PEABODY ENERGY CORP
Form 10-K
February 26, 2018
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2017
or
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission File Number 1-16463

PEABODY ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	13-4004153
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
701 Market Street, St. Louis, Missouri	63101
(Address of principal executive offices)	(Zip Code)

(314) 342-3400
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 Stock, par value $0.01 per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No þ
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 o No þ
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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. þ
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. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o	Emerging growth company o

(Do not check if a smaller reporting 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. o

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

Aggregate market value of the voting stock held by non-affiliates (stockholders who are not directors or executive officers) of the Registrant, calculated using the closing price on June 30, 2017: Common Stock, par value $0.01 per share, $1.4 billion.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes þ No o

Number of shares outstanding of each of the Registrant's classes of Common Stock, as of February 19, 2018: Common Stock, par value $0.01 per share, 129,717,428 shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company's 2018 Annual Meeting of Shareholders (the Company's 2018 Proxy Statement) are incorporated by reference into Part III hereof. Other documents incorporated by reference in this report are listed in the Exhibit Index of this Form 10-K.

CAUTIONARY NOTICE REGARDING FORWARD-LOOKING STATEMENTS

This report includes statements of our expectations, intentions, plans and beliefs that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended, and are intended to come within the safe harbor protection provided by those sections. These statements relate to future events or our future financial performance, including, without limitation, the section captioned "Outlook" in Management's Discussion and Analysis of Financial Condition and Results of Operations. We use words such as "anticipate," "believe," "expect," "may," "forecast," "project," "should," "estimate," "plan," "target," "likely," "will," "to be" or other similar words to identify forward-looking statements.

Without limiting the foregoing, all statements relating to our future operating results, anticipated capital expenditures, future cash flows and borrowings, and sources of funding are forward-looking statements and speak only as of the date of this report. These forward-looking statements are based on numerous assumptions that we believe are reasonable, but are subject to a wide range of uncertainties and business risks, and actual results may differ materially from those discussed in these statements. These factors are difficult to accurately predict and may be beyond our control. Factors that could affect our results or an investment in our securities include, but are not limited to:

- as a result of our emergence from our Chapter 11 Cases, our historical financial information is not indicative of our future financial performance;
- our profitability depends upon the prices we receive for our coal;
- if a substantial number of our long-term coal supply agreements terminate, our revenues and operating profits could suffer if we are unable to find alternate buyers willing to purchase our coal on comparable terms to those in our contracts;
- the loss of, or significant reduction in, purchases by our largest customers could adversely affect our revenues;
- our trading and hedging activities do not cover certain risks, and may expose us to earnings volatility and other risks;
- our operating results could be adversely affected by unfavorable economic and financial market conditions;
- our ability to collect payments from our customers could be impaired if their creditworthiness or contractual performance deteriorates;
- risks inherent to mining could increase the cost of operating our business;
- if transportation for our coal becomes unavailable or uneconomic for our customers, our ability to sell coal could suffer;
- a decrease in the availability or increase in costs of key supplies, capital equipment or commodities such as diesel fuel, steel, explosives and tires could decrease our anticipated profitability;
- take-or-pay arrangements within the coal industry could unfavorably affect our profitability;
- an inability of trading, brokerage, mining or freight counterparties to fulfill the terms of their contracts with us could reduce our profitability;
- we may not recover our investments in our mining, exploration and other assets, which may require us to recognize impairment charges related to those assets;
- our ability to operate our company effectively could be impaired if we lose key personnel or fail to attract qualified personnel;
- we could be negatively affected if we fail to maintain satisfactory labor relations;
- we could be adversely affected if we fail to appropriately provide financial assurances for our obligations;
- our mining operations are extensively regulated, which imposes significant costs on us, and future regulations and developments could increase those costs or limit our ability to produce coal;
- our operations may impact the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, which could result in material liabilities to us;
- we may be unable to obtain, renew or maintain permits necessary for our operations, which would reduce our production, cash flows and profitability;
- our mining operations are subject to extensive forms of taxation, which imposes significant costs on us, and future regulations and developments could increase those costs or limit our ability to produce coal competitively;
- if the assumptions underlying our asset retirement obligations for reclamation and mine closures are materially inaccurate, our costs could be significantly greater than anticipated;

- our future success depends upon our ability to continue acquiring and developing coal reserves that are economically recoverable;

- we face numerous uncertainties in estimating our economically recoverable coal reserves and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs and decreased profitability;
- our global operations increase our exposure to risks unique to international mining and trading operations;
- joint ventures, partnerships or non-managed operations may not be successful and may not comply with our operating standards;
- we may undertake further repositioning plans that would require additional charges;
- we could be exposed to significant liability, reputational harm, loss of revenue, increased costs or other risks if we sustain cyber attacks or other security breaches that disrupt our operations or result in the dissemination of proprietary or confidential information about us, our customers or other third-parties;
- our expenditures for postretirement benefit and pension obligations could be materially higher than we have predicted if our underlying assumptions prove to be incorrect;
- 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 government-backed lending institutions and development banks toward the financing of new overseas coal-fueled power plants and divestment efforts affecting the investment community, which could significantly affect demand for our products or our securities;
- our financial performance could be adversely affected by our indebtedness;
- despite our and our subsidiaries' indebtedness, we may still be able to incur substantially more debt, including secured debt. This could further increase the risks associated with our indebtedness;
- we may not be able to generate sufficient cash to service all of our indebtedness or other obligations;
- the terms of our indenture governing our senior secured notes and the agreements and instruments governing our other post-emergence indebtedness impose restrictions that may limit our operating and financial flexibility;
- the price of our securities may be volatile;
- our Common Stock is subject to dilution and may be subject to further dilution in the future;
- there may be circumstances in which the interests of a significant stockholder could be in conflict with other stockholders' interests;
- the payment of dividends on our stock or repurchases of our stock is dependent on a number of factors, and future payments and repurchases cannot be assured;
- we may not be able to fully utilize our deferred tax assets;
- divestitures and acquisitions are a potentially important part of our long-term strategy, subject to our investment criteria, and involve a number of risks, any of which could cause us not to realize the anticipated benefits;
- our certificate of incorporation and by-laws include provisions that may discourage a takeover attempt;
- diversity in interpretation and application of accounting literature in the mining industry may impact our reported financial results; and
- other risks and factors, including those discussed in "Legal Proceedings," set forth in Part I, Item 3 of this report and "Risk Factors," set forth in Part I, Item 1A of this report.

When considering these forward-looking statements, you should keep in mind the cautionary statements in this document and in our other Securities and Exchange Commission (SEC) filings. These forward-looking statements speak only as of the date on which such statements were made, and we undertake no obligation to update these statements except as required by federal securities laws.

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Note: The words "we," "us," "our," "Peabody" or "the Company" as used in this report, refer to Peabody Energy Corporation its applicable subsidiary or subsidiaries. Unless otherwise noted herein, disclosures in this Annual Report on Form 10-K relate only to our continuing operations.
When used in this filing, the term "ton" refers to short or net tons, equal to 2,000 pounds (907.18 kilograms), while "tonne" refers to metric tons, equal to 2,204.62 pounds (1,000 kilograms).

PART I

Item 1. Business.

Overview

We are the world's largest private-sector coal company by volume. We own interests in 23 coal mining operations located in the United States (U.S.) and Australia. We have a majority interest in 22 of those mining operations and a 50% equity interest in Middlemount Coal Pty Ltd. (Middlemount), which owns the Middlemount Mine in Queensland, Australia. In addition to our mining operations, we market and broker coal from other coal producers, both as principal and agent, and trade coal and freight-related contracts through trading and business offices in the U.S., Australia, China, and the United Kingdom. In 2017, we achieved a global safety incidence rate of 1.38 incidents per 200,000 hours worked, which was a 26% improvement in our global safety performance over the past five years. We were also recognized by the U.S. National Mining Association as the first in the industry to achieve independent certification under the CORESafety® system.

Filing Under Chapter 11 of the United States Bankruptcy Code

On April 13, 2016 (the Petition Date), Peabody Energy Corporation and a majority of its wholly owned domestic subsidiaries as well as one international subsidiary in Gibraltar (the Filing Subsidiaries, and together with Peabody, the Debtors) filed voluntary petitions for reorganization (the Bankruptcy Petitions) under Chapter 11 of Title 11 of the U.S. Code (the Bankruptcy Code) in the United States Bankruptcy Court for the Eastern District of Missouri (the Bankruptcy Court). The Company's Australian operations and other international subsidiaries were not included in the filings. The Debtors' Chapter 11 cases (collectively, the Chapter 11 Cases) were jointly administered under the caption In re Peabody Energy Corporation, et al., Case No. 16-42529 (Bankr. E.D. Mo.). During the Chapter 11 Cases, the Debtors continued to operate their business as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. In general, as debtors-in-possession, the Debtors were authorized under Chapter 11 to continue to operate as an ongoing business, but could not engage in transactions outside the ordinary course of business without the prior approval of the Bankruptcy Court.

On January 27, 2017, the Debtors filed with the Bankruptcy Court the Second Amended Joint Plan of Reorganization of Debtors and Debtors in Possession (as further modified, the Plan) and the Second Amended Disclosure Statement with Respect to the Second Amended Joint Plan of Reorganization of Debtors and Debtors in Possession (previous versions of the Plan and Disclosure Statement were filed with the Bankruptcy Court on December 22, 2016 and January 25, 2017). Subsequently, the Debtors solicited votes on the Plan. On March 15, 2017, the Debtors filed a revised version of the Plan and on March 16, 2017, the Bankruptcy Court held a hearing to determine whether the Plan should be confirmed. On March 17, 2017, the Bankruptcy Court entered an order, Docket No. 2763 (the Confirmation Order), confirming the Plan. On April 3, 2017 (the Effective Date), the Debtors satisfied the conditions to effectiveness set forth in the Plan, the Plan became effective in accordance with its terms and the Debtors emerged from the Chapter 11 Cases.

A group of creditors (the Ad Hoc Committee) that held certain interests in the Company's prepetition indebtedness appealed the Bankruptcy Court's order confirming the Plan. On December 29, 2017, the United States District Court for the Eastern District of Missouri (the District Court) entered an order dismissing the Ad Hoc Committee's appeal, and, in the alternative, affirming the order confirming the Plan. On January 26, 2018, the Ad Hoc Committee appealed the District Court's order to the United States Court of Appeals for the Eighth Circuit (the Eighth Circuit). In its appeal, the Ad Hoc Committee does not ask the Eighth Circuit to reverse the order confirming the Plan. Instead, the Ad Hoc Committee asks the Eighth Circuit to award the Ad Hoc Committee members either unspecified damages or the right to buy an unspecified amount of Company stock at a discount. The Company does not believe the appeal is meritorious and will vigorously defend it.

Upon emergence, in accordance with Accounting Standards Codification (ASC) 852, we applied fresh start reporting to our consolidated financial statements as of April 1, 2017 and became a new entity for financial reporting purposes reflecting the Successor (as defined below) capital structure. As a new entity, a new accounting basis in the identifiable assets and liabilities assumed was established with no retained earnings or accumulated other comprehensive income (loss). For additional details, refer to Note 1. "Summary of Significant Accounting Policies" and Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting" to the accompanying consolidated financial statements.

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In connection with our emergence from the Chapter 11 Cases and the adoption of fresh start reporting, the results of operations for 2017 separately present a Successor period (for the period April 2, 2017 through December 31, 2017) and a Predecessor period (for the period January 1, 2017 through April 1, 2017). The results of operations for the years ended 2016 and 2015 are presented as Predecessor periods. References to “Successor” are in reference to reporting dates on or after April 2, 2017; references to “Predecessor” are in reference to reporting dates through April 1, 2017, which include the impact of the Plan provisions and the application of fresh start reporting. Although the 2017 Successor period and the 2017 Predecessor period are distinct reporting periods, the effects of emergence and fresh start reporting did not have a material impact on the comparability of our results of operations between the periods, unless otherwise noted herein. Accordingly, references to 2017 results of operations for year ended December 31, 2017 combine the two periods to enhance the comparability of such information to the prior year.

Segment and Geographic Information

We conduct business through six operating segments: Powder River Basin Mining, Midwestern U.S. Mining, Western U.S. Mining, Australian Metallurgical Mining, Australian Thermal Mining and Trading and Brokerage. Segment and geographic financial information is contained in Note 27. “Segment and Geographic Information” to our consolidated financial statements and is incorporated herein by reference.

Mining Segments

The maps that follow display our active mine locations as of December 31, 2017. Also shown are the primary ports that we use in Australia for coal exports and our corporate headquarters in St. Louis, Missouri.

U.S. Mining Operations - Powder River Basin, Midwestern, Western

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The principal business of our mining segments in the U.S. is the mining, preparation and sale of thermal coal, sold primarily to electric utilities in the U.S. under long-term contracts, with a portion sold as international exports as conditions warrant. Our Powder River Basin Mining operations consist of our mines in Wyoming. The mines in that segment are characterized by surface mining extraction processes, coal with a lower sulfur content and Btu and higher customer transportation costs (due to longer shipping distances). Our Midwestern U.S. Mining operations include our Illinois and Indiana mining operations, which are characterized by a mix of surface and underground mining extraction processes, coal with a higher sulfur content and Btu, and lower customer transportation costs (due to shorter shipping distances). Our Western U.S. Mining operations reflect the aggregation of our New Mexico, Arizona and Colorado mining operations. The mines in that segment are characterized by a mix of surface and underground mining extraction processes, coal with a mid-range sulfur content and Btu. Geologically, our Powder River Basin Mining operations mine sub-bituminous coal deposits, our Midwestern U.S. Mining operations mine bituminous coal deposits and our Western U.S. Mining operations mine both bituminous and sub-bituminous coal deposits.

As described more fully in Part I, Item 1 under the heading “Transportation”, coal consumed in the U.S. is usually sold at the mine with transportation costs borne by the purchaser. Our U.S. mine sites are typically adjacent to a rail loop; however in limited circumstances coal may be trucked to a barge site. Title predominately passes to the purchaser at the rail or barge, as applicable.

Our U.S. export coal is more typically sold on a delivered basis into the unloading port, and we pay ocean freight. In each case, exporters usually pay shipping costs from the mine to the port, including any demurrage costs (fees paid to third-party shipping companies for loading time that exceeded the stipulated time). The primary ports used for U.S. exports are the United Bulk Terminal near New Orleans, Louisiana, the St. James Stevedoring Anchorages terminal in Convent, Louisiana and the Kinder Morgan terminal near Houston, Texas.

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Australian Mining Operations - Metallurgical, Thermal

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The business of our Australian operating platform is primarily export focused with customers spread across several countries, while a portion of our metallurgical and thermal coal is sold within Australia. Generally, revenues from individual countries vary year by year based on electricity and steel demand, the strength of the global economy, governmental policies and several other factors, including those specific to each country. Our Australian Metallurgical Mining operations consist of mines in Queensland and one in New South Wales, Australia. The mines in that segment are characterized by both surface and underground extraction processes used to mine various qualities of metallurgical coal (low-sulfur, high Btu coal). The metallurgical coal qualities include hard coking coal, semi-hard coking coal, semi-soft coking coal and low-volatile pulverized coal injection (LV PCI) coal. Our Australian Thermal Mining operations consist of mines in New South Wales, Australia. The mines in that segment are characterized by both surface and underground extraction processes used to mine low-sulfur, high Btu thermal coal. We classify our Australian mines within the Australian Metallurgical Mining or Australian Thermal Mining segments based on the primary customer base and coal reserve type of each mining operation. A small portion of the coal mined by the Australian Metallurgical Mining segment is of a thermal grade. Similarly, a small portion of the coal mined by the Australian Thermal Mining segment is of a metallurgical grade. Additionally, we may market some of our metallurgical coal products as a thermal coal product from time to time depending on supply and demand conditions. As described more fully in Part I, Item 1 under the heading “Transportation”, our Australian export coal is usually sold at the loading port, with purchasers paying ocean freight. We have generally secured our ability to transport coal in Australia through rail and port contracts and interests in five east coast coal export terminals. In Queensland, seaborne metallurgical and thermal coal from our mines is exported through the Dalrymple Bay Coal Terminal, in addition to the Abbot Point Coal Terminal used by our joint venture Middlemount Mine. In New South Wales, our primary ports for exporting metallurgical and thermal coal are at Port Kembla and Newcastle, which includes both the Port Waratah Coal Services terminal and the terminal operated by Newcastle Coal Infrastructure Group (NCIG).

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The table below summarizes information regarding the operating characteristics of each of our mines that were active in 2017 in the U.S. and Australia. The mines are listed within their respective mining segment in descending order, as determined by tons sold in 2017.

Segment/Mining Complex	Location	Mine Type	Mining Method	Coal Type	Primary Transport Method	2017 Tons Sold (In millions)
Powder River Basin Mining						
North Antelope Rochelle	Wyoming	S	D, DL, T/S	T	R	101.5
Caballo	Wyoming	S	D, T/S	T	R	11.1
Rawhide	Wyoming	S	D, T/S	T	R	10.3
Third party (1)	—	—	—	—	—	2.1
Midwestern U.S. Mining						
Bear Run	Indiana	S	DL, D, T/S	T	Tr, R	7.3
Wild Boar	Indiana	S	D, T/S	T	Tr, R, R/B, T/B	2.7
Gateway North	Illinois	U	CM	T	Tr, R, R/B, T/B	2.5
Somerville Central	Indiana	S	DL, D, T/S	T	R, R/B, T/B, T/R	2.2
Francisco Underground	Indiana	U	CM	T	R	2.1
Wildcat Hills Underground	Illinois	U	CM	T	T/B	1.4
Cottage Grove	Illinois	S	D, T/S	T	T/B	0.3
Western U.S. Mining						
Kayenta	Arizona	S	DL, T/S	T	R	6.2
El Segundo	New Mexico	S	D, DL, T/S	T	R	5.1
Twentymile	Colorado	U	LW	T	R, Tr	3.4
Lee Ranch	New Mexico	S	T/S	T	R	—
Australian Metallurgical Mining						
Coppabella (2)	Queensland	S	DL, D, T/S	P	R, EV	2.9
North Goonyella	Queensland	U	LW	M	R, EV	2.9
Millennium	Queensland	S	D, T/S	M, P	R, EV	2.8
Moorvale (2)	Queensland	S	D, T/S	P, T	R, EV	2.0
Metropolitan	New South Wales	U	LW	M, P, T	R, EV	1.1
Middlemount (3)	Queensland	S	D, T/S	M, P	R, EV	—
Australian Thermal Mining						
Wilpinjong	New South Wales	S	D, T/S	T	R, EV	13.4
Wambo Open-Cut (4)	New South Wales	S	T/S	T	R, EV	3.5
Wambo Underground (4)	New South Wales	U	LW	M, T	R, EV	2.3

Legend:

S	Surface Mine	Tr	Truck
U	Underground Mine	R/B	Rail to Barge
DL	Dragline	T/B	Truck to Barge
D	Dozer/Casting	T/R	Truck to Rail
T/S	Truck and Shovel	EV	Export Vessel
LW	Longwall	T	Thermal/Steam
CM	Continuous Miner	M	Metallurgical
R	Rail	P	Pulverized Coal Injection

(1) Third party purchased coal used to satisfy coal supply agreements.

(2) We own a 73.3% undivided interest in an unincorporated joint venture that owns the Coppabella and Moorvale mines. The tons shown reflect our share.

(3) We own a 50% equity interest in Middlemount, which owns the Middlemount Mine. Because that entity is accounted for as an unconsolidated equity affiliate, 2017 tons sold from that mine, which totaled 4.2 million tons (on a 100% basis), have been excluded from the table above.

(4) Represents our majority-owned mines in which there is an outside non-controlling ownership interest.

Refer to the “Summary of Coal Production and Sulfur Content of Assigned Reserves” table within Part I, Item 2. “Properties,” which is incorporated by reference herein, for additional information regarding coal reserves, product characteristics and production volume associated with each mine.

Trading and Brokerage Segment

Our Trading and Brokerage segment engages in the direct and brokered trading of coal and freight-related contracts through our trading and business offices. Coal brokering is conducted both as principal and agent in support of various coal production-related activities that may involve coal produced from our mines, including optimization and blending of such coal, coal sourcing arrangements with third-party mining companies or offtake agreements with other coal producers. Our Trading and Brokerage segment also provides transportation-related services, which involve both financial derivative contracts and physical contracts. Collectively, coal and freight-related hedging activities include both economic hedging and, from time to time, cash flow hedging in support of our coal trading strategy.

Corporate and Other Segment

Our Corporate and Other segment includes selling and administrative expenses, including our technical and shared services functions, corporate hedging activities, mining and export/transportation joint ventures, restructuring charges and activities associated with the optimization of our coal reserve and real estate holdings, minimum charges on certain transportation-related contracts, the closure of inactive mining sites and certain energy-related commercial matters.

Resource Management. As of December 31, 2017, we controlled approximately 5.2 billion tons of proven and probable coal reserves and approximately 600,000 acres of surface property through ownership and lease agreements. We have an ongoing asset optimization program whereby our property management group regularly reviews these reserves and surface properties for opportunities to generate earnings and cash flow through the sale or exchange of non-strategic coal reserves and surface lands. These surface lands include acres where we have completed post-mining reclamation. In addition, we generate revenue through royalties from coal reserves and oil and gas rights leased to third parties and farm income from surface lands under third-party contracts.

Middlemount Mine. We own a 50% equity interest in Middlemount, which owns the Middlemount Mine in Queensland, Australia. The mine predominantly produces semi-hard coking coal and LV PCI coal for sale into seaborne coal markets through rail and port capacity contracted through Abbot Point Coal Terminal, with future capacity also secured at Dalrymple Bay Coal Terminal. Mining operations first commenced at the Middlemount Mine in late 2011. During the years ended December 31, 2017, 2016 and 2015, the mine sold 4.2 million, 4.5 million and 4.2 million tons of coal, respectively (on a 100% basis).

Coal Supply Agreements

Customers. Our coal supply agreements are primarily with electricity generators, industrial facilities and steel manufacturers. Most of our sales (excluding trading and brokerage transactions) are made under long-term coal supply agreements (those with initial terms of one year or longer and which often include price reopener and/or extension provisions). A smaller portion of our sales are made under contracts with terms of less than one year, including sales made on a spot basis. Sales under long-term coal supply agreements comprised approximately 83%, 86% and 88% of our worldwide sales from our mining operations (by volume) for the years ended December 31, 2017, 2016 and 2015, respectively. A recent trend has been for our customers under long-term coal supply agreements to seek contracts of shorter duration.

For the year ended December 31, 2017, we derived 27% of our total revenues from our five largest customers. Those five customers were supplied primarily from 21 coal supply agreements (excluding trading and brokerage transactions) expiring at various times from 2018 to 2025. The contract contributing the greatest amount of annual revenue in 2017 was approximately $277 million, or approximately 5% of our 2017 total revenues, and is due to expire in 2019.

Backlog. Our sales backlog (excluding trading and brokerage transactions), which includes coal supply agreements subject to price reopener and/or extension provisions, was approximately 507 million and 587 million tons of coal as of January 1, 2018 and 2017, respectively. Contracts in backlog have remaining terms ranging from one to 12 years and represent approximately three years of production based on our 2017 production volume of 188.3 million tons. Approximately 69% of our backlog is expected to be filled beyond 2018.

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U.S. Mining Operations. Revenues from our Powder River Basin Mining, Western U.S. Mining and Midwestern U.S. Mining segments, in aggregate, represented approximately 53%, 59% and 63% of our total revenue base for the years ended December 31, 2017, 2016 and 2015, respectively, during which periods the coal mining activities of those segments contributed respective aggregate amounts of approximately 84%, 81% and 83% of our sales volumes from mining operations. We expect to continue selling a significant portion of our Powder River Basin Mining, Western U.S. Mining and Midwestern U.S. Mining segment coal production under long-term supply agreements, and customers of those segments continue to pursue long-term sales agreements in recognition of the importance of reliability, service and predictable coal prices to their operations. The terms of coal supply agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of those agreements vary significantly in many respects, including price adjustment features, price reopener terms, coal quality requirements, quantity parameters, permitted sources of supply, treatment of environmental constraints, extension options, force majeure and termination and assignment provisions. Our approach is to selectively renew, or enter into new, long-term supply agreements when we can do so at prices and terms and conditions we believe are favorable.

Australian Mining Operations. Revenues from our Australian Metallurgical Mining and Australian Thermal Mining segments represented approximately 46%, 41% and 36% of our total revenue base for the years ended December 31, 2017, 2016 and 2015, respectively, during which periods the coal mining activities of those segments contributed respective amounts of 16%, 19% and 17% of our sales volumes from mining operations. Our production is primarily sold into the seaborne metallurgical and thermal markets, with a majority of those sales executed through annual and multi-year international coal supply agreements that contain provisions requiring both parties to renegotiate pricing periodically. Industry commercial practice, and our typical practice, is to negotiate pricing for seaborne metallurgical coal contracts on a quarterly, spot or index basis and seaborne thermal coal contracts on an annual, spot or index basis. The portion of volume priced on a shorter-term basis and index linked basis has increased in recent years and represented 30% in 2017.

Transportation

Methods of Distribution. Coal consumed in the U.S. is usually sold at the mine with transportation costs borne by the purchaser. Our Australian export coal is usually sold at the loading port, with purchasers paying ocean freight. Our U.S. export coal is more typically sold on a delivered basis into the unloading port, and we pay ocean freight. In each case, exporters usually pay shipping costs from the mine to the port, including any demurrage costs (fees paid to third-party shipping companies for loading time that exceeded the stipulated time).

We believe we have good relationships with U.S. and Australian rail carriers and port and barge companies due, in part, to our modern coal-loading facilities and the experience of our transportation coordinators. Refer to the table in the foregoing “Mining Segments” section for a summary of transportation methods by mine.

Export Facilities. Our U.S. Mining operations exported approximately 1%, 0% and 0% of its annual tons sold for the years ended December 31, 2017, 2016 and 2015, respectively. The primary ports used for U.S. exports are the United Bulk Terminal near New Orleans, Louisiana, the St. James Stevedoring Anchorages terminal in Convent, Louisiana and the Kinder Morgan terminal near Houston, Texas. We periodically assess opportunities for access to West Coast port facilities that will allow us to export our Powder River Basin coal products to serve demand in the Asian region, should market conditions warrant.

Our Australian Mining operations sold approximately 73%, 75% and 77% of its tons into the seaborne coal markets for the years ended December 31, 2017, 2016 and 2015, respectively. We have generally secured our ability to transport coal in Australia through rail and port contracts and interests in five east coast coal export terminals that are primarily funded through take-or-pay arrangements (refer to the “Liquidity and Capital Resources” section in Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for additional information on our take-or-pay obligations). In Queensland, seaborne metallurgical and thermal coal from our mines is exported through the Dalrymple Bay Coal Terminal, in addition to the Abbot Point Coal Terminal used by our joint venture Middlemount Mine. In New South Wales, our primary ports for exporting metallurgical and thermal coal are at Port Kembla and Newcastle, which includes both the Port Waratah Coal Services terminal and the terminal operated by NCIG.

Suppliers

Mining Supplies and Equipment. The principal goods we purchase in support of our mining activities are mining equipment and replacement parts, diesel fuel, ammonium-nitrate and emulsion-based explosives, off-the-road (OTR) tires, steel-related products (including roof control materials), lubricants and electricity. We have many well-established, strategic relationships with our key suppliers of goods and do not believe that we are overly dependent on any of our individual suppliers.

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There has been consolidation in the supplier base providing certain mining materials and equipment to the coal industry. This has limited the number of global sources for these items, such as surface and underground mining equipment. In situations where we have elected to concentrate a large portion of our purchases with one supplier in lieu of seeking other alternatives, it has been to take advantage of cost savings from larger volumes of purchases, benefit from long-term pricing for parts, ensure security of supply and/or allow for equipment fleet standardization. Supplier concentration related to our mining equipment also allows us to benefit from fleet standardization, which in turn improves asset utilization by facilitating the development of common maintenance practices across our global platform and enhancing our flexibility to move equipment between mines as necessary.

Surface and underground mining equipment demand and lead times have begun to extend in recent periods due to recovering market conditions experienced across several extractive industry sectors. We do not expect this to impact our own near-term demand for such equipment as we extend the lives of existing equipment through improved maintenance practices and equipment rebuilds in order to defer the requirement for larger capital purchases. We continue to use our global leverage with major suppliers to ensure security of supply to meet the requirements of our active mines.

Services. We also purchase services at our mine sites, including services related to maintenance for mining equipment, construction, temporary labor, use of explosives and various other requirements. We do not believe that we have undue operational or financial risk associated with our dependence on any individual service providers.

Competition

Demand for coal and the prices that we will be able to obtain for our coal are highly competitive and influenced by factors beyond our control, including but not limited to global economic conditions, the demand for electricity and steel, the cost of alternative fuels, the cost of electricity generation from alternative fuels, including wind, solar, oil, hydro, nuclear, natural gas and biomass, the impact of weather on heating and cooling demand and taxes and environmental regulations imposed by the U.S. and foreign governments.

Thermal Coal

Demand for our thermal coal products is impacted by economic conditions, demand for electricity, including the impact of energy efficient products, and the cost of electricity generation from coal and alternative fuels. Our products compete with producers of other forms of electric generation, including natural gas, oil, nuclear, hydro, wind, solar and biomass, that provide an alternative to coal use. The use and price of thermal coal is heavily influenced by the availability and relative cost of alternative fuels and the generation of electricity utilizing alternative fuels, with customers focused on securing the lowest cost fuel supply in order to coordinate the most efficient utilization of generating resources in the economic dispatch of the power grid at the most competitive price.

In the U.S., natural gas is highly competitive (along with other alternative fuel sources) with thermal coal for electricity generation. The competitiveness of natural gas has been strengthened by accelerated growth in domestic natural gas production and transmission facilities over the last five years and comparatively low natural gas prices (versus historic levels). Gas prices averaged $3.02 per mmBtu in 2017, versus $2.55, $2.63 and $4.26 per mmBtu in 2016, 2015 and 2014, respectively. Natural gas price trends can significantly impact U.S. coal burn and production. We believe the U.S. Powder River and Illinois basins in which we produce are competitive against natural gas when natural gas prices average in excess of $2.50 to $2.75 per mmBtu and $3.00 to $3.50 per mmBtu, respectively. In addition, the competitiveness of other alternative fuel sources for electricity generation with coal has been strengthened by the growth of low-cost and government subsidized generation fueled by other alternative fuel sources.

Internationally, thermal coal also competes with alternative forms of electric generation. The competitiveness and availability of natural gas, oil, nuclear, hydro, wind, solar and biomass varies by country and region. In addition, seaborne thermal coal import demand can be significantly impacted by the availability of indigenous coal production, particularly in the two leading coal import countries, China and India, among others, and the competitiveness of seaborne supply from leading thermal coal exporting countries, including Indonesia, Australia, Russia, Colombia and South Africa, among others.

In addition to our alternative fuel source competitors, our principal U.S. direct coal supply competitors (listed alphabetically) are other large coal producers, including Alliance Resource Partners, Arch Coal, Inc., Cloud Peak Energy Inc., Contura Energy Inc., Murray Energy Corporation and Westmoreland Coal Company, which collectively accounted for approximately 43% of total U.S. coal production in 2016 according to the U.S. Energy Information Administration's "Annual Coal Report 2016," the most recent data publicly available as of November 15, 2017. Major international direct coal supply competitors (listed alphabetically) include Anglo-American PLC, BHP Billiton, China Coal, Coal India Limited, Glencore PLC, PT Bumi Resources Tbk., Rio Tinto, Shenhua Group and Yancoal Australia Ltd, among others.

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Metallurgical Coal

Demand for our metallurgical coal products is impacted by economic conditions, demand for steel and competing technologies used to make steel, some of which do not use coal as a manufacturing input. We compete on the basis of coal quality and characteristics, delivered energy cost (including transportation costs), customer service and support and reliability of supply.

Seaborne metallurgical coal import demand can be significantly impacted by the availability of indigenous coal production, particularly in leading metallurgical coal import countries of China, India, Japan, South Korea and Brazil, among others, and the competitiveness of seaborne metallurgical coal supply, including from leading metallurgical coal exporting countries of Australia, U.S., Russia, Canada and Mongolia, among others.

Major international direct competitors (listed alphabetically) include Anglo-American PLC, BHP Billiton, China Coal, Glencore PLC, PT Bumi Resources Tbk., Rio Tinto and Shenhua Group, among others.

Working Capital

We generally fund our working capital requirements through a combination of existing cash and cash equivalents, proceeds from the sale of our coal production to customers and our trading and brokerage activities. Our current accounts receivable securitization program and revolving credit facility are also available to fund our working capital requirements to the extent we have remaining availability. Refer to the “Liquidity and Capital Resources” section of Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for additional information regarding working capital.

Employees

We had approximately 7,100 employees as of December 31, 2017, including approximately 5,500 hourly employees. Additional information on our employees and related labor relations matters is contained in Note 23. “Management - Labor Relations” to our consolidated financial statements, which information is incorporated herein by reference.

Executive Officers of the Company

Set forth below are the names, ages and positions of our executive officers. Executive officers are appointed by, and hold office at the discretion of, our Board of Directors, subject to the terms of any employment agreements.

Name	Age [1]	Position [1]
Glenn L. Kellow	50	President and Chief Executive Officer
Amy B. Schwetz	43	Executive Vice President and Chief Financial Officer
A. Verona Dorch	50	Executive Vice President, Chief Legal Officer, Government Affairs and Corporate Secretary
Charles F. Meintjes	55	Executive Vice President - Corporate Services and Chief Commercial Officer
Paul V. Richard	58	Senior Vice President and Chief Human Resources Officer
George J. Schuller Jr.	54	President - Australia
Kemal Williamson	58	President - Americas

(1) As of February 19, 2018.

Glenn L. Kellow was named our President and Chief Operating Officer in August 2013; our President, Chief Executive Officer-elect and a director in January 2015; and our President and Chief Executive Officer in May 2015. Mr. Kellow has extensive experience in the global resource industry, where he has served in multiple executive, operational and financial roles in coal and other commodities in the United States, Australia and South America. From 1985 to 2013, Mr. Kellow served in a number of roles with BHP Ltd., including senior appointments as President, Aluminum and Nickel (2012-2013), President, Stainless Steel Materials (2010-2012), President and Chief Operating Officer, New Mexico Coal (2007-2010), and Chief Financial Officer, Base Metals (2003-2007). He is a Vice Chairman of the World Coal Association, a director and executive committee member of the U.S. National Mining Association and the Vice Chairman of the International Energy Agency Coal Industry Advisory Board. Mr. Kellow is a graduate of the Advanced Management Program at the University of Pennsylvania’s Wharton School of Business, holds a Master’s of Business Administration and a Bachelor’s Degree in Commerce from the University of Newcastle, and is a Fellow of CPA Australia. He holds an honorary Doctor of Science degree from the South Dakota School of Mines and Technology.

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Amy B. Schwetz was named our Executive Vice President and Chief Financial Officer in July 2015. Ms. Schwetz serves as our principal accounting officer. Ms. Schwetz has executive responsibility for the Company’s financial and accounting functions, including treasury, insurance, risk management, accounting, financial reporting, tax, forecasting, capital management and budgeting, as well as investor relations and communications. She has previously served as our Senior Vice President of Finance and Administration - Australia, from June 2013 to June 2015; Senior Vice President of Finance and Administration - Americas, from March 2012 to June 2013; Vice President of Investor Relations, from December 2011 to March 2012; Vice President of Capital and Financial Planning, from November 2009 to December 2011; Director of Financial Planning, from August 2007 to October 2009; and Director of Compliance and Accounting Policies, from August 2005 to August 2007. Prior to joining us, Ms. Schwetz was employed by Ernst & Young LLP, an international accounting firm, where she held multiple audit roles over eight years. She holds a bachelor’s degree in Accounting from Indiana University. Ms. Schwetz is a member of the Dean’s Council at Indiana University’s Kelley School of Business and serves on the board of Downtown STL, Inc.

A. Verona Dorch was named our Executive Vice President, Chief Legal Officer, Governmental Affairs and Corporate Secretary in August 2015. In this role, she has executive responsibility for providing comprehensive legal counsel for Peabody's business activities and leads the Company's global legal, compliance and government affairs functions. Ms. Dorch has more than 20 years of legal experience counseling diverse global businesses. Prior to joining Peabody, from 2006 to March 2015, she served in a variety of roles for Harsco Corporation, a leading global industrial services company, where she advised the leadership team and board on strategic legal and business initiatives, most recently serving as Chief Legal Officer, Chief Compliance Officer and Corporate Secretary. She also has experience in corporate and securities law from top-tier law firms and with Sumitomo Chemical Co. following a multi-year secondment in Tokyo, Japan. Ms. Dorch is a Fellow of the American Bar Foundation and is a member of the Boards of Directors of Girls Inc. (St. Louis) and the United Way (St. Louis). Ms. Dorch holds a bachelor’s degree from Dartmouth College and a Juris Doctor degree from Harvard Law School.

Charles F. Meintjes was named our Executive Vice President - Corporate Services and Chief Commercial Officer in April 2017. Mr. Meintjes has executive responsibility for sales and marketing, corporate development, information technology, business services, technical services, and coal generation and emissions technology. Mr. Meintjes has extensive senior operational, strategy, continuous improvement and information technology experience with mining companies on three continents. He has also led financial and technical functions, large re-engineering programs, information technology system implementations and large industrial construction projects. He joined us in 2007, and prior to serving in his current post, he was our President - Australia. Other past positions with us include Acting President - Americas, Group Executive of Midwest and Colorado Operations, Senior Vice President of Operations Improvement and Senior Vice President Engineering and Continuous Improvement. Prior to joining us, Mr. Meintjes served as a consultant to Exxaro Resources Limited in South Africa, and is a former Executive Director and Board Member for Kumba Resources Limited in South Africa. He has senior management experience in the steel and the aluminum industry with Iscor and Alusaf in South Africa. Mr. Meintjes holds dual Bachelor of Commerce degrees in accounting from Rand Afrikaans University and the University of South Africa. He is a Chartered Accountant in South Africa and completed the advanced management program at the University of Pennsylvania’s Wharton School of Business.

Paul V. Richard was named our Senior Vice President and Chief Human Resources Officer in November 2017. He has executive responsibility for organizational and employee development, benefits, compensation, international human resources, security, travel and facilities management. Mr. Richard has more than 30 years of human resources experience and has been instrumental in leading his prior organizations to achieve Great Place to Work and Top Training Organization designations. From 2002 to 2017, Mr. Richard served as Vice President - Human Resources for Shaw Industries Group, Inc., a leading flooring materials producer and a subsidiary of Berkshire Hathaway, Inc. Prior to that, he served as a human resources leader for 19 years at Ferro Corporation, a global supplier of technology-based manufacturing, including 4 years as Vice President - Human Resources. Mr. Richard holds a Bachelor of Science degree in Management and a Masters of Business Administration from Louisiana Tech University.

George J. Schuller, Jr. was named our President - Australia in April 2017. He has executive responsibility for our Australia operating platform, which includes overseeing the areas of health and safety, operations, sales and marketing, product delivery and support functions. Mr. Schuller has been with the Company for three decades serving in both domestic and international operational posts. His extensive experience includes operations management for both surface and underground mining, continuous improvement and engineering services. Prior to serving as Chief Operations Officer in Australia, he served as Group Executive PRB & SW, Senior Vice President Engineering Services, Vice President Engineering Technical Services and Vice President Continuous Improvement following his holding various operations and mine management positions with increasing responsibility. Mr. Schuller originally joined the Company as a Mine Engineer-in-Training following a student co-op program. He holds a Bachelor of Science in mining engineering from West Virginia University as well as a Master of Business Administration degree from the University of Charleston.

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Kemal Williamson was named our President - Americas in October 2012. He has executive responsibility for our U.S. operating platform, which includes overseeing the areas of health and safety, operations, product delivery and support functions. Mr. Williamson has more than 30 years of experience in mining engineering and operations roles across North America and Australia. He most recently served as Group Executive Operations for the Peabody Energy Australia operations. He also has held executive leadership roles across project development, as well as in positions overseeing our Western U.S., Powder River Basin and Midwest operations. Mr. Williamson joined us in 2000 as Director of Land Management. Prior to that, he served for two years at Cyprus Australia Coal Corporation as Director of Operations and managed coal operations in Australia for half a decade. He also has mining engineering, financial analysis and management experience across Colorado, Kentucky and Illinois. Mr. Williamson holds a Bachelor of Science degree in mining engineering from Pennsylvania State University as well as a Master of Business Administration degree from the Kellogg School of Management, Northwestern University in Evanston, Illinois.

Regulatory Matters — U.S.

Federal, state and local authorities regulate the U.S. coal mining industry with respect to matters such as employee health and safety, permitting and licensing requirements, air quality standards, water pollution, plant and wildlife protection, the reclamation and restoration of mining properties after mining has been completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects of mining on groundwater quality and availability. In addition, the industry is affected by significant requirements mandating certain benefits for current and retired coal miners. Numerous federal, state and local governmental permits and approvals are required for mining operations. We believe that we have obtained all permits currently required to conduct our present mining operations.

We endeavor to conduct our mining operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time in the industry.

Mine Safety and Health

We are subject to health and safety standards both at the federal and state level. The regulations are comprehensive and affect numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations and other matters.

The Mine Safety and Health Administration (MSHA) is the entity responsible for monitoring compliance with the federal mine health and safety standards. MSHA employs various enforcement measures for noncompliance, including the issuance of monetary penalties and orders of withdrawal from a mine or part of a mine.

In Part I, Item 4. “Mine Safety Disclosures” and in Exhibit 95 to this Annual Report on Form 10-K, we provide additional details on MSHA compliance, through the mine safety disclosures required by SEC regulations.

Black Lung (Coal Worker’s Pneumoconiosis)

Under the U.S. Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each U.S. coal mine operator must pay federal black lung benefits and medical expenses to claimants who are current and former employees who last worked for the operator after July 1, 1973, and whose claims for benefits are allowed. Coal mine operators must also make payments to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to July 1, 1973. Historically, very few of the miners who sought federal black lung benefits were awarded these benefits; however, the approval rate has increased following implementation of black lung provisions contained in the Affordable Care Act. The trust fund is funded by an excise tax on U.S. production of up to $1.10 per ton for deep-mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

Environmental Laws and Regulations

We are subject to various federal, state, local and tribal environmental laws and regulations. These laws and regulations place substantial requirements on our coal mining operations, and require regular inspection and monitoring of our mines and other facilities to ensure compliance. We are also affected by various other federal, state, local and tribal environmental laws and regulations that impact our customers.

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Surface Mining Control and Reclamation Act. In the U.S., the Surface Mining Control and Reclamation Act of 1977 (SMCRA), which is administered by the Office of Surface Mining Reclamation and Enforcement (OSMRE), established mining, environmental protection and reclamation standards for all aspects of U.S. surface mining and many aspects of underground mining. Mine operators must obtain SMCRA permits and permit renewals for mining operations from the OSMRE. Where state regulatory agencies have adopted federal mining programs under SMCRA, the state becomes the primary regulatory authority, with oversight from OSMRE. Except for Arizona, states in which we have active mining operations have achieved primary control of enforcement through federal authorization. In Arizona, we mine on tribal lands and are regulated by the OSMRE because the tribes do not have SMCRA authorization.

SMCRA provides for three categories of bonds: surety bonds, collateral bonds and self-bonds. A surety bond is an indemnity agreement in a sum certain payable to the regulatory authority, executed by the permittee as principal and which is supported by the performance guarantee of a surety corporation. A collateral bond can take several forms, including cash, letters of credit, first lien security interest in property or other qualifying investment securities. A self-bond is an indemnity agreement in a sum certain executed by the permittee or by the permittee and any corporate guarantor made payable to the regulatory authority.

Our total reclamation bonding requirements in the U.S. were $1,249.2 million as of December 31, 2017. The bond requirements for a mine represent the calculated cost to reclaim the current operations of a mine if it ceased to operate in the current period. The cost calculation for each bond must be completed according to the regulatory authority of each state. Our asset retirement obligations calculated in accordance with generally accepted accounting principles for our U.S. operations were $457.9 million as of December 31, 2017. The bond requirement amount for our U.S. operations significantly exceeds the financial liability for final mine reclamation because the asset retirement obligation liability is discounted from the end of the mine's economic life to the balance sheet date in recognition that the final reclamation cash outlay is a number of years (and in some cases decades) away. The bond amount, in contrast with the asset retirement obligation, presumes reclamation begins immediately.

After a permit application is prepared and submitted to the regulatory agency, it goes through a completeness and technical review. Public notice of the proposed permit is given for a comment period before a permit can be issued. Regulatory authorities have considerable discretion in the timing of the permit issuance and the public has the right to comment on and otherwise engage in the permitting process, including public hearings and through intervention in the courts. Before a SMCRA permit is issued, a mine operator must submit a bond or other form of financial security to guarantee the performance of reclamation bonding requirements.

In situations where our coal resources are federally owned, the U.S. Bureau of Land Management oversees a substantive exploration and leasing process. If surface land is managed by the U.S. Forest Service, that agency serves as the cooperating agency during the federal coal leasing process. Federal coal leases also require an approved federal mining permit under the signature of the Assistant Secretary of the Department of the Interior.

The SMCRA Abandoned Mine Land Fund requires a fee on all coal produced in the U.S. The proceeds are used to rehabilitate lands mined and left unreclaimed prior to August 3, 1977 and to pay health care benefit costs of orphan beneficiaries of the Combined Fund created by the Coal Industry Retiree Health Benefit Act of 1992. The fee amount can change periodically based on changes in federal legislation. Pursuant to the Tax Relief and Health Care Act of 2006, from October 1, 2007 to September 30, 2012, the fee was $0.315 and $0.135 per ton of surface-mined and underground-mined coal, respectively. From October 1, 2012 through September 30, 2021, the fee is $0.28 and $0.12 per ton of surface-mined and underground-mined coal, respectively. We recognized expense related to the fees of $31.6 million for the Successor period April 2 through December 31, 2017 and $10.3 million, $38.7 million and $47.0 million for the Predecessor period January 1 through April 1, 2017 and the years ended December 31, 2016 and 2015, respectively.

Clean Air Act (CAA). The CAA, enacted in 1970, and comparable state and tribal laws that regulate air emissions affect our U.S. coal mining operations both directly and indirectly.

Direct impacts on coal mining and processing operations may occur through the CAA permitting requirements and/or emission control requirements relating to particulate matter (PM), nitrogen dioxide, ozone and sulfur dioxide (SO_2). In recent years the United States Environmental Protection Agency (EPA) has adopted more stringent national ambient air quality standards (NAAQS) for PM, nitrogen oxide, ozone and SO_2. It is possible that these modifications as well as future modifications to NAAQS could directly or indirectly impact our mining operations in a manner that includes, but is not limited to, designating new nonattainment areas or expanding existing nonattainment areas, serving as a basis for changes in vehicle emission standards or prompting additional local control measures pursuant to state implementation plans required to address revised NAAQS.

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In 2009, the EPA adopted revised rules to add more stringent PM emissions limits for coal preparation and processing plants constructed or modified after April 28, 2008. The PM NAAQS was thereafter revised and made more stringent in 2012. In 2015, the EPA issued a final rule setting the ozone NAAQS at 70 parts per billion (ppb). (80 Fed. Reg. 65,292, (Oct. 25, 2015)). This final rule has been challenged in the United States Court of Appeals for the D.C. Circuit (D.C. Circuit), however, the case has been held in abeyance pending the EPA's review of the final rule. More stringent ozone standards would require new state implementation plans to be developed and filed with the EPA and may trigger additional control technology for mining equipment, or result in additional challenges to permitting and expansion efforts. This could also be the case with respect to the implementation for other NAAQS for nitrogen oxide and SO_2.

The CAA also indirectly, but significantly affects the U.S. coal industry by extensively regulating the air emissions of SO_2, nitrogen oxides, mercury, PM and other substances emitted by coal-fueled electricity generating plants, imposing more capital and operating costs on such facilities. In addition, other CAA programs may require further emission reductions to address the interstate transport of air pollution or regional haze. The air emissions programs that may affect our operations, directly or indirectly, include, but are not limited to, the Acid Rain Program, interstate transport rules such as the Cross-State Air Pollution Rule (CSAPR) and the CSAPR Update Rule, New Source Performance Standards (NSPS), Maximum Achievable Control Technology (MACT) emissions limits for Hazardous Air Pollutants, the Regional Haze program and source permitting programs, including requirements related to New Source Review.

In addition, since 2011, the EPA has required underground coal mines to report on their greenhouse gas emissions. Regulations regarding reporting requirements for underground coal mines were updated in 2016 and now include the ability to cease reporting if mines are abandoned and sealed. At present, however, the EPA does not directly regulate such emissions.

Final NSPS for Fossil Fuel-Fired Electricity Utility Generating Units (EGUs). The EPA promulgated a final rule to limit carbon dioxide (CO_2) from new, modified and reconstructed fossil fuel-fired EGUs under section 111(b) of the CAA on August 3, 2015, and published it in the Federal Register on October 23, 2015.

This rule requires that newly-constructed fossil fuel-fired steam generating units achieve an emission standard for carbon dioxide of 1,400 lb carbon dioxide per megawatt-hour gross output (CO_2/MWh-gross). The standard is based on the performance of a supercritical pulverized coal boiler implementing partial carbon capture, utilization and storage (CCUS). Modified and reconstructed fossil fuel-fired steam generating units must implement the most efficient generation achievable through a combination of best operating practices and equipment upgrades, to meet an emission standard consistent with best historical performance. Reconstructed units must implement the most efficient generating technology based on the size of the unit (supercritical steam conditions for larger units, to meet a standard of 1,800 lb CO_2/MWh-gross, and subcritical conditions for smaller units to meet a standard of 2,000 lb CO_2/MWh-gross.).

Numerous legal challenges to the final rule were filed in the D.C. Circuit. Sixteen separate petitions for review were filed, and the challengers include 25 states, utilities, mining companies (including Peabody Energy), labor unions, trade organizations and other groups. The cases were consolidated under the case filed by North Dakota (D.C. Cir. No. 15-1381). Four additional cases were filed seeking review of the EPA's denial of reconsideration petitions in a final action published in the May 6, 2016 Federal Register entitled "Reconsideration of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Generating Units; Notice of final action denying petitions for reconsideration." Pursuant to an order of the court, these cases remain in abeyance, subject to requirements for the EPA to file 90-day status reports. Thus, the NSPS remains in effect.

Final Rule Regulating Carbon Dioxide Emissions From Existing Fossil Fuel-Fired EGUs. On October 23, 2015, the EPA published a final rule in the Federal Register regulating CO_2 emissions from existing fossil fuel-fired EGUs under section 111(d) of the CAA (80 Fed. Reg. 64,662 (Oct. 23, 2015)). The rule (known as the Clean Power Plan (CPP)) establishes emission guidelines for states to follow in developing plans to reduce greenhouse gas emissions from existing fossil fuel-fired EGUs. These final guidelines require that the states individually or collectively create systems that would reduce carbon emissions from any EGU located within their borders by 28% in 2025 and 32% in 2030 (compared with a 2005 baseline).

Following Federal Register publication, 39 separate petitions for review of the CPP by approximately 157 entities were filed in the D.C. Circuit. The petitions reflect challenges by 27 states and governmental entities, as well as challenges by utilities, industry groups, trade associations, coal companies, and other entities. The lawsuits were consolidated with the case filed by West Virginia and Texas (in which other states have also joined). (D.C. Cir. No. 15-1363). On October 29, 2015, we filed a motion to intervene in the case filed by West Virginia and Texas, in support of the petitioning states. The motion was granted on January 11, 2016. Numerous states and cities have also been allowed to intervene in support of the EPA.

On February 9, 2016, the Supreme Court granted a motion to stay implementation of the CPP until its legal challenges are resolved. Thereafter, oral arguments in the case were heard in the D.C. Circuit sitting en banc by ten active D.C. Circuit judges, but to date, the D.C. Circuit has not issued an opinion. On April 28, 2017, the D.C. Circuit granted a motion by the EPA to hold the case in abeyance while the Agency reconsidered the rule.

In October 2017, the EPA proposed to change its legal interpretation of CAA section 111(d), the authority that the Agency relied on for the 2015 CPP. (82 Fed. Reg. 48,035 (Oct. 16, 2017)). The EPA will accept public comments through April 26, 2018. If this proposed reinterpretation is finalized by the EPA, the CPP would be repealed. The EPA has also published an Advance Notice of Proposed Rulemaking to solicit information concerning a potential new rule for emission guidelines for existing EGUs pursuant to CAA section 111(d). 82 Fed. Reg. 61,508 (Dec. 28, 2017).

EPA's Greenhouse Gas (GHG) Permitting Regulations for Major Emission Sources. In May 2010, the EPA published final rules requiring permitting and control technology requirements for GHGs under the Prevention of Significant Deterioration (PSD) and Title V permitting programs that apply to stationary sources of air pollution. The EPA determined that these requirements were "triggered" by the EPA's prior regulation of GHGs from motor vehicles.These rules were subsequently upheld by the D.C. Circuit on June 26, 2012. On June 23, 2014, however, the U.S. Supreme Court ruled that the EPA could not require PSD and Title V permitting for GHGs emitted from stationary sources if those sources were not otherwise considered to be "major sources" of conventional pollutants for purposes of PSD and Title V. Affected sources are required to employ the best available control technology for GHGs as determined by the governmental entity that issues the permit (most often a state environmental agency).

Cross State Air Pollution Rule (CSAPR) and CSAPR Update Rule. On July 6, 2011, the EPA finalized the CSAPR, which requires the District of Columbia and 27 states from Texas eastward (not including the New England states or Delaware) to reduce power plant emissions that cross state lines and significantly contribute to ozone and/or fine particle pollution in other states. Following litigation in the D.C. Circuit and U.S. Supreme Court, the first phase of the nitrogen oxide and SO_2 emissions reductions required by CSAPR commenced in January 2015; further reductions of both pollutants in the second phase of CSAPR became effective in January 2017. The EPA subsequently revised CSAPR requirements for the state of Texas to remove that state from second phase requirements regarding SO_2 (82 Fed. Reg. 45,481 (Sept. 29, 2017)).

On October 26, 2016, the EPA promulgated the CSAPR Update Rule to address implementation of the 2008 ozone national air quality standards. This rule imposed further reductions in nitrogen oxides in 2017 in 22 states subject to CSAPR. Several states and utilities as well as agricultural and industry groups utilities have filed petitions for review of the CSAPR Update Rule in the D.C. Circuit. Other states and interest groups have filed to intervene on behalf of the EPA. These petitions have been consolidated under D.C. Cir. No. 16-1406.

Mercury and Air Toxic Standards (MATS). The EPA published the final MATS rule in the Federal Register on February 16, 2012. The MATS rule revised the NSPS for nitrogen oxides, SO_2 and PM for new and modified coal-fueled electricity generating plants, and imposed MACT emission limits on hazardous air pollutants (HAPs) from new and existing coal-fueled and oil-fueled electric generating plants. MACT standards limit emissions of mercury, acid gas HAPs, non-mercury HAP metals and organic HAPs. The rule provided three years for compliance with MACT standards and a possible fourth year if a state permitting agency determined that such was necessary for the installation of controls.

Following issuance of the final rule, numerous petitions for review were filed. The D.C. Circuit upheld the NSPS portion of the rulemaking in a unanimous decision on March 11, 2014, and upheld the limits on HAPs against all challenges on April 15, 2014, in a two-to-one decision. Industry groups and a number of states filed and were granted review of the D.C. Circuit decision in the U.S. Supreme Court. On June 29, 2015 the U.S. Supreme Court held that the EPA interpreted the CAA unreasonably when it deemed cost irrelevant to the decision to regulate HAPs from power plants. The court reversed the D.C. Circuit and remanded the case for further proceedings. On December 1, 2015, in response to the court's decision the EPA published a proposed supplemental finding in the Federal Register that consideration of costs does not alter the EPA's previous determination regarding the control of HAPs in the MATS rule. On December 15, 2015, the D.C. Circuit issued an order providing that the rule will remain in effect while the EPA responds to the U.S. Supreme Court decision.

On April 14, 2016, the EPA issued a final supplemental finding that largely tracked its proposed finding. Several states, companies and industry groups challenged that supplemental finding in the D.C. Circuit in separate petitions for review, which were subsequently consolidated. D.C. Cir. No. 116-1127. Several states and environmental groups also filed as intervenors for the respondent EPA. Although briefing in this litigation has concluded, the case remains in abeyance while the EPA reviews the supplemental finding to determine whether the rule should be maintained, modified, or otherwise reconsidered.

Federal Coal Leasing Moratorium. President Trump’s Executive Order on Promoting Energy Independence and Economic Growth (EI Order) signed on March 28, 2017, lifted the Department of Interior’s federal coal leasing moratorium and rescinded guidance on the inclusion of social cost of carbon in federal rulemaking. Following the EI Order, the Interior Secretary issued Order 3349 ending the federal coal leasing moratorium.

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Stream Protection Rule. On July 27, 2015, the OSMRE issued its proposed Stream Protection Rule (SPR). The proposed rule would have impacted both surface and underground mining operations and would have increased testing and monitoring requirements related to the quality or quantity of surface water and groundwater or the biological condition of streams. The SPR would have also required the collection of increased pre-mining data about the site of the proposed mining operation and adjacent areas to establish a baseline for evaluation of the impacts of mining and the effectiveness of reclamation associated with returning streams to pre-mining conditions. Both chambers of Congress have already passed legislation to repeal and invalidate the rulemaking, pursuant to the Congressional Review Act. The House passed H.J. Res. 38 on February 1, 2017 and the Senate passed the bill the next day. On February 16, 2017, President Trump signed H.J. Res. 38, resulting in the repeal of the SPR and preventing the OSMRE from promulgating any substantially similar rule.

Clean Water Act (CWA). The CWA of 1972 directly impacts U.S. coal mining operations by requiring effluent limitations and treatment standards for wastewater discharge from mines through the National Pollutant Discharge Elimination System (NPDES). Regular monitoring, reporting and performance standards are requirements of NPDES permits that govern the discharge of water from mine-related point sources into receiving waters.

The U.S. Army Corps of Engineers (Corps) regulates certain activities affecting navigable waters and waters of the U.S., including wetlands. Section 404 of the CWA requires mining companies to obtain Corps permits to place material in streams for the purpose of creating slurry ponds, water impoundments, refuse areas, valley fills or other mining activities.

States are empowered to develop and apply “in stream” water quality standards. These standards are subject to change and must be approved by the EPA. Discharges must either meet state water quality standards or be authorized through available regulatory processes such as alternate standards or variances. “In stream” standards vary from state to state. Additionally, through the CWA section 401 certification program, states have approval authority over federal permits or licenses that might result in a discharge to their waters. States consider whether the activity will comply with their water quality standards and other applicable requirements in deciding whether or not to certify the activity.

A final rule defining the scope of waters protected under the Clean Water Act (commonly called the Waters of the United States (WOTUS) Rule) was published by the EPA and the Corps in June 2015, but the U.S. Court of Appeals for the Sixth Circuit stayed the rule nationwide since October 9, 2015. Numerous lawsuits challenging the 2015 WOTUS Rule remain pending at this time, though all litigation has been stayed, while the U.S. Supreme Court considered whether the Sixth Circuit (where all challenges that were filed in the courts of appeals were consolidated) has exclusive jurisdiction over challenges to the rule or whether challenges must begin in district courts. On January 22, 2018, the Supreme Court held that challenges to the WOTUS Rule must begin in the district courts, and ordered the Sixth Circuit to dismiss the challenges pending before it. As a result of the Supreme Court’s ruling, litigation on the merits of the 2015 WOTUS Rule will likely resume in one or more district courts. On February 28, 2017 the Trump Administration released an Executive Order directing the EPA and the Corps to consider rescinding or revising the WOTUS Rule, and the EPA and the Corps issued a similar notice that same day. The EPA and the Corps are in the process of repealing the 2015 WOTUS Rule and developing a replacement rule. The agencies have proposed, but not yet finalized, a repeal action, and they plan to propose a replacement rule in mid-2018. The agencies also recently revised the 2015 WOTUS Rule by postponing its application until February 6, 2020. Several states and environmental groups immediately challenged this action, but for the time being, the pre-2015 definitions of WOTUS remain in effect nationwide. If CWA authority is eventually expanded, it may impact our operations in some areas by way of additional requirements.

National Environmental Policy Act (NEPA). NEPA, signed into law in 1970, requires federal agencies to review the environmental impacts of their decisions and issue either an environmental assessment or an environmental impact statement. We must provide information to agencies when we propose actions that will be under the authority of the federal government. The NEPA process involves public participation and can involve lengthy timeframes.

Resource Conservation and Recovery Act (RCRA). RCRA, which was enacted in 1976, affects U.S. coal mining operations by establishing “cradle to grave” requirements for the treatment, storage and disposal of hazardous wastes. Typically, the only hazardous wastes generated at a mine site are those from products used in vehicles and for machinery maintenance. Coal mine wastes, such as overburden and coal cleaning wastes, are not considered hazardous wastes under RCRA.

Subtitle C of RCRA exempted fossil fuel combustion wastes from hazardous waste regulation until the EPA completed a report to Congress and made a determination on whether the wastes should be regulated as hazardous. On December 19, 2014, the EPA announced the final rule on coal combustion residuals (CCR or coal ash). As finalized, the rule continues the exemption of CCR from regulation as a hazardous waste, but does impose new requirements at existing CCR surface impoundments and landfills that will need to be implemented over a number of different time-frames in the coming months and years, as well as at new surface impoundments and landfills. Generally these requirements will increase the cost of CCR management, but not as much as if the rule had regulated CCR as hazardous. This EPA initiative is separate from the OSMRE CCR rulemaking mentioned above.

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Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). Although generally not a prominent environmental law in the coal mining sector, CERCLA, which was enacted in 1980, nonetheless may affect U.S. coal mining operations by creating liability for investigation and remediation in response to releases of hazardous substances into the environment and for damages to natural resources. Under CERCLA, joint and several liabilities may be imposed on waste generators, site owners or operators and others, regardless of fault.

Toxic Release Inventory. Arising out of the passage of the Emergency Planning and Community Right-to-Know Act in 1986 and the Pollution Prevention Act passed in 1990, the EPA's Toxic Release Inventory program requires companies to report the use, manufacture or processing of listed toxic materials that exceed established thresholds, including chemicals used in equipment maintenance, reclamation, water treatment and ash received for mine placement from power generation customers.

Endangered Species Act (ESA). The ESA of 1973 and counterpart state legislation is intended to protect species whose populations allow for categorization as either endangered or threatened. Changes in listings or requirements under these regulations could have a material adverse effect on our costs or our ability to mine some of our properties in accordance with our current mining plans.

Use of Explosives. Our surface mining operations are subject to numerous regulations relating to blasting activities. Pursuant to these regulations, we incur costs to design and implement blast schedules and to conduct pre-blast surveys and blast monitoring. The storage of explosives is subject to strict federal regulatory requirements. The U.S. Bureau of Alcohol, Tobacco and Firearms (ATF) regulates the use of explosive blasting materials. In addition to ATF regulation, the Department of Homeland Security is expected to finalize an ammonium nitrate security program rule. The OSMRE has also initiated a rulemaking addressing nitrous clouds that may be produced during blasting. While such new regulations may result in additional costs related to our surface mining operations, such costs are not expected to have a material adverse effect on our results of operations, financial condition or cash flows.

OSMRE Self-Bonding Notice of Rulemaking. On August 16, 2016, the OSMRE announced a decision to initiate a rulemaking process to update the OSMRE's bonding regulations. The decision stated that the OSMRE will be reviewing the self-bonding program and will consider revising the review process for determining if a company qualifies for self-bonding as well as the process for replacing self-bonds in the event a company no longer qualifies for self-bonding. There is no anticipated timing for the proposed rule and the new Director of OSMRE has not indicated he will continue with the proposed rulemaking.

Grid Resiliency Pricing Rule. On October 10, 2017, the Secretary of Energy (the Secretary) published a Notice of Proposed Rulemaking entitled the Grid Resiliency Pricing Rule (the Proposed Rule). The Proposed Rule was issued by the Secretary pursuant to section 403 of the Department of Energy Organization Act. 42 U.S.C. § 7173. In the Proposed Rule, the Secretary instructed the Federal Energy Regulatory Commission (FERC) to impose rules to ensure that reliability and resiliency attributes of certain electric generation units with a 90-day on-site fuel supply are fully compensated for the benefits and services they provide to grid operations. The Secretary directed FERC to take final action on the Proposed Rule within 60 days of publication or, in the alternative, to issue the rule as an interim final rule immediately, with provision for later modifications after consideration of public comments. The Proposed Rule cites the retirements of coal and nuclear plants as a potential threat to grid reliability and resilience, and provides for the creation of a "reliability and resiliency rate" that would compensate certain eligible resources for the benefits and services they provide to grid operations, allowing such eligible resources to recover their fully allocated costs and a fair return on equity. The "reliability and resiliency rate" would be available to eligible resources operating within FERC-approved independent system operators or regional transmission organizations with energy and capacity markets. The rate would apply only to generators that are not currently subject to cost-of-service regulation by a state or other authority. On January 8, 2018, FERC unanimously denied the petition and requested additional information from power grid operators thus putting off any new rulemaking by at least two months, dismissing the Secretary's call to act immediately. FERC has opened a new proceeding to "take additional steps to explore resilience issues in the [regional transmission organizations and independent system operators]." That docket will aim to develop an understanding of what resilience actually means for the grid and to understand how each grid operator addresses the issue.

Regulatory Matters — Australia

The Australian mining industry is regulated by Australian federal, state and local governments with respect to environmental issues such as land reclamation, water quality, air quality, dust control, noise, planning issues (such as approvals to expand existing mines or to develop new mines) and health and safety issues. The Australian federal government retains control over the level of foreign investment and export approvals. Industrial relations are regulated under both federal and state laws. Australian state governments also require coal companies to post deposits or give other security against land which is being used for mining, with those deposits being returned or security released after satisfactory reclamation is completed.

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Native Title and Cultural Heritage. Since 1992, the Australian courts have recognized that native title to lands, as recognized under the laws and customs of the Aboriginal inhabitants of Australia, may have survived the process of European settlement. These developments are supported by the Federal Native Title Act which recognizes and protects native title, and under which a national register of native title claims has been established. Native title rights do not extend to minerals; however, native title rights can be affected by the mining process unless those rights have previously been extinguished thereby requiring negotiation with the traditional owners (and potentially the payment of compensation) prior to the grant of certain mining tenements. There is also federal and state legislation to prevent damage to Aboriginal cultural heritage and archaeological sites.

Mining Tenements and Environmental. In Queensland and New South Wales, the development of a mine requires both the grant of a right to extract the resource and an approval which authorizes the environmental impact. These approvals are obtained under separate legislation from separate government authorities. However, the application processes run concurrently and are also concurrent with any native title or cultural heritage process that is required. The environmental impacts of mining projects are regulated by state and federal governments. Federal regulation will only apply if the particular project will significantly impact a matter of national environmental significance (for example, a water resource, an endangered species or particular protected places). Environmental approvals processes involve complex issues that, on occasion, require lengthy studies and documentation. Typically mining proponents must also reach agreement with the owners of land underlying proposed mining tenements prior to the grant and/or conduct of mining activities or otherwise acquire the land. These arrangements generally involve the payment of compensation in lieu of the impacts of mining on the land.

Our Australian mining operations are generally subject to local, state and federal laws and regulations. At the federal level, these legislative acts include, but are not limited to, the Environment Protection and Biodiversity Conservation Act 1999, Native Title Act 1993, Fair Work Act 2009 and the Aboriginal and Torres Strait Islander Heritage Protection Act 1984.

In Queensland, laws and regulations related to mining include, but are not limited to, the Mineral Resources Act 1989, Environmental Protection Act 1994 (EP Act), Environmental Protection Regulation 1998, Sustainable Planning Act 2009, Building Act 1975, Explosives Act 1999, Aboriginal Cultural Heritage Act 2003, Water Act 2000, State Development and Public Works Organisation Act 1971, Queensland Heritage Act 1992, Transport Infrastructure Act 1994, Nature Conservation Act 1992, Vegetation Management Act 1999, Land Protection (Pest and Stock Route Management) Act 2002, Land Act 1994, Regional Planning Interests Act 2014, Fisheries Act 1994 and Forestry Act 1959. Under the EP Act, policies have been developed to achieve the objectives of the law and provide guidance on specific areas of the environment, including air, noise, water and waste management. State planning policies address matters of Queensland State interest, and must be adhered to during mining project approvals. Increased emphasis has recently been placed on topics including, but not limited to, hazardous dams assessment and the protection of strategic cropping land. The Mineral Resources Act 1989 was amended effective September 27, 2016 to include significant changes to the management of overlapping coal and coal seam gas tenements and the coordination of activities and access to private and public land. In November 2016, amendments to the EP Act and the Water Act 2000 became effective and facilitate regulatory scrutiny of the environmental impacts of underground water extraction during the operational phase of resource projects for all tenements yet to commence mineral extraction. The ‘Chain of Responsibility’ provisions of the EP Act, effective in April 2016, allow the regulator to issue an environmental protection order (EPO) to a related person of a company in two circumstances; (a) if an EPO has been issued to the company, an EPO can also be issued to a related person of the company (at the same time or later); or (b) if the company is a high risk company (as defined in the EP Act), an EPO can be issued to a related person of the company (whether or not an EPO has also been issued to the company). A guideline has been issued to provide more certainty to the industry on the circumstances when an EPO may be issued.

In New South Wales, laws and regulations related to mining include, but are not limited to, the Mining Act 1992, Work Health and Safety (Mines) Act 2013, Mine Subsidence Compensation Act 1961, Environmental Planning and Assessment Act 1979 (EP&A Act), Environmental Planning and Assessment Regulations 2000, Protection of the Environment Operations Act 1997, Contaminated Land Management Act 1997, Explosives Act 2003, Water Management Act 2000, Water Act 1912, Radiation Control Act 1990, Heritage Act 1977, Aboriginal Land Rights Act

1983, Crown Lands Act 1989, Dangerous Goods (Road and Rail Transport) Act 2008, Fisheries Management Act 1994, Forestry Act 1916, Native Title (New South Wales) Act 1994, Native Vegetation Act 2003, Noxious Weeds Act 1993, Roads Act 1993 and National Parks & Wildlife Act 1974. Under the EP&A Act, environmental planning instruments must be considered when approving a mining project development application. There are multiple State Environmental Planning Policies (SEPPs) relevant to coal projects in New South Wales. Amendments to the SEPPs that cover mining have occurred in the past two years and are aimed at protecting agriculture, water resources and critical industry clusters. One SEPP, referred to as the Mining SEPP, was amended in late 2013 to make it mandatory for decision makers to consider the economic significance of coal resources when determining a development application for a mine and to give primacy to that consideration. This amendment was repealed in 2015. However, decision makers review the significance of a resource and the state and regional economic benefits of a proposed coal mine when considering a development application on the basis that it is an element of the "public interest" consideration contained in the legislation.

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Mining Rehabilitation (Reclamation). Mine reclamation is regulated by state specific legislation. As a condition of approval for mining operations, companies are required to progressively reclaim mined land and provide appropriate bonding to the relevant state government as a safeguard to cover the costs of reclamation in circumstances where mine operators are unable to do so. Self-bonding is not permitted. Our mines provide financial assurance to the relevant authorities which is calculated in accordance with current regulatory requirements. This financial assurance is in the form of cash or bank guarantees which are supported by a combination of cash collateral and letters of credit drawn upon our credit facility and securitization program. We operate in both the Queensland and New South Wales state jurisdictions.

Our reclamation bonding requirements in Australia were $281.3 million as of December 31, 2017. The bond requirements represent the calculated cost to reclaim the current operations of a mine if it ceased to operate in the current period less any discounts agreed with the state. The cost calculation for each bond must be completed according to the regulatory authority of each state. The costs associated with our Australian asset retirement obligations are calculated in accordance with generally accepted accounting principles and were $233.2 million as of December 31, 2017. The total bonding requirements for our Australian operations differ from the calculated costs associated with the asset retirement obligations because the costs associated with asset retirement obligations are discounted from the end of the mine’s economic life to the balance sheet date in recognition of the economic reality that reclamation is conducted progressively and final reclamation is a number of years (and in some cases decades) away, whereas the bonding amount represents the cost of reclamation if a mine ceases to operate immediately.

New South Wales Reclamation. The Mining Act 1992 (Mining Act) is administered by the Department of Industry - Resources & Energy and authorizes the holder of a mining tenement to extract a mineral subject to obtaining consent under the Environmental Planning & Assessment Act 1979 and other auxiliary approvals and licenses.

Through the Mining Act, environmental protection and reclamation are regulated by conditions in all mining leases including requirements for the submission of a Mining Operations Plan (MOP) prior to the commencement of operations. All mining operations must be carried out in accordance with the MOP which describes site activities and the progress toward environmental and reclamation outcomes and are updated on a regular basis or if mine plans change. The mines publicly report their reclamation performance on an annual basis.

In support of the MOP process, a reclamation cost estimate is calculated periodically to determine the amount of bond support required to cover the cost of reclamation based on extent of disturbance during the MOP period.

Queensland Reclamation. The Environmental Protection Act 1994 (EP Act) is administered by the Department of Environment and Heritage Protection which authorizes environmentally relevant activities such as mining activities relating to a mining lease through an Environmental Authority (EA). Environmental protection and reclamation activities are regulated by conditions in the EA, including the requirement for the submission of a Plan of Operations (PO) prior to the commencement of operations. All mining operations must be carried out in accordance with the PO which describes site activities and the progress toward environmental and rehabilitation outcomes and are updated on a regular basis or if mine plans change. The mines submit an annual return reporting on their EA compliance including reclamation performance.

As a condition of the EA, bonding requirements are calculated to determine the amount of bonding required to cover the cost of reclamation based on extent of disturbance during the PO period.

In May 2017, the Queensland government announced broad policy reform proposals in relation to financial assurance (FA) and rehabilitation for the mining and petroleum sector. The proposed regime represents a new approach to managing Queensland’s existing rehabilitation risks.

On October 25, 2017, the Queensland Parliament introduced the Mineral and Energy Resources (Financial Provisioning) Bill 2017 (MERFP Bill), which contained proposed legislation to give effect to some of the policy reforms, including a remodeled FA framework that takes into account the financial strength of the FA holder and the risk level of the mine, a state-wide pooled FA fund covering most mines and most of the total industry liability, discontinuation of prior discounting of FA requirements, other options for providing FA for those mines that are not part of the pooled FA fund (for example, allowing insurance bonds or cash), updated rehabilitation calculations, and regular monitoring and reporting measures for progressive mine rehabilitation.

However, the MERFP Bill lapsed on October 29, 2017 when a Queensland state election was called. It is expected that the MERFP Bill, or a bill substantially similar thereto, will be reintroduced into Parliament in the near future.
Federal Reclamation. In February 2017, the Australian Senate established a Committee of Inquiry into the rehabilitation of mining and resources projects as it relates to Commonwealth responsibilities, for example, under the Environment Protection and Biodiversity Conservation Act 1999. The Committee is holding public hearings and is expected to issue a report during the second quarter of 2018.

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Occupational Health and Safety. State legislation requires us to provide and maintain a safe workplace by providing safe systems of work, safety equipment and appropriate information, instruction, training and supervision. In recognition of the specialized nature of mining and mining activities, specific occupational health and safety obligations have been mandated under state legislation specific to the coal mining industry. There are some differences in the application and detail of the laws, and mining operators, directors, officers and certain other employees are all subject to the obligations under this legislation.

A small number of coal mine workers in Queensland and New South Wales have been diagnosed with coal worker's pneumoconiosis (CWP, also known as black lung) following decades of assumed eradication of the disease. This has led the Queensland government to sponsor review of the system of screening coal mine workers for the disease with a view to improving early detection. The Queensland government has instituted increased reporting requirements for dust monitoring results, broader coal mine worker health assessment requirements and voluntary retirement examinations for coal mine workers to be arranged by the relevant employer and further reform may follow. Peabody has undertaken a review of its practices and offered its Queensland workers the opportunity for additional CWP screening.

The Queensland government held a Parliamentary inquiry into the re-emergence of CWP in the State which included public hearings with appearances by representatives of the coal mining industry, including us, coal mine workers, the Department of Natural Resources and others. The Queensland Parliamentary Committee conducting the inquiry issued its final report on May 29, 2017. In finding that it is highly unlikely CWP was ever eradicated in Queensland, the Committee made 68 recommendations to ensure the safety and health of mine workers. These include an immediate reduction to the occupational exposure limit for respirable coal dust equivalent to 1.5mg/m^3 for coal dust and 0.05 mg/m^3 for silica and the establishment of a new and independent Mine Safety Authority to be funded by a dedicated proportion of coal and mineral royalties and overseeing the Mines Safety Inspectorate.

On August 23, 2017, the Queensland Parliament passed the Workers' Compensation and Rehabilitation (Coal Workers' Pneumoconiosis) and Other Legislation Amendment Act 2017, which amends the Workers' Compensation and Rehabilitation Act 2003 by establishing a medical examination process for retired or former coal workers with suspected CWP, introducing an additional lump sum compensation for workers with CWP, and clarifying that a worker with CWP can access further workers' compensation entitlements if they experience disease progression.

On August 24, 2017, the Queensland Parliamentary Committee released a report containing a draft of the Mine Safety and Health Authority Bill 2017, which proposes to establish the Mine Safety Authority foreshadowed in the Committee's recommendations released in May 2017. The draft bill has been referred to the Parliamentary Portfolio Committee for review.

On September 7, 2017, the Queensland Parliament introduced a bill to amend legislation which, if passed, would increase civil penalties for mining companies breaching their obligations under the Coal Mining Safety and Health Act 1999 (CMSHA Bill). The proposed amendments would also give the Chief Executive of the Department of Natural Resources and Mining new powers to suspend or cancel an individual's statutory certificate of competency and issue site senior executives (SSEs) notices if they fail to meet their safety and health obligations. Higher levels of competency for the statutory position of ventilation officer at underground mines will also be required if the legislation is passed.

However, the CMSHA Bill lapsed on October 29, 2017 when a Queensland state election was called. It is expected that the bill, or one substantially similar thereto, will be reintroduced into Parliament in the near future.

Industrial Relations. A national industrial relations system administered by the federal government applies to all private sector employers and employees. The matters regulated under the national system include employment conditions, unfair dismissal, enterprise bargaining, bullying claims, industrial action and resolution of workplace disputes. Many of the workers employed in our mines are covered by enterprise agreements approved under the national system.

National Greenhouse and Energy Reporting Act 2007 (NGER Act). The NGER Act imposes requirements for corporations meeting a certain threshold to register and report greenhouse gas emissions and abatement actions, as well as energy production and consumption as part of a single, national reporting system. The Clean Energy Regulator administers the NGER Act. The Department of Environment and Energy is responsible for NGER Act-related policy developments and review. Both foreign and local corporations that meet the prescribed carbon dioxide and energy production or consumption limits in Australia (Controlling Corporations) must comply with the NGER Act. One of our subsidiaries is now registered as a Controlling Corporation and must report annually on the greenhouse gas emissions and energy production and consumption of our Australian entities.

On July 1, 2016, amendments to the NGER Act implemented the Emissions Reduction Fund Safeguard Mechanism. From that date, large designated facilities such as coal mines were issued with a baseline for their covered emissions and must take steps to keep their emissions at or below the baseline or face penalties.

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Queensland Royalty. Royalties are payable to the State of Queensland at a rate of 12.5% on coal prices over $100 Australian dollars per tonne and up to $150 Australian dollars per tonne and 15% on pricing over $150 Australian dollars per tonne. The rate is 7% for coal sold below $100 Australian dollars per tonne. The periodic impact of these royalty rates is dependent upon the volume of tonnes produced at each of our Queensland mining locations and coal prices received for those tonnes. The Queensland Office of State Revenue issues determinations setting out its interpretation of the laws that impose royalties and provide guidance on how royalty rates should be calculated.

New South Wales Royalty. In New South Wales, the royalty applicable to coal is charged as a percentage of the value of production (total revenue less allowable deductions). This is equal to 6.2% for deep underground mines (coal extracted at depths greater than 400 meters below ground surface), 7.2% for underground mines and 8.2% for open-cut mines.

Global Climate

In the U.S., Congress has considered legislation addressing global climate issues and greenhouse gas emissions, but to date nothing has been enacted. While it is possible that the U.S. will adopt legislation in the future, the timing and specific requirements of any such legislation are uncertain. In the absence of new U.S. federal legislation, the EPA is undertaking steps to regulate greenhouse gas emissions pursuant to the Clean Air Act. In response to the 2007 U.S. Supreme Court ruling in Massachusetts v. EPA, the EPA commenced several rulemaking projects as described under "Regulatory Matters-U.S. - Environmental Laws and Regulations." In particular, on August 3, 2015, the EPA announced the final rules (which were published in the Federal Register on October 23, 2015) for regulating carbon dioxide emissions from existing and new fossil fuel-fired EGUs. The EPA has set emission performance rates for existing plants to be phased in over the period from 2022 through 2030. This rule is intended to reduce carbon dioxide emissions from the 2005 baseline by 28% in 2025 and 32% in 2030. The EPA has also set standards applying to new, modified and reconstructed sources beginning in 2015.

A number of states in the U.S. have adopted programs to regulate greenhouse gas emissions. For example, 10 northeastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont) entered into the Regional Greenhouse Gas Initiative (RGGI) in 2005, which is a mandatory cap-and-trade program to cap regional carbon dioxide emissions from power plants. In 2011, New Jersey announced its withdrawal from RGGI effective January 1, 2012. Six mid-western states (Illinois, Iowa, Kansas, Michigan, Minnesota and Wisconsin) and one Canadian province have entered into the Midwestern Regional Greenhouse Gas Reduction Accord (MGGRA) to establish voluntary regional greenhouse gas reduction targets and develop a voluntary multi-sector cap-and-trade system to help meet the targets. It has been reported that, while the MGGRA has not been formally suspended, the participating states are no longer pursuing it. Seven western states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and four Canadian provinces entered into the Western Climate Initiative (WCI) in 2008 to establish a voluntary regional greenhouse gas reduction goal and develop market-based strategies to achieve emissions reductions. However, in November 2011, the WCI announced that six states had withdrawn from the WCI, leaving California and four Canadian provinces as the remaining members. Of those five jurisdictions, only California and Quebec have adopted greenhouse gas cap-and-trade regulations to date and both programs have begun operating. Many of the states and provinces that left WCI, RGGI and MGGRA, along with many that continue to participate, have joined the new North America 2050 initiative, which seeks to reduce greenhouse gas emissions and create economic opportunities in ways not limited to cap-and-trade programs.

In the U.S., several states have enacted legislation establishing greenhouse gas emissions reduction goals or requirements. In addition, several states have enacted legislation or have in effect regulations requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power or that provide financial incentives to electricity suppliers for using renewable energy sources. Some states have initiated public utility proceedings that may establish values for carbon emissions.

We participated in the Department of Energy's Voluntary Reporting of Greenhouse Gases Program until its suspension in May 2011, and regularly disclose in our Corporate and Social Responsibility Report the quantity of emissions per ton of coal produced by us in the U.S. The vast majority of our emissions are generated by the operation of heavy machinery to extract and transport material at our mines and fugitive emissions from the extraction of coal.

In 2013, the U.S. and a number of international development banks, including the World Bank, the European Investment Bank and the European Bank for Reconstruction and Development, announced that they would no longer provide financing for the development of new coal-fueled power plants or would do so only in narrowly defined circumstances. Other international development banks, such as the Asian Development Bank and the Japanese Bank for International Cooperation, have continued to provide such financing.

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The Kyoto Protocol, adopted in December 1997 by the signatories to the 1992 United Nations Framework Convention on Climate Change (UNFCCC), established a binding set of greenhouse gas emission targets for developed nations. The U.S. signed the Kyoto Protocol but it has never been ratified by the U.S. Senate. Australia ratified the Kyoto Protocol in December 2007 and became a full member in March 2008. There were discussions to develop a treaty to replace the Kyoto Protocol after the expiration of its commitment period in 2012, including at the UNFCCC conferences in Cancun (2010), Durban (2011), Doha (2012) and Paris (2015). At the Durban conference, an ad hoc working group was established to develop a protocol, another legal instrument or an agreed outcome with legal force under the UNFCCC, applicable to all parties. At the Doha meeting, an amendment to the Kyoto Protocol was adopted, which included new commitments for certain parties in a second commitment period, from 2013 to 2020. In December 2012, Australia signed on to the second commitment period. During the UNFCCC conference in Paris, France in late 2015, an agreement was adopted calling for voluntary emissions reductions contributions after the second commitment period ends in 2020. The agreement was entered into force on November 4, 2016 after ratification and execution by more than 55 countries, including Australia, that account for at least 55% of global greenhouse gas emissions. The Trump Administration has announced the U.S. will begin the process of withdrawing from the Paris Agreement.

Australia's Parliament passed carbon pricing legislation in November 2011. The first program involved the imposition of a carbon tax that commenced in July 2012. On July 16, 2014, Australia's Parliament repealed the legislation, which was retrospectively abolished from July 1, 2014.

In October 2017, the Australian government announced the National Energy Guarantee (NEG). The NEG is intended to reduce the supply volatility and escalating prices that currently exist in the Australian east coast electricity network and provide for affordable, reliable electricity while still meeting Australia's emissions targets. The NEG has an energy neutral focus. It is expected that the Renewable Energy Target (RET) will not continue beyond its currently planned end date in 2020.

The impact of the NEG on the Company's operations using electricity is yet to be determined as the details of the NEG are still being formulated by the Australian government. The NEG requires approval of the Council of Australian Governments to come into effect.

Enactment of laws or passage of regulations regarding emissions from the use of coal by the U.S., some of its states or other countries, or other actions to limit such emissions, could result in electricity generators switching from coal to other fuel sources. Further, policies limiting available financing for the development of new coal-fueled power stations could adversely impact the global demand for coal in the future. The potential financial impact on us of future laws, regulations or other policies will depend upon the degree to which any such laws or regulations force electricity generators to diminish their reliance on coal as a fuel source. That, in turn, will depend on a number of factors, including the specific requirements imposed by any such laws, regulations or other policies, the time periods over which those laws, regulations or other policies would be phased in, the state of development and deployment of CCUS technologies as well as acceptance of CCUS technologies to meet regulations and the alternative uses for coal. Similarly, higher-efficiency coal-fired power plants may also be an option for meeting laws or regulations related to emissions from coal use. Several countries, including some major coal users such as China, India and Japan, included using higher-efficiency coal-fueled power plants in their plans under the Paris Agreement. From time to time, we attempt to analyze the potential impact on the Company of as-yet-unadopted, potential laws, regulations and policies. Such analyses require that we make significant assumptions as to the specific provisions of such potential laws, regulations and policies. These analyses sometimes show that certain potential laws, regulations and policies, if implemented in the manner assumed by the analyses, could result in material adverse impacts on our operations, financial condition or cash flow, in view of the significant uncertainty surrounding each of these potential laws, regulations and policies. We do not believe that such analyses reasonably predict the quantitative impact that future laws, regulations or other policies may have on our results of operations, financial condition or cash flows.

Available Information

We file or furnish annual, quarterly and current reports (including any exhibits or amendments to those reports), proxy statements and other information with the SEC. These materials are available free of charge through our website (www.peabodyenergy.com) as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Information included on our website does not constitute part of this document. These materials may also be accessed through the SEC's website (www.sec.gov) or in the SEC's Public Reference Room located at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling 1-800-SEC-0330.

In addition, copies of our filings will be made available, free of charge, upon request by telephone at (314) 342-7900 or by mail at: Peabody Energy Corporation, Peabody Plaza, 701 Market Street, St. Louis, Missouri 63101-1826, attention: Investor Relations.

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Item 1A. Risk Factors.

We operate in a rapidly changing environment that involves a number of risks. The following discussion highlights some of these risks and others are discussed elsewhere in this report. These and other risks could materially and adversely affect our business, financial condition, prospects, operating results or cash flows. The following risk factors are not an exhaustive list of the risks associated with our business. New factors may emerge or changes to these risks could occur that could materially affect our business.

Risks Associated with Our Emergence from the Chapter 11 Cases

As a result of our emergence from our Chapter 11 Cases, our historical financial information is not indicative of our future financial performance.

Our capital structure was significantly altered through the implementation of the Plan. As a result, we are subject to the fresh start reporting rules required under the Financial Accounting Standards Board Accounting Standards Codification Topic 852, Reorganizations. Under applicable fresh start reporting rules, our assets and liabilities were adjusted to fair values and our accumulated deficit was restated to zero. Accordingly, our consolidated financial condition and results of operations from and after the Effective Date are not comparable to the financial condition or results of operations reflected in our consolidated historical financial statements.

Risks Associated with Our Operations

Our profitability depends upon the prices we receive for our coal.

We operate in a competitive and highly regulated industry that has previously experienced strong headwinds. In 2017, the coal industry saw sharp upturns in seaborne metallurgical and thermal coal pricing primarily due to restrictive production policies in China. However, these recent industry events do not demonstrate that these prices will be sustainable in the future and the vast majority of third-party analysts project that prices are likely to decline. If coal prices decrease or return to depressed levels, our operating results and profitability and value of our coal reserves could be materially and adversely affected.

Coal prices are dependent upon factors beyond our control, including:

- the demand for electricity;
- the strength of the global economy;
- the relative price of natural gas and other energy sources used to generate electricity;
- the demand for electricity and capacity utilization of electricity generating units (whether coal or non-coal);
- the demand for steel, which may lead to price fluctuations in the monthly and quarterly repricing of our metallurgical coal contracts;
- the global supply and production costs of thermal and metallurgical coal;
- changes in the fuel consumption and dispatch patterns of electric power generators;
- weather patterns and natural disasters;
- competition within our industry and the availability, quality and price of alternative fuels, including natural gas, fuel oil, nuclear, hydroelectric, wind, biomass and solar power;
- the proximity, capacity and cost of transportation and terminal facilities;
- coal and natural gas industry output and capacity;
- governmental regulations and taxes, including those establishing air emission standards for coal-fueled power plants or mandating or subsidizing increased use of electricity from renewable energy sources;
- regulatory, administrative and judicial decisions, including those affecting future mining permits and leases; and
- technological developments, including those related to alternative energy sources, those intended to convert coal-to-liquids or gas and those aimed at capturing, using and storing carbon dioxide.

In the U.S., our strategy is to selectively renew, or enter into new, long-term supply agreements when we can do so at prices we believe are favorable. In Australia we negotiate pricing for metallurgical coal contracts on a quarterly, spot or index basis and seaborne thermal coal contracts on an annual, spot or index basis.

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Thermal coal accounted for the majority of our coal sales during 2016 and 2017. The vast majority of our sales of thermal coal were to electric power generators. The demand for coal consumed for electric power generation is affected by many of the factors described above, but primarily by (i) the overall demand for electricity; (ii) the availability, quality and price of competing fuels, such as natural gas, nuclear fuel, oil and alternative energy sources; (iii) utilization of all electricity generating units (whether using coal or not), including the relative cost of producing electricity from all fuels, including coal; (iv) increasingly stringent environmental and other governmental regulations; and (v) the coal inventories of utilities. Gas-fueled generation has displaced and is expected to continue to displace coal-fueled generation, particularly from older, less efficient coal-powered generators. Many of the new power plants in the U.S. may be fueled by natural gas because gas-fired plants are viewed as cheaper to construct and permits to construct these plants are easier to obtain as natural gas is seen as having a lower environmental impact than coal-fueled generators. Increasingly stringent regulations along with flat electricity demand have also reduced the number of new power plants being built. These trends have reduced demand for our coal and the related prices. Any further reduction in the amount of coal consumed by electric power generators could reduce the volume and price of coal that we mine and sell.

Lower demand for metallurgical coal by steel producers would reduce our revenues and could further reduce the price of our metallurgical coal. We produce metallurgical coal that is used in the global steel industry. Metallurgical coal accounted for approximately 28% and 23% of our coal sales revenue in 2017 and 2016, respectively. Deteriorating conditions in the steel industry, including the demand for steel, could reduce the demand for our metallurgical coal. Lower demand for metallurgical coal in international markets would reduce the amount of metallurgical coal that we sell and the prices that we receive for it, thereby reducing our revenues and adversely impacting our earnings and the value of our coal reserves.

Additionally, we compete with numerous other domestic and foreign coal producers for domestic and international sales. This competition affects domestic and foreign coal prices and our ability to attract and retain customers. The balance between coal demand and supply within the coal industry, factoring in demand and supply of closely related and competing segments such as natural gas, both domestically and internationally, could materially reduce coal prices and therefore materially reduce our revenues and profitability. We compete with producers of other low cost fuels used for electricity generation, such as natural gas and renewables. Declines in the price of natural gas, or continued low natural gas prices, could cause demand for coal to decrease and adversely affect the price of coal. Sustained periods of low natural gas prices or other fuels may also cause utilities to phase out or close existing coal-fired power plants or reduce construction of new coal-fired power plants, which could have a material adverse effect on demand and prices for our coal, thereby reducing our revenues and materially and adversely affecting our business and results of operations.

If a substantial number of our long-term coal supply agreements terminate, our revenues and operating profits could suffer if we are unable to find alternate buyers willing to purchase our coal on comparable terms to those in our contracts.

Most of our sales are made under coal supply agreements, which are important to the stability and profitability of our operations. The execution of a satisfactory coal supply agreement is frequently the basis on which we undertake the development of coal reserves required to be supplied under the contract, particularly in the U.S.

Many of our coal supply agreements contain provisions that permit the parties to adjust the contract price upward or downward at specified times. We may adjust these contract prices based on inflation or deflation and/or changes in the factors affecting the cost of producing coal, such as taxes, fees, royalties and changes in the laws regulating the mining, production, sale or use of coal. In a limited number of contracts, failure of the parties to agree on a price under those provisions may allow either party to terminate the contract. We sometimes experience a reduction in coal prices in new long-term coal supply agreements replacing some of our expiring contracts. Coal supply agreements also typically contain force majeure provisions allowing temporary suspension of performance by us or the customer during the duration of specified events beyond the control of the affected party. Most of our coal supply agreements contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as Btu, sulfur content, ash content, grindability and ash fusion temperature. Failure to meet these specifications could result in economic penalties, including price adjustments, the rejection of deliveries or termination of the contracts. Moreover, some of these agreements allow our customers to terminate their contracts in the event of changes in regulations affecting our industry that restrict the use or type of coal permissible at the customer’s plant or increase the price of coal beyond specified limits.

The operating profits we realize from coal sold under supply agreements depend on a variety of factors. In addition, price adjustment and other provisions may increase our exposure to short-term coal price volatility provided by those contracts. If a substantial portion of our coal supply agreements were modified or terminated, we could be materially adversely affected to the extent that we are unable to find alternate buyers for our coal at the same level of profitability. Prices for coal vary by mining region and country. As a result, we cannot predict the future strength of the coal industry overall or by mining region and cannot provide assurance that we will be able to replace existing long-term coal supply agreements at the same prices or with similar profit margins when they expire.

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The loss of, or significant reduction in, purchases by our largest customers could adversely affect our revenues.
For the year ended December 31, 2017, we derived 27% of our total revenues from our five largest customers, similar to the prior year. Those five customers were supplied primarily from 21 coal supply agreements (excluding trading transactions) expiring at various times from 2018 to 2025. On an ongoing basis, we discuss the extension of existing agreements or entering into new long-term agreements with various customers, but these negotiations may not be successful and these customers may not continue to purchase coal from us under long-term supply agreements. If a number of these customers significantly reduce their purchases of coal from us, or if we are unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our financial condition and results of operations could suffer materially. In addition, our revenue could be adversely affected by a decline in customer purchases (including contractually obligated purchases) due to lack of demand and oversupply, cost of competing fuels and environmental and other governmental regulations.
One of our five largest customers, the Navajo Generating Station (NGS) is served by a single Peabody mine, included in our Western U.S. Mining operations, that has no other customers. Given the mine’s location, it is currently unable to economically market its coal to other utility customers. This mine has a contract to supply coal to NGS through December 2019. We estimate that the mine will sell between five million and six million tons in 2018 at Adjusted EBTIDA Margin per Ton in line with those seen in our Western U.S. Mining Segment during the Successor period ended December 31, 2017. NGS is owned by several private companies and one governmental entity. The non-governmental owners of the customer recently completed an evaluation of the plant and determined to continue operating the plant through December 2019, subject to certain conditions. Those non-governmental owners of the plant then issued a statement that they do not currently intend to be the operators of the plant beyond December 2019. We have engaged an investment banking firm to lead an ownership transition process for the plant. On October 2, 2017, we confirmed that a number of potential investors had expressed interest in pursuing an ownership position in NGS. Additionally, we are currently discussing options to improve the plant’s economics. If the customer closes the plant, our Western U.S. Mining operations revenues, Adjusted EBITDA and cash flows would be materially reduced and our proven and probable reserves would be reduced by approximately 180 million tons. We could also incur accelerated costs related to the mine’s closure and may be required to record other charges. Under the terms of the contract, NGS is responsible for reimbursing us for the majority of our post-mining obligations, including reclamation and retiree healthcare costs.
Our trading and hedging activities do not cover certain risks, and may expose us to earnings volatility and other risks.
We historically entered into hedging arrangements designed primarily to manage market price volatility of foreign currency (primarily the Australian dollar), diesel fuel and coal. Currently, we primarily enter into hedging arrangements designed to manage coal industry price through our trading and marketing functions and increases in foreign currency exchange rates; however, we may in the future enter into hedging arrangements to manage the volatility of diesel fuel, or other matters.
Some of these derivative trading instruments require us to post margin based on the value of those instruments and other credit factors. If the fair value of our hedge portfolio moves significantly, or if laws or regulations are passed requiring all hedge arrangements to be exchange-traded or exchange-cleared, we could be required to post additional margin, which could negatively impact our liquidity.
Through our trading and hedging activities, we are also exposed to nonperformance and credit risk with various counterparties, including exchanges and other financial intermediaries. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements, which could negatively impact our profitability and/or liquidity.
We are currently subject to price risk on diesel fuel utilized in our mining operations. As noted above, we have historically used derivative financial instruments, including forward contracts, swaps and options, designated as cash flow hedges, to manage these risks. We are exposed to the risk of fluctuations in the price of fuel.
Our operating results could be adversely affected by unfavorable economic and financial market conditions.
Our profits are affected, in large part, by industry conditions. Industry conditions are subject to a variety of factors beyond our control. In recent years, the global economic recession and the worldwide financial and credit market disruptions had a negative impact on us and on the coal industry generally. These conditions, among other factors, led

to the filing of the Chapter 11 Cases. If any of these conditions return, if coal prices continue at or below levels experienced in 2015 and early 2016 for a prolonged period or if there are further downturns in economic conditions, particularly in developing countries such as China and India, our business, financial condition or results of operations could be adversely affected. While we are focused on cost control, productivity improvements, increased contributions from our higher-margin operations and capital discipline, there can be no assurance that these actions, or any others we may take, will be sufficient in response to challenging economic and financial conditions.

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Our ability to collect payments from our customers could be impaired if their creditworthiness or contractual performance deteriorates.

Our ability to receive payment for coal sold and delivered or for financially settled contracts will depend on the continued creditworthiness and contractual performance of our customers and counterparties. Our customer base has changed with deregulation in the U.S. as utilities have sold their power plants to their non-regulated affiliates or third parties. These new customers may have credit ratings that are below investment grade or are not rated. If deterioration of the creditworthiness of our customers occurs or if they fail to perform the terms of their contracts with us, our accounts receivable securitization program and our business could be adversely affected.

Risks inherent to mining could increase the cost of operating our business.

Our mining operations are subject to conditions that can impact the safety of our workforce, or delay coal deliveries or increase the cost of mining at particular mines for varying lengths of time. These conditions include:

- fires and explosions, including from methane gas or coal dust;
- accidental mine water discharges;
- weather, flooding and natural disasters;
- hazardous geologic events such as roof falls and high wall failures;
- key equipment failures;
- variations in coal seam thickness, coal quality, the amount of rock and soil overlying coal deposits, and geologic conditions impacting mine sequencing;
- unexpected maintenance problems; and
- unforeseen delays in implementation of mining technologies that are new to our operations.

We maintain insurance policies that provide limited coverage for some of these risks, although there can be no assurance that these risks would be fully covered by our insurance policies. Despite our efforts, such conditions could occur and have a substantial impact on our results of operations, financial condition or cash flows.

If transportation for our coal becomes unavailable or uneconomic for our customers, our ability to sell coal could suffer.

Transportation costs represent a significant portion of the total cost of coal use and the cost of transportation is a critical factor in a customer’s purchasing decision. Increases in transportation costs and the lack of sufficient rail and port capacity could lead to reduced coal sales.

We depend upon rail, barge, trucking, overland conveyor and ocean-going vessels to deliver coal to our customers. While our coal customers typically arrange and pay for transportation of coal from the mine or port to the point of use, disruption of these transportation services because of weather-related problems, infrastructure damage, strikes, lock-outs, lack of fuel or maintenance items, underperformance of the port and rail infrastructure, congestion and balancing systems which are imposed to manage vessel queuing and demurrage, non-performance or delays by co-shippers, transportation delays or other events could temporarily impair our ability to supply coal to our customers and thus could adversely affect our results of operations.

A decrease in the availability or increase in costs of key supplies, capital equipment or commodities such as diesel fuel, steel, explosives and tires could decrease our anticipated profitability.

Our mining operations require a reliable supply of mining equipment, replacement parts, fuel, explosives, tires, steel-related products (including roof control materials), lubricants and electricity. There has been some consolidation in the supplier base providing mining materials to the coal industry, such as with suppliers of explosives in the U.S. and both surface and underground equipment globally, that has limited the number of sources for these materials. In situations where we have chosen to concentrate a large portion of purchases with one supplier, it has been to take advantage of cost savings from larger volumes of purchases and to ensure security of supply. If the cost of any of these inputs increased significantly, or if a source for these supplies or mining equipment were unavailable to meet our replacement demands, our profitability could be reduced or we could experience a delay or halt in our production.

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Take-or-pay arrangements within the coal industry could unfavorably affect our profitability.

We have substantial take-or-pay arrangements, predominately in Australia, totaling $1.3 billion, with terms ranging up to 25 years, that commit us to pay a minimum amount for rail and port commitments for the delivery of coal even if those commitments go unused. The take-or-pay provisions in these contracts sometimes allow us to apply amounts paid for subsequent deliveries, but these provisions have limitations and we may not be able to apply all such amounts so paid in all cases. Also, we may not be able to utilize the amount of capacity for which we have previously paid. Additionally, coal companies, including us, may continue to deliver coal during times when it might otherwise be optimal to suspend operations because these take-or-pay provisions effectively convert a variable cost of selling coal to a fixed operating cost.

We have contract-based intangible liabilities primarily consisting of unutilized capacity under port and rail take-or-pay contracts. Future unutilized capacity and the amortization periods related to the take-or-pay contract intangible liabilities are based upon estimates of forecasted usage. We anticipate that the amortization of the intangible liability, which is classified as a reduction to “Operating costs and expenses,” will extend through 2043.

An inability of trading, brokerage, mining or freight counterparties to fulfill the terms of their contracts with us could reduce our profitability.

In conducting our trading, brokerage and mining operations, we utilize third-party sources of coal production and transportation, including contract miners and brokerage sources, to fulfill deliveries under our coal supply agreements. Employee relations at mines that use contractors are the responsibility of the contractor.

Our profitability or exposure to loss on transactions or relationships is dependent upon the reliability (including financial viability) and price of the third-party suppliers; our obligation to supply coal to customers in the event that weather, flooding, natural disasters or adverse geologic mining conditions restrict deliveries from our suppliers; our willingness to participate in temporary cost increases experienced by our third-party coal suppliers; our ability to pass on temporary cost increases to our customers; the ability to substitute, when economical, third-party coal sources with internal production or coal purchased in the market and the ability of our freight sources to fulfill their delivery obligations. Market volatility and price increases for coal or freight on the international and domestic markets could result in non-performance by third-party suppliers under existing contracts with us, in order to take advantage of the higher prices in the current market. Such non-performance could have an adverse impact on our ability to fulfill deliveries under our coal supply agreements.

We may not recover our investments in our mining, exploration and other assets, which may require us to recognize impairment charges related to those assets.

The value of our assets may be adversely affected by numerous uncertain factors, some of which are beyond our control, including unfavorable changes in the economic environments in which we operate, lower-than-expected coal pricing, technical and geological operating difficulties, an inability to economically extract our coal reserves and unanticipated increases in operating costs. These may cause us to fail to recover all or a portion of our investments in those assets and may trigger the recognition of impairment charges in the future, which could have a substantial impact on our results of operations. This may be mitigated by our application of fresh start reporting rules.

As described in Note 3. “Asset Impairment” to the accompanying consolidated financial statements, we recognized aggregate asset impairment costs of $30.5 million, $247.9 million and $1,277.8 million in the predecessor period January 1 through April 1, 2017 and the years ended December 31, 2016 and 2015, respectively. Because of the volatile and cyclical nature of U.S. and international coal markets, it is reasonably possible that our current estimates of projected future cash flows from our mining assets may change in the near term, which may result in the need for adjustments to the carrying value of our assets.

Our ability to operate our company effectively could be impaired if we lose key personnel or fail to attract qualified personnel.

We manage our business with a number of key personnel, the loss of whom could have a material adverse effect on us, absent the completion of an orderly transition. In addition, we believe that our future success will depend greatly on our continued ability to attract and retain highly skilled and qualified personnel, particularly personnel with mining experience. We cannot provide assurance that key personnel will continue to be employed by us or that we will be able to attract and retain qualified personnel in the future. Failure to retain or attract key personnel could have a material adverse effect on us.

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We could be negatively affected if we fail to maintain satisfactory labor relations.

As of December 31, 2017, we had approximately 7,100 employees (excluding employees that were employed at operations classified as discontinued), which included approximately 5,500 hourly employees. Approximately 38% of our hourly employees were represented by organized labor unions and generated approximately 20% of 2017 coal production for the 12 months ended December 31, 2017. Relations with our employees and, where applicable, organized labor are important to our success. If some or all of our current non-union operations were to become unionized, we could incur an increased risk of work stoppages, reduced productivity and higher labor costs. Also, if we fail to maintain good relations with our employees who are represented by unions, we could potentially experience labor disputes, work stoppages or other disruptions in production that could negatively impact our profitability.

We could be adversely affected if we fail to appropriately provide financial assurances for our obligations.

U.S. federal and state laws and Australian laws require us to provide financial assurances related to requirements to reclaim lands used for mining, to pay federal and state workers' compensation, to provide financial assurances for coal lease obligations and to satisfy other miscellaneous obligations. The primary methods we use to meet those obligations are to provide a third-party surety bond or provide a letter of credit. In the past in the U.S., we also posted a corporate guarantee (i.e., self- bond). As of December 31, 2017, we had outstanding surety bonds with third parties, bank guarantees and letters of credit of $1,675.2 million, of which $1,325.3 million was for post-mining reclamation, $214.5 million related to workers' compensation and other insurance obligations, $95.4 million was for coal lease obligations and $40.0 million was for other obligations, including road maintenance and performance guarantees. In addition, as of December 31, 2017, we had posted cash collateral of $323.1 million, primarily in support of our reclamation obligations in Australia. Surety bond issuers may demand additional collateral, which may in turn affect our available liquidity.

Our bonding obligations may increase due to a number of factors, and we may not qualify to self-bond or self-bonding programs may be terminated. Alternative forms of financial assurance such as surety bonds and letters of credit may not be available to us. Our failure to retain, or inability to obtain surety bonds, bank guarantees or letters of credit, or to provide a suitable alternative, could have a material adverse effect on us. That failure could result from a variety of factors including the following:

- lack of availability, higher expense or unfavorable market terms of new surety bonds; and
- inability to provide or fund collateral for current and future third-party surety bond issuers.

Our failure to maintain adequate bonding would invalidate our mining permits and prevent mining operations from continuing, which would cast substantial doubt on our ability to continue as a going concern.

Our mining operations are extensively regulated, which imposes significant costs on us, and future regulations and developments could increase those costs or limit our ability to produce coal.

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

- workplace health and safety;
- limitations on land use;
- mine permitting and licensing requirements;
- reclamation and restoration of mining properties after mining is completed;
- the storage, treatment and disposal of wastes;
- remediation of contaminated soil, sediment and groundwater;
- air quality standards;
- water pollution;
- protection of human health, plant-life and wildlife, including endangered or threatened species and habitats;
- protection of wetlands;
- the discharge of materials into the environment; and
- the effects of mining on surface water and groundwater quality and availability.

Regulatory agencies have the authority under certain circumstances following significant health and safety incidents to order a mine to be temporarily or permanently closed. In the event that such agencies ordered the closing of one of our mines, our production and sale of coal would be disrupted and we may be required to incur cash outlays to re-open the mine. Any of these actions could have a material adverse effect on our financial condition, results of operations and cash flows.

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The possibility exists that new legislation or regulations and orders, including without limitation related to the environment or employee health and safety may be adopted and may materially adversely affect our mining operations, our cost structure or our customers' ability to use coal. New legislation or administrative regulations (or new interpretations by the relevant government of existing laws, regulations and approvals), including proposals related to the protection of the environment or the reduction of greenhouse gas emissions that would further regulate and tax the coal industry, may also require us or our customers to change operations significantly or incur increased costs. Some of our coal supply agreements contain provisions that allow a purchaser to terminate its contract if legislation is passed that either restricts the use or type of coal permissible at the purchaser's plant or results in specified increases in the cost of coal or its use. These factors and legislation, if enacted, could have a material adverse effect on our financial condition and results of operations.

For additional information about the various regulations affecting us, see the sections entitled "Regulatory Matters —U.S." and "Regulatory Matters — Australia".

Our operations may impact the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, which could result in material liabilities to us.

Our operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time. A number of laws, including in the U.S., CERCLA and RCRA, impose liability relating to contamination by hazardous substances. Such liability may involve the costs of investigating or remediating contamination and damages to natural resources, as well as claims seeking to recover for property damage or personal injury caused by hazardous substances. Such liability may arise from conditions at formerly, as well as currently, owned or operated properties, and at properties to which hazardous substances have been sent for treatment, disposal or other handling. Liability under RCRA, CERCLA and similar state statutes is without regard to fault, and typically is joint and several, meaning that a person may be held responsible for more than its share, or even all, of the liability involved.

We may be unable to obtain, renew or maintain permits necessary for our operations, which would reduce our production, cash flows and profitability.

Numerous governmental and tribal permits and approvals are required for mining operations. The permitting rules, and the interpretations of these rules, are complex and are often subject to discretionary interpretations by regulators, all of which may make compliance more difficult or impractical. As part of this permitting process, when we apply for permits and approvals, we are required to prepare and present to governmental authorities data pertaining to the potential impact or effect that any proposed exploration for or production of coal may have upon the environment. The public, including non-governmental organizations, opposition groups and individuals, have statutory rights to comment upon and submit objections to requested permits and approvals (including modifications and renewals of certain permits and approvals). In recent years, the permitting required for coal mining has been the subject of increasingly stringent regulatory and administrative requirements and extensive litigation by environmental groups. The costs, liabilities and requirements associated with these permitting requirements and opposition may be costly and time-consuming and may delay commencement or continuation of exploration or production and as a result, adversely affect our coal production, cash flows and profitability. Further, required permits may not be issued or renewed in a timely fashion or at all, or permits issued or renewed may be conditioned in a manner that may restrict our ability to efficiently and economically conduct our mining activities, any of which would materially reduce our production, cash flow and profitability.

The Corps regulates certain activities affecting navigable waters and waters of the U.S., including wetlands. Section 404 of the CWA requires mining companies like us to obtain Corps permits to place material in streams for the purpose of creating slurry ponds, water impoundments, refuse areas, valley fills or other mining activities. In recent years, the Section 404 permitting process has been subject to increasingly stringent regulatory and administrative requirements and a series of court challenges, which have resulted in increased costs and delays in the permitting process. Additionally, increasingly stringent requirements governing coal mining also are being considered or implemented under the Surface Mining Control and Reclamation Act, the National Pollution Discharge Elimination System permit process and various other environmental programs. Potential laws, regulations and policies could result in material adverse impacts on our operations, financial condition or cash flow, in view of the significant uncertainty surrounding each of these potential laws, regulations and policies.

Our mining operations are subject to extensive forms of taxation, which imposes significant costs on us, and future regulations and developments could increase those costs or limit our ability to produce coal competitively.

Federal, state, provincial or local governmental authorities in nearly all countries across the global coal mining industry impose various forms of taxation, including production taxes, sales-related taxes, royalties, environmental taxes, mining profits taxes and income taxes. If new legislation or regulations related to various forms of coal taxation, which increase our costs or limit our ability to compete in the areas in which we sell our coal, are adopted, our business, financial condition or results of operations could be adversely affected.

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If the assumptions underlying our asset retirement obligations for reclamation and mine closures are materially inaccurate, our costs could be significantly greater than anticipated.

Our asset retirement obligations primarily consist of spending estimates for surface land reclamation and support facilities at both surface and underground mines in accordance with federal and state reclamation laws in the U.S. and Australia as defined by each mining permit. These obligations are determined for each mine using various estimates and assumptions including, among other items, estimates of disturbed acreage as determined from engineering data, estimates of future costs to reclaim the disturbed acreage and the timing of these cash flows, which is driven by the estimated economic life of the mine and the applicable reclamation laws. These cash flows are discounted using a credit-adjusted, risk-free rate. Our management and engineers periodically review these estimates. If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could be materially different than currently estimated. Moreover, regulatory changes could increase our obligation to perform reclamation, mine closing and post-closure activities. The resulting estimated asset retirement obligation could change significantly if actual amounts change significantly from our assumptions, which could have a material adverse effect on our results of operations and financial condition.

Our future success depends upon our ability to continue acquiring and developing coal reserves that are economically recoverable.

Our recoverable reserves decline as we produce coal. We have not yet applied for the permits required or developed the mines necessary to use all of our reserves. Moreover, the amount of proven and probable coal reserves described in Part I, Item 2. “Properties” involves the use of certain estimates and those estimates could be inaccurate. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our staff. Some of the factors and assumptions which impact economically recoverable coal reserve estimates include geological conditions, historical production from the area compared with production from other producing areas, the assumed effects of regulations and taxes by governmental agencies and assumptions governing future prices and future operating costs. Actual production, revenues and expenditures with respect to our coal reserves may vary materially from estimates.

Our future success depends upon our conducting successful exploration and development activities or acquiring properties containing economically recoverable reserves. Our current strategy includes increasing our reserves through acquisitions of government and other leases and producing properties and continuing to use our existing properties and infrastructure. In certain locations, leases for oil, natural gas and coalbed methane reserves are located on, or adjacent to, some of our reserves, potentially creating conflicting interests between us and lessees of those interests. Other lessees’ rights relating to these mineral interests could prevent, delay or increase the cost of developing our coal reserves. These lessees may also seek damages from us based on claims that our coal mining operations impair their interests. Additionally, the U.S. federal government limits the amount of federal land that may be leased by any company to 75,000 acres in any one state and 150,000 acres nationwide. As of December 31, 2017, we leased a total of 55,228 acres from the federal government subject to those limitations. Many of these leases are in place for the next 20 years.

Our planned mine development projects and acquisition activities may not result in significant additional reserves, and we may not have success developing additional mines. Most of our mining operations are conducted on properties owned or leased by us. Our right to mine some of our reserves may be materially adversely affected if defects in title or boundaries exist. In order to conduct our mining operations on properties where these defects exist, we may incur unanticipated costs. In addition, in order to develop our reserves, we must also own the rights to the related surface property and receive various governmental permits. We cannot predict whether we will continue to receive the permits or appropriate land access necessary for us to operate profitably in the future. We may not be able to negotiate new leases from the government or from private parties, obtain mining contracts for properties containing additional reserves or maintain our leasehold interest in properties on which mining operations have not commenced or have not met minimum quantity or product royalty requirements. From time to time, we have experienced litigation with lessors of our coal properties and with royalty holders. In addition, from time to time, our permit applications and federal and state coal leases have been challenged, causing production delays.

To the extent that our existing sources of liquidity are not sufficient to fund our planned mine development projects and reserve acquisition activities, we may require access to capital markets, which may not be available to us or, if available, may not be available on satisfactory terms. If we are unable to fund these activities, we may not be able to maintain or increase our existing production rates and we could be forced to change our business strategy, which could have a material adverse effect on our financial condition, results of operations and cash flows.

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We face numerous uncertainties in estimating our economically recoverable coal reserves and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs and decreased profitability.

Coal is economically recoverable when the price at which our coal can be sold exceeds the costs and expenses of mining and selling the coal. The costs and expenses of mining and selling the coal are determined on a mine-by-mine basis, and as a result, the price at which our coal is economically recoverable varies based on the mine. Forecasts of our future performance are based on, among other things, estimates of our recoverable coal reserves. We base our reserve information on engineering, economic and geological data assembled and analyzed by our staff and third parties, which includes various engineers and geologists. The reserve estimates as to both quantity and quality are updated from time to time to reflect production of coal from the reserves and new drilling or other data received. There are numerous uncertainties inherent in estimating quantities and qualities of coal and costs to mine recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves necessarily depend upon a number of variable factors and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. These factors and assumptions include:

- geologic and mining conditions, which may not be fully identified by available exploration data and may differ from our experience in areas we currently mine;
- current and future market prices for coal, contractual arrangements, operating costs and capital expenditures;
- severance and excise taxes, royalties and development and reclamation costs;
- future mining technology improvements;
- the effects of regulation by governmental agencies;
- the ability to obtain, maintain and renew all required permits;
- employee health and safety; and
- historical production from the area compared with production from other producing areas

As a result, actual coal tonnage recovered from identified reserve areas or properties and revenues and expenditures with respect to our reserves may vary materially from estimates. These estimates thus may not accurately reflect our actual reserves. Any material inaccuracy in our estimates related to our reserves could result in lower than expected revenues, higher than expected costs or decreased profitability which could materially and adversely affect our business, results of operations, financial position and cash flows.

Our global operations increase our exposure to risks unique to international mining and trading operations.

Our international platform increases our exposure to country risks, international regulatory requirements and the effects of changes in currency exchange rates. Some of our international activities are in developing countries where the economic strength, business practices and counterparty reputations may not be as well developed as in our U.S. or Australian operations. We are exposed to various business and political risks, including political instability, heightened levels of corruption or fraud in certain markets, the potential for expropriation of assets, costs associated with the repatriation of earnings and the potential for unexpected changes in regulatory requirements. Despite our efforts to perform due diligence, screening, training and auditing of internal and external business agents, vendors, partners and customers to mitigate these risks, our results of operations, financial position or cash flows could be adversely affected by these activities.

Joint ventures, partnerships or non-managed operations may not be successful and may not comply with our operating standards.

We participate in several joint venture and partnership arrangements and may enter into others, all of which necessarily involve risk. Whether or not we hold majority interests or maintain operational control in our joint ventures, our partners may, among other things, (1) have economic or business interests or goals that are inconsistent with, or opposed to, ours; (2) seek to block actions that we believe are in our or the joint venture’s best interests; or (3) be unable or unwilling to fulfill their obligations under the joint venture or other agreements, such as contributing capital, each of which may adversely impact our results of operations and our liquidity or impair our ability to recover our investments.

Where our joint ventures are jointly controlled or not managed by us, we may provide expertise and advice but have limited control over compliance with our operational standards. We also utilize contractors across our mining platform, and may be similarly limited in our ability to control their operational practices. Failure by non-controlled joint venture partners or contractors to adhere to operational standards that are equivalent to ours could unfavorably affect operating costs and productivity and adversely impact our results of operations and reputation.

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We may undertake further repositioning plans that would require additional charges.
As a result of our continuing review of our business or changing demand, we may choose to further reduce our workforce in the future. These actions may result in further restructuring charges, cash expenditures and the consumption of management resources, any of which could cause our operating results to decline and may fail to yield the expected benefits.
We could be exposed to significant liability, reputational harm, loss of revenue, increased costs or other risks if we sustain cyber attacks or other security breaches that disrupt our operations or result in the dissemination of proprietary or confidential information about us, our customers or other third-parties.
We have implemented security protocols and systems with the intent of maintaining the physical security of our operations and protecting our and our counterparties' confidential information and information related to identifiable individuals against unauthorized access. Despite such efforts, we may be subject to security breaches which could result in unauthorized access to our facilities or the information we are trying to protect. Unauthorized physical access to one of our facilities or electronic access to our information systems could result in, among other things, unfavorable publicity, litigation by affected parties, damage to sources of competitive advantage, disruptions to our operations, loss of customers, financial obligations for damages related to the theft or misuse of such information and costs to remediate such security vulnerabilities, any of which could have a substantial impact on our results of operations, financial condition or cash flows.
Our expenditures for postretirement benefit and pension obligations could be materially higher than we have predicted if our underlying assumptions prove to be incorrect.
We provide postretirement health and life insurance benefits to eligible employees. Our total accumulated postretirement benefit obligation related to such benefits was a liability of $783.3 million as of December 31, 2017, of which $53.3 million was classified as a current liability. Certain of our U.S. subsidiaries also sponsor defined benefit pension plans. Net pension liabilities were $98.0 million as of December 31, 2017, of which none was classified a current liability.
These liabilities are actuarially determined and we use various actuarial assumptions, including the discount rate, future cost trends, and rates of return on plan assets to estimate the costs and obligations for these items. Our discount rate is determined by utilizing a hypothetical bond portfolio model which approximates the future cash flows necessary to service our liabilities. A decrease in the discount rate used to determine our postretirement benefit and defined benefit pension obligations could result in an increase in the valuation of these obligations, thereby increasing the cost in subsequent fiscal years. We have made assumptions related to future trends for medical care costs in the estimates of retiree health care obligations. Our medical trend assumption is developed by annually examining the historical trend of our cost per claim data. If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could differ materially from our current estimates. Moreover, regulatory changes or changes in healthcare benefits provided by the government could increase our obligation to satisfy these or additional obligations. Additionally, our reported defined benefit pension funding status may be affected, and we may be required to increase employer contributions, due to increases in our defined benefit pension obligation or poor financial performance in asset markets in future years.
Our defined benefit pension plans are subject to the provisions of the Employee Retirement Income Security Act of 1974, as amended (ERISA). It is implicit in our underlying assumptions that those plans continue to operate in the normal course of business. However, the Pension Benefit Guaranty Corporation (PBGC) may terminate our plans under certain circumstances pursuant to ERISA, including in the event that the PBGC concludes that its risk may increase unreasonably if such plans continue to operate based on its assessment of the plans' funded status, our financial condition or other factors. Termination of the plans would require us to provide immediate funding or other financial assurance to the PBGC for all or a substantial portion of the underfunded amounts, as determined by the PBGC based on its own assumptions. Those assumptions may differ from our own. Any of those consequences could have a material adverse effect on our results of operations, financial conditions or available liquidity.
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 government-backed lending institutions and development banks toward the financing of new overseas coal-fueled

power plants 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. Numerous reports, such as the Fourth and the 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 what are commonly referred to as greenhouse gases, including emissions of carbon dioxide from coal combustion by power plants.

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Enactment of laws or passage of regulations regarding emissions from the combustion of coal by the U.S., some of its states or other countries, or other actions to limit such emissions, could result in electricity generators switching from coal to other fuel sources or coal-fueled power plant closures. Further, policies limiting available financing for the development of new coal-fueled power plants could adversely impact the global demand for coal. The potential financial impact on us of future laws, regulations or other policies will depend upon the degree to which any such laws or regulations force electricity generators to diminish their reliance on coal as a fuel source. That, in turn, will depend on a number of factors, including the specific requirements imposed by any such laws, regulations or other policies, the time periods over which those laws, regulations or other policies would be phased in, the state of commercial development and deployment of CCUS technologies and the alternative markets for coal. From time to time, we attempt to analyze the potential impact on the Company of as-yet-unadopted potential laws, regulations and policies. Such analyses require that we make significant assumptions as to the specific provisions of such potential laws, regulations and policies. These analyses sometimes show that certain potential laws, regulations and policies, if implemented in the manner assumed by the analyses, could result in material adverse impacts on our operations, financial condition or cash flow, in view of the significant uncertainty surrounding each of these potential laws, regulations and policies. We do not believe that such analyses reasonably predict the quantitative impact that future laws, regulations or other policies may have on our results of operations, financial condition or cash flows.

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. 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.

Risks Related to Our Indebtedness and Capital Structure

Our financial performance could be adversely affected by our indebtedness.

As of December 31, 2017, we had approximately $1.4 billion of indebtedness outstanding, excluding capital leases, on a consolidated basis.

The degree to which we are leveraged could have important consequences, including, but not limited to:

- making it more difficult for us to pay interest and satisfy our debt obligations;
- increasing the cost of borrowing under our credit facilities;
- increasing our vulnerability to general adverse economic and industry conditions;
- requiring the dedication of a substantial portion of our cash flow from operations to the payment of principal and interest on our indebtedness, thereby reducing the availability of our cash flow to fund working capital, capital expenditures, business development or other general corporate requirements;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, business development or other general corporate requirements;
- making it more difficult to obtain surety bonds, letters of credit, bank guarantees or other financing, particularly during periods in which credit markets are weak;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the coal industry;
- causing a decline in our credit ratings; and
- placing us at a competitive disadvantage compared to less leveraged competitors.

In addition, our indebtedness subjects us to certain restrictive covenants. Failure by us to comply with these covenants could result in an event of default that, if not cured or waived, could have a material adverse effect on us and result in amounts outstanding thereunder to be immediately due and payable.

Any downgrade in our credit ratings could result in, among other matters, additional required financial assurances related to our reclamation bonding requirements, a requirement to post additional collateral on derivative trading instruments that we may enter into, the loss of trading counterparties for corporate hedging and trading and brokerage activities or an increase in the cost of, or a limit on our access to, various forms of credit used in operating our business.

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If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to sell assets, seek additional capital or seek to restructure or refinance our indebtedness. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. In the absence of sufficient operating results and resources, we could face substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. Our indebtedness restricts our ability to sell assets outside of the ordinary course of business and restricts the use of the proceeds from any such sales. We may not be able to complete those sales or obtain the proceeds which we could realize from them, and these proceeds may not be adequate to meet any debt service obligations then due. In addition, the terms of our indebtedness provide that if we cannot meet our debt service obligations, the lenders could foreclose against the assets securing their borrowings and we could be forced into bankruptcy or liquidation.

Despite our and our subsidiaries' indebtedness, we may still be able to incur substantially more debt, including secured debt. This could further increase the risks associated with our indebtedness.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future, including additional secured debt. Although covenants under the indenture governing our senior secured notes and the agreements governing our other post-emergence indebtedness, including our senior secured term loan facility and capital leases limit our ability to incur additional indebtedness, these restrictions are subject to a number of qualifications and exceptions and, under certain circumstances, debt incurred in compliance with these restrictions can be substantial. In addition, the indenture governing the senior secured notes and the agreements governing our other indebtedness do not limit us from incurring obligations that do not constitute indebtedness as defined therein.

We may not be able to generate sufficient cash to service all of our indebtedness or other obligations.

Our ability to make scheduled payments on, or refinance our debt obligations, depends on our financial condition and operating performance, which are subject to prevailing economic, industry, and competitive conditions and to certain financial, business, legislative, regulatory, and other factors beyond our control. We may be unable to maintain a level of cash flow from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness or other obligations.

The terms of our indenture governing our senior secured notes and the agreements and instruments governing our other post-emergence indebtedness impose restrictions that may limit our operating and financial flexibility.

The indenture governing our senior secured notes and the agreements and instruments governing our other post-emergence indebtedness will contain certain restrictions and covenants which restrict our ability to incur liens and/or debt or provide guarantees in respect of obligations of any other person, which could adversely affect our ability to operate our business, as well as significantly affect our liquidity, and therefore could adversely affect our results of operations. Our senior secured term loan facility also contains a mandatory prepayment provision providing that certain amounts of excess cash flow (as defined in the agreements governing the facility) must be utilized to make payments on the outstanding balance under that facility.

These covenants restrict, among other things, our ability to:

- incur additional indebtedness;
- pay dividends on or make distributions in respect of stock or make certain other restricted payments or investments;
- enter into agreements that restrict distributions from certain subsidiaries;
- sell or otherwise dispose of assets;
- incur capital expenditures beyond a specified amount;
- enter into transactions with affiliates;
- create or incur liens;
- merge, consolidate or sell all or substantially all of our assets; and
- place restrictions on the ability of subsidiaries to pay dividends or make other payments to us.

Our ability to comply with these covenants may be affected by events beyond our control and we may need to refinance existing debt in the future. A breach of any of these covenants together with the expiration of any cure period, if applicable, could result in a default under our senior secured notes. If any such default occurs, subject to applicable grace periods, the holder of our senior secured notes may elect to declare all outstanding senior secured notes, together with accrued interest and other amounts payable thereunder, to be immediately due and payable. If the obligations under our senior secured notes were to be accelerated, our financial resources may be insufficient to repay the notes and any other indebtedness becoming due in full.

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In addition, if we breach the covenants in the indentures governing the senior secured notes and do not cure such breach within the applicable time periods specified therein, we would cause an event of default under the indenture governing the senior secured notes and a cross-default to certain of our other post-emergence indebtedness and the lenders or holders thereunder could accelerate their obligations. If our indebtedness is accelerated, we may not be able to repay our indebtedness or borrow sufficient funds to refinance it. Even if we are able to obtain new financing, it may not be on commercially reasonable terms or on terms that are acceptable to us. If our indebtedness is in default for any reason, our business, financial condition and results of operations could be materially and adversely affected. In addition, complying with these covenants may make it more difficult for us to successfully execute our business strategy and compete against companies who are not subject to such restrictions.

Risks Related to Ownership of Our Securities

The price of our securities may be volatile.

The price of our common stock ("Common Stock") may fluctuate due to a variety of market and industry factors that may materially reduce the market price of our Common Stock regardless of our operating performance, including, among others:

- actual or anticipated fluctuations in our quarterly and annual results and those of other public companies in our industry;
- industry cycles and trends;
- mergers and strategic alliances in the coal industry;
- changes in government regulation;
- potential or actual military conflicts or acts of terrorism;
- the failure of securities analysts to publish research about us or to accurately predict the results we actually achieve;
- the limited trading history of our Common Stock;
- changes in accounting principles;
- announcements concerning us or our competitors; and
- the general state of the securities market.

In addition, the stock market in general has experienced significant volatility that often has been unrelated to the operating performance of companies whose shares are traded. These market fluctuations could adversely affect the trading price of our Common Stock, regardless of our actual operating performance. As a result of all of these factors, investors in our Common Stock may not be able to resell their stock at or above the price they paid or at all. Further, we could be the subject of securities class action litigation due to any such stock price volatility, which could divert management's attention and have a material adverse effect on our results of operation.

Our Common Stock is subject to dilution and may be subject to further dilution in the future.

Our Common Stock is subject to dilution from our long-term incentive plan. In addition, in the future, we may issue equity securities in connection with future investments, acquisitions or capital raising transactions. Such issuances or grants could constitute a significant portion of the then-outstanding Common Stock, which may result in significant dilution in ownership of Common Stock.

There may be circumstances in which the interests of a significant stockholder could be in conflict with other stockholders' interests.

Circumstances may arise in which a significant stockholder may have an interest in exerting influence to pursue or prevent acquisitions, divestitures or other transactions, including the issuance of additional shares or debt, that, in its judgment, could enhance its investment in us or another company in which it invests. Such transactions might adversely affect us or other holders of our Common Stock.

The payment of dividends on our stock or repurchases of our stock is dependent on a number of factors, and future payments and repurchases cannot be assured.

Restrictive covenants in our Credit Facility and in the indenture governing our senior secured notes limit our ability to pay cash dividends and repurchase shares. Other debt instruments to which we or our subsidiaries are, or may be, a party, also contain restrictive covenants that may limit our ability to pay dividends or for us to receive dividends from our subsidiaries, any of which may negatively impact the trading price of the Common Stock. In addition, holders of capital stock will only be entitled to receive such cash dividends as our Board of Directors may declare out of funds legally available for such payments, and our Board of Directors may only authorize us to repurchase shares of our capital stock with funds legally available for such repurchases. The payment of future cash dividends and future repurchases will depend upon our earnings, economic conditions, liquidity and capital requirements, and other factors, including our debt leverage. Accordingly, we cannot make any assurance that future dividends will be paid or future repurchases will be made.

Other Business Risks

We may not be able to fully utilize our deferred tax assets.

We are subject to income and other taxes in the U.S. and numerous foreign jurisdictions, most significantly Australia. As of December 31, 2017, we had gross deferred income tax assets, including net operating loss carryforwards, and liabilities of $2,981.3 million and $468.6 million, respectively, as described further in Note 11. “Income Taxes” to the accompanying consolidated financial statements. At that date, we also had recorded a valuation allowance of $2,432.5 million, substantially comprised of a full valuation allowance against our net deferred tax asset positions in the U.S. and Australia driven by recent cumulative book losses, as determined by considering all sources of available income (including items classified as discontinued operations or recorded directly to “Accumulated other comprehensive income (loss)”), which limited our ability to look to future taxable income in assessing the likelihood of realizing those assets.

Although we may be able to utilize some or all of those deferred tax assets in the future if we have income of the appropriate character in those jurisdictions (subject to loss carryforward and tax credit expiry, in certain cases), there is no assurance that we will be able to do so. Further, we are presently unable to record tax benefits on future losses in the U.S. and Australia until such time as sufficient income is generated by our operations in those jurisdictions to support the realization of the related net deferred tax asset positions. Our results of operations, financial condition and cash flows may adversely be affected in future periods by these limitations.

Divestitures and acquisitions are a potentially important part of our long-term strategy, subject to our investment criteria, and involve a number of risks, any of which could cause us not to realize the anticipated benefits.

We may engage in divestiture or acquisition activity based on our set of investment criteria to produce outcomes that increase shareholder value. As it relates to divestitures, we may dispose of certain assets within our portfolio if we determine that the price received is more beneficial to us than keeping the assets within our portfolio. Conversely, acquisitions are a potentially important part of our long-term strategy, and we may pursue acquisition opportunities. If we fail to accurately estimate the future results and value of a divested or acquired business and the related risk associated with such a transaction, or are unable to successfully integrate the businesses or properties we acquire, our business, financial condition or results of operations could be negatively affected. Moreover, any transactions we pursue could materially impact our liquidity and an acquisition could increase capital resource needs and may require us to incur indebtedness, seek equity capital or both. We may not be able to satisfy these liquidity and capital resource needs on acceptable terms or at all. In addition, future acquisitions could result in our assuming significant long-term liabilities relative to the value of the acquisitions.

Our certificate of incorporation and by-laws include provisions that may discourage a takeover attempt.

Provisions contained in our certificate of incorporation and by-laws and Delaware law could make it more difficult for a third-party to acquire us, even if doing so might be beneficial to our stockholders. Provisions of our by-laws and certificate of incorporation impose various procedural and other requirements that could make it more difficult for stockholders to effect certain corporate actions. These provisions could limit the price that certain investors might be willing to pay in the future for shares of our Common Stock and may have the effect of delaying or preventing a change in control.

Diversity in interpretation and application of accounting literature in the mining industry may impact our reported financial results.

The mining industry has limited industry-specific accounting literature and, as a result, we understand diversity in practice exists in the interpretation and application of accounting literature to mining-specific issues. As diversity in mining industry accounting is addressed, we may need to restate our reported results if the resulting interpretations differ from our current accounting practices. Refer to Note 1. "Summary of Significant Accounting Policies" to the accompanying consolidated financial statements for a summary of our significant accounting policies.

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Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

Coal Reserves

We controlled an estimated 5.2 billion tons of proven and probable coal reserves as of December 31, 2017. An estimated 4.7 billion tons of our attributable proven and probable coal reserves are in the U.S., with the remainder in Australia. Approximately 51% of our Australian proven and probable coal reserves, or 282 million tons, are metallurgical coal, comprised of approximately 151 million and 131 million tons of coking coal and LV PCI coals, respectively. The remainder of our Australian coal reserves consists of thermal coal. We own approximately 30% of these reserves and leased property comprises the remaining 70%. Approximately 63% of our reserves, or 3.3 billion tons, are compliance coal and 37% are non-compliance coal (assuming application of the U.S. industry standard definition of compliance coal to all of our reserves). Compliance coal is defined by Phase II of the CAA as coal having sulfur dioxide content of 1.2 pounds or less per million Btu. Electricity generators are able to use coal that exceeds these specifications by using emissions reduction technology, using emission allowance credits or blending higher sulfur coal with lower sulfur coal.

Below is a table summarizing the locations and proven and probable coal reserves of our major mining segments.

		Proven and Probable Reserves as of December 31, 2017 (1)		
Mining Segment	Locations	Owned Tons	Leased Tons	Total Tons
		(Tons in millions)		
Powder River Basin Mining	Wyoming	—	2,568	2,568
Midwestern U.S. Mining	Illinois, Indiana and Kentucky	1,386	289	1,675
Western U.S. Mining	Arizona, New Mexico and Colorado	161	285	446
Total United States		1,547	3,142	4,689
Australian Metallurgical Mining	Queensland and New South Wales	—	256	256
Australian Thermal Mining	New South Wales	—	291	291
Total Australia		—	547	547
Total Proven and Probable Coal Reserves		1,547	3,689	5,236

(1) Estimated proven and probable coal reserves have been adjusted to account for estimated process dilutions and losses during mining and processing involved in producing a saleable coal product.

Reserves are defined by SEC Industry Guide 7 as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. Proven and probable coal reserves are defined by SEC Industry Guide 7 as follows:

- Proven (Measured) Reserves — Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.
- Probable (Indicated) Reserves — Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

Our estimates of proven and probable coal reserves are established within these guidelines. Estimates within the proven category have the highest degree of assurance, while estimates within the probable category have only a moderate degree of geologic assurance. Further exploration is necessary to place probable reserves into the proven reserve category. Our active properties generally have a much higher degree of reliability because of increased drilling density.

Our guidelines for geologic assurance surrounding estimated proven and probable U.S. and Australian coal reserves generally follow the respective industry-accepted practices of those countries. In the U.S., our estimated proven coal reserves lie within one-quarter mile of a valid point of measure or point of observation, such as exploratory drill holes or previously mined areas, while our estimated probable coal reserves may lie more than one-quarter mile, but less than three-quarters of a mile, from a point of thickness measurement. In Australia, our estimated proven coal reserves generally lie within 250 meters of a point of observation, while our estimated probable coal reserves may lie more than 250 meters, but less than 500 meters, from a point of observation. For some of our Australian coal reserves, the distance between points of observation is determined by a geostatistical study.

The preparation of our coal reserve estimates is completed in accordance with our prescribed internal control procedures, which include verification of input data into a coal reserve forecasting and economic evaluation software system, as well as multi-functional management review. Our reserve estimates are prepared by our staff of experienced geologists and engineers. Our corporate Geological Services group is responsible for tracking changes in reserve estimates, supervising our other geologists and coordinating periodic third-party reviews of our reserve estimates by qualified mining consultants.

Our coal reserve estimates are predicated on information obtained from an extensive historical database of drill holes and information obtained from our ongoing drilling program. We compile data from individual drill holes in a computerized drill-hole database from which the depth, thickness and, where core drilling is used, the quality of the coal is determined. The density of a drill pattern determines whether the related coal reserves will be classified as proven or probable. Our coal reserve estimates are then input into our computerized land management system, which overlays that geological data with data on ownership or control of the mineral and surface interests to determine the extent of our attributable coal reserves in a given area. Our land management system contains reserve information, including the quantity and quality (where available) of reserves, as well as production data, surface and coal ownership, lease payments and other information relating to our coal reserves and land holdings. We periodically update our coal reserve estimates to reflect production of coal from those reserves and new drilling or other data received. Accordingly, our coal reserve estimates will change from time to time to reflect the effects of our mining activities, analysis of new engineering and geological data, changes in coal reserve holdings, modification of mining methods and other factors.

Our estimate of the economic recoverability of our coal reserves is generally based upon a comparison of unassigned reserves to assigned reserves currently in production in the same geologic setting to determine an estimated mining cost. These estimated mining costs are compared to expected market prices for the quality of coal expected to be mined and take into consideration typical contractual sales agreements for the region and product. Where possible, we also review coal production by competitors in similar mining areas. Only coal reserves expected to be mined economically are included in our reserve estimates. Finally, our coal reserve estimates consider dilutions and losses during mining and processing for recoverability factors to estimate a saleable product. Factors impacting our assessment include geological conditions, production expectations for certain areas, the effects of regulation and taxes by governmental agencies, future price and operating cost assumptions and adverse changes in market conditions and mine closure activities. The estimates are also impacted by decreases resulting from current year production and increases resulting from information obtained from additional drilling. Our estimation as of December 31, 2017 reflected a net reduction compared to the prior year of 407 million tons of coal reserves. The decrease was driven by changes to our estimates of economic recoverability, the modification and rejection of certain leases, mine plan changes and the sale of non-strategic coal reserves, partially offset by acquisitions and new drilling with the addition of 55 million production tons.

We periodically engage independent mining and geological consultants and consider their input regarding the procedures used by us to prepare our internal estimates of coal reserves, selected property reserve estimates and tabulation of reserve groups according to standard classifications of reliability. Our December 31, 2017 reserve estimates for the Indiana region in the U.S. were audited by John T. Boyd Company, an independent mining and geological consulting firm, which included a review of the data, procedures and parameters employed by us in developing our Indiana reserve estimates. The audit found that (1) the reserve estimates we prepared for the region were properly calculated in accordance with our stated procedures, (2) the procedures used by us are reasonable and comply with accepted industry standards and (3) our Indiana reserve estimates, as a whole, provided a reasonable estimate of available controlled mineralization that can be expected to be legally and economically extractable at the time of determination. We plan to complete additional audits of our reserve estimates on a cycled basis for each of our major operating regions.

With respect to the accuracy of our coal reserve estimates, our experience is that recovered reserves are within plus or minus 10% of our proven and probable estimates, on average, and our probable estimates are generally within the same statistical degree of accuracy when the necessary drilling is completed to move reserves from the probable to the proven classification.

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For each mine or future mine, we employ a market-driven, risk adjusted capital allocation process to guide long-term mine planning of active operations and development projects for economically mineable coal. We refer to this process as Life-of-Mine (LOM) planning. The LOM plan projects, among other things, annual quantities and qualities for each coal product. The saleable product mix for a mine may include multiple thermal and metallurgical products with different targeted qualities. The expected volumes for each mine and product, as well as annual pricing forecasts for each product, developed as described below, and related cost forecasts, developed as described below, are then evaluated to determine the economically recoverable coal in the LOM plan.

Pricing

The pricing information used to establish our reserves includes internal, proprietary price forecasts and existing contract economics, in each case on a mine-by-mine and product-by-product basis. In general, our price forecasts are based on a thorough analytical process utilizing detailed supply and demand models, global economic indicators, projected foreign exchange rates, analyses of price relationships among various commodities, competing fuels analyses, projected steel demand, analyses of supplier costs and other variables. Price forecasts, supply and demand models and other key assumptions and analyses are stress tested against independent third-party research not commissioned by us to confirm the conclusions reached through our analytical processes, and our price forecasts fall within the ranges of the projections included in this third-party research. The development of the analyses, price forecasts, supply and demand models and related assumptions are subject to multiple levels of management review.

Below is a description of some of the specific factors that we evaluate in developing our price forecasts for thermal and metallurgical coal products on a mine-by-mine and product-by-product basis. Differences between the assumptions and analyses included in our price forecasts and realized factors could cause actual pricing to differ from our forecasts.

Thermal. Several factors can influence thermal coal supply and demand and pricing. Demand is sensitive to total electric power generation volumes, which are determined in part by the impact of weather on heating and cooling demand, inter-fuel competition in the electric power generation mix, changes in capacity (additions and retirements), inter-basin or inter-country coal competition, coal stockpiles and policy and regulations. Supply considerations impacting pricing include reserve positions, mining methods, strip ratios, production costs and capacity and the cost of new supply (greenfield developments or extensions at existing mines).

In the United States, natural gas is the most significant substitute for thermal coal for electricity generation and can be one of the largest drivers of shifts in supply and demand and pricing. The competitiveness of natural gas as a generation fuel source has been strengthened by accelerated growth in domestic natural gas production over the last five years and comparatively low natural gas prices versus historic levels. The build out of renewable generation and subsidized power can also be a key driver of power market pricing and hence coal prices.

Internationally, thermal coal-fueled generation also competes with alternative forms of electric generation. The competiveness and availability of generation fueled by natural gas, oil, nuclear, hydro, wind, solar and biomass vary by country and region and can have a meaningful impact on coal pricing. Policy and regulations, which vary from country to country, can also influence prices. In addition, seaborne thermal coal import demand can be significantly impacted by the availability of indigenous coal production, particularly in the two leading coal import countries, China and India, and the competitiveness of seaborne supply from leading thermal coal exporting countries, including Indonesia, Australia, Russia, Colombia and South Africa.

Metallurgical. Several factors can influence metallurgical coal supply and demand and pricing. Demand is impacted by economic conditions and demand for steel, and is also impacted by competing technologies used to make steel, some of which do not use coal as a manufacturing input. Competition from other types of coal is also a key price consideration and can be impacted by coal quality and characteristics, delivered energy cost (including transportation costs), customer service and support and reliability of supply.

Seaborne metallurgical coal import demand can also be significantly impacted by the availability of indigenous coal production, particularly in metallurgical coal import countries such as China and India, among others, as well as country-specific policies restricting or promoting domestic supply. The competitiveness of seaborne metallurgical coal supply from coal exporting countries, including Australia, the United States, Russia, Canada and Mongolia, among others, is also an important price consideration.

In addition to the factors noted above, the prices which may be obtained at each individual mine or future mine can be impacted by factors such as (i) the mine’s location, which impacts the total delivered energy costs to its customers, (ii) quality characteristics, particularly if they are unique relative to competing mines, (iii) assumed transportation costs and (iv) other mine costs that are contractually passed on to customers in certain commercial relationships.

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Costs

The cost estimates we use to establish our reserves are generally estimated according to internal processes that project future costs based on historic costs and expected future trends. The estimated costs normally include mining, processing, transportation, royalty, add-on tax and other mining-related costs. Our estimated mining and processing costs reflect projected changes in prices of consumable commodities (mainly diesel fuel, explosives and steel), labor costs, geological and mining conditions, targeted product qualities and other mining-related costs. Estimates for other sales-related costs (mainly transportation, royalty and add-on tax) are based on contractual prices or fixed rates.

Specific factors that may impact the cost at our various operations include:

- Geological settings. The geological characteristics of each mine are among the most important factors that determine the mining cost. Our geology department conducts the exploration program and provides geological models for the LOM process. Coal seam depth, thickness, dipping angle, partings and quality constrain the available mining methods and size of operations. Shallow coal is typically mined by surface mining methods by which the primary cost is overburden removal. Deep coal is typically mined by underground mining methods where the primary costs include coal extraction, conveyance and roof control.
- Scale of operations and the equipment sizes. For surface mines, our dragline systems generally have a lower unit cost than truck-and-shovel systems for overburden removal. The longwall operations generally are more cost effective than room-and-pillar operations for underground mines.
- Commodity prices. For surface mines, the costs of diesel fuel and explosives are major components of the total mining cost. For underground mines, the steel used for roof bolts represents a significant cost. Forecasted commodity prices are used to project those costs in the financial models we use to establish our reserves.
- Target product quality. By targeting a premium quality product, our mining and processing processes may experience more coal losses. By lowering product quality the coal losses can be minimized and therefore a lower cost per ton can be achieved. In our mine plans, the product qualities are estimated to correspond to existing contracts and forecasted market demands.
- Transportation costs. Transportation costs vary by region. Most of our U.S. operations sell coal at mine loadouts. Therefore, no transportation expenses are included in our U.S. cost estimates. Our Australian operations sell coal at designated ports or local power plants. The estimated costs for our Australian operations include rail transportation and related fees at ports.
- Royalty costs. Our royalty costs are based upon contractual agreements for the coal leased from governments or private owners. The royalty rates for coal leased from governments differ by country and, in some cases, by mining method. Estimated add-on taxes and other sales-related costs are determined according to government regulations or historic costs.
- Exchange rates. Costs related to our Australian production are predominantly denominated in Australian dollars, while the Australian coal that we export is sold in U.S. dollars. As a result, Australian/U.S. dollar exchange rates impact the U.S. dollar cost of Australian production.

Based on our evaluations of the estimated prices for our coal, and costs and expenses of mining and selling our coal, which evaluations are performed on a mine-by-mine and product-by-product basis, we have concluded our reserves were economically recoverable as of December 31, 2017.

We have numerous U.S. federal coal leases that are administered by the U.S. Department of the Interior under the Federal Coal Leasing Amendments Act of 1976. These leases cover our principal reserves in the Powder River Basin and other reserves in Colorado and New Mexico. Each of these leases continues indefinitely, provided there is diligent development of the property and continued operation of the related mine or mines. The U.S. Bureau of Land Management (BLM) has asserted the right to adjust the terms and conditions of these leases, including rent and royalties, after the first 20 years of their term and at 10-year intervals thereafter. Annual rents on surface land under our federal coal leases are now set at $3.00 per acre. Production royalties on federal leases are set by statute at 12.5% of the gross proceeds of coal mined and sold for surface-mined coal and 8% for underground-mined coal. The U.S. federal government limits by statute the amount of federal land that may be leased by any company and its affiliates at any time to 75,000 acres in any one state and 150,000 acres nationwide. As of December 31, 2017, we leased 6,407 acres of federal land in Colorado, 640 acres in New Mexico and 48,181 acres in Wyoming, for a total of

55,228 acres nationwide subject to those limitations.

Similar provisions govern three coal leases with the Navajo and Hopi Indian tribes. These leases cover coal contained in 64,783 acres of land in northern Arizona lying within the boundaries of the Navajo Nation and Hopi Indian reservations. We also lease coal-mining properties from various state governments in the U.S.

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Private U.S. coal leases normally have terms of between 10 and 20 years and usually give us the right to renew the lease for a stated period or to maintain the lease in force until the exhaustion of mineable and merchantable coal contained on the relevant site. These private U.S. leases provide for royalties to be paid to the lessor either as a fixed amount per ton or as a percentage of the sales price. Many U.S. leases also require payment of a lease bonus or minimum royalty, payable either at the time of execution of the lease or in periodic installments. The terms of our private U.S. leases are normally extended by active production at or near the end of the lease term. U.S. leases containing undeveloped reserves may expire or these leases may be renewed periodically.
Mining and exploration in Australia is generally carried out under leases or licenses granted by state governments. Mining leases are typically for an initial term of up to 21 years (but which may be renewed) and contain conditions relating to such matters as minimum annual expenditures, restoration and rehabilitation. Royalties are paid to the state government as a percentage of the sales price. Generally landowners do not own the mineral rights or have the ability to grant rights to mine those minerals. These rights are retained by state governments. Compensation is payable to landowners for loss of access to the land, and the amount of compensation can be determined by agreement or arbitration. Surface rights are typically acquired directly from landowners and, in the absence of agreement, there is an arbitration provision in the mining law.
Consistent with industry practice, we conduct only limited investigation of title to our coal properties prior to leasing. Title to lands and reserves of the lessors or grantors and the boundaries of our leased properties are not completely verified until we prepare to mine those reserves.
With a portfolio of approximately 5.2 billion tons, we believe that we have sufficient coal reserves to replace capacity from depleting mines for the foreseeable future and that our significant coal reserve holdings are one of our competitive strengths.

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The following charts provide a summary, by mining complex, of production (in descending order by mining segment) for the years ended December 31, 2017, 2016 and 2015, tonnage of coal reserves that are assigned to our active operating mines, our property interest in those reserves and other characteristics of the facilities.
SUMMARY OF COAL PRODUCTION AND SULFUR CONTENT OF ASSIGNED RESERVES
(Tons in millions)

Segment/Mining Complex	Production Year Ended December 31, 2017	2016	2015	Type of Coal	Sulfur Content of Assigned Reserves as of December 31, 2017 [(1)] <1.2 lbs. Sulfur Dioxide per Million Btu	>1.2 to 2.5 lbs. Sulfur Dioxide per Million Btu	>2.5 lbs. Sulfur Dioxide per Million Btu	As Received Btu per pound [(2)]
Powder River Basin Mining:								
North Antelope Rochelle	101.6	92.9	109.3	T	1,797	—	—	8,800
Caballo	11.1	11.2	11.4	T	465	6	6	8,400
Rawhide	10.4	8.1	15.2	T	242	51	1	8,300
Total	123.1	112.2	135.9		2,504	57	7	
Midwestern U.S. Mining:								
Bear Run	7.3	7.3	7.9	T	4	27	202	10,900
Wild Boar	2.7	2.6	2.7	T	—	—	39	11,100
Gateway North	2.5	1.8	1.8	T	—	—	55	10,900
Somerville Central	2.2	2.3	3.0	T	—	—	11	11,200
Francisco Underground	2.2	2.1	2.9	T	—	—	21	11,500
Wildcat Hills Underground	1.5	1.5	1.7	T	—	—	43	12,100
Cottage Grove	0.3	0.2	1.1	T	—	—	5	12,100
Total	18.7	17.8	21.1		4	27	376	
Western U.S. Mining:								
Kayenta [(3)]	6.2	5.4	6.8	T	134	59	3	10,600
El Segundo	4.9	4.9	7.5	T	12	32	36	9,000
Twentymile	3.8	2.0	3.5	T	30	—	—	11,200
Lee Ranch	—	—	—	T	14	66	9	9,300
Total	14.9	12.3	17.8		190	157	48	
Australian Metallurgical Mining:								
North Goonyella	3.4	1.3	2.6	M	71	—	—	12,700
Millennium	3.3	3.5	4.4	M/P	3	—	—	12,600
Coppabella	2.8	2.4	2.8	P	23	—	—	12,600
Moorvale	1.8	1.9	2.2	P/T	15	—	—	12,500
Metropolitan	1.0	1.9	2.1	M/P/T	25	—	—	12,600
Burton [(4)] (Operations ceased in 2016)	—	1.5	1.3	M/T	—	—	—	NA
Middlemount [(5)]	—	—	—	M/P	25	—	—	12,400

Total	12.3	12.5	15.4		162	—	—	
Australian Thermal Mining:								
Wilpinjong	13.4	14.0	12.0	T	133	—	—	10,000
Wambo (6)	5.9	6.8	6.5	T/M	158	—	—	11,300
Total	19.3	20.8	18.5		291	—	—	
Total Assigned	188.3	175.6	208.7		3,151	241	431	

T: Thermal
M: Metallurgical
P: Pulverized Coal Injection Metallurgical

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ASSIGNED RESERVES [7]
AS OF DECEMBER 31, 2017

(Tons in millions) Segment/Mining Complex	Interest	Attributable Ownership: Proven and Probable Reserves	Owned	Leased	Surface	Underground	100% Project Basis: Proven and Probable Reserves	Owned	Leased	Surface	Underground	Modifying Factors [8]: ROM Factor	Yield
Powder River Basin Mining:													
North Antelope Rochelle	100%	1,797	—	1,797	1,797	—	1,797	—	1,797	1,797	—	92 %	100%
Caballo	100%	477	—	477	477	—	477	—	477	477	—	90 %	100%
Rawhide	100%	294	—	294	294	—	294	—	294	294	—	93 %	100%
Total		2,568	—	2,568	2,568	—							
Midwestern U.S. Mining:													
Bear Run	100%	233	101	132	233	—	233	101	132	233	—	107%	70 %
Wild Boar	100%	39	19	20	39	—	39	19	20	39	—	102%	79 %
Gateway North	100%	55	54	1	—	55	55	54	1	—	55	65 %	66 %
Somerville Central	100%	11	10	1	11	—	11	10	1	11	—	108%	71 %
Francisco Underground	100%	21	4	17	—	21	21	4	17	—	21	74 %	63 %
Wildcat Hills Underground	100%	43	10	33	—	43	43	10	33	—	43	74 %	58 %
Cottage Grove	100%	5	3	2	5	—	5	3	2	5	—	104%	82 %
Total		407	201	206	288	119							
Western U.S. Mining:													
Kayenta [3]	100%	196	—	196	196	—	196	—	196	196	—	88 %	100%
El Segundo	100%	80	66	14	80	—	80	66	14	80	—	87 %	100%
Twentymile	100%	30	8	22	—	30	30	8	22	—	30	106%	66 %
Lee Ranch	100%	89	86	3	89	—	89	86	3	89	—	87 %	100%
Total		395	160	235	365	30							
Australian Metallurgical Mining:													
North Goonyella	100%	71	—	71	—	71	71	—	71	—	71	62 %	78 %
Millennium	100%	3	—	3	3	—	3	—	3	3	—	92 %	80 %
Coppabella	73.3%	23	—	23	23	—	31	—	31	31	—	92 %	78 %
Moorvale	73.3%	15	—	15	15	—	20	—	20	20	—	107%	79 %
Metropolitan	100%	25	—	25	—	25	25	—	25	—	25	116%	79 %
Middlemount [5]	50.0%	25	—	25	25	—	50	—	50	50	—	85 %	77 %
Total		162	—	162	66	96							
Australian Thermal Mining:													

Wilpinjong	100%	133	—	133	133	—	133	—	133	133	—	112%	84 %
Wambo (6)	100%	158	—	158	43	115	158	—	158	43	115	100%	73 %
Total		291	—	291	176	115							
Total Assigned		3,823	361	3,462	3,463	360							

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES [7]
AS OF DECEMBER 31, 2017
(Tons in millions)

	Attributable Ownership					100% Project Basis				
Coal Seam Location	Total Tons Assigned	Unassigned	Proven and Probable Reserves	Proven	Probable	Total Tons Assigned	Unassigned	Proven and Probable Reserves	Proven	Probable
Powder River Basin Mining (Wyoming)	2,568	—	2,568	2,445	123	2,568	—	2,568	2,445	123
Midwestern U.S. Mining:										
Illinois	103	1,154	1,257	556	701	103	1,154	1,257	556	701
Indiana	304	14	318	270	48	304	14	318	270	48
Kentucky [9]	—	100	100	46	54	—	100	100	46	54
Total	407	1,268	1,675	872	803					
Western U.S. Mining:										
Arizona [3]	196	—	196	196	—	196	—	196	196	—
New Mexico	169	—	169	168	1	169	—	169	168	1
Colorado	30	51	81	65	16	30	51	81	65	16
Total	395	51	446	429	17					
Australian Metallurgical Mining:										
New South Wales	25	—	25	4	21	25	—	25	4	21
Queensland	137	94	231	135	96	175	122	297	168	129
Total	162	94	256	139	117					
Australian Thermal Mining (New South Wales)	291	—	291	252	39	291	—	291	252	39
Total Proven and Probable	3,823	1,413	5,236	4,137	1,099					

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ASSIGNED AND UNASSIGNED - RESERVE CONTROL AND MINING METHOD
AS OF DECEMBER 31, 2017
(Tons in millions)

	Attributable Ownership				100% Project Basis			
	Reserve Control		Mining Method		Reserve Control		Mining Method	
Coal Seam Location	Owned	Leased	Surface	Underground	Owned	Leased	Surface	Underground
Powder River Basin Mining (Wyoming)	—	2,568	2,568	—	—	2,568	2,568	—
Midwestern U.S. Mining:								
Illinois	1,208	49	5	1,252	1,208	49	5	1,252
Indiana	143	175	293	25	143	175	293	25
Kentucky (9)	35	65	—	100	35	65	—	100
Total	1,386	289	298	1,377				
Western U.S. Mining:								
Arizona (3)	—	196	196	—	—	196	196	—
New Mexico	152	17	169	—	152	17	169	—
Colorado	9	72	—	81	9	72	—	81
Total	161	285	365	81				
Australia Metallurgical Mining:								
New South Wales	—	25	—	25	—	25	—	25
Queensland	—	231	90	141	—	297	132	165
Total	—	256	90	166				
Australian Thermal Mining (New South Wales)	—	291	176	115	—	291	176	115
Total Proven and Probable	1,547	3,689	3,497	1,739				

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES - SULFUR CONTENT
AS OF DECEMBER 31, 2017
(Tons in millions)

		Attributable Ownership Sulfur Content (1)			100% Project Basis Sulfur Content (1)			
Coal Seam Location	Type of Coal	<1.2 lbs. Sulfur Dioxide per Million Btu	>1.2 to 2.5 lbs. Sulfur Dioxide per Million Btu	>2.5 lbs. Sulfur Dioxide per Million Btu	<1.2 lbs. Sulfur Dioxide per Million Btu	>1.2 to 2.5 lbs. Sulfur Dioxide per Million Btu	>2.5 lbs. Sulfur Dioxide per Million Btu	As Received Btu per Pound (2)
Powder River Basin Mining (Wyoming)	T	2,504	57	7				