properties as a result of compliance with or liability under environmental laws could result in reduced exploratory and production activities on our properties and thus adversely affect the income those properties generate.

Employees

To conduct our operations, as of December 31, 2018, we employed 3,599 full-time employees, including 3,212 employees involved in active mining operations, 212 employees in other operations, and 175 corporate employees. Our work force is entirely union-free.

Administrative Services

On April 1, 2010, effective January 1, 2010, ARLP entered into an administrative services agreement ("Administrative Services Agreement") with our general partner, the Intermediate Partnership, AGP, AHGP and Alliance Resource Holdings II, Inc. ("ARH II"). Under the Administrative Services Agreement, certain employees, including some executive officers, provided administrative services for AHGP, AGP and ARH II and their respective affiliates. Prior to the Simplification Transactions, we were 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, 2018 of $0.2 million from AHGP. In conjunction with the Simplification Transactions, we discontinued the Administrative Service Agreement.

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.

Table of Contents

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, including unit repurchases;
· our debt service requirements and restrictions on distributions contained in our current or future debt agreements;
· fluctuations in our working capital needs;
· the amount of revenues we generate from our oil & gas interests;
· 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 9 – 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.

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.

Table of Contents

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

Our unitholders do not elect our general partner or vote on our general partner's officers or directors.

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.

Our 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, the Chairman, President and CEO 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.

Table of Contents

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. 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.

Table of Contents

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 United States 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;

Table of Contents

- the effect of worldwide energy consumption, including the impact of technological advances on energy consumption;
- overall domestic and global economic conditions;
- international developments impacting supply of coal, including supply side reforms promulgated in China and continued expected growth in demand for seaborne coal in India; and
- the impact of domestic and foreign governmental laws and regulations, including environmental and climate change regulations and regulations affecting the coal mining industry and coal-fired power plants, and delays in the receipt of, failure to receive, failure to maintain or revocation of necessary governmental permits.

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. In addition, foreign currency fluctuations could adversely affect the competitiveness of our coal abroad.

We compete with other coal producers in various regions of the United States 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.

We sell coal to the export thermal and metallurgical coal market, both of which are significantly affected by international demand and competition. The coal industry has experienced consolidation in recent years, including consolidation among some of our major competitors. Current or further consolidation in the coal industry or current or future bankruptcy proceedings of coal competitors may adversely affect us. In addition, increases in coal prices could encourage existing producers to expand capacity or could encourage new producers to enter the market. If overcapacity results, the prices of and demand for our coal could significantly decline, which could have a material adverse effect on our business, financial condition, results of operations and cash flows and could reduce our revenues and cash available for distribution.

In addition, we face competition from foreign producers that sell their coal in the export market. Potential changes to international trade agreements, trade concessions or other political and economic arrangements may benefit coal producers operating in countries other than the United States. We may be adversely impacted on the basis of price or other factors with companies that in the future may benefit from favorable foreign trade policies or other arrangements. In addition, coal is sold internationally in United States dollars and, as a result, general economic conditions in foreign markets and changes in foreign currency exchange rates may provide our foreign competitors with a competitive advantage. If our competitors' currencies decline against the United States dollar or against foreign purchasers' local currencies, those competitors may be able to offer lower prices for coal to those purchasers. Furthermore, if the currencies of overseas purchasers were to significantly decline in value in comparison to the United States dollar, those purchasers may seek decreased prices for the coal we sell. Consequently, currency fluctuations could adversely affect the competitiveness of our coal in international markets, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Table of Contents

New tariffs and other trade measures could adversely affect our results of operations, financial position and cash flows.

New tariffs and other trade measures could adversely affect our results of operations, financial position and cash flows. Recently, the Trump Administration imposed tariffs on steel and aluminum and a broad range of other products imported into the United States. In response to the tariffs imposed by the United States, the European Union, Canada, Mexico and China have announced tariffs on United States goods and services. The new tariffs, along with any additional tariffs or trade restrictions that may be implemented by the United States or retaliatory trade measures or tariffs implemented by other countries, could result in reduced economic activity, increased costs in operating our business, reduced demand and changes in purchasing behaviors for thermal and metallurgical coal, limits on trade with the United States or other potentially adverse economic outcomes. Additionally, we sell coal into the export thermal and metallurgical markets. Accordingly, our international sales may also be impacted by the tariffs and other restrictions on trade between the United States and other countries. While tariffs and other retaliatory trade measures imposed by other countries on United States goods have not yet had a significant impact on our business or results of operations, we cannot predict further developments, and such existing or future tariffs could have a material adverse effect on our results of operations, financial position and cash flows and 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 United States electricity production has fallen from 53% to 27%, while natural gas' share has increased from 16% to 35%.

The domestic electric utility industry accounts for over 92.7% 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 United States 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 United States Please read "Item 1. Business—Regulation and Laws—Air Emissions," "—Carbon Dioxide Emissions" and "—Hazardous Substances and Wastes."

Table of Contents

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 December 2018, the EPA re-proposed the NSPS with a standard reflecting the performance of currently demonstrated supercritical technologies with an emission limit of 1,900 lbs. CO_2/MWh for large units (heat input greater than 2,000 MMBtu/hour) and subcritical technologies with an emission limit of 2,000 lbs. CO_2/MWh for small units. 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 United States 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 the EPA's regulations for CO_2 emissions from existing power plants and will not affect the 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 the 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, the EPA issued an ANPRM in December 2017 regarding emission guidelines to limit GHG emissions from existing electricity utility generating units. In August 2018, the EPA proposed the ACE rule to replace the CPP with a rule that utilizes heat rate improvement measures as the "best system of emission reduction". The ACE rule adopts new implementing regulations under the CAA to clarify the roles of the EPA and the states, including an extension of the deadline for state plans and EPA approvals; and, the rule revises the NSR permitting program to provide EGUs the opportunity to make efficiency improvements without triggering NSR permit requirements. If the effort to replace the NSPS and CPP is unsuccessful and the rules were upheld at the conclusion of this appellate process and were implemented in their current form, 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.

Governments, both domestic and foreign, 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 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 United States, 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.

Internationally, a growing number of countries are passing new laws and regulations that could have an adverse impact on demand for coal. For example, China's latest five-year plan calls for reducing the share of coal in terms of the country's total energy consumption to 58 percent by 2020 from 64 percent in 2015. The plan also calls for China to increase the share of electricity it generates from nuclear and renewable energy sources to 20 percent. Separately, in Europe, multiple countries have announced their intent to phase out existing coal-fired power plants between 2025 and 2030. In addition, in December 2018, the European Union announced that it would be phasing out subsidies for coal plants unless facilities meet a performance standard of 550 grammes of CO2 per kilowatt hour. All of these developments have the potential to adversely impact demand for coal in international markets.

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 requires California's state pension funds to divest investments in companies that generate 50% or more of their revenue from coal mining. 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 630 coal-fired electric generating units through 2030. These retirements and conversions amount to nearly 120,000 megawatts ("MW") or almost 40% of the 2010 total coal electric generating capacity. At the end of 2018 retirement and conversions affecting more than 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 United States Supreme Court issued a unanimous decision holding that the plaintiffs' federal common law claims were displaced by federal legislation and regulations. The United States 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 United States 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 2018, we sold approximately 69.1% 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.

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.

During 2018, we derived approximately 10.9% of our total revenues from Louisville Gas and Electric Company. If we were to lose this or 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."

Table of Contents

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, 2018, 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 60, 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

Table of Contents

of small shipments, the steeper average grades of the terrain and a more unionized workforce are all issues that combine to make coal shipments originating in the eastern United States inherently more expensive on a per-mile basis than coal shipments originating in the western United States. Historically, high coal transportation rates from the western coal producing areas into certain eastern markets limited the use of western coal in those markets. Lower rail rates from the western coal producing areas to markets served by eastern United States 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. At times, 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 constraints in the capital markets as well as numerous other factors, including higher than anticipated capital expenditures or lower than

Table of Contents

expected cash flow from operations. In addition, we may be unable to refinance our current debt obligations 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 United States, which could affect the mining operations and cost structures of these areas.

The geological characteristics of some of our coal reserves, such as depth of overburden and coal seam thickness, make them difficult and costly to mine. As mines become depleted, replacement reserves may not be available when required or, if available, may not be mineable at costs comparable to those characteristic of the depleting mines. In

Table of Contents

addition, permitting, licensing and other environmental and regulatory requirements associated with certain of our mining operations are more costly and time-consuming to satisfy. Subsidence issues are particularly important to our operations engaged in longwall mining. Failure to timely and economically secure subsidence rights or any associated mitigation agreements could materially affect our results by causing delays or changes in our mining plan. 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 and revolving credit facility. At December 31, 2018, our total long-term indebtedness outstanding was $677.0 million. Our leverage may:

- adversely affect our ability to finance future operations and capital needs;

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

In addition, we have unused borrowing capacity under our revolving credit facility. Future borrowings, under our credit facilities or otherwise, could result in 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 6 – Long-Term Debt" for further discussion.

Table of Contents

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, 2018, our total of such bonds was $269.6 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 & gas industry could affect our profitability and distributable cash flow.

We have investments in oil & gas mineral interests in the continental United States. Consequently, the value of the investments as well as any resulting cash flows, may fluctuate with changes in the market and prices for oil & gas. Since we began these investments in late 2014, the oil & 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 United States. 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 in these matters, please read "Item 8. Financial Statements and Supplementary Data—Note 10— Investments."

We depend on unaffiliated operators for all of the exploration, development and production on the oil & gas properties in which we own mineral interests.

Because we depend on our third-party operators for all of the exploration, development and production on our oil & gas properties, we have no control over the operations related to our oil & gas properties. The operators of our properties are often not obligated to undertake any development activities. In the absence of a specific contractual obligation, any development and production activities will be subject to their sole discretion (subject, however, to certain implied obligations to develop imposed by state law). The success and timing of drilling and development activities on our oil & gas properties, and whether the operators elect to drill any additional wells on our acreage, depends on a number of factors that will be largely outside of our control, including:

- the capital costs required for drilling activities by the operators of our oil & gas properties, which could be significantly more than anticipated;
- the ability of the operators of our properties to access capital;
- prevailing commodity prices;
- the availability of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;

Table of Contents

- the operators' expertise, operating efficiency and financial resources;
- approval of other participants in drilling wells;
- the operators' expected return on investment in wells drilled on our acreage as compared to opportunities in other areas;
- the selection of technology;
- the selection of counterparties for the marketing and sale of production; and
- the rate of production of the reserves.

The operators may elect not to undertake development activities, or may undertake these activities in an unanticipated fashion, which may result in significant fluctuations in our oil & gas revenues and cash available for distribution.

Oil, natural gas and NGL operations are subject to various governmental laws and regulations. Compliance with these laws and regulations can be burdensome and expensive for our operators, and failure to comply could result in our operators incurring significant liabilities, either of which may impact our operators' willingness to develop our interests.

Our operators' operations on the properties in which we hold interests are subject to various federal, state and local governmental regulations that may change from time to time in response to economic and political conditions. Matters subject to regulation include drilling operations, production and distribution activities, discharges or releases of pollutants or wastes, plugging and abandonment of wells, maintenance and decommissioning of other facilities, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil & gas wells below actual production capacity to conserve supplies of oil, natural gas and NGLs. In addition, the production, handling, storage and transportation of oil, natural gas and NGLs, as well as the remediation, emission and disposal of oil, natural gas and NGL wastes, by-products thereof and other substances and materials produced or used in connection with oil, natural gas and NGL operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of worker health and safety, natural resources and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions on our operators, including administrative, civil or criminal penalties, permit revocations, requirements for additional pollution controls and injunctions limiting or prohibiting some or all of our operators' operations on our properties. Moreover, these laws and regulations have generally imposed increasingly strict requirements related to water use and disposal, air pollution control and waste management. Laws and regulations governing exploration and production may also affect production levels. Our operators must comply with federal and state laws and regulations governing conservation matters, including:

- provisions related to the unitization or pooling of the oil & gas properties;
- the establishment of maximum rates of production from wells;
- the spacing of wells;
- the plugging and abandonment of wells; and
- the removal of related production equipment.

Additionally, federal and state regulatory authorities may expand or alter applicable pipeline-safety laws and regulations, compliance with which may require increased capital costs for third-party oil, natural gas and NGL transporters. These transporters may attempt to pass on such costs to our operators, which in turn could affect profitability on the properties in which we own mineral and royalty interests.

Our operators must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent the operators of our properties are shippers on interstate pipelines, they must comply with the tariffs of those pipelines and with federal policies related to the use of interstate capacity. Our operators may be required to make significant expenditures to comply with the governmental laws and regulations described above and may be subject to potential fines and penalties if they are found to have violated these laws and regulations. We believe the trend of more expansive and stricter environmental legislation and regulations will continue. These current laws and regulations and other potential regulations could increase the operating costs of our operators and delay production and may ultimately impact our operators' ability and willingness to develop our properties.

Table of Contents

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 United States. Deliberate attacks on, or security breaches in, our systems or infrastructure, or the systems or infrastructure of third parties 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.

Tax Risks to Our Common Unitholders

Our tax treatment depends on our status as a partnership for federal income 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 United States 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 United States federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations and current Treasury Regulations, 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 United States federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for United States federal income tax purposes, we would pay United States 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 United States 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 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 United States

Table of Contents

federal income tax purposes. Although there are no current legislative or administrative proposals, there can be no assurance that there will not be further changes to United States federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a publicly traded partnership in the future.

Any modification to the United States 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 United States 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,

Table of Contents

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.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion. If our "business interest" is subject to limitation under these rules, our unitholders will be limited in their ability to deduct their share of any interest expense that has been allocated to them. As a result, unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

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 United States federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. With respect to taxable years beginning after December 31, 2017, subject to the proposed aggregation rules for certain similarly situated businesses or activities issued by the Treasury Department, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) 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-United States Unitholders will be subject to United States taxes and withholding with respect to their income and gain from owning our units.

Non-United States unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a United States 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 United States trade or business. As a result, distributions to a Non-United States unitholder will be subject to withholding at the highest applicable effective tax rate and a Non-United States unitholder who sells or otherwise disposes of a unit will also be subject to United States 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-United States unitholder's sale or exchange of an interest in a partnership that is engaged in a United States 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-United States 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 have adopted certain methods for allocating depreciation and amortization deductions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to the use of these methods 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 (i) certain deductions for depreciation of capital additions, (ii) gain or loss realized on a sale or other disposition of our assets, and (iii) 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. 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 United States 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 methodologies 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.

Table of Contents

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 United States 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 United States 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 United States federal, state and local tax returns and pay any taxes due in these jurisdictions. You should consult with your tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

ITEM 1B.UNRESOLVED STAFF COMMENTS

None.

Table of Contents

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, 2018, we had approximately 1.70 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 United States 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, 2018 about our coal operations:

	Mine Type (1)	Heat Content (BTUs per pound)	Pounds S02 per MMBTU <1.2 (tons in millions)	1.2-2.5	>2.5	Total	Classification Proven	Probable	Reserve Assignment Assigned	Unassigned	Reserve Owned
	U	12,100	—	4.0	73.8	77.8	52.3	25.5	37.4	40.4	27.2
	U	12,300	—	—	93.4	93.4	72.7	20.7	93.4	—	22.9
)	U	12,000	—	—	13.9	13.9	9.7	4.2	—	13.9	4.4

	S	11,500	—	—	7.8	7.8	7.8	—	7.8	—	7.8
XY)	U	11,500	—	—	236.2	236.2	117.3	118.9	236.2	—	68.8
nion											
	U	11,400	—	5.7	421.0	426.7	159.3	267.4	—	426.7	59.5
	U	11,750	—	—	40.3	40.3	22.6	17.7	40.3	—	0.2
nty											
	U	11,650	—	—	545.8	545.8	237.8	308.0	134.6	411.2	52.9
n)											
	U	11,500	—	8.2	15.8	24.0	18.7	5.3	24.0	—	0.7
n)											
	U	11,500	1.6	15.9	42.9	60.4	51.4	9.0	60.4	—	18.4
			1.6	33.8	1,490.9	1,526.3	749.6	776.7	634.1	892.2	262.8
	U	12,600	13.7	2.4	1.7	17.8	12.6	5.2	15.6	2.2	—
)	U	13,200	—	1.6	3.7	5.3	5.2	0.1	5.3	—	—
)	U	13,200	—	7.6	8.3	15.9	10.9	5.0	9.9	6.0	1.7
e											
	U	12,600	—	—	77.7	77.7	33.2	44.5	77.7	—	—
	U	12,500	—	—	56.7	56.7	5.8	50.9	56.7	—	56.7
			13.7	11.6	148.1	173.4	67.7	105.7	165.2	8.2	58.4
			15.3	45.4	1,639.0	1,699.7	817.3	882.4	799.3	900.4	321.2
			0.9%	2.7%	96.4%	100.0%	48.1%	51.9%	47.0%	53.0%	18.9%

(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 adheres 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

Table of Contents

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 13.7 million tons of reserves listed at MC Mining as <1.2 pounds of SO2 per million British thermal units ("MMBTU") are marketable as compliance coal under Phase II of CAA.

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

We own or control certain leases for coal deposits that do not currently meet the criteria to be reflected as reserves but may be reclassified as reserves in the future. These tons are classified as non-reserve coal deposits and are not included in our reported reserves. These non-reserve coal deposits include the following: Mettiki—2.9 million tons, Tunnel Ridge—16.7 million tons, Hamilton—33.7 million tons, Warrior—4.5 million tons, Dotiki—0.5 million tons, Onton mine—4.6 million tons, Sebree—7.0 million tons, Riverview—3.1 million tons, Gibson (South)—0.6 million tons, Elk Creek— million tons and Pattiki—48.4 million tons. The Henderson/Union Reserves account for the majority of our non-reserve coal deposits with 191.3 million tons. In addition, there are 17.1 million tons located near our Dotiki complex for total non-reserve coal deposits of 335.3 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 2018	2017	2016	Transportation	Equipment
		(in millions)				
Illinois Basin Operations						
Dotiki	Kentucky	2.5	2.6	3.7	CSX, PAL, truck, barge	CM
Warrior	Kentucky	3.5	3.6	3.8	CSX, PAL, truck, barge	CM
Hopkins	Kentucky	—	—	0.4	CSX, PAL, truck, barge	CM
River View	Kentucky	9.8	9.0	8.6	Truck, barge	CM
Hamilton	Illinois	6.3	6.1	3.0	CSX, EVW, barge	LW, CM
Pattiki	Illinois	—	—	1.9	CSX, EVW, barge	CM
Gibson (North)	Indiana	0.9	—	—	CSX, NS, truck, barge	CM
Gibson (South)	Indiana	6.9	6.0	4.0	CSX, NS, truck, barge	CM
Region Total		29.9	27.3	25.4		
Appalachia Operations						
MC Mining	Kentucky	1.3	1.4	1.2	CSX, truck, barge	CM
Mettiki	WV, MD	2.3	2.1	2.0	CSX, truck	LW, CM
Tunnel Ridge	West Virginia	6.8	6.8	6.6	CSX, NS, barge	LW, CM
Region Total		10.4	10.3	9.8		
TOTAL		40.3	37.6	35.2		

Table of Contents

CSX	-	CSX Railroad
EVW	-	Evansville Western Railroad
NS	-	Norfolk Southern Railroad
PAL	-	Paducah & Louisville Railroad
CM	-	Continuous Miner
LW	-	Longwall

ITEM 3.LEGAL PROCEEDINGS

From time to time we are party to litigation matters incidental to the conduct of our business. 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.

Table of Contents

PART II

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

The common units representing limited partners' interests are listed on the NASDAQ Global Select Market under the symbol "ARLP." The common units began trading on August 20, 1999. There were approximately 41,765 record holders of common units at December 31, 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 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 minimum quarterly distribution ("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.

Unit Repurchase Program

On May 31, 2018, ARLP announced that the Board of Directors approved the establishment of a unit repurchase program authorizing ARLP to repurchase up to $100 million of its outstanding limited partner common units. The unit repurchase program is intended to enhance ARLP's ability to achieve its goal of creating long-term value for its unitholders and provides another means, along with quarterly cash distributions, of returning cash to unitholders. The program has no time limit and ARLP may repurchase units from time to time in the open market or in other privately negotiated transactions. The unit repurchase program authorization does not obligate ARLP to repurchase any dollar amount or number of units, and repurchases may be commenced or suspended from time to time without prior notice.

Table of Contents

The table below represents all unit repurchases for the three months ended December 31, 2018:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Program	Maximum Dollar Value that May Yet Be Used to Repurchase Units Under the Publicly Announced Program (in thousands)
October 1 through October 31, 2018	218,352	$ 19.49	218,352	$ 74,683
November 1 through November 30, 2018	1,276,920	$ 19.30	1,276,920	$ 50,042
December 1 through December 31, 2018	1,121,563	$ 18.40	1,121,563	$ 29,404
Total	2,616,835		2,616,835	

Since inception of the unit repurchase program, we have repurchased and retired 3,684,040 units at an average unit price of $19.16 for an aggregate purchase price of $70.6 million as of December 31, 2018. The remaining authorized amount for unit repurchases under this program was $29.4 million.

Table of Contents

ITEM 6.SELECTED FINANCIAL DATA

Our historical financial data below were derived from our audited consolidated financial statements as of and for the years ended December 31, 2018, 2017, 2016, 2015 and 2014.

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

	Year Ended December 31,				
	2018	2017	2016	2015	2014
Statements of Income					
Sales and operating revenues:					
Coal sales	$ 1,844.8	$ 1,711.1	$ 1,861.8	$ 2,158.0	$ 2,208.6
Transportation revenues	112.4	41.7	30.1	33.6	26.0
Other sales and operating revenues	45.7	43.4	39.6	82.1	66.1
Total revenues	2,002.9	1,796.2	1,931.5	2,273.7	2,300.7
Expenses:					
Operating expenses (excluding depreciation, depletion and amortization)	1,207.7	1,091.9	1,122.7	1,386.8	1,383.4
Transportation expenses	112.4	41.7	30.1	33.6	26.0
Outside coal purchases	1.5	—	1.5	0.3	—
General and administrative	68.3	61.8	72.6	67.5	72.5
Depreciation, depletion and amortization	280.2	269.0	336.5	324.0	274.6
Settlement gain	(80.0)	—	—	—	—
Asset impairment	40.5	—	—	100.1	—
Total operating expenses	1,630.6	1,464.4	1,563.4	1,912.3	1,756.5
Income from operations	372.3	331.8	368.1	361.4	544.2
Interest expense (net of interest capitalized)	(40.2)	(39.4)	(30.7)	(31.2)	(33.6)
Interest income	0.2	0.1	—	1.5	1.7
Equity method investment income (loss)	22.2	13.9	3.5	(49.0)	(16.7)
Equity securities income	15.7	6.4	—	—	—
Acquisition gain, net	—	—	—	22.5	—
Debt extinguishment loss	—	(8.1)	—	—	—
Other (expense) income	(2.6)	(0.3)	(1.4)	1.0	1.6
Income before income taxes	367.5	304.4	339.5	306.2	497.2
Income tax expense	0.0	0.2	—	—	—

Net income	367.5	304.2	339.5	306.2	497.2
Less: Net income attributable to noncontrolling interest	(0.9)	(0.6)	(0.1)	—	—
Net income attributable to Alliance Resource Partners, L.P. ("Net Income of ARLP")	$ 366.6	$ 303.6	$ 339.4	$ 306.2	$ 497.2
General Partners' interest in Net Income of ARLP (1)	$ 1.6	$ 21.9	$ 80.9	$ 146.3	$ 138.3
Limited Partners' interest in Net Income of ARLP	$ 365.0	$ 281.7	$ 258.5	$ 159.9	$ 358.9
Basic and diluted net income of ARLP per limited partner unit (2) (3)	$ 2.74	$ 2.80	$ 3.39	$ 2.11	$ 4.77
Pro forma basic and diluted net income of ARLP per limited partner unit (2) (4)	$ 2.73	$ 2.25	$ 2.51	$ 2.28	$ 3.71
Distributions paid per limited partner unit	$ 2.07	$ 1.88	$ 1.9875	$ 2.6625	$ 2.4725
Weighted-average number of units outstanding-basic and diluted	130,758,169	98,707,696	74,354,162	74,174,389	74,044,417
Balance Sheet Data:					
Working capital (5)	$ 169.8	$ (8.0)	$ (50.2)	$ (108.2)	$ (80.0)
Total assets	2,394.7	2,219.4	2,193.0	2,361.3	2,285.1
Long-term obligations (6)	574.6	473.0	485.0	658.6	606.9
Total liabilities	1,207.0	1,067.9	1,099.6	1,372.0	1,270.0
Partners' capital	$ 1,187.7	$ 1,151.5	$ 1,093.4	$ 989.3	$ 1,015.1
Other Operating Data:					
Tons sold	40.4	37.8	36.7	40.2	39.7
Tons produced	40.3	37.6	35.2	41.2	40.7
Coal sales per ton sold (7)	$ 45.64	$ 45.24	$ 50.76	$ 53.62	$ 55.59
Cost per ton sold (8)	$ 29.91	$ 28.87	$ 30.65	$ 34.46	$ 34.82
Other Financial Data:					
Net cash provided by operating activities	$ 694.3	$ 556.1	$ 703.5	$ 716.3	$ 739.2
Net cash used in investing activities	(245.2)	(244.8)	(191.8)	(355.9)	(441.2)
Net cash used in financing activities	(211.7)	(344.4)	(505.4)	(351.6)	(367.0)
EBITDA (9)	686.9	612.1	706.6	659.9	803.7
Adjusted EBITDA (9)	647.4	620.3	706.6	737.5	803.7
	$ 222.4	$ 140.0	$ 93.3	$ 236.3	$ 236.3

Maintenance capital expenditures (10)

(1) Amounts for 2018 reflect the impact of the Simplification Transactions which ended net income allocations and quarterly cash distributions to MGP after May 31, 2018. Amounts for 2017 reflect the impact of the Exchange

Table of Contents

Transaction ending distributions that would have been paid for the IDRs and a 0.99% general partner interest in ARLP, both of which were held by MGP prior to the Exchange Transaction. For the time period between the Exchange Transaction and the Simplification Transactions, MGP maintained a 1.0001% general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal and thus received quarterly distributions and income and loss allocations during this time period. See "Item 8. Financial Statements and Supplementary Data—Note 12. Net Income of ARLP Per Limited Partner Unit" for more information.

(2) 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, 2018, 2017, 2016, 2015 and 2014, long-term incentive plan ("LTIP"), Supplemental Executive Retirement Plan ("SERP") and Directors' compensation units of 1,658,908 1,466,404, 922,386, 734,171 and 798,701, respectively, were considered anti-dilutive.

(3) As a result of the Exchange Transaction, net income beginning with the second quarter of 2017 was not allocated to IDRs 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.

(4) On a pro forma basis, as if the Exchange Transaction and the Simplification Transactions had taken place on January 1, 2014, the reconciliation of net income of ARLP to basic and diluted earnings per unit and the weighted-average units used in computing EPU are as follows:

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(in thousands, except per unit data)				
Net income of ARLP	$ 366,604	$ 303,638	$ 339,398	$ 306,198	$ 497,229
Pro forma adjustments (a)	(1,265)	(1,943)	(2,985)	(2,013)	(4,544)
Pro forma net income of ARLP	365,339	301,695	336,413	304,185	492,685
Less:					
Distributions to participating securities	(5,114)	(4,339)	(3,391)	(3,493)	(2,956)
Undistributed earnings attributable to participating securities	(1,627)	(680)	(1,548)	—	(1,426)
Net income of ARLP available to limited partners (b)	$ 358,598	$ 296,676	$ 331,474	$ 300,692	$ 488,303
Weighted-average limited partner units outstanding – basic and diluted (b)	131,310	132,024	131,805	131,625	131,495
Pro forma basic and diluted net income of ARLP per limited partner unit	$ 2.73	$ 2.25	$ 2.51	$ 2.28	$ 3.71

(a) Pro forma adjustments to the net income of ARLP primarily represent the elimination of administrative service revenues from AHGP and the inclusion of general and administrative expenses incurred at AHGP.

(b) Net income of ARLP available to limited partners reflects net income allocations made for all periods presented based on the ownership structure subsequent to the Simplification Transactions. Accordingly, no general partner income allocations are presented above. Pro forma amounts above also reflect weighted average units outstanding as if the issuance of 56,128,141 ARLP common units in the Exchange Transaction and 1,322,388 ARLP common units in the Simplification Transactions applied to all periods presented.

(5) 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 6. Long-Term Debt."

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

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

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

(9) EBITDA and Adjusted EBITDA are financial measures not calculated in accordance with generally accepted accounting principles ("GAAP"). EBITDA is defined as net income attributable to ARLP 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).

Table of Contents

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,				
	2018	2017	2016	2015	2014
	(in thousands)				
Cash flows provided by operating activities	$ 694,345	$ 556,116	$ 703,544	$ 716,342	$ 739,201
Non-cash compensation expense	(12,114)	(12,326)	(13,885)	(12,631)	(11,250)
Asset retirement obligations	(3,926)	(3,793)	(3,769)	(3,192)	(2,730)
Coal inventory adjustment to market	(1,455)	(449)	—	(1,952)	(377)
Equity investment income (loss)	22,189	13,860	3,543	(49,046)	(16,648)
Distributions received from investments	(21,971)	(13,939)	(2,719)	—	—
Income from equity securities paid-in-kind	15,696	6,398	—	—	—
Net gain on sale of property, plant and equipment	1,285	696	76	1	4,409
Valuation allowance of deferred tax assets	1,560	3,339	1,365	(1,557)	(1,636)
Other	(3,171)	(6,212)	(3,300)	(6,388)	5,151
Net effect of working capital changes	(4,260)	37,640	(8,808)	66,159	55,659
Interest expense, net	40,059	39,291	30,659	29,694	31,913
Income tax expense	22	210	13	21	—
Settlement gain	(80,000)	—	—	—	—
Net (income) loss attributable to noncontrolling interests	(866)	(563)	(140)	27	16
Adjusted EBITDA	647,393	620,268	706,579	737,478	803,708
Settlement gain	80,000	—	—	—	—
Asset impairment	(40,483)	—	—	(100,130)	—
Acquisition gain, net	—	—	—	22,548	—
Debt extinguishment loss	—	(8,148)	—	—	—
EBITDA	686,910	612,120	706,579	659,896	803,708
Depreciation, depletion and amortization	(280,225)	(268,981)	(336,509)	(323,983)	(274,566)
Interest expense, net	(40,059)	(39,291)	(30,659)	(29,694)	(31,913)
Income tax expense	(22)	(210)	(13)	(21)	—
Net income attributable to ARLP	$ 366,604	$ 303,638	$ 339,398	$ 306,198	$ 497,229

(10) 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.

54

Table of Contents

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 natural resource company that generates income from coal production and oil & gas mineral interests located in strategic producing regions across the United States. We are currently the second-largest coal producer in the eastern United States with eight underground mining complexes in Illinois, Indiana, Kentucky, Maryland and West Virginia, as well as a coal-loading terminal in Indiana. In addition, we generate royalty income from mineral interests we own in premier oil & gas producing regions in the United States, primarily in the Anadarko, Permian, Williston and Appalachian basins.

Our mining operations are located near many of the major eastern utility generating plants and on major coal hauling railroads in the eastern United States. 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. As of December 31, 2018, we had approximately 1.70 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.

In 2018, we sold a record 40.4 million tons of coal and produced 40.3 million tons. The coal we sold in 2018 was approximately 28.1% low-sulfur coal, 40.1% medium-sulfur coal and 31.8% 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.

During 2018, approximately 68.2% of our tons sold were purchased by United States electric utilities and 27.8% were sold into the international markets through brokered transactions. The balance of tons sold were to third-party resellers and industrial consumers. Although many utility customers continue to favor a shorter-term contracting strategy, in 2018, approximately 69.1% 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 2018, approximately 78.8% of our medium- and high-sulfur coal was sold to utility plants with installed pollution control devices.

During 2018, our Alliance Minerals subsidiary indirectly held equity investments in AllDale I & II through its investment in Cavalier Minerals. Alliance Minerals also held directly an equity investment in AllDale III. The AllDale Partnerships hold royalty interests in premier basins concentrated in the SCOOP/STACK, Delaware Basin, Midland Basin and Bakken.

On January 3, 2019, we paid $176.0 million to acquire the general partner interests and all the limited partner interests not owned by Cavalier Minerals in AllDale I & II (the "Acquisition") giving us ownership of 100% of the general partner interest and approximately 97% of the limited partner interests in AllDale I & II. As of January 3, 2019, AllDale I & II controlled approximately 43,000 net royalty acres, including 3,823 gross producing wells, 529 wells being drilled and another 903 permitted well locations. The acquired interests will provide us with diversified exposure to industry-leading operators. For more information on the Acquisition see "Item 8. Financial Statement and Supplemental Data – Note 23 – Subsequent Events".

As of December 31, 2018, we held a $122.1 million equity investment of Series A-1 Preferred Interests in Kodiak, a privately-held company providing large-scale, high-utilization gas compression assets to customers operating primarily in the Permian Basin. On February 8, 2019, Kodiak redeemed our investment for $135.0 million cash. For more information

Table of Contents

on our investments in the AllDale Partnerships and Kodiak please see "Item 8. Financial Statements and Supplementary Data – Note 10 – Investments and Note 23 – Subsequent Events."

As discussed in more detail in "Item 1A. Risk Factors," our results of operations could be impacted by variability in coal sales prices in addition to 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 mining regulatory environment in which we operate has grown increasingly stringent as a result of legislation and initiatives pursued during previous administrations. 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 United States 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 fossil fuels including coal which could materially and adversely impact our results of operations. We are dependent on third-party operators ("Operators") for the exploration, development and production of our oil & gas mineral interests; therefore, the success and timing of drilling and development of our oil & gas mineral interests depend on a number of factors outside our control. Some of those factors include the Operators' capital costs for drilling, development and production activities, the Operators' ability to access capital, the Operators' selection of counterparties for the marketing and sale of production and oil & gas prices in general, among others. The operations on the properties in which we hold oil & gas mineral interests are also subject to various governmental laws and regulations. Compliance with these laws and regulations could be burdensome or expensive for these Operators and could result in the Operators incurring significant liabilities, either of which could delay production and may ultimately impact the Operators' ability and willingness to develop the properties in which we hold oil & gas mineral interests. For additional information regarding some of the risks and uncertainties that affect our business and the industry in which we operate, see "Item 1A. Risk Factors."

Our principal expenses related to the production of coal are labor and benefits, equipment, materials and supplies, maintenance, royalties and excise taxes in addition to capital required to maintain our current levels of production. 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 primary business strategy is to create sustainable, capital-efficient growth in available cash to maximize the return of cash 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 & gas mineral interests in various geographic locations within producing basins in the continental United States.

As of December 31, 2018, we had 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 United States. 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 had been idled since the fourth quarter of 2015 in response to market conditions but resumed production in May 2018.

Table of Contents

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 in April 2016.

- Appalachia reportable segment is comprised of multiple operating segments, including the Mettiki mining complex, the Tunnel Ridge mining complex, the MC Mining mining complex and the Penn Ridge property. 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 investments in a) AllDale III, b) Kodiak and c) Cavalier Minerals, Cavalier Minerals' investments in AllDale I & II, AROP Funding, LLC ("AROP Funding") and Alliance Resource Finance Corporation ("Alliance Finance"). The AllDale Partnerships receive revenues from oil & gas royalties and Kodiak receives revenues for gas compression services. Please read "Item 8. Financial Statements and Supplementary Data—Note 6 – Long-Term Debt," "—Note 9 – Variable Interest Entities" and "—Note 10 – Investments for more information on AROP Funding, Alliance Finance, Alliance Minerals and Cavalier Minerals.

- We anticipate reorganizing our reportable segments in the first quarter of 2019 because of our royalty business expansion in January 2019 through the Acquisition discussed above. We anticipate adding a third reportable segment which will include our royalty businesses and specifically our mineral interest investments in the AllDale Partnerships.

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 expense divided by total tons sold. We review Segment Adjusted EBITDA Expense per ton for cost trends.

Table of Contents

EBITDA. We define EBITDA (a non-GAAP financial measure) as net income attributable to ARLP 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 attributable to ARLP before net interest expense, income taxes, depreciation, depletion and amortization, general and administrative expense, settlement gain, debt extinguishment loss and asset impairment. 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

2018 Compared with 2017

We reported net income attributable to ARLP of $366.6 million for 2018 compared to $303.6 million for 2017. The increase of $63.0 million was due to record coal sales volumes, which rose to 40.4 million tons sold in 2018 compared to 37.8 million tons sold in 2017, an $80.0 million net gain on settlement of litigation and higher investment income in 2018 and a debt extinguishment loss of $8.1 million in 2017, offset in part by increased operating expenses, transportation expenses and depreciation, depletion and amortization and the impact of a $40.5 million non-cash asset impairment charge in 2018. Increased coal sales volumes drove total revenues higher by 11.5% to $2.00 billion in 2018 compared to $1.80 billion in 2017 and drove operating expenses higher to $1.21 billion in 2018 compared to $1.09 billion in 2017.

EPU for 2018 reflects the impact of the Simplification Transactions eliminating general partner net income allocations to MGP beginning with the second quarter of 2018. EPU for 2017 reflects the impact of the Exchange Transaction eliminating general partner net income allocations associated with the IDRs and a 0.99% general partner interest in ARLP, both of which were held by MGP prior to the Exchange Transaction. MGP exchanged both its general partner interest and IDRs for a non-economic general partner interest and significant limited partner units beginning with distributions for the second quarter of 2017. See "Item 1. Business—Partnership Simplification" for more information on the Exchange Transaction and Simplification Transactions. For the time between the Exchange Transaction and the Simplification Transactions, MGP maintained a 1.0001% general partner interest in the Intermediate Partnership and a 0.001% managing member interest in Alliance Coal and thus was allocated income and loss in our calculation of EPU. We reported EPU of $2.74 in 2018 compared to $2.80 in 2017. On a pro forma basis, as if the Exchange

Transaction and Simplification Transactions had taken place on January 1, 2017, basic and diluted net income of ARLP per limited partner unit ("Pro Forma EPU") in 2018 would have been $2.73 compared to $2.25 in 2017. 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 and Simplification Transactions on EPU, including a table providing a reconciliation of Pro Forma EPU amounts to net income of ARLP.

	Year Ended December 31,		Year Ended December 31,	
	2018	2017	2018	2017
	(in thousands)		(per ton sold)	
Tons sold	40,421	37,824	N/A	N/A
Tons produced	40,266	37,609	N/A	N/A
Coal sales	$ 1,844,808	$ 1,711,114	$ 45.64	$ 45.24
Operating expenses and outside coal purchases	$ 1,209,179	$ 1,091,855	$ 29.91	$ 28.87

Coal sales. Coal sales increased $133.7 million or 7.8% to $1.84 billion for 2018 from $1.71 billion for 2017. The increase in coal sales was attributable to a volume variance of $117.5 million resulting from increased tons sold and a price variance of $16.2 million due to higher average coal sales prices. For 2018, strong performances at River View and our Gibson County Complex mines, which include the resumption of operations at Gibson North in 2018, drove total coal

Table of Contents

sales volumes up 6.9% to a record 40.4 million tons and production volumes higher by 7.1% to 40.3 million tons compared to 2017.

Operating expenses and outside coal purchases. Operating expenses and outside coal purchases increased 10.7% to $1.21 billion for 2018 from $1.09 billion for 2017 primarily as a result of increased coal sales volumes. On a per ton basis, operating expenses and outside coal purchases increased 3.6% to $29.91 per ton sold from $28.87 per ton sold in 2017, due primarily to difficult mining conditions encountered at several mines and additional longwall move days at our Tunnel Ridge mine in 2018. The most significant operating expense variances by category are discussed below:

· Labor and benefit expenses per ton produced, excluding workers' compensation, increased 1.6% to $9.31 per ton in 2018 from $9.16 per ton in 2017. This increase of $0.15 per ton was primarily attributable to increased labor expenses at various mines; and

· Material and supplies expenses per ton produced increased 13.1% to $11.04 per ton in 2018 from $9.76 per ton in 2017. The increase of $1.28 per ton produced resulted primarily from increases of $0.47 per ton for roof support, $0.29 per ton for contract labor used in the mining process and $0.11 per ton for power and fuel used in the mining process.

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

· Production taxes and royalty expenses incurred as a percentage of coal sales prices and volumes decreased $0.12 per produced ton sold in 2018 compared to 2017 primarily as a result of a favorable state production mix, increased sales into the export market and lower average coal sales prices in the Illinois Basin region partially offset by higher average coal sales prices in Appalachia.

General and administrative. General and administrative expenses for 2018 increased to $68.3 million compared to $61.8 million in 2017. The increase of $6.5 million was primarily due to higher incentive compensation expenses and other professional services.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased to $280.2 million for 2018 compared to $269.0 million for 2017 primarily as a result of the previously discussed increase in coal sales volumes.

Settlement gain. During 2018, we finalized an agreement with a customer and certain of its affiliates to settle litigation we initiated in 2015. The agreement provided for a $93.0 million cash payment to us in 2018, future conditional coal supply commitments, continued export transloading capacity for our Appalachian mines and the acquisition of certain coal reserves near our Tunnel Ridge operation. A settlement gain of $80.0 million was recorded in 2018 reflecting the cash payment received net of $13.0 million of combined legal fees paid and associated incentive compensation accruals.

Asset impairment. We recognized $40.5 million of non-cash impairment charges in 2018, comprised of a $34.3 million impairment related to the reduction of the economic mine life at our Dotiki mine and a $6.2 million impairment as a result of a decrease in the fair value of an option entitling us to lease certain coal reserves in Illinois.

Equity method investment income. Equity method investment income increased to $22.2 million in 2018 from $13.9 million in 2017 due to increased income from our investments in the AllDale Partnerships.

Equity securities income. Equity securities income increased $9.3 million to $15.7 million in 2018 compared to $6.4 million in 2017 due to increased distributions of preferred interests from our Kodiak investment.

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 $112.4 million and $41.7 million for 2018 and 2017, respectively. The increase of $70.7 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 2018 both primarily due to increased export shipments. The cost of third-party transportation services are passed through to our

Table of Contents

customers and we recognize transportation revenue equal to transportation expense when title of the coal passes to the customer.

Segment Information. Our 2018 Segment Adjusted EBITDA increased 4.9% to $715.7 million from 2017 Segment Adjusted EBITDA of $682.0 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,								
	2018		2017		Increase (Decrease)				
	(in thousands)								
Segment Adjusted EBITDA									
Illinois Basin	$	408,047	$	391,426	$	16,621	4.2	%
Appalachia		240,286		234,124		6,162	2.6	%
Other and Corporate		75,913		65,247		10,666	16.3	%
Elimination		(8,555)		(8,769)		214	2.4	%
Total Segment Adjusted EBITDA (1)	$	715,691	$	682,028	$	33,663	4.9	%
Tons sold								
Illinois Basin		30,055		27,026		3,029	11.2	%
Appalachia		10,364		10,783		(419)	(3.9)	%
Other and Corporate		994		1,636		(642)	(39.2)	%
Elimination		(992)		(1,621)		629	38.8	%
Total tons sold		40,421		37,824		2,597	6.9	%
Coal sales								
Illinois Basin	$	1,197,143	$	1,078,255	$	118,888	11.0	%
Appalachia		635,530		616,305		19,225	3.1	%
Other and Corporate		43,393		74,973		(31,580)	(42.1)	%
Elimination		(31,258)		(58,419)		27,161	46.5	%
Total coal sales	$	1,844,808	$	1,711,114	$	133,694	7.8	%
Other sales and operating revenues								
Illinois Basin	$	975	$	1,638	$	(663)	(40.5)	%
Appalachia		3,000		3,621		(621)	(17.1)	%
Other and Corporate		58,065		54,070		3,995	7.4	%
Elimination		(16,376)		(15,923)		(453)	(2.8)	%
Total other sales and operating revenues	$	45,664	$	43,406	$	2,258	5.2	%
Segment Adjusted EBITDA Expense								
Illinois Basin	$	790,072	$	688,468	$	101,604	14.8	%
Appalachia		398,243		385,802		12,441	3.2	%
Other and Corporate		62,564		83,490		(20,926)	(25.1)	%
Elimination		(39,079)		(65,573)		26,494	40.4	%
Total Segment Adjusted EBITDA Expense (1)	$	1,211,800	$	1,092,187	$	119,613	11.0	%

(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 attributable to ARLP" and reconciliation of non-GAAP "Segment Adjusted EBITDA Expense" to GAAP "Operating Expenses."

Illinois Basin – Segment Adjusted EBITDA increased 4.2% to $408.0 million in 2018 from $391.4 million in 2017. The increase of $16.6 million was primarily attributable to higher coal sales, which increased 11.0% to $1.20 billion in 2018 from $1.08 billion in 2017, partially offset by increased operating expenses. The increase of $118.9 million in coal sales reflects higher coal sales volumes of 30.1 million tons sold in 2018 compared to 27.0 million tons sold in 2017, partially offset by lower average coal sales prices in 2018. The increase in coal sales volumes resulted from strong performances at our River View and Gibson County Complex mines, which includes the resumption of operations at Gibson North in 2018, due in part to increased export volumes. Segment Adjusted EBITDA Expense increased 14.8% to

$790.1 million in 2018 from $688.5 million in 2017 due to increased sales volumes and higher expenses per ton. Segment Adjusted EBITDA Expense per ton increased $0.82 per ton sold to $26.29 from $25.47 per ton sold in 2017, primarily due to the previously mentioned difficult mining conditions in addition to increased roof support and contract labor costs per ton at various mines and start-up costs associated with reopening the Gibson North mine in 2018.

Appalachia – Segment Adjusted EBITDA increased 2.6% to $240.3 million for 2018 from $234.1 million in 2017. The increase of $6.2 million was primarily attributable to higher coal sales, which increased 3.1% to $635.5 million in 2018 from $616.3 million in 2017 partially offset by increased operating expenses. The increase of $19.2 million in coal sales reflects higher average coal sales prices of $61.32 per ton in 2018 compared to $57.16 per ton in 2017 due to increased export sales of higher priced metallurgical coal at our Mettiki mine and improved prices at our MC Mining and Tunnel Ridge mines. The price benefit was offset partially by lower coal sales volumes of 10.4 million tons sold in 2018 compared to 10.8 million tons in 2017 due to decreased volumes at our Tunnel Ridge and MC Mining mines. Segment Adjusted EBITDA Expense increased 3.2% to $398.2 million in 2018 from $385.8 million in 2017 and Segment Adjusted EBITDA Expense per ton increased $2.65 per ton sold to $38.43 compared to $35.78 per ton sold in 2017. The increase was primarily due to difficult mining conditions and additional longwall move days at our Tunnel Ridge mine and an increased sales mix of higher-cost Mettiki coal production in 2018 as well as certain cost increases described above under "–Operating expenses and outside coal purchases."

Other and Corporate – Segment Adjusted EBITDA increased by $10.7 million to $75.9 million in 2018 compared to $65.2 million in 2017. The increase was primarily attributable to higher equity income from our Kodiak investment and the AllDale Partnerships in 2018.

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 & 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.

As a result of the Exchange Transaction, net income beginning with the second quarter of 2017 was not allocated to IDRs and the related general partner interests exchanged; however, additional net income, in a corresponding amount, was allocated to limited partner interests. We reported EPU of $2.80 in 2017 compared to $3.39 in 2016. On a pro forma basis, as if the Exchange Transaction and Simplification Transactions had taken place on January 1, 2016, basic and diluted net income of ARLP per limited partner unit in 2017 would have been $2.25 compared to $2.51 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 and Simplification Transactions on EPU, including a table providing a reconciliation of Pro Forma EPU amounts to net income of ARLP.

	Year Ended December 31,		Year Ended 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	$ 1,091,855	$ 1,124,192	$ 28.87	$ 30.65

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

61

Table of Contents

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 2.9% to $1.09 billion for 2017 from $1.12 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 5.8% to $28.87 per ton sold from $30.65 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 13.4% to $9.16 per ton in 2017 from $10.58 per ton in 2016. This decrease of $1.42 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.

Equity method investment income. Equity method 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.

Equity securities income. Distributions of additional preferred interests received from our Kodiak investment contributed $6.4 million of equity securities income to 2017.

Table of Contents

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 and we recognize transportation revenue equal to transportation expense when title of the coal passes to the customer.

Segment Information. Our 2017 Segment Adjusted EBITDA decreased 12.5% to $682.0 million from 2016 Segment Adjusted EBITDA of $779.1 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	65,247	46,199	19,048	41.2 %
Elimination	(8,769)	(10,862)	2,093	19.3 %
Total Segment Adjusted EBITDA (1)	$ 682,028	$ 779,108	$ (97,080)	(12.5) %
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	3,621	3,404	217	6.4 %

Other and Corporate	54,070	46,216	7,854	17.0	%
Elimination	(15,923)	(17,752)	1,829	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 attributable to ARLP" and reconciliation of non-GAAP "Segment Adjusted EBITDA Expense" to GAAP "Operating Expenses."

Table of Contents

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 $19.0 million to $65.2 million in 2017 compared to $46.2 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.

Reconciliation of non-GAAP "Segment Adjusted EBITDA" to GAAP "net income attributable to ARLP" 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 attributable to ARLP before net interest expense, income taxes, depreciation, depletion and amortization, settlement gain, asset impairment, 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.

Table of Contents

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

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Consolidated Segment Adjusted EBITDA	$ 715,691	$ 682,028	$ 779,108
General and administrative	(68,298)	(61,760)	(72,529)
Settlement gain	80,000	—	—
Asset impairment	(40,483)	—	—
Debt extinguishment loss	—	(8,148)	—
EBITDA	686,910	612,120	706,579
Depreciation, depletion and amortization	(280,225)	(268,981)	(336,509)
Interest expense, net	(40,059)	(39,291)	(30,659)
Income tax expense	(22)	(210)	(13)
Net income attributable to ARLP	$ 366,604	$ 303,638	$ 339,398

Segment Adjusted EBITDA Expense (a non-GAAP financial measure) includes operating expenses, coal purchases and other expense. 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.

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

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Segment Adjusted EBITDA Expense	$ 1,211,800	$ 1,092,187	$ 1,125,637
Outside coal purchases	(1,466)	—	(1,514)
Other expense	(2,621)	(332)	(1,445)
Operating expenses (excluding depreciation, depletion and amortization)	$ 1,207,713	$ 1,091,855	$ 1,122,678

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. On January 3, 2019, ARLP acquired the general partner interests and all of the limited partner interests not owned by Cavalier Minerals in AllDale I & II. For more information on this acquisition, please read "Item 8. Financial Statements and Supplementary Data—Note 23 – Subsequent Events."

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, to service our debt obligations or to pay distributions will depend upon

Table of Contents

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 and oil & gas industries 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."

In May 2018, the Board of Directors approved the establishment of a unit repurchase program authorizing us to repurchase up to $100 million of ARLP common units. The program has no time limit and we may repurchase units from time to time in the open market or in other privately negotiated transactions. The unit repurchase program authorization does not obligate us to repurchase any dollar amount or number of units. As of December 31, 2018, we had repurchased 3,684,075 units at an average unit price of $19.16 for an aggregate purchase price of $70.6 million. Please read "Part II - Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities" for more information on the unit repurchase program.

As of December 31, 2018, we owned limited partner interests in the AllDale Partnerships, which own oil & gas mineral interests in various geographic locations within producing basins in the continental United States. We had provided funding of $179.0 million to the AllDale Partnerships as of December 31, 2018. On January 3, 2019, we acquired the general partner interests and all of the limited partner interests in AllDale I & II not owned by Cavalier Minerals for $176.0 million, which was funded with cash on hand and borrowings under our revolving credit facility. 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. On February 8, 2019, Kodiak redeemed our preferred interests for $135.0 million cash. For more information on transactions with the AllDale Partnerships and Kodiak, please read "Item 8. Financial Statements and Supplementary Data—Note 9 – Variable Interest Entities," "Note 10 – Investments" and "Note 23 – Subsequent Events."

Mine Development Project

We have begun development activity for MC Mining's Excel Mine No. 5 and currently anticipate deploying total capital of approximately $45.0 million to $50.0 million over the next 12 to 18 months, including $40.0 million to $45.0 million in 2019, which we expect to fund with cash from operations or borrowings under our credit facilities. We anticipate the new mine will enable us to access an additional 15 million tons of coal reserves with an expected mine life of approximately 12 years assuming the current level of production at MC Mining's Excel Mine No. 4 continues at the new mine. We expect the development plan for the new Excel Mine No. 5 will provide a seamless transition from the current MC Mining operation as its reserves deplete in 2020.

Cash Flows

Cash provided by operating activities was $694.3 million for 2018 compared to $556.1 million for 2017. The increase in cash provided by operating activities was primarily due to an increase in net income adjusted for non-cash items and favorable working capital changes related to trade receivables, payroll and related benefits accruals and prepaid expenses and other assets in 2018 compared to 2017. These increases were offset in part by a decrease in accounts payable in 2018 compared to an increase in accounts payable in 2017.

Net cash used in investing activities was $245.2 million for 2018 compared to $244.8 million for 2017. The increase in cash used in investing activities was primarily attributable to increased capital expenditures for mine infrastructure and equipment at various mines in 2018 compared to 2017. The increase in capital expenditures was offset by reduced equity investments in 2018 compared to 2017. Net cash used in investing activities for 2017 included the $100.0 million purchase of our Kodiak investment.

Net cash used in financing activities was $211.7 million for 2018 compared to $344.4 million for 2017. The decrease in cash used in financing activities was primarily attributable to overall net borrowings in 2018 compared to overall net payments in 2017 on the securitization and revolving credit facilities and the payment of debt issuance and extinguishment costs as well as the repayment of Series B Senior Notes in 2017. These decreases were partially offset by an increase in

Table of Contents

distributions paid to partners and payments made to repurchase units in 2018 as well as proceeds received from the issuance of debt in 2017.

We have various commitments primarily related to long-term debt, including capital and operating leases, 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, 2018:

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(in thousands)				
Long-term debt	$ 667,000	$ 92,000	$ 175,000	$ —	$ 400,000
Future interest obligations(1)	210,522	38,691	71,886	60,000	39,945
Operating leases					