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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2018

or

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

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. ☑

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 ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

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

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

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, 2018: Common Stock, par value $0.01 per share, $3.9 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 ☑ No ☐

Number of shares outstanding of each of the Registrant's classes of Common Stock, as of February 20, 2019: Common Stock, par value $0.01 per share, 108,267,736 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 2019 Annual Meeting of Shareholders (the Company's 2019 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 (the Exchange Act), 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,” “outlook,” “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, and events and conditions that could occur during the course of our mining operations could have a material adverse impact on us;
- if transportation for our coal becomes unavailable or uneconomic for our customers, our ability to sell coal may be diminished;
- 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 impacts of coal combustion on global climate are increasingly leading to consequences that have and could continue to affect demand for our products or our securities, including the following: increased regulation of coal combustion in many jurisdictions; investment decisions by electricity generators that are unfavorable to coal-fueled generation units; unfavorable lending policies by lending institutions and development banks toward the financing of new overseas coal-fueled power plants; and divestment efforts affecting the institutional investment community;
- numerous activist groups are devoting substantial resources to anti-coal activities to minimize or eliminate the use of coal as a source of electricity generation, domestically and internationally, thereby further reducing the demand and pricing for coal, and potentially materially and adversely impacting our future financial results, liquidity and growth prospects;
- we may not be able to successfully integrate the recently acquired Shoal Creek Mine or other companies, assets or properties that we may acquire in the future;
- if we fail to establish and maintain proper internal controls for the Shoal Creek Mine, our ability to produce accurate financial statements or comply with applicable regulations could be impaired;
- our financial performance could be adversely affected by our indebtedness;
- despite our indebtedness, we may still be able to incur substantially more debt, including secured debt, which 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 indebtedness impose restrictions that may limit our operating and financial flexibility;
- the number and quantity of viable financing alternatives available to us may be significantly impacted by unfavorable lending and investment policies by financial institutions and insurance companies associated with concerns about environmental impacts of coal combustion;
- 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 stakeholders' 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;
- acquisitions and divestitures 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 or 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. As of December 31, 2018, 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 2018, we achieved a global safety incidence rate of 1.45 incidents per 200,000 hours worked, which was 54% better than the 2017 industry average incidence rate of 3.18 incidents per 200,000 hours worked per the Mine Safety and Health Administration (MSHA). 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.

On December 3, 2018, we acquired the Shoal Creek metallurgical coal mine, preparation plant and supporting assets located in Alabama (Shoal Creek Mine) as further discussed in Note 3. "Acquisition of Shoal Creek Mine" to the accompanying consolidated financial statements. Our results of operations include the Shoal Creek Mine's results of operations from December 4, 2018 through December 31, 2018. The Shoal Creek Mine's results are reflected in our Seaborne Metallurgical Mining segment.

Our current focus is on enhancing shareholder value through successfully integrating the Shoal Creek Mine, accelerating a safe return to operations at our North Goonyella Mine as further discussed in Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 22. "Other Events" to the accompanying consolidated financial statements, advancing attractive mine life extension projects in seaborne segments, continuing to emphasize value over volume, particularly in the U.S. thermal operations, and maintaining our commitment to returning cash to shareholders.

Segment and Geographic Information

During the fourth quarter of 2018, we purchased the Shoal Creek Mine. Due to the acquisition, we updated our reportable segments to reflect the manner in which our chief operating decision maker (CODM) views our businesses for purposes of reviewing performance, allocating resources and assessing future prospects and strategic execution. We now report our results of operations primarily through the following reportable segments: Powder River Basin Mining, Midwestern U.S. Mining, Western U.S. Mining, Seaborne Metallurgical Mining, Seaborne Thermal Mining and Corporate and Other.

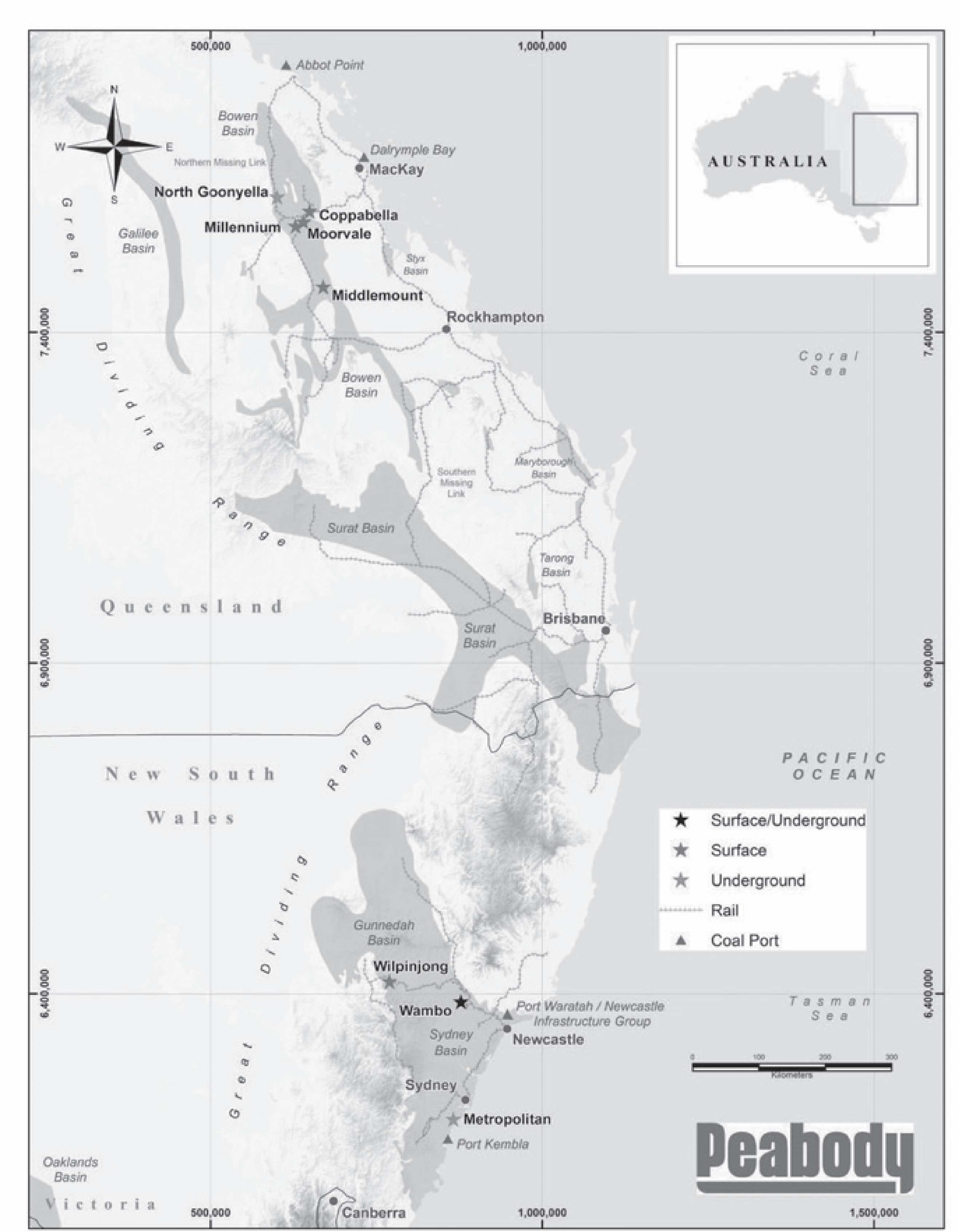
Refer to Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information regarding our segments. Segment and geographic financial information is also contained in Note 28. "Segment and Geographic Information" to the accompanying consolidated financial statements and is incorporated herein by reference.

Mining Locations

The maps that follow display our active mine locations as of December 31, 2018. Also shown are the primary ports that we use in Australia for coal exports and our corporate headquarters in St. Louis, Missouri.

U.S. Locations

Australian Locations



The table below summarizes information regarding the operating characteristics of each of our mines that were active in 2018 in the U.S. and Australia. The mines are listed within their respective mining segment in descending order, as determined by tons sold in 2018.

Segment/Mining Complex	Location	Mine Type	Mining Method	Coal Type	Primary Transport Method	2018 Tons Sold (In millions)
Powder River Basin Mining						
North Antelope Rochelle	Wyoming	S	D, DL, T/S	T	R	98.4
Caballo	Wyoming	S	D, T/S	T	R	11.3
Rawhide	Wyoming	S	D, T/S	T	R	9.5
Third party (1)	—	—	—	—	—	1.1
Midwestern U.S. Mining						
Bear Run	Indiana	S	DL, D, T/S	T	Tr, R	6.9
Gateway North	Illinois	U	CM	T	Tr, R, R/B, T/B	3.1
Wild Boar	Indiana	S	D, T/S	T	Tr, R, R/B, T/B	2.7
Francisco Underground	Indiana	U	CM	T	R	2.3
Somerville Central	Indiana	S	DL, D, T/S	T	R, R/B, T/B, T/R	2.0
Wildcat Hills Underground	Illinois	U	CM	T	T/B	1.4
Cottage Grove	Illinois	S	D, T/S	T	T/B	0.5
Western U.S. Mining						
Kayenta	Arizona	S	DL, T/S	T	R	6.6
El Segundo	New Mexico	S	D, DL, T/S	T	R	5.2
Twentymile	Colorado	U	LW	T	R, Tr	2.9
Lee Ranch (2)	New Mexico	S	T/S	T	R	—
Seaborne Metallurgical Mining						
Coppabella (3)	Queensland	S	DL, D, T/S	P	R, EV	2.7
Millennium (4)	Queensland	S	HW, D, T/S	M, P	R, EV	2.4
Moorvale (3)	Queensland	S	D, T/S	P, T	R, EV	2.1
Metropolitan	New South Wales	U	LW	M, P, T	R, EV	1.9
North Goonyella (5)	Queensland	U	LW	M	R, EV	1.8
Shoal Creek (6)	Alabama	U	LW	M	B, EV	0.1
Middlemount (7)	Queensland	S	D, T/S	M, P	R, EV	—
Seaborne Thermal Mining						
Wilpinjong	New South Wales	S	D, T/S	T	R, EV	13.9
Wambo Open-Cut (8)	New South Wales	S	T/S	T	R, EV	3.6
Wambo Underground (8)	New South Wales	U	LW	T, M	R, EV	1.6

Legend:

S	Surface Mine	B	Barge
U	Underground Mine	Tr	Truck
HW	Highwall Miner	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) Mine was suspended in 2018.

(3) 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.

(4) The mine ceased open-cut mining in September 2018 and now exclusively conducts highwall mining.

(5) Our North Goonyella Mine experienced a fire in a portion of the mine during September 2018.

(6) Tons sold is for the period December 4 through December 31, 2018.

(7) We own a 50% equity interest in Middlemount, which owns the Middlemount Mine. Because that entity is accounted for as an unconsolidated equity affiliate, 2018 tons sold from that mine, which totaled 4.2 million tons (on a 100% basis), have been excluded from the table above.

(8) 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.

Coal Supply Agreements

Customers. Our coal supply agreements are primarily with electricity generators, industrial facilities and steel manufacturers. Most of our sales from our mining operations 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 from our mining operations 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 87%, 83% and 86% of our worldwide sales from our mining operations (by volume) for the years ended December 31, 2018, 2017 and 2016, 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, 2018, we derived 25% of our revenues from coal supply agreements from our five largest customers. Those five customers were supplied primarily from 48 coal supply agreements (excluding trading and brokerage transactions) expiring at various times from 2019 to 2025. The contract contributing the greatest amount of annual revenue in 2018 was approximately $327 million, or approximately 6% of our 2018 total revenues from coal supply agreements, and is due to expire in 2019.

Backlog. Our sales backlog, which includes coal supply agreements subject to price reopener and/or extension provisions, was approximately 401 million and 476 million tons of coal as of January 1, 2019 and 2018, respectively. Contracts in backlog have remaining terms ranging from one to nine years and represent approximately two years of production based on our 2018 production volume of 182.1 million tons. Approximately 63% of our backlog is expected to be filled beyond 2019.

U.S. Thermal Mining Operations. Revenues from our Powder River Basin Mining, Western U.S. Mining and Midwestern U.S. Mining segments, in aggregate, represented approximately 52%, 53% and 59% of our revenues from coal supply agreements for the years ended December 31, 2018, 2017 and 2016, respectively, during which periods the coal mining activities of those segments contributed respective aggregate amounts of approximately 84%, 84% and 81% 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 may vary 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.

Seaborne Mining Operations. Revenues from our Seaborne Metallurgical Mining and Seaborne Thermal Mining segments represented approximately 48%, 46% and 41% of our total revenues from coal supply agreements for the years ended December 31, 2018, 2017 and 2016, respectively, during which periods the coal mining activities of those segments contributed respective amounts of 16%, 16% and 19% 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 sales volume under contracts with a duration of less than one year represented 27% in 2018.

Transportation

Methods of Distribution. 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 or directly to customers. Title predominately passes to the purchaser at the rail or barge, as applicable. Our U.S. and Australian export coal is usually sold at the loading port, with purchasers paying ocean freight. In each case, we 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 Locations” section for a summary of transportation methods by mine.

Export Facilities. Our U.S. thermal mining operations exported approximately 1%, 1% and 0% of its annual tons sold for the years ended December 31, 2018, 2017 and 2016, respectively. The primary ports used for U.S. thermal 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 seaborne mining operations, which include our Shoal Creek Mine, sold approximately 75%, 73% and 75% of its tons into the seaborne coal markets for the years ended December 31, 2018, 2017 and 2016, 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 Newcastle Coal Infrastructure Group. We have secured our ability to transport coal from our Shoal Creek Mine under barge and port contracts; the primary port is the McDuffie Terminal in Mobile, Alabama, which we utilize without a take-or-pay arrangement.

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 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.

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). The Henry Hub Natural Gas Prompt Price averaged $3.07 per mmBtu in 2018, versus $3.02, $2.55 and $2.63 per mmBtu in 2017, 2016 and 2015, 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 the prices exceed $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. These pressures, coupled with increasing regulatory burdens, have contributed to a significant number of coal plant retirements. During 2018, approximately 17 gigawatts of U.S. coal power capacity was retired, and since 2010, U.S. coal power capacity has fallen by nearly a quarter.

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. Seaborne thermal coal consumption is also impacted by the competitiveness of delivered seaborne thermal coal supply from key exporting countries such Indonesia, Australia, Russia, Colombia, the U.S. and South Africa, among others. 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.

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, Blackjewel, Cloud Peak Energy, CONSOL Energy, and Murray Energy Corporation, among others. Major international direct coal supply competitors (listed alphabetically) include Anglo American plc, BHP Billiton, China Shenhua Energy, Coal India Limited, Drummond Company, Glencore plc, PT Adaro Energy Tbk, SUEK and Whitehaven Coal Limited, among others.

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, Mongolia and Mozambique, among others.

Major international direct competitors (listed alphabetically) include Anglo American plc, BHP Billiton, China Coal, China Shenhua Energy, Teck Resources, Rio Tinto and Whitehaven, among others.

Cybersecurity Risk Management

We use digital technology to conduct our business operations and engage with our customers, vendors and partners. As we implement newer technologies such as cloud, analytics, automation and "internet of things", the threats to our business operations from cyber intrusions, denial of service attacks, manipulation and other cyber misconduct increase. To address the risk, we continue to evolve our risk management approach in an effort to continually assesses and improve our cybersecurity risk detection, deterrence and recovery capabilities. Our cybersecurity strategy emphasizes reduction of cyber risk exposure and continuous improvement of our cyber defense and resilience capabilities. These include: (i) proactive management of cyber risk to ensure compliance with contractual, legal and regulatory requirements, (ii) performing due diligence on third parties to ensure they have sound cybersecurity practices in place, (iii) ensuring essential business services remain available during a business disruption, (iv) implementing data policies and standards to protect sensitive company information and (v) exercising cyber incident response plans and risk mitigation strategies to address potential incidents should they occur. For more information regarding the risks associated with these matters, see "Item 1A. Risk Factors."

Working Capital

We generally fund our working capital requirements through a combination of existing cash and cash equivalents and proceeds from the sale of our coal production to customers. 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 7,400 employees as of December 31, 2018, including approximately 5,600 hourly employees. Additional information on our employees and related labor relations matters is contained in Note 24. “Management — Labor Relations” to the accompanying 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	51	President and Chief Executive Officer
Amy B. Schwetz	44	Executive Vice President and Chief Financial Officer
A. Verona Dorch	51	Executive Vice President, Chief Legal Officer, Government Affairs and Corporate Secretary
Charles F. Meintjes	56	Executive Vice President - Corporate Services and Chief Commercial Officer
Paul V. Richard	59	Senior Vice President and Chief Human Resources Officer
George J. Schuller Jr.	55	President - Australia
Kemal Williamson	59	President - Americas

(1) As of February 20, 2019.

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 a career that gives insights from the miner, competitor fuel and industrial customer perspectives. From 1985 to 2013, he worked for BHP Ltd. in the United States, Australia and South America. Mr. Kellow has held chief executive leadership, operating or financial roles in global business in coal, copper, nickel, aluminum, steel, oil and gas. He is 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 of Business Administration and a Bachelor Degree in Commerce from the University of Newcastle. He holds an honorary Doctor of Science degree from the South Dakota School of Mines and Technology.

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 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 and government relations counsel for Peabody’s business activities and leads the Company’s global legal, government affairs and compliance functions. Ms. Dorch has close to 25 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 board of directors of Enterprise Bank & Trust, a regional bank with over $5.5 billion in assets, 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 over three decades serving in both domestic and international operational posts, most recently serving as Chief Operating Officer in Australia. 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 of Powder River Basin & Southwest Operations, Senior Vice President Engineering Services, Vice President Engineering Technical Services and Vice President Continuous Improvement following 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 and also an Honorary Doctorate in engineering from West Virginia University.

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 of 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.

Filing Under Chapter 11 of the United States Bankruptcy Code

On April 13, 2016 (the Petition Date), Peabody and a majority of its wholly owned domestic subsidiaries as well as one international subsidiary in Gibraltar (collectively 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 U.S. Bankruptcy Court for the Eastern District of Missouri (the Bankruptcy Court). 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.).

On March 17, 2017, the Bankruptcy Court entered an order, Docket No. 2763 (the Confirmation Order), confirming the Debtors' Second Amended Joint Plan of Reorganization of Debtors and Debtors in Possession (as further modified, 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.

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 Workers' 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 who was the last to employ a claimant for a cumulative year of employment, with the last day worked for the operator after July 1, 1973, must pay federal black lung benefits and medical expenses to claimants 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 was 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. The tax reverted to its original level of $0.50 per ton of underground coal and $0.25 per ton of surface coal on January 1, 2019. We recognized expense related to the tax of $78.6 million, $60.9 million, $20.1 million and $77.4 million for the year ended December 31, 2018, the period April 2 through December 31, 2017, the period January 1 through April 1, 2017 and the year ended December 31, 2016, respectively.

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.

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 primacy 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 $1,238.9 million as of December 31, 2018. 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 $503.3 million as of December 31, 2018. 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, 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 $40.9 million, $31.6 million, $10.3 million and $38.7 million for the year ended December 31, 2018, the period April 2 through December 31, 2017, the period January 1 through April 1, 2017 and the year ended December 31, 2016, 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.

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 had been held in abeyance pending the EPA's review of the final rule. In August 2018, the EPA said it would continue with the rule, meaning the lawsuit was revived and oral arguments were heard in the D.C. Circuit in December 2018. 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 New Source Performance Standards (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), 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.

On December 6, 2018, the EPA proposed to revise the 2015 NSPS to modify the minimum requirements for newly constructed coal-fired units from partial carbon capture and storage to efficiency-based standards. The proposal now defines the Best System of Emission Reduction (BSER) as the most efficient demonstrated steam cycle in combination with the best operating practices. The EPA has noted that the primary reason for this proposed revision is the high costs and limited geographic availability of carbon capture and storage technology. The comment period on the proposed rule concluded on February 19, 2019.

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 for 60 days while the agency reconsidered the rule. The D.C. Circuit renewed the abeyance several times, but the most recent abeyance expired on August 27, 2018. The D.C. Circuit is considering filings by the EPA and the petitioners that ask it to issue an additional abeyance over the opposition of some states and their supporters that asked the court to issue a decision on the merits.

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)). If this proposed reinterpretation is finalized by the EPA, the CPP would be repealed.

The EPA relied on the proposed reinterpretation until August 2018, when it proposed the Affordable Clean Energy (ACE) Rule, which proposes to replace the CPP with a system where states will develop emissions reduction plans using BSER measures, which are essentially efficiency heat rate improvements, and the EPA will approve the state plans if they use EPA-approved candidate technologies. Changes in the New Source Review (NSR) program are also proposed to allow efficiency improvements to be made without triggering NSR requirements. If adopted, ACE will provide states with the flexibility to regulate on a plant-by-plant basis with a focus on coal-fired EGUs. Public comments on the rule were due October 31, 2018, and the EPA is expected to finalize the rule in March 2019. Litigation may be initiated, however, and the final timeline may shift.

EPA's Greenhouse Gas Permitting Regulations for Major Emission Sources. In May 2010, the EPA published final rules requiring permitting and control technology requirements for greenhouse gases 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 greenhouse gases 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 greenhouse gases 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 (known as Step 2 sources). In accordance with that decision, the D.C. Circuit vacated the federal regulations that implemented Step 2 of the Greenhouse Gas Tailoring Rule in 2015. Subsequently, the EPA removed the vacated elements from its rules to ensure that neither the PSD nor Title V rules require a source to obtain a permit solely because the source emits or has the potential to emit greenhouse gases above the applicable thresholds. The EPA therefore no longer has the authority to conduct PSD permitting for Step 2 sources, nor can the EPA approve provisions submitted by a state for inclusion in its SIP providing this authority.

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. Oral argument was held in October 2018 and a decision is pending.

In the meantime, on December 6, 2018, the EPA issued a final determination that the existing CSAPR Update fully addresses the CAA's "good neighbor" requirements for 20 states with respect to the 2008 ground-level ozone standard. The final rule determines that 2023 is an appropriate future analytic year to evaluate further good neighbor requirements. As a result, these 20 states are not expected to contribute significantly to nonattainment or interfere with maintenance of the NAAQS in any other state. With this determination, the EPA has no obligation to establish additional requirements for sources in theses states to further reduce transported ozone pollution under the 2008 ozone NAAQS. In addition, the covered states do not need to submit state implementation plans (SIPs) that would establish additional requirements beyond the existing CSAPR Update.

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.

On December 27, 2018, the EPA issued a proposed revised Supplemental Cost Finding for the MATS rule that would revoke the determination that regulating HAPs from coal-fired power plants is "appropriate and necessary" under Section 112(n)(1)(A) of the CAA. The finding was based on an EPA assessment that health and environmental benefits from the MATS rule that are not directly related to mercury pollution should not be included in the benefit portion of the analysis. In the new proposed cost-benefit analysis, the EPA found the costs "grossly outweigh" any possible benefits.

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. Environmental groups took the issue to court and in September 2018, Wyoming and Montana opposed the suits in court and defended against the freeze possibly being reinstated. This litigation is ongoing.

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 CWA (commonly called the Waters of the United States (WOTUS Rule)), was published by the EPA and the Corps in June 2015. The U.S. Court of Appeals for the Sixth Circuit stayed the 2015 Rule nationwide on October 9, 2015, and that stay remained in place until early 2018. Before the Sixth Circuit lifted its stay, the EPA and the Corps finalized a rule, also known as the "Delay Rule," on February 6, 2018 that amended the 2015 WOTUS Rule by specifying that the Rule does not apply until February 6, 2020. Consequently, the pre-2015 definitions of WOTUS remained in effect nationwide. However, in August 2018, the U.S. District Court in South Carolina overturned the "Delay Rule" saying the administration had failed to offer the public a proper opportunity to comment. That put the 2015 rule into effect in 26 states, but not in the other 24 states where federal court injunctions are still in place. In September 2018, a federal district court judge in Texas granted an injunction request for three more states; Texas, Louisiana and Mississippi. Also that month, industry filed a motion in a Georgia district court to expand its previous injunction, which stopped implementation in 11 states, to apply nationwide. Other district courts may also consider the issue in the coming months. The EPA and the Corps are still in the process of repealing the 2015 WOTUS Rule and developing a replacement rule. The agencies proposed to repeal the 2015 Rule in July 2017, but they have not yet finalized a repeal action, and the final rule was expected before the end of 2018, but is now expected in 2019. Further, the EPA and the Corps issued a proposed rule in December 2018 offering a replacement definition of WOTUS. The proposal would remove federal protections for streams that flow only after rain or snowfall, as well as wetlands that do not have surface water connections to larger waterways. The public comment period on the proposed rule ends on February 27, 2019. Depending on the outcome of litigation and/or rulemaking activity, the scope of CWA authority could increase, decrease, or stay the same relative to the current, pre-2015 definitions of WOTUS, which could impact our operations in some areas.

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. The White House Council on Environmental Quality (CEQ) issued an Advance Notice of Proposed Rulemaking in June 2018 seeking comment on a number of ways to streamline and improve the NEPA process. The comment period closed in August 2018. It is unclear how far reaching the changes will be and if they will be able to withstand expected court challenges.

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.

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. The Department of the Interior issued three proposed rules in August 2018 aiming to streamline and update the ESA.

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.

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.

Wyoming Land Quality Division Self-Bonding Rules. On August 20, 2018, the Wyoming Land Quality Division, through the Land Quality Advisory Board, offered for public comment proposed changes to self-bonding rules related to reclamation obligations. The proposal included requiring that the self-bonding guarantor be the ultimate parent company and that the maximum amount of bonding be limited to 75% of the company’s calculated bond amount. Additionally, the proposal required the self-bonding party to be of investment grade quality using ratings issued by nationally recognized credit rating services, such as the Moody’s Investor Service or Standard and Poor’s Corporation. This requirement would replace the current qualifying tests using a bonding party’s audited financial statements.

The Company currently meets all its bonding obligations in Wyoming through the use of commercial surety bonds. If the proposed rule becomes effective, the Company would not qualify for self-bonding based on its current credit rating. The proposed rule was approved by the Wyoming Land Quality Advisory Board on September 19, 2018 and the Environmental Quality Council on February 19, 2019. It will now be sent to the Governor for his signature to become effective.

Federal Report on Climate Change. On November 23, 2018, the U.S. Global Change Research Program, a working group comprised of 13 U.S. governmental departments and agencies, issued the Fourth National Climate Assessment. The report lists the observed effects of “increasing greenhouse gas concentrations on Earth’s climate” and enumerates the impacts of those observed effects. The report also discusses the alternatives for reducing the impacts of climate-related risks, including through mitigation and adaptation. While there are no explicit regulatory actions that flow from the issuance of the report, both the legislative and executive branches of government may rely on its conclusions to shape and justify policies and actions going forward.

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.

Native Title and Cultural Heritage. Since 1992, the Australian courts have recognized that native title to lands and water, 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 mining activities 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. A recent decision of the New South Wales Land and Environment Court refused planning approval for a non-Peabody mining project (*Gloucester Resources Limited v Minister for Planning*). The judge in that case considered the relevance of downstream greenhouse gas emissions resulting from the consumption of coal to be mined under the proposed project. The decision adds to an existing body of Australian case law concerning greenhouse gas emissions of mining projects and how they are to be assessed in the context of planning approvals, including planning approvals for Peabody mining projects. 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 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 2008, Planning Act 2016, Coal Mining Safety and Health Act 1999, Minerals and Energy Resources (Common Provisions) Act 2014, 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, Biosecurity Act 2014, 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. 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 that provides more certainty to the industry on the circumstances in which 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, Coal Mine Subsidence Compensation Act 2017, Environmental Planning and Assessment Act 1979 (EPA 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, Biodiversity Conservation Act 2016 (BC Act), Heritage Act 1977, Aboriginal Land Rights Act 1983, Crown Land Management Act 2016, Dangerous Goods (Road and Rail Transport) Act 2008, Fisheries Management Act 1994, Forestry Act 2012, Native Title (New South Wales) Act 1994, Biosecurity Act 2015, Roads Act 1993 and National Parks & Wildlife Act 1974.

Under the EPA Act, environmental planning instruments must be considered when approving a mining project development application. 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 relevant legislation. Effective from March 1, 2018, the EPA Act was amended to introduce a number of changes to planning laws in New South Wales. The EPA Act was further amended in June 2018 to revoke a process for modifying development approvals under the former section 75W of the EPA Act. As a result, new development approvals will need to be obtained unless the proposed project will be substantially the same development as it was when the development approval was last modified under section 75W, in which case the existing development approval can be modified. If a new development approval is required then this could take additional time to achieve.

On August 25, 2017, the BC Act commenced in New South Wales and imposes a revised framework for the assessment of potential impacts on biodiversity that may be caused by a development, such as a proposed mining project. The BC Act requires these potential impacts on biodiversity to be offset in perpetuity, by one or more of the following means: securing land based offsets and retiring biodiversity credits, making a payment into a biodiversity conservation fund or in some cases through mine site ecological rehabilitation. The data collected from the biodiversity impact assessment process is inputted into a new offsets payment calculator in order to determine the amount payable by the proponent to offset the impacts. The proposed development can only proceed once the biodiversity offset obligations have been satisfied.

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, surety bonds or bank guarantees which are supported by a combination of cash collateral, deeds of indemnity and guarantee and letters of credit issued under our credit facility and accounts receivable securitization program. We operate in both the Queensland and New South Wales state jurisdictions.

Our reclamation bonding requirements in Australia were $225.4 million as of December 31, 2018. The bond requirements represent the calculated cost to reclaim the current operations of a mine if it ceases 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 $246.9 million as of December 31, 2018. 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. The bond requirement is lower than the asset retirement obligation as the bond calculation includes the discounts noted above and excludes certain of our mining overhead costs that would not be applicable if the government managed the closure process.

New South Wales Reclamation. The Mining Act 1992 (Mining Act) is administered by the Department of Planning and Environment and the New South Wales Resources Regulator and authorizes the holder of a mining tenement to extract a mineral subject to obtaining consent under the EPA Act 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 the extent of disturbance during the MOP period.

Queensland Reclamation. The EP Act is administered by the Department of Environment and Science 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 the extent of disturbance during the PO period.

On November 19, 2018, the Queensland government passed the Mineral and Energy Resources (Financial Provisioning) Act 2018 providing for a new financial assurance (FA) framework and new progressive rehabilitation requirements. The new FA framework creates a pooled fund covering most mines and most of the total industry liability, plus other options for providing FA if not part of the pooled fund (for example, allowing insurance bonds or cash). The percentage rate of the total rehabilitation cost payable into the pooled fund will take into account the financial strength of the holder of the EA for the mine and the project strength of the mine. The total rehabilitation cost is determined using an updated rehabilitation cost calculator, which no longer provides for discounting. The commencement date for the new FA framework is April 1, 2019 and there will be a transitional period. The Company is waiting to receive guidelines from the government on how the new FA framework will be applied in respect of the Company's Queensland mines.

The new progressive rehabilitation requirements will commence on November 1, 2019 and will require each mine to establish a schedule of rehabilitation milestones covering the life of the mine, and any significant changes to the timing of rehabilitation will require regulatory approval. If there is to remain an area within the mine that is not to be rehabilitated such that it does not have a post-mining land use (referred to as a non-use management area or NUMA) then each such NUMA will need to pass a public interest evaluation test as part of the approval process. An example of a NUMA is the void that remains after open-cut mining activities have been completed. Under the legislation, each current mine is exempt from the requirement to justify its existing NUMAs to the extent that its current approvals provide for such areas. The Company is currently assessing the impact of the new rehabilitation requirements on its Queensland mines including whether there will be a need to seek any further regulatory approvals for any of the NUMAs at any of those mines.

Residual Risks. On November 19, 2018 the Queensland government released for public consultation a discussion paper on managing 'residual risks' of mining activities. On completion of all mining activities, the holder of the EA for the mine can apply to surrender the EA once all conditions, requirements and rehabilitation obligations have been met. When approving the surrender, the government can request a residual risk payment from the holder of the EA for the mine to cover potential rehabilitation or maintenance costs incurred after the surrender has been accepted. The discussion paper contemplates two approaches for determining residual risk payments. Depending on the level of risk of a particular site, a cost calculator tool might be used or a panel of appropriately qualified experts might undertake a qualitative and quantitative risk assessment. Industry and the Company continue to consult with the government on the proposed residual risk payment regime.

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 expected to issue a report in due course.

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.

Starting in 2015, a small number of coal mine workers in Queensland and New South Wales have been diagnosed with coal workers' pneumoconiosis (CWP, also known as black lung) following decades of assumed eradication of the disease. 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, coal mine workers, the regulator 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 coal 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. 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.

Since August 2017, the Workers' Compensation and Rehabilitation Act 2003 provides for a medical examination process for retired or former coal workers with suspected CWP, 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 October 31, 2018 the Queensland government passed the Mines Legislation (Resources Safety) Amendment Act 2018, which introduces significant changes to the Coal Mining Safety and Health Act 1999 concerning, among other things, duties of officers, reporting requirements for coal mine worker diseases, reporting defects and hazards affecting plant and substances, contractor and service provider safety and health management plans, new powers to suspend or cancel an individual's statutory certificate of competency and increasing penalties and inspector powers.

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 federal Department of Environment and Energy is responsible for NGER Act-related policy developments and review.

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.

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.

Sydney Water Catchment Areas. In November 2017, the New South Wales government established an independent expert panel (Panel) to advise the Department of Planning and Environment on the impact of underground mining activities in Sydney's water catchment areas, including at Peabody's Metropolitan Mine. The Panel issued an initial report to the government in November 2018, which was released by the government on December 20, 2018. The initial report only concerns mining activities at two mines, Peabody's Metropolitan Mine and a competitor's Dendrobium Mine. A final report is currently expected to be issued in August 2019, which will cover mining activities and effects across the catchment as a whole, with a particular focus on risks to the quantity of water available, the environmental consequences for swamps and the issue of cumulative impacts.

The Panel's initial report acknowledges the major effort at the Metropolitan and Dendrobium Mines over the last decade to employ best practice modeling and assessment methods undertaken by suitable experts, while recommending continued rigorous monitoring and impact assessment in order to build on the knowledge base regarding mining-induced subsidence and its impacts on groundwater and surface water. The initial report endorses the government taking an incremental approach to mining approvals that provides for considering existing and emerging information and knowledge gaps. The latest extraction plans for the Metropolitan Mine are progressing on an incremental basis and Peabody continues to conduct robust monitoring, data collection and reporting and has been actively consulting with the government on Metropolitan's approval processes and mine design to ensure that operational impacts are appropriately managed and minimized as far as possible.

Global Climate

In the U.S., Congress has considered legislation addressing global climate issues and greenhouse gas emissions, but to date, no such legislation has been signed into law. 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 CAA. 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." In particular, in 2015, the EPA announced final rules (known as the CPP) for regulating carbon dioxide emissions from existing and new fossil fuel-fired EGUs. Twenty-seven states and governmental entities, as well as utilities, industry groups, trade associations, coal companies (including Peabody), and other entities, challenged the CPP in federal court.

Since 2016, implementation of the CPP has been stayed by the U.S. Supreme Court pending resolution of its legal challenges. In October 2017, the EPA proposed to change its legal interpretation of section 111(d) of the CAA, the authority that the agency relied on for the original CPP. If this proposed reinterpretation were finalized by the EPA, the CPP would be repealed.

The EPA relied on the proposed reinterpretation until August 2018, when it proposed the ACE Rule, which would replace the CPP with a system where states will develop emissions reduction plans using BSER measures (essentially efficiency heat rate improvements), and the EPA will approve the state plans if they use EPA-approved candidate technologies. Changes in the NSR program are also proposed to allow efficiency improvements to be made without triggering NSR requirements. If adopted, ACE will provide states with the flexibility to regulate on a plant-by-plant basis with a focus on coal-fired EGUs. Public comments on the rule were due October 31, 2018, and the EPA is expected to finalize the rule during 2019. Litigation may be initiated, however, and the final timeline may shift.

At the same time, 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.

Several other U.S. 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 we 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. Other banks (such as BNP Paribas and HSBC) have pledged to end financing of certain fossil fuel projects and companies. Some insurance companies (such as Zurich and Swiss Re) have announced that they will no longer insure coal operations and companies. And some large investors (including Lloyd's of London) have announced that they plan to divest coal stocks from their investment holdings.

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 U.S. has begun the process of withdrawing from the Paris Agreement, which cannot be completed until 2020 under the terms of the 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 Federal Government released a plan aimed at delivering an affordable and reliable energy system that meets Australia's international commitments to emissions reduction. The plan was referred to as the National Energy Guarantee (NEG) and was aimed at changing the National Electricity Market and associated legislative framework. The NEG was abandoned by the Australian government in September 2018. The current Coalition government has confirmed that it remains committed to meeting Australia's Paris Agreement targets but that the focus of energy policy will be on driving down electricity prices. The opposition Labor party has indicated that it will adopt a NEG-style energy policy if it wins the next Federal election and has committed to a 45% emissions reduction target by 2030, based on 2005 levels. This compares to the Coalition's previous target under the NEG of a 26% reduction by 2030, which is in line with the Paris Agreement. The Labor party has also committed to a 50% renewables energy target by 2030.

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).

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.

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 our Plan. As a result, we are subject to the fresh start reporting rules required under the Financial Accounting Standards Board ASC 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 April 2, 2017 are not directly 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 2018, the coal industry saw continued buoyancy in seaborne metallurgical pricing, while thermal coal pricing trended down toward historical averages. These prices may not be sustainable in the future; in fact 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 and capacity utilization of electricity generating units (whether coal or non-coal);
- changes in the fuel consumption and dispatch patterns of electric power generators;
- the proximity, capacity and cost of transportation and terminal facilities;
- the relative price of natural gas and other energy sources used to generate electricity;
- competition with and the availability, quality and price of coal and alternative fuels, including natural gas, fuel oil, nuclear, hydroelectric, wind, biomass and solar power;
- the strength of the global economy;
- the global supply and production costs of thermal and metallurgical coal;
- the demand for steel, which may lead to price fluctuations in the monthly and quarterly repricing of our metallurgical coal contracts;
- weather patterns, severe weather and natural disasters;
- governmental regulations and taxes, including tariffs or other trade restrictions as well as 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.

For our U.S. thermal coal, 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. For our seaborne coal, 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.

Thermal coal accounted for the majority of our coal sales by volume during 2018 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 older, less efficient coal-fueled generation units) as current and potentially increasing regulatory costs impact the budgetary decisions of electric power 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, permits to construct these plants are easier to obtain as natural gas is seen as having a lower environmental impact than coal-fueled generators, and electric power generators are facing public and, in some cases, legislative pressure to generate a larger portion of their electricity from natural gas-fueled units and from alternative energy sources. 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% of our revenues in 2018 and 2017. Changes in governmental policies and regulations and 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 could 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 low prices for other fuels may also cause utilities to phase out or close existing coal-fueled power plants or reduce construction of new coal-fueled 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, price indices 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.

The loss of, or significant reduction in, purchases by our largest customers could adversely affect our revenues.

For the year ended December 31, 2018, we derived 25% of our total revenues from our five largest customers, similar to the prior year. Those five customers were supplied primarily from 48 coal supply agreements (excluding trading transactions) expiring at various times from 2019 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 exclusively served by our Kayenta 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. The mine's approximate Adjusted EBITDA contribution, approximate depreciation, depletion and amortization and asset retirement obligation expense, and tons of coal sold are presented in the table below for the respective periods. Depreciation, depletion and amortization and asset retirement obligation expense for the Successor periods are not comparable to those of the Predecessor periods due to the revaluation of the Company's property, plant, equipment, and mine development to fair value in connection with fresh start reporting, as further described in Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting" to the accompanying consolidated financial statements.

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars and tons in millions)			
Adjusted EBITDA	$ 110	$ 77	$ 27	$ 79
Depreciation, depletion and amortization and asset retirement obligation expense	$ 120	$ 60	$ 19	$ 26
Tons of coal sold	6.6	4.8	1.5	5.8

The mine's Adjusted EBITDA was higher for the year ended December 31, 2018 as compared to the combined 2017 periods due to increased volume and increased reimbursements of certain costs under the customer contract. Adjusted EBITDA was higher for the combined 2017 periods as compared to the year ended December 31, 2016 due to increased volume. The mine's contract to supply coal to NGS expires in December 2019. We estimate that the mine will sell between 3.5 million and 4.0 million tons of coal in 2019. NGS is owned by several private companies and one governmental entity. The owners of NGS have stated that they do not currently intend to operate the plant beyond December 2019. As a result, we anticipate that the mine's production and sales will cease in the third quarter of 2019 given inventory levels.

If a buyer does not purchase the plant and the customer closes the plant, our Western U.S. Mining operations revenues, Adjusted EBITDA and cash flows would be materially reduced. 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 sharing in the estimated cost of our post-mining obligations, including reclamation and retiree healthcare costs, a portion of which has already been collected.

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 price volatility of the Australian dollar, coal and diesel fuel. Currently, we primarily enter into derivative financial instruments, including financial swaps and options, designed to manage coal price volatility and increases in the Australian dollar exchange rate. We are currently subject to price volatility on diesel fuel utilized in our mining operations. We may in the future enter into hedging arrangements to manage this price risk, or other exposures.

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.

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. A global economic recession and/or a worldwide financial and credit market disruption could have a negative impact on us and on the coal industry generally. If any of these conditions occur, if coal prices recede to or below levels experienced in 2015 and early 2016 for a prolonged period or if there are 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, would be sufficient in response to challenging economic and financial conditions.

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, and events and conditions that could occur during the course of our mining operations could have a material adverse impact on us.

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:

- elevated gas levels;
- fires and explosions, including from methane gas or coal dust;
- accidental mine water discharges;
- weather, flooding and natural disasters;
- hazardous events such as roof falls and high wall or tailings dam 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.

In this regard, our North Goonyella Mine in Queensland, Australia experienced a fire in a portion of the mine in September 2018. Mine management continues to evaluate the impact of the fire on the mine from the surface. The situation at North Goonyella remains complex and uncertain, and we are executing a multi-phased re-ventilation and re-entry project targeted to commence in the first quarter 2019. Mining operations were suspended in September 2018 and it is uncertain when or if mining operations will restart. If after exploring all reasonable mine-planning steps focused on resuming mining activities at the North Goonyella Mine, we determine that we are unable to extract coal from all or a significant portion of the mine, our results of operations, financial condition and cash flows could be materially and adversely impacted. In addition, the costs that may be incurred to address the impacts of the fire and to return the mine to active operations (if the mine returns to active operations) are uncertain and could be significant. We maintain insurance policies for losses associated with the events at our North Goonyella Mine, as well as the other risks referenced above, and those insurance policies may lessen the impact associated with these events and risks. However, there can be no assurance as to the amount or timing of recovery under our insurance policies in connection with losses associated with these events and risks.

If transportation for our coal becomes unavailable or uneconomic for our customers, our ability to sell coal may be diminished.

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.

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 24 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.

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.

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

As of December 31, 2018, we had approximately 7,400 employees (excluding employees that were employed at operations classified as discontinued), which included approximately 5,600 hourly employees. After the acquisition of the Shoal Creek Mine, which employs approximately 350 union employees, approximately 42% of our hourly employees were represented by organized labor unions and generated approximately 20% of 2018 coal production for the 12 months ended December 31, 2018. 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, 2018, we had $1,589.8 million of outstanding surety bonds and $245.0 million of letters of credit with third parties in order to provide required financial assurances for post-mining reclamation, workers' compensation and other insurance obligations, coal lease-related and other obligations and performance guarantees.

Our financial assurance obligations may increase or become more costly due to a number of factors, and surety bonds and letters of credit may not be available to us, particularly in light of some insurance companies' announced unwillingness to support fossil fuel companies. Alternative forms of financial assurance such as self-bonding may be terminated where currently available. 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.

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 SMCRA, 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.

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, 2018, we leased a total of 56,546 acres from the federal government subject to those limitations.

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.

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;
- current and future market prices for coal, contractual arrangements, operating costs and capital expenditures;
- demand for coal;
- 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, political and sovereign 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.

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 modify our portfolio of operations and/or 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 $580.4 million as of December 31, 2018, of which $32.7 million was classified as a current liability. Certain of our U.S. subsidiaries also sponsor defined benefit pension plans. Net pension liabilities were $31.1 million as of December 31, 2018, of which none was classified a current liability.

These liabilities are actuarially determined. We use various actuarial assumptions, including the discount rate, future cost trends, mortality tables 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. We develop our actuarial determinations of liabilities using actuarial mortality tables we believe best fit our population's actual results. In deciding which mortality tables to use, we periodically review our population's actual mortality experience and evaluate results against our current assumptions as well as consider recent mortality tables published by the Society of Actuaries Retirement Plans Experience Committee in order to select mortality tables for use in our year end valuations. If our mortality tables do not anticipate our population's mortality experience as accurately as expected, actual cash expenditures and costs that we incur could differ materially from our current estimates. 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 impacts of coal combustion on global climate are increasingly leading to consequences that have and could continue to affect demand for our products or our securities, including the following: increased regulation of coal combustion in many jurisdictions; investment decisions by electricity generators that are unfavorable to coal-fueled generation units; unfavorable lending policies by lending institutions and development banks toward the financing of new overseas coal-fueled power plants; and divestment efforts affecting the institutional investment community.

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 greenhouse gases, including emissions of carbon dioxide from coal combustion by power plants.

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.

There have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other institutional investors, promoting the divestment of fossil fuel equities. 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 markets.

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

Several non-governmental organizations have undertaken campaigns to minimize or eliminate the use of coal as a source of electricity generation in the U.S. and across the globe. In an effort to stop or delay coal mining activities, activist groups have brought lawsuits challenging the issuance of individual coal leases, and challenging the federal coal leasing program more broadly. Other lawsuits challenge historical and pending regulatory approvals, permits and processes that are necessary to conduct coal mining operations or to operate coal-fueled power plants, including so-called "sue and settle" lawsuits where regulatory authorities in the past have reached private agreements with environmental activists that often involve additional regulatory restrictions or processes being implemented without formal rulemaking.

The effect of these and other similar developments has been to make it more costly and difficult to maintain our business. These cost increases and/or a substantial or extended decline in the prices we receive for our coal due to these or other factors could reduce our revenue and profitability, cash flows, liquidity, and value of our coal reserves and could result in losses.

We may not be able to successfully integrate the recently acquired Shoal Creek Mine or other companies, assets or properties that we may acquire in the future.

There can be no assurance that the anticipated benefits of the recently completed acquisition of the Shoal Creek Mine, or any future acquisitions, will be realized. The success of our integration efforts will depend upon our ability to effectively manage companies, assets or properties we acquire and to realize their anticipated benefits. The process of managing acquired companies, assets or properties may involve unforeseen difficulties and may require a disproportionate amount of management resources, which could divert focus and resources from other strategic opportunities and from operational matters during this process.

In addition to the above, any acquisition would be accompanied by risks, including difficulties integrating and assimilating the operations and personnel of any acquired companies, failure to realize the anticipated synergies and maximize the financial and strategic position of the combined enterprise and inability to maintain uniform standards, policies and controls across the organization. Additionally, the acquired companies, assets or properties may have unknown liabilities which could be significant.

If we fail to establish and maintain proper internal controls for the Shoal Creek Mine, our ability to produce accurate financial statements or comply with applicable regulations could be impaired.

Prior to the acquisition, the Shoal Creek Mine was not subject to the reporting requirements of the Exchange Act or the Sarbanes-Oxley Act of 2002. As a subsidiary consolidated with our financial statements, the Shoal Creek Mine is subject to such rules and regulations. We are incorporating the internal controls and procedures of Shoal Creek into our internal control over financial reporting, and we expect to be able to perform an assessment of and report on internal control over financial reporting for the combined business for the year ending December 31, 2019. If we fail to establish and maintain proper internal controls for the combined business, our ability to produce accurate financial statements or comply with applicable regulations could be impaired.

Risks Related to Our Indebtedness and Capital Structure

Our financial performance could be adversely affected by our indebtedness.

As of December 31, 2018, we had approximately $1.4 billion of indebtedness outstanding, excluding capital leases and debt issuance costs.

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;
- 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.

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 indebtedness, we may still be able to incur substantially more debt, including secured debt, which could further increase the risks associated with our indebtedness.

We 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 indebtedness, including our credit facility, revolver 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 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 indebtedness 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, all of 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 credit 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 limit, 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.

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 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.

The number and quantity of viable financing alternatives available to us may be significantly impacted by unfavorable lending and investment policies by financial institutions and insurance companies associated with concerns about environmental impacts of coal combustion.

Global climate issues, including with respect to greenhouse gases such as carbon dioxide and methane and the relationship that greenhouse gases may have with climate change, continue to attract significant public and scientific attention.

Certain banks, other financing sources and insurance companies have taken actions to limit available financing and insurance coverage for the development of new coal-fueled power plants and coal miners and utilities that derive a majority of their revenue from thermal coal, which also may adversely impact the future global demand for coal. Further, there have been recent efforts by members of the general financial and investment communities, such as investment advisors, sovereign wealth funds, public pension funds, universities and other groups, to divest themselves and to promote the divestment of securities issued by companies involved in the fossil fuel extraction market, such as coal producers. Those entities also have been pressuring lenders to limit financing available to such companies. These efforts may adversely affect the market for our securities and our ability to access capital and financial markets in the future.

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;
- changes in accounting principles;
- announcements concerning us or our competitors;
- lack of trading liquidity; 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 stakeholders' 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 or debt instruments.

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 leverage and other financial ratios. 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, 2018, we had gross deferred income tax assets, including net operating loss carryforwards, and liabilities of $2,389.5 million and $256.4 million, respectively, as described further in Note 12. "Income Taxes" to the accompanying consolidated financial statements. At that date, we also had recorded a valuation allowance of $2,094.3 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"), which limited our ability to look to future taxable income in assessing the likelihood of realizing those assets.

The Company's ability to use its net operating loss carryforwards may be limited if it experiences an "ownership change" as defined in Section 382 (Section 382) of the Internal Revenue Code of 1986, as amended. An ownership change generally occurs if certain stockholders increase their aggregate percentage ownership of a corporation's stock by more than 50 percentage points over their lowest percentage ownership at any time during the testing period, which is generally the three-year period preceding any potential ownership change.

There is no assurance that the Company will not experience a future ownership change under Section 382 that may significantly limit or possibly eliminate its ability to use its net operating loss carryforwards. Potential future transactions involving the sale or issuance of our Common Stock, including the exercise of conversion options under the terms of any convertible debt that Peabody may issue in the future, the repurchase of such debt with Common Stock, any issuance of Common Stock for cash and the acquisition or disposition of such stock by a stockholder owning 5% or more of our Common Stock, or a combination of such transactions, may increase the possibility that the Company will experience a future ownership change under Section 382.

Under Section 382, a future ownership change would subject the Company to additional annual limitations that apply to the amount of pre-ownership change net operating losses that may be used to offset post-ownership change taxable income. This limitation is generally determined by multiplying the value of a corporation's stock immediately before the ownership change by the applicable long-term tax-exempt rate. Any unused annual limitation may, subject to certain limits, be carried over to later years, and the limitation may under certain circumstances be increased by built-in gains in the assets held by such corporation at the time of the ownership change. This limitation could cause the Company's U.S. federal income taxes to be greater, or to be paid earlier, than they otherwise would be, and could cause all or a portion of the Company's net operating loss carryforwards to expire unused. Similar rules and limitations may apply for state income tax purposes. The Company's ability to use its net operating loss carryforwards will also depend on the amount of taxable income it generates in future periods. Its net operating loss carryforwards may expire before the Company can generate sufficient taxable income to use them in full.

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.

Acquisitions and divestitures 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 acquisition or divestiture 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 an acquired or divested 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.

Item 1B. *Unresolved Staff Comments.*

None.

Item 2. *Properties.*

Coal Reserves

We controlled an estimated 4.9 billion tons of proven and probable coal reserves as of December 31, 2018. An estimated 4.4 billion tons of our attributable proven and probable coal reserves are in the U.S., with the remainder in Australia. Approximately 1.3% of our U.S. proven and probable coal reserves, or 55 million tons, are metallurgical coking coal. The remainder of our U.S. coal reserves consists of thermal coal. Approximately 53% of our Australian proven and probable coal reserves, or 274 million tons, are metallurgical coal, comprised of approximately 139 million and 135 million tons of coking coal and low-volatile pulverized coal injection (LV PCI) coals, respectively. The remainder of our Australian coal reserves consists of thermal coal. We own approximately 31% of these reserves and leased property comprises the remaining 69%. Approximately 62% of our reserves, or 3.0 billion tons, are compliance coal and 38% 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.

Mining Segment	Locations	Proven and Probable Reserves as of December 31, 2018 [1] Owned Tons	Leased Tons	Total Tons
			(Tons in millions)	
Powder River Basin Mining	Wyoming	—	2,421	2,421
Midwestern U.S. Mining	Illinois, Indiana and Kentucky	1,382	273	1,655
Western U.S. Mining	Arizona, New Mexico and Colorado	154	91	245
Seaborne Metallurgical Mining	Queensland, New South Wales and Alabama	—	304	304
Seaborne Thermal Mining	New South Wales	—	266	266
Total Proven and Probable Coal Reserves		1,536	3,355	4,891
Total United States		1,536	2,840	4,376
Total Australia		—	515	515
Total Proven and Probable Coal Reserves		1,536	3,355	4,891

(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, 2018 reflected a net reduction compared to the prior year of 345 million tons of coal reserves. The decrease was driven by production, changes to our estimates of economic recoverability, mine plan changes and the sale of non-strategic coal reserves, partially offset by acquisitions and new drilling.

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, 2018 reserve estimates for the Colorado region in the U.S. and the Queensland region in Australia were audited by Weir International, Inc. and Palaris Australia Pty Ltd, respectively, independent mining and geological consulting firms, which included a review of the data, procedures and parameters employed by us in developing our Colorado and Queensland reserve estimates. The audits 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 Colorado and Queensland 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.

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 competitiveness 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, among others.

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 be significantly impacted by the availability of indigenous coal production, particularly in leading 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 leading metallurgical coal exporting countries of 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.

Costs

The cost estimates we use to establish our reserves are generally estimated according to internal processes that project future costs based on historical 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. thermal operations sell coal at mine loadouts. Therefore, no transportation expenses are included in our U.S. thermal cost estimates. Our seaborne operations typically sell coal at designated ports. The estimated costs for our seaborne operations include rail and barge 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 historical 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 mine-by-mine and product-by-product evaluations of the estimated prices for our coal, and the costs and expenses of mining and selling our coal, we have concluded our reserves were economically recoverable as of December 31, 2018.

On October 31, 2018, the SEC voted to adopt amendments to modernize the property disclosure requirements for mining registrants and related guidance under the Securities Act of 1933 and the Securities Exchange Act of 1934. The final rules provide a three-year transition period, thus, we will be required to begin to comply with the new rules for the fiscal year beginning on January 1, 2021 (reported in the Annual Report on Form 10-K for the year ended December 31, 2021). We are in the process of assessing the impact the new rules will have on our disclosures.

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, 2018, we leased 1,610 acres of federal land in Alabama, 6,407 acres in Colorado, 640 acres in New Mexico and 47,889 acres in Wyoming, for a total of 56,546 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.

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 court process. Surface rights are typically acquired directly from landowners through agreement or court determination, subject to some exceptions.

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.

The following charts provide a summary, by mining complex, of production (in descending order by mining segment) for the years ended December 31, 2018, 2017 and 2016, 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)

	Production				Sulfur Content of Assigned Reserves as of December 31, 2018 (1)			
	Year Ended December 31,				<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)
Segment/Mining Complex	2018	2017	2016	Type of Coal				
Powder River Basin Mining:								
North Antelope Rochelle	98.3	101.6	92.9	T	1,698	—	—	8,800
Caballo	11.3	11.1	11.2	T	453	6	6	8,400
Rawhide	9.5	10.4	8.1	T	209	49	—	8,300
Total	119.1	123.1	112.2		2,360	55	6	
Midwestern U.S. Mining:								
Bear Run	6.9	7.3	7.3	T	4	27	207	10,900
Gateway North	3.1	2.5	1.8	T	—	—	56	10,900
Wild Boar	2.7	2.7	2.6	T	—	—	35	11,100
Francisco Underground	2.2	2.2	2.1	T	—	—	15	11,500
Somerville Central	2.0	2.2	2.3	T	—	—	8	11,200
Wildcat Hills Underground	1.3	1.5	1.5	T	—	—	38	12,100
Cottage Grove	0.4	0.3	0.2	T	—	—	—	12,100
Total	18.6	18.7	17.8		4	27	359	
Western U.S. Mining:								
Kayenta (3)	6.5	6.2	5.4	T	4	—	—	10,600
El Segundo	5.5	4.9	4.9	T	11	29	34	9,000
Twentymile	3.1	3.8	2.0	T	28	—	—	11,200
Lee Ranch	—	—	—	T	14	66	9	9,300
Total	15.1	14.9	12.3		57	95	43	
Seaborne Metallurgical Mining:								
Coppabella	2.7	2.8	2.4	P	24	—	—	12,600
Moorvale	2.1	1.8	1.9	P/T	16	—	—	12,500
Millennium	1.9	3.3	3.5	M/P	1	—	—	12,600
Metropolitan	1.7	1.0	1.9	M/P/T	21	—	—	12,600
North Goonyella	1.4	3.4	1.3	M	70	—	—	12,700
Shoal Creek (4)	0.2	—	—	M	55	—	—	12,700
Burton (5) (Operations ceased in 2016)	—	—	1.5	M/T	—	—	—	NA
Middlemount (6)	—	—	—	M/P	23	—	—	12,400
Total	10.0	12.3	12.5		210	—	—	
Seaborne Thermal Mining:								
Wilpinjong	14.1	13.4	14.0	T	114	—	—	10,000
Wambo (7)	5.2	5.9	6.8	T/M	152	—	—	11,300
Total	19.3	19.3	20.8		266	—	—	
Total Assigned	**182.1**	**188.3**	**175.6**		**2,897**	**177**	**408**	

T: Thermal

M: Metallurgical

P: Pulverized Coal Injection Metallurgical

ASSIGNED RESERVES [8]

AS OF DECEMBER 31, 2018

(Tons in millions)		Attributable Ownership					100% Project Basis					Modifying Factors [9]	
Segment/Mining Complex	Interest	Proven and Probable Reserves	Owned	Leased	Surface	Underground	Proven and Probable Reserves	Owned	Leased	Surface	Underground	ROM Factor	Yield
Powder River Basin Mining:													
North Antelope Rochelle	100%	1,698	—	1,698	1,698	—	1,698	—	1,698	1,698	—	92%	100%
Caballo	100%	465	—	465	465	—	465	—	465	465	—	90%	100%
Rawhide	100%	258	—	258	258	—	258	—	258	258	—	93%	100%
Total		2,421	—	2,421	2,421	—							
Midwestern U.S. Mining:													
Bear Run	100%	238	105	133	238	—	238	105	133	238	—	106%	73%
Gateway North	100%	56	54	2	—	56	56	54	2	—	56	72%	62%
Wild Boar	100%	35	15	20	35	—	35	15	20	35	—	103%	81%
Francisco Underground	100%	15	3	12	—	15	15	3	12	—	15	70%	65%
Somerville Central	100%	8	7	1	8	—	8	7	1	8	—	107%	72%
Wildcat Hills Underground	100%	38	10	28	—	38	38	10	28	—	38	74%	58%
Cottage Grove	100%	—	—	—	—	—	—	—	—	—	—	102%	81%
Total		390	194	196	281	109							
Western U.S. Mining:													
Kayenta [3]	100%	4	—	4	4	—	4	—	4	4	—	88%	100%
El Segundo	100%	74	61	13	74	—	74	61	13	74	—	87%	100%
Twentymile	100%	28	6	22	—	28	28	6	22	—	28	99%	68%
Lee Ranch	100%	89	86	3	89	—	89	86	3	89	—	87%	100%
Total		195	153	42	167	28							
Seaborne Metallurgical Mining:													
Coppabella	73.3%	24	—	24	24	—	33	—	33	33	—	88%	79%
Moorvale	73.3%	16	—	16	16	—	22	—	22	22	—	108%	77%
Millennium	100%	1	—	1	1	—	1	—	1	1	—	95%	85%
Metropolitan	100%	21	—	21	—	21	21	—	21	—	21	118%	78%
North Goonyella	100%	70	—	70	—	70	70	—	70	—	70	65%	75%
Shoal Creek [4]	100%	55	—	55	—	55	55	—	55	—	55	102%	57%
Middlemount [6]	50.0%	23	—	23	23	—	46	—	46	46	—	85%	77%
Total		210	—	210	64	146							
Seaborne Thermal Mining:													
Wilpinjong	100%	114	—	114	114	—	114	—	114	114	—	104%	88%
Wambo [7]	100%	152	—	152	39	113	152	—	152	39	113	99%	73%
Total		266	—	266	153	113							
Total Assigned		3,482	347	3,135	3,086	396							

ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES [8]
AS OF DECEMBER 31, 2018
(Tons in millions)

	Attributable Ownership					100% Project Basis				
	Total Tons		Proven and Probable			Total Tons		Proven and Probable		
Coal Seam Location	Assigned	Unassigned	Reserves	Proven	Probable	Assigned	Unassigned	Reserves	Proven	Probable
Powder River Basin Mining (Wyoming)	2,421	—	2,421	2,297	124	2,421	—	2,421	2,297	124
Midwestern U.S. Mining:										
Illinois	94	1,158	1,252	536	716	94	1,158	1,252	536	716
Indiana	296	8	304	226	78	296	8	304	226	78
Kentucky [10]	—	99	99	45	54	—	99	99	45	54
Total	390	1,265	1,655	807	848					
Western U.S. Mining:										
Arizona [3]	4	—	4	4	—	4	—	4	4	—
New Mexico	163	—	163	163	—	163	—	163	163	—
Colorado	28	50	78	61	17	28	50	78	61	17
Total	195	50	245	228	17					
Seaborne Metallurgical Mining:										
Alabama	55	—	55	54	1	55	—	55	54	1
New South Wales	21	—	21	3	18	21	—	21	3	18
Queensland	134	94	228	187	41	172	126	298	242	56
Total	210	94	304	244	60					
Seaborne Thermal Mining (New South Wales)	266	—	266	235	31	266	—	266	235	31
Total Proven and Probable	3,482	1,409	4,891	3,811	1,080					

ASSIGNED AND UNASSIGNED - RESERVE CONTROL AND MINING METHOD
AS OF DECEMBER 31, 2018
(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)	—	2,421	2,421	—	—	2,421	2,421	—
Midwestern U.S. Mining:								
Illinois	1,212	40	—	1,252	1,212	40	—	1,252
Indiana	135	169	289	15	135	169	289	15
Kentucky (10)	35	64	—	99	35	64	—	99
Total	1,382	273	289	1,366				
Western U.S. Mining:								
Arizona (3)	—	4	4	—	—	4	4	—
New Mexico	147	16	163	—	147	16	163	—
Colorado	7	71	—	78	7	71	—	78
Total	154	91	167	78				
Seaborne Metallurgical Mining:								
Alabama	—	55	—	55	—	55	—	55
New South Wales	—	21	—	21	—	21	—	21
Queensland	—	228	75	153	—	298	117	181
Total	—	304	75	229				
Seaborne Thermal Mining (New South Wales)	—	266	153	113	—	266	153	113
Total Proven and Probable	1,536	3,355	3,105	1,786				

ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES - SULFUR CONTENT
AS OF DECEMBER 31, 2018
(Tons in millions)

		Attributable Ownership			100% Project Basis			
		Sulfur Content [1]			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	2,360	55	6	2,360	55	6	8,700
Midwestern U.S. Mining:								
Illinois	T	—	—	1,252	—	—	1,252	10,800
Indiana	T	4	27	273	4	27	273	11,000
Kentucky [10]	T	—	—	99	—	—	99	12,000
Total		4	27	1,624				
Western U.S. Mining:								
Arizona [3]	T	4	—	—	4	—	—	10,600
New Mexico	T	25	95	43	25	95	43	9,200
Colorado	T	78	—	—	78	—	—	11,200
Total		107	95	43				
Seaborne Metallurgical Mining:								
Alabama	M	55	—	—	55	—	—	12,700
New South Wales	M/P/T	21	—	—	21	—	—	12,600
Queensland	M/P/T	228	—	—	298	—	—	12,400
Total		304	—	—				
Seaborne Thermal Mining (New South Wales)	T/M	266	—	—	266	—	—	10,700
Total Proven and Probable		3,041	177	1,673				

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

(1) 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. Non-compliance coal is defined as coal having sulfur dioxide content in excess of this standard. 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.

(2) As-received Btu per pound includes the weight of moisture in the coal on an as sold basis. The range of variability of the moisture content in coal across a given region may affect the actual shipped Btu content of current production from assigned reserves.

(3) The NGS is exclusively served by our Kayenta 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. NGS is owned by several private companies and one governmental entity. The owners of the customer have stated that they do not currently intend to operate the plant beyond December 2019. See Item 1A. "Risk Factors" for additional information.

(4) On December 3, 2018, Peabody completed the acquisition of the Shoal Creek Mine from Drummond Company, Inc. The Shoal Creek Mine produced 0.2 million tons from December 4 to December 31, 2018 and 2.7 million tons for the entire year of 2018.

(5) On November 27, 2017, Peabody completed the sale of the majority of its Burton Mine and related infrastructure to the Lenton Joint Venture.

(6) Represents our 50% interest in Middlemount, which owns the Middlemount Mine in Queensland, Australia. Because that entity is accounted for as an unconsolidated equity affiliate, 2018, 2017 and 2016 tons produced by Middlemount have been excluded from the "Summary of Coal Production and Sulfur Content of Assigned Reserves" table. Middlemount produced 4.2 million tons, 4.3 million tons, and 4.5 million tons of coal in 2018, 2017 and 2016, respectively (on a 100% basis).

(7) Includes the Wambo Open-Cut Mine and the Wambo Underground Mine areas.

(8) Assigned reserves represent recoverable coal reserves that are controlled and accessible at active operations as of December 31, 2018. Unassigned reserves represent coal at currently non-producing locations that would require significant new mine development, mining equipment or plant facilities before operations could begin on the property.

(9) The modifying factors reflect the assumptions which are utilized to convert coal quantities and qualities as in ground to run of mine (ROM) coal after mining, and eventually to saleable product coal after processing. Coal reserves are reported as an estimation of the final saleable quantity, which takes into account any losses and dilutions during mining and processing. We generally keep track of coal reserves through in place coal, ROM coal and product coal. In place coal for U.S. underground reserves excludes planned barrier pillars, but includes regular pillars from projected underground extractions. In place coal for Australian underground reserves is exclusive of all planned pillars. The difference is due to historic practice and software used by each country. The ROM factor represents the estimated ROM coal in relation to the coal in place with considerations of coal losses, dilutions and remaining pillars during mining processes. The yield is the ratio of estimated saleable product coal over ROM coal tons with mainly processing loss considered.

(10) All coal reserves in Kentucky are leased to third parties.

Item 3. *Legal Proceedings.*

See Note 26. "Commitments and Contingencies" to the accompanying consolidated financial statements for a description of our pending legal proceedings, which information is incorporated herein by reference.

Item 4. *Mine Safety Disclosures.*

Our "Safety a Way of Life Management System" has been designed to set clear and consistent expectations for safety and health across our business. It aligns to the National Mining Association's CORESafety® framework and encompasses three fundamental areas: leadership and organization, safety and health risk management and assurance. We also partner with other companies and certain governmental agencies to pursue new technologies that have the potential to improve our safety performance and provide better safety protection for employees. On September 7, 2018, a haul truck driver at the Bear Run Mine was transporting spoil to a dump site when a bulldozer operator saw a fire on the truck. While exiting the truck, the driver received burns and was taken to the hospital. Tragically, on September 12, 2018, he suffered a cardiac arrest and passed away.

We continually monitor our safety performance and regulatory compliance. The information concerning mine safety violations or other regulatory matters required by SEC regulations is included in Exhibit 95 to this Annual Report on Form 10-K.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*

Our Common Stock is listed on the New York Stock Exchange, under the symbol "BTU." As of February 20, 2019 there were 148 holders of our Common Stock, as determined by counting our record holders and the number of participants reflected in a security position listing provided to us by the Depository Trust Company (DTC). Because such DTC participants are brokers and other institutions holding shares of our Common Stock on behalf of their customers, we do not know the actual number of unique shareholders represented by these record holders.

Dividend Policy

The payment of dividends is subject to certain limitations, as set forth in our debt agreements. Such limitations on dividends are discussed in Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations." We declared and paid quarterly dividends every quarter in 2018. On February 6, 2019, our Board of Directors declared a dividend of $0.13 per share of Common Stock, payable on March 6, 2019, to shareholders of record on February 20, 2019. On February 27, 2019, our Board of Directors declared a supplemental dividend of $1.85 per share of Common Stock, payable on March 20, 2019, to shareholders of record on March 12, 2019. Upon payment of the supplemental dividend, outstanding restricted stock units will receive dividend equivalent units with a value of approximately $6 million, which would equate to approximately 0.2 million units using the quoted share price of our Common Stock on February 26, 2019 of $30.53 per share. Our Board of Directors will continue to evaluate the appropriate dividend rate on a quarterly basis and the declaration and payment of dividends in the future and the amount of those dividends will depend on our results of operations, financial condition, cash requirements, future prospects, any limitations imposed by our debt covenants and other factors that our Board of Directors may deem relevant to such evaluations.

Share Relinquishments

We routinely allow employees to relinquish Common Stock to pay estimated taxes upon the vesting of restricted stock units and the payout of performance units that are settled in Common Stock under our equity incentive plans. The value of Common Stock tendered by employees is determined based on the closing price of our Common Stock on the dates of the respective relinquishments.

Share Repurchase Programs

On August 1, 2017, we announced that our Board of Directors authorized a share repurchase program to allow repurchases of up to $500 million of the then outstanding shares of our common stock and/or preferred stock (Repurchase Program). On April 25, 2018, we announced that the Board authorized the expansion of the Repurchase Program to $1.0 billion. On October 30, 2018, we announced that the Board authorized an additional expansion of the Repurchase Program to $1.5 billion. Repurchases may be made from time to time at the Company's discretion. The specific timing, price and size of purchases will depend on the share price, general market and economic conditions and other considerations, including compliance with various debt agreements as they may be amended from time to time. The Repurchase Program does not have an expiration date and may be discontinued at any time. Through December 31, 2018, we repurchased 26.9 million shares of our Common Stock for $1,010.4 million, which included commissions paid of $0.5 million, leaving $490.1 million available for share repurchase under the Repurchase Program. Included in the shares repurchased during the year ended December 31, 2018 were approximately 7.2 million shares of our Common Stock for $300.0 million from entities advised by Elliott Management pursuant to a definitive agreement to directly repurchase those shares. Subsequent to December 31, 2018 and through February 20, 2019, we have purchased an additional 2.3 million shares of our Common Stock for $75 million. The purchases were made in compliance with our debt provisions that limit our ability to repurchase shares following the Effective Date. Limitations on share repurchases imposed by our debt instruments are discussed in Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Purchases of Equity Securities

The following table summarizes all share purchases for the three months ended December 31, 2018:

Period	Total Number of Shares Purchased [1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Dollar Value of Shares that May Yet Be Used to Repurchase Shares Under the Publicly Announced Program (In millions)
October 1 through October 31, 2018	36	$ 35.00	—	$ 625.1
November 1 through November 30, 2018	2,218,458	33.58	2,218,422	548.3
December 1 through December 31, 2018	1,936,767	31.31	1,935,663	490.1
Total	4,155,261	32.52	4,154,085	

(1) Includes shares withheld to cover the withholding taxes upon the vesting of equity awards, which are not a part of the Repurchase Program.

Mandatory Conversion of Preferred Shares

Each share of our Series A Convertible Preferred Stock (Convertible Preferred Stock) that was previously outstanding was subject to mandatory automatic conversion into a number of shares of Common Stock if the volume weighted average price of the Common Stock exceeded $32.50 for at least 45 trading days in a 60 consecutive trading day period, including each of the last 20 days in such 60 consecutive trading day period. On January 31, 2018, the requirements for such a mandatory conversion were met and the then outstanding 13.2 million shares of Convertible Preferred Stock were automatically converted into 24.8 million shares of Common Stock. As a result of this mandatory conversion, we recorded a non-cash preferred dividend charge of $102.5 million during the year ended December 31, 2018. After the mandatory conversion, no shares of Convertible Preferred Stock are issued or outstanding and all rights of the prior holders of Convertible Preferred Stock have terminated.

Item 6. *Selected Financial Data.*

This item presents selected financial and other data about us for the most recent five fiscal years.

The table that follows and the discussion of our results of operations in 2018, 2017 and 2016 in Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" includes references to and analysis of Adjusted EBITDA which is a financial measure not recognized in accordance with U.S. generally accepted accounting principles (U.S. GAAP).

Adjusted EBITDA is used by management as the primary metric to measure our segments' operating performance. We believe non-GAAP performance measures are used by investors to measure our operating performance and lenders to measure our ability to incur and service debt. Adjusted EBITDA is defined as income (loss) from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expenses, depreciation, depletion and amortization and reorganization items, net. Adjusted EBITDA is also adjusted for the discrete items that management excluded in analyzing each of our segments' operating performance, as displayed in the reconciliation. A reconciliation of income (loss) from continuing operations, net of income taxes to Adjusted EBITDA is included on page 53 of this report. Adjusted EBITDA is not intended to serve as an alternative to U.S. GAAP measures of performance and may not be comparable to similarly-titled measures presented by other companies.

The selected financial data for all periods presented reflect the classification as discontinued operations of certain operations previously divested (by sale or otherwise).

We have derived the selected historical financial data as of and for the years ended December 31, 2018, 2017, 2016, 2015 and 2014 from our audited financial statements, adjusted retrospectively for items subsequently classified as discontinued operations and the implementation of certain accounting literature. Also, all share and per share data have been retroactively restated to reflect the September 30, 2015 1-for-15 reverse stock split. The following table should be read in conjunction with the accompanying consolidated financial statements, including the related notes to those financial statements, and Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

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.

The results of operations for the historical periods included in the following table are not necessarily indicative of the results to be expected for future periods. In addition, Part I, Item 1A. “Risk Factors” of this report includes a discussion of risk factors that could impact our future results of operations.

	Successor		Predecessor			
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016	2015	2014
	(In millions, except per share data)					
Results of Operations Data						
Total revenues	$ 5,581.8	$ 4,252.6	$ 1,326.2	$ 4,715.3	$ 5,609.2	$ 6,792.2
Costs and expenses	4,920.2	3,588.8	1,113.7	4,935.1	6,995.0	6,844.9
Operating profit (loss)	661.6	663.8	212.5	(219.8)	(1,385.8)	(52.7)
Interest expense, net	117.7	135.0	30.2	322.4	525.5	412.8
Net periodic benefit costs, excluding service cost	18.1	21.9	14.4	57.1	79.0	82.4
Net mark-to-market adjustment on actuarially determined liabilities	(125.5)	(45.2)	—	—	—	—
Reorganization items, net	(12.8)	—	627.2	159.0	—	—
Income (loss) from continuing operations before income taxes	664.1	552.1	(459.3)	(758.3)	(1,990.3)	(547.9)
Income tax provision (benefit)	18.4	(161.0)	(263.8)	(94.5)	(207.1)	147.4
Income (loss) from continuing operations, net of income taxes	645.7	713.1	(195.5)	(663.8)	(1,783.2)	(695.3)
Income (loss) from discontinued operations, net of income taxes	18.1	(19.8)	(16.2)	(57.6)	(175.0)	(28.2)
Net income (loss)	663.8	693.3	(211.7)	(721.4)	(1,958.2)	(723.5)
Less: Series A Convertible Preferred Stock dividends	102.5	179.5	—	—	—	—
Less: Net income attributable to noncontrolling interests	16.9	15.2	4.8	7.9	7.1	9.7
Net income (loss) attributable to common stockholders	$ 544.4	$ 498.6	$ (216.5)	$ (729.3)	$ (1,965.3)	$ (733.2)
Basic EPS - Income (loss) from continuing operations	$ 4.35	$ 3.85	$ (10.93)	$ (36.72)	$ (98.65)	$ (39.51)
Diluted EPS - Income (loss) from continuing operations	$ 4.28	$ 3.81	$ (10.93)	$ (36.72)	$ (98.65)	$ (39.51)
Weighted average shares used in calculating basic EPS	119.3	101.1	18.3	18.3	18.1	17.9
Weighted average shares used in calculating diluted EPS	121.0	102.5	18.3	18.3	18.1	17.9
Dividends declared per share	$ 0.485	$ —	$ —	$ —	$ 0.075	$ 5.100
Other Data						
Tons produced	182.1	142.7	45.6	175.6	208.7	227.2
Tons sold	186.7	145.4	46.1	186.8	228.8	249.8
Net cash provided by (used in) continuing operations:						
Operating activities	$ 1,516.9	$ 832.2	$ (804.8)	$ 33.6	$ 69.7	$ 389.5
Investing activities	(517.3)	(93.4)	15.1	(244.1)	(290.0)	(314.5)
Financing activities	(1,025.2)	(745.4)	952.3	907.9	267.7	(168.1)
Adjusted EBITDA	1,379.3	1,145.3	341.3	532.0	432.4	806.3
Balance Sheet Data (at period end)						
Total assets	$ 7,423.7	$ 8,181.2	$ 8,266.9	$ 11,777.7	$ 10,946.9	$ 13,126.4
Total long-term debt (including capital leases)	1,367.0	1,460.8	1,881.4	7,791.4	6,241.2	5,922.1
Total stockholders’ equity	3,451.6	3,655.8	3,131.9	181.5	751.7	2,529.0

Adjusted EBITDA is calculated as follows:

	Successor		Predecessor			
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016	2015	2014
	(Dollars in millions)					
Income (loss) from continuing operations, net of income taxes	$ 645.7	$ 713.1	$ (195.5)	$ (663.8)	$(1,783.2)	$ (695.3)
Depreciation, depletion and amortization	679.0	521.6	119.9	465.4	572.2	655.7
Asset retirement obligation expenses	53.0	41.2	14.6	41.8	45.5	81.0
Selling and administrative expenses related to debt restructuring	—	—	—	21.5	—	—
Asset impairment	—	—	30.5	247.9	1,277.8	154.4
Provision for North Goonyella equipment loss	66.4	—	—	—	—	—
Changes in deferred tax asset valuation allowance and reserves and amortization of basis difference related to equity affiliates	(18.3)	(17.3)	(5.2)	(7.5)	3.9	58.0
Interest expense	149.3	119.7	32.9	298.6	465.4	426.6
Loss on early debt extinguishment	2.0	20.9	—	29.5	67.8	1.6
Interest income	(33.6)	(5.6)	(2.7)	(5.7)	(7.7)	(15.4)
Net mark-to-market adjustment on actuarially determined liabilities	(125.5)	(45.2)	—	—	—	—
Reorganization items, net	(12.8)	—	627.2	159.0	—	—
Gain on disposal of reclamation liability	—	(31.2)	—	—	—	—
Gain on disposal of Burton Mine assets	—	(52.2)	—	—	—	—
Break fees related to terminated asset sales	—	(28.0)	—	—	—	—
Unrealized (gains) losses on economic hedges	(18.3)	23.0	(16.6)	39.8	(2.2)	(7.7)
Unrealized losses on non-coal trading derivative contracts	0.7	1.5	—	—	—	—
Fresh start coal inventory revaluation	—	67.3	—	—	—	—
Fresh start take-or-pay contract-based intangible recognition	(26.7)	(22.5)	—	—	—	—
Income tax provision (benefit)	18.4	(161.0)	(263.8)	(94.5)	(207.1)	147.4
Adjusted EBITDA	$ 1,379.3	$ 1,145.3	$ 341.3	$ 532.0	$ 432.4	$ 806.3

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

Overview

In 2018, we produced and sold 182.1 million and 186.7 million tons of coal, respectively, from continuing operations.

During the fourth quarter of 2018, we purchased the Shoal Creek Mine, as further discussed in Note 3. "Acquisition of Shoal Creek Mine" to the accompanying consolidated financial statements. Due to the acquisition, we updated our reportable segments to reflect the manner in which our CODM views our businesses for purposes of reviewing performance, allocating resources and assessing future prospects and strategic execution. We now report our results of operations primarily through the following reportable segments: Powder River Basin Mining, Midwestern U.S. Mining, Western U.S. Mining, Seaborne Metallurgical Mining, Seaborne Thermal Mining and Corporate and Other.

The principal business of our thermal 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 relatively small 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 and 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.

The business of our seaborne operating platform is primarily export focused with customers spread across several countries, with a portion of our metallurgical and thermal coal sold within Australia. Generally, revenues from individual countries vary year by year based on steel and electricity demand, the strength of the global economy, governmental policies and several other factors, including those specific to each country. We classify our seaborne mines within the Seaborne Metallurgical Mining or Seaborne 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 Seaborne Metallurgical Mining segment is of a thermal grade. Similarly, a small portion of the coal mined by the Seaborne 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 market conditions.

Our Seaborne Metallurgical Mining operations consist of mines in Queensland, Australia, one in New South Wales, Australia and one in Alabama. 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 PCI coal.

Our Seaborne 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.

Our Corporate and Other segment includes selling and administrative expenses, including our technical and shared services functions, results from equity affiliates, corporate hedging activities, trading and brokerage activities, certain 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 commercial matters.

Resource Management. As of December 31, 2018, we controlled approximately 4.9 billion tons of proven and probable coal reserves and approximately 500,000 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 Abbot Point Coal Terminal, with some 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, 2018, 2017 and 2016, the mine sold 4.2 million, 4.2 million and 4.5 million tons of coal, respectively (on a 100% basis).

North Goonyella Mine

Our North Goonyella Mine experienced a fire in a portion of the mine during September 2018. The underground mine and portions of the surface area remain restricted to access through exclusion zones as mine management continues to evaluate the impact of the fire on the mine and determine potential next phases, including establishing protocols and implementing procedures for re-ventilating and re-entering portions of the mine. Mining operations have been suspended since September 2018. On November 13, 2018 the Queensland Mine Inspectorate (QMI) initiated an investigation into the events that occurred at the mine to determine the cause of the event, assess the response to it and make recommendations to reduce the possibility of future incidents and improve response. The QMI has issued an initial series of document and records requests to the Company, and formal witness interviews are anticipated to follow.

During the year ended December 31, 2018, we recorded $58.0 million in containment and idling costs related to the events at North Goonyella and a provision of $66.4 million for expected equipment losses. This provision includes $50.4 million for the estimated cost to replace leased equipment and $16.0 million related to the cost of Company-owned equipment. This provision represents the best estimate of potential loss based on the assessments made to date. In the event that no future mining occurs at our North Goonyella Mine, we may record additional charges for the remaining carrying value of the North Goonyella Mine and additional leased equipment of approximately $285 million and $16 million, respectively. Incremental exposures include take-or-pay obligations and other costs associated with idling or closing the mine. We have filed an insurance claim against applicable insurance policies with combined property damage and business interruption loss limits of $125 million above a $50 million deductible.

We have now identified a plan that targets limited continuous-miner volumes in 2019 with longwall production beginning to ramp up in early 2020. This scenario contemplates approximately 2 million tons of sales from North Goonyella in 2020. As part of our recovery plan for North Goonyella, the team is advancing a multi-zone re-ventilation and re-entry plan targeted to commence in the first quarter 2019, enabling a stage-gate approach to periodically re-evaluate progress, costs and investments.

At this time, we expect idling and re-ventilation/re-entry costs to average $30 to $35 million per quarter in 2019, with first quarter costs expected to come in above the high-end of that range. We are targeting approximately $110 million in capital for North Goonyella, including previously planned new longwall equipment. In addition, we expect cash outlays associated with leased equipment settlements. Mitigating these cash outlays is the potential recovery of up to $125 million in insurance proceeds.

Impact of Emergence from the Chapter 11 of the United States Bankruptcy Code

Upon emergence, in accordance with 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.

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 through December 31, 2017) and a Predecessor period (for the period January 1, 2017 through April 1, 2017). The results of operations for the year ended 2016 are presented as a Predecessor period. 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 each of our operating segments’ financial and operational performance measures, which include tons sold, revenues and Adjusted EBITDA. Accordingly, references to these 2017 financial and operational performance measures for the year ended December 31, 2017 combine the two periods to enhance the comparability of such information to the current and prior years.

Results of Operations

Non-GAAP Financial Measures

The following discussion of our results of operations includes references to and analysis of Adjusted EBITDA, which is a financial measure not recognized in accordance with U.S. GAAP. Adjusted EBITDA is used by management as the primary metric to measure each of our segments’ operating performance.

Also included in the following discussion of our results of operations are references to Revenues per Ton, Costs per Ton and Adjusted EBITDA Margin per Ton for each mining segment. These metrics are used by management to measure each of our mining segments’ operating performance. Management believes Costs per Ton and Adjusted EBITDA Margin per Ton best reflect controllable costs and operating results at the mining segment level. We consider all measures reported on a per ton basis to be operating/statistical measures; however, we include reconciliations of the related non-GAAP financial measures (Adjusted EBITDA and Total Reporting Segment Costs) in the “Reconciliation of Non-GAAP Financial Measures” sections contained within this Item 7.

In our discussion of liquidity and capital resources, we include references to Free Cash Flow which is also a non-GAAP measure. Free Cash Flow is used by management as a measure of our financial performance and our ability to generate excess cash flow from our business operations.

We believe non-GAAP performance measures are used by investors to measure our operating performance and lenders to measure our ability to incur and service debt. These measures are not intended to serve as alternatives to U.S. GAAP measures of performance and may not be comparable to similarly-titled measures presented by other companies. Refer to the “Reconciliation of Non-GAAP Financial Measures” sections contained within this Item 7 for definitions and reconciliations to the most comparable measures under U.S. GAAP.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Summary

Spot pricing for premium low-vol hard coking coal (Premium HCC), premium low-vol pulverized coal injection (Premium PCI) coal, Newcastle index thermal coal and API 5 thermal coal, and prompt month pricing for Powder River Basin (PRB) 8,880 Btu/Lb coal and Illinois Basin 11,500 Btu/Lb coal during the year ended December 31, 2018 is set forth in the table below. Pricing for our Western U.S. Mining segment is not included as there is no similar spot or prompt pricing data available.

In the U.S., the pricing included in the table below is not necessarily indicative of the pricing we realized during the year ended December 31, 2018 since we generally sell coal under long-term contracts where pricing is determined based on various factors. Such long-term contracts in the U.S. may 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. Competition from alternative fuels such as natural gas and other coal producers may also impact our realized pricing.

The seaborne pricing included in the table below is also not necessarily indicative of the pricing we realized during the year ended December 31, 2018 due to quality differentials and the majority of our seaborne sales being executed through annual and multi-year international coal supply agreements that contain provisions requiring both parties to renegotiate pricing periodically. 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.

	High	Low	Average	December 31, 2018
Premium HCC [(1)]	$ 262.25	$ 172.00	$ 207.11	$ 220.00
Premium PCI coal [(1)]	$ 158.75	$ 118.15	$ 136.22	$ 121.90
Newcastle index thermal coal [(1)]	$ 119.90	$ 92.00	$ 107.25	$ 102.05
API 5 thermal coal [(1)]	$ 86.40	$ 58.50	$ 72.14	$ 60.20
PRB 8,800 Btu/Lb coal [(2)]	$ 13.00	$ 12.25	$ 12.49	$ 12.45
Illinois Basin 11,500 Btu/Lb coal [(2)]	$ 48.00	$ 36.55	$ 41.35	$ 48.00

(1) Prices expressed per tonne.

(2) Prices expressed per ton.

With respect to seaborne metallurgical coal, global steel production increased approximately 5% during the year ended December 31, 2018 as compared to 2017. India imports increased approximately 5% through December 31, 2018, as compared to the prior year driven by an increase of approximately 5% in steel production for the year ended December 31, 2018. Despite continued strength in Chinese steel production, metallurgical coal imports declined approximately 5 million tonnes during the year ended December 31, 2018, as compared to 2017 primarily due to increased reliance on domestic supplies and scrap steel.

Seaborne thermal coal demand and pricing continue to be supported by robust Asian demand, primarily in China and India. Chinese thermal coal imports rose approximately 8%, or 16 million tonnes, through December 31, 2018, compared to the prior year on sturdy industrial activity and an increase of approximately 6% in thermal coal power generation driven by economic growth and favorable weather conditions. In addition, Chinese domestic coal production has been unable to keep pace with the increased power generation and industrial demands, along with customer restocking. India's domestic coal production has also been unable to keep pace with growing electricity demand in the industrial sector, resulting in an increase of approximately 18%, or 25 million tonnes, in thermal coal imports through December 31, 2018, as compared to 2017. Coal inventories at India's power plants remain below targeted levels while industrial demand is strong, supporting the need for additional thermal coal imports.

In the United States, stronger weather compared to 2017 drove overall electricity demand higher year-over-year through December 31, 2018. However, the combination of year-to-date coal plant retirements, weak natural gas prices for most of the year and increased renewable generation have negatively impacted coal generation. Through December 31, 2018, utility consumption of Powder River Basin coal fell approximately 3% as compared to the prior year due to ongoing pressure from retirements and regional natural gas prices that continue to trade at a discount to quoted Henry Hub natural gas spot prices.

Income from continuing operations, net of income taxes of $645.7 million for the year ended December 31, 2018 included revenues of $5,581.8 million, income from equity affiliates of $68.1 million and net gain on disposals of $48.2 million. These were offset by operating costs of $4,072.6 million, depreciation, depletion and amortization of $679.0 million, selling and administrative expenses of $158.1 million, interest expense of $149.3 million and a provision related to the North Goonyella equipment loss of $66.4 million. Net income attributable to common stockholders of $544.4 million included dividends of $102.5 million related to the conversion of the remaining shares of Convertible Preferred Stock. Adjusted EBITDA for the year ended December 31, 2018 was $1,379.3 million.

Income from continuing operations, net of income taxes of $713.1 million for the period April 2 through December 31, 2017 included revenues of $4,252.6 million, a tax benefit of $161.0 million and net gain on disposals of $84.0 million. These were offset by operating costs of $3,052.7 million, depreciation, depletion and amortization of $521.6 million, interest expense of $119.7 million and selling and administrative expenses of $106.3 million. Adjusted EBITDA for the period April 2 through December 31, 2017 was $1,145.3 million.

For the period January 1 through April 1, 2017, loss from continuing operations, net of income taxes of $195.5 million included revenues of $1,326.2 million and a tax benefit of $263.8 million. These were offset by operating costs of $950.2 million, depreciation, depletion and amortization of $119.9 million, interest expense of $32.9 million and reorganization items, net of $627.2 million which included the impact of the Plan provisions and the application of fresh start reporting. Adjusted EBITDA for the Predecessor period January 1 through April 1, 2017 was $341.3 million.

As of December 31, 2018, our available liquidity was approximately $1.3 billion. Refer to the “Liquidity and Capital Resources” section contained within this Item 7 for a further discussion of factors affecting our available liquidity.

Tons Sold

The following table presents tons sold by operating segment:

	Successor		Predecessor	Combined	(Decrease) Increase to Volumes	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	Tons	%
	(Tons in millions)					
Powder River Basin Mining	120.3	94.0	31.0	125.0	(4.7)	(3.8)%
Midwestern U.S. Mining	18.9	14.0	4.5	18.5	0.4	2.2 %
Western U.S. Mining	14.7	11.3	3.4	14.7	—	— %
Seaborne Metallurgical Mining	11.0	9.5	2.2	11.7	(0.7)	(6.0)%
Seaborne Thermal Mining	19.1	14.6	4.6	19.2	(0.1)	(0.5)%
Total tons sold from mining segments	184.0	143.4	45.7	189.1	(5.1)	(2.7)%
Corporate and Other	2.7	2.0	0.4	2.4	0.3	12.5 %
Total tons sold	186.7	145.4	46.1	191.5	(4.8)	(2.5)%

Supplemental Financial Data

The following table presents supplemental financial data by operating segment:

	Successor		Predecessor	Combined	(Decrease) Increase	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	$	%
Revenues per Ton - Mining Operations [1]						
Powder River Basin	$ 11.84	$ 12.54	$ 12.70	$ 12.58	$ (0.74)	(5.9)%
Midwestern U.S.	42.44	42.45	42.96	42.58	(0.14)	(0.3)%
Western U.S.	40.20	38.75	44.68	40.10	0.10	0.2 %
Seaborne Metallurgical	141.06	128.14	150.22	132.29	8.77	6.6 %
Seaborne Thermal	57.58	52.84	48.65	51.83	5.75	11.1 %
Costs per Ton - Mining Operations [1] [2]						
Powder River Basin	$ 9.47	$ 9.57	$ 9.75	$ 9.62	$ (0.15)	(1.6)%
Midwestern U.S.	34.75	33.53	31.84	33.13	1.62	4.9 %
Western U.S.	30.33	27.16	29.76	27.75	2.58	9.3 %
Seaborne Metallurgical	100.97	84.60	100.16	87.52	13.45	15.4 %
Seaborne Thermal	33.90	31.87	32.27	31.97	1.93	6.0 %
Adjusted EBITDA Margin per Ton - Mining Operations [1] [2]						
Powder River Basin	$ 2.37	$ 2.97	$ 2.95	$ 2.96	$ (0.59)	(19.9)%
Midwestern U.S.	7.69	8.92	11.12	9.45	(1.76)	(18.6)%
Western U.S.	9.87	11.59	14.92	12.35	(2.48)	(20.1)%
Seaborne Metallurgical	40.09	43.54	50.06	44.77	(4.68)	(10.5)%
Seaborne Thermal	23.68	20.97	16.38	19.86	3.82	19.2 %

(1) This is an operating/statistical measure not recognized in accordance with U.S. GAAP. Refer to the “Reconciliation of Non-GAAP Financial Measures” section below for definitions and reconciliations to the most comparable measures under U.S. GAAP.

(2) Includes revenue-based production taxes and royalties; excludes depreciation, depletion and amortization; asset retirement obligation expenses; selling and administrative expenses; restructuring charges; asset impairment; provision for North Goonyella equipment loss; amortization of fresh start reporting adjustments related to coal inventory revaluation and take-or-pay contract-based intangibles; and certain other costs related to post-mining activities.

Revenues

The following table presents revenues by reporting segment:

	Successor		Predecessor	Combined	(Decrease) Increase to Revenues	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	$	%
			(Dollars in millions)			
Powder River Basin Mining	$ 1,424.8	$ 1,178.7	$ 394.3	$ 1,573.0	$ (148.2)	(9.4)%
Midwestern U.S. Mining	801.0	592.3	193.2	785.5	15.5	2.0 %
Western U.S. Mining	592.0	440.7	149.7	590.4	1.6	0.3 %
Seaborne Metallurgical Mining	1,553.0	1,221.0	328.9	1,549.9	3.1	0.2 %
Seaborne Thermal Mining	1,099.2	772.5	224.8	997.3	101.9	10.2 %
Corporate and Other	111.8	47.4	35.3	82.7	29.1	35.2 %
Total revenues	$ 5,581.8	$ 4,252.6	$ 1,326.2	$ 5,578.8	$ 3.0	0.1 %

Powder River Basin Mining. The decrease in Powder River Basin Mining segment revenues during the year ended December 31, 2018 compared to the prior year was due to lower realized coal pricing ($81.8 million) related to the roll-off of higher priced legacy sales contracts and demand-based volume decreases of 4.7 million tons which were impacted by natural gas pricing and plant retirements ($66.4 million).

Midwestern U.S. Mining. Revenues from our Midwestern U.S. Mining segment increased during the year ended December 31, 2018 compared to the prior year due to favorable volume and mix variances ($15.8 million).

Western U.S. Mining. The increase in Western U.S. Mining segment revenues for the year ended December 31, 2018 compared to the prior year was predominately driven by higher realized coal pricing ($4.5 million), partially offset by lower liquidated damages received ($2.3 million).

Seaborne Metallurgical Mining. The increase in our Seaborne Metallurgical Mining segment revenues for the year ended December 31, 2018 compared to the prior year was primarily due to higher realized coal pricing ($127.0 million) and the inclusion of revenues from our newly acquired Shoal Creek Mine ($12.8 million). This was offset by an unfavorable volume and mix variance ($136.7 million) driven by the 2018 impacts of the longwall move and the fire at our North Goonyella Mine.

Seaborne Thermal Mining. The increase in our Seaborne Thermal Mining segment revenues for the year ended December 31, 2018 compared to the prior year was primarily driven by higher realized coal pricing ($138.4 million). The increase was partially offset by the unfavorable impact of changes in volume and mix ($36.5 million) which was impacted by an increased volume of lower calorific value coal sold in 2018 as compared to 2017.

Corporate and Other. The increase in Corporate and Other revenues for the year ended December 31, 2018 compared to the prior year was due to improved results on economic hedges and favorable results from trading and brokerage activities due to increased pricing, partially offset by the prior year receipt of break fees related to terminated asset sale agreements which are further described in Note 22. “Other Events” to the accompanying consolidated financial statements.

Adjusted EBITDA

The following table presents Adjusted EBITDA for each of our reporting segments:

	Successor		Predecessor	Combined	(Decrease) Increase to Adjusted EBITDA	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	$	%
	(Dollars in millions)					
Powder River Basin Mining	$ 284.5	$ 278.8	$ 91.7	$ 370.5	$ (86.0)	(23.2)%
Midwestern U.S. Mining	145.2	124.4	50.0	174.4	(29.2)	(16.7)%
Western U.S. Mining	145.4	131.8	50.0	181.8	(36.4)	(20.0)%
Seaborne Metallurgical Mining	441.4	414.9	109.6	524.5	(83.1)	(15.8)%
Seaborne Thermal Mining	452.0	306.6	75.6	382.2	69.8	18.3 %
Corporate and Other	(89.2)	(111.2)	(35.6)	(146.8)	57.6	39.2 %
Adjusted EBITDA [(1)]	$ 1,379.3	$ 1,145.3	$ 341.3	$ 1,486.6	$ (107.3)	(7.2)%

(1) This is a financial measure not recognized in accordance with U.S. GAAP. Refer to the “Reconciliation of Non-GAAP Financial Measures” section below for definitions and reconciliations to the most comparable measures under U.S. GAAP.

Powder River Basin Mining. The decrease in Powder River Basin Mining segment Adjusted EBITDA for the year ended December 31, 2018 compared to the prior year was due to lower realized coal pricing, net of sales-related costs ($66.3 million), increased pricing for fuel and explosives ($18.4 million) and lower sales volumes ($24.9 million). This was partially offset by lower costs for materials, services and repairs ($18.3 million) and operating leases ($10.2 million).

Midwestern U.S. Mining. The decrease in Midwestern U.S. Mining segment Adjusted EBITDA for the year ended December 31, 2018 compared to the prior year was due to increased pricing for fuel and explosives ($13.5 million), increased labor costs ($9.4 million) and higher materials, services and repairs costs ($5.4 million).

Western U.S. Mining. The decrease in Western U.S. Mining segment Adjusted EBITDA for the year ended December 31, 2018 compared to the prior year was primarily due to higher materials, services and repairs costs ($28.2 million), increased labor costs ($6.7 million), lower realized coal pricing, net of sales related costs ($6.6 million), partially offset by improved sales volumes from higher margin operations ($9.8 million).

Seaborne Metallurgical Mining. The decrease in Seaborne Metallurgical Mining segment Adjusted EBITDA during the year ended December 31, 2018 compared to the prior year reflected unfavorable volume variances ($114.5 million) primarily at our North Goonyella Mine due to a longwall move in the current year and the idling of the mine as a result of the fire further described in Note 22. "Other Events." The decrease in segment Adjusted EBITDA was further impacted by unfavorable production costs at our North Goonyella Mine related to containment and idling ($58.0 million) and the longwall move ($44.0 million), increased planned dragline and other maintenance costs at our Coppabella Mine ($39.9 million) and increased pricing for fuel ($12.4 million). These were partially offset by improved realized coal pricing, net of sales-related costs ($114.5 million), favorable production costs at our Metropolitan Mine due to an extended longwall move in the prior year ($37.3 million) and the favorable impact of exchange rate movement ($18.7 million). The acquisition of the Shoal Creek Mine resulted in additional segment Adjusted EBITDA of $2.1 million.

Seaborne Thermal Mining. The increase in Seaborne Thermal Mining segment Adjusted EBITDA during the year ended December 31, 2018 compared to the prior year reflected improved realized coal pricing, net of sales-related costs ($127.4 million) and favorable production costs at our Wilpinjong Mine ($21.2 million), partially offset by unfavorable volume variances ($30.5 million) resulting from decreased sales and geologic and longwall production issues at our Wambo Mine which contributed to unfavorable production costs ($40.5 million) and increased pricing for fuel ($9.1 million).

Corporate and Other Adjusted EBITDA. The following table presents a summary of the components of Corporate and Other Adjusted EBITDA:

	Successor		Predecessor	Combined	Increase (Decrease) to Income	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	$	%
	(Dollars in millions)					
Resource management activities [1]	$ 44.7	$ 2.5	$ 2.9	$ 5.4	$ 39.3	727.8 %
Selling and administrative expenses	(158.1)	(106.3)	(36.3)	(142.6)	(15.5)	(10.9)%
Acquisition costs related to Shoal Creek	(7.4)	—	—	—	(7.4)	n.m.
Gain on sale of interest in Dominion Terminal Associates	—	—	19.7	19.7	(19.7)	(100.0)%
Other items, net [2]	31.6	(7.4)	(21.9)	(29.3)	60.9	207.8 %
Corporate and Other Adjusted EBITDA	$ (89.2)	$ (111.2)	$ (35.6)	$ (146.8)	$ 57.6	39.2 %

(1) Includes gains on certain surplus coal reserve and surface land sales and property management costs and revenues.

(2) Includes results from equity affiliates (before the impact of related changes in deferred tax asset valuation allowance and reserves and amortization of basis difference), trading and brokerage activities, costs associated with post mining activities, certain coal royalty expenses, gains (losses) on certain asset disposals, minimum charges on certain transportation-related contracts and expenses related to our other commercial activities.

The increase associated with "Other items, net" as compared to prior year was attributable to a decrease in realized losses associated with our corporate hedging results ($15.9 million), which included foreign currency and commodity hedging, and the favorable results from our trading and brokerage activities ($11.7 million) due to increased pricing. The increase in "Other items, net" was also impacted by a gain recognized on the sale of our interest in the Red Mountain Joint Venture ($7.1 million), the impact of the accounting policy election made in connection with fresh start reporting to prospectively record amounts attributable to actuarial valuation changes in earnings rather than accumulated other comprehensive income and amortizing to expense ($7.1 million), improved Middlemount results as compared to the prior year driven by higher pricing ($6.8 million) and a reduction in restructuring charges ($6.5 million). The increase associated with resource management activities was primarily due to gains recorded during 2018 in connection with the sale of certain surplus land assets in Queensland's Bowen Basin ($20.6 million) and the sale of surplus coal resources associated with the Millennium Mine ($20.5 million). These increases were offset by higher selling and administrative expenses as compared to the prior year resulting from charges for share-based compensation and project work around the industry and our portfolio. In addition, during the first quarter of 2017, a $19.7 million gain was recorded in connection with the sale of our interest in Dominion Terminal Associates.

Income (Loss) From Continuing Operations, Net of Income Taxes

The following table presents income (loss) from continuing operations, net of income taxes:

	Successor		Predecessor	Combined
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017
	(Dollars in millions)			
Adjusted EBITDA	$ 1,379.3	$ 1,145.3	$ 341.3	$ 1,486.6
Depreciation, depletion and amortization	(679.0)	(521.6)	(119.9)	(641.5)
Asset retirement obligation expenses	(53.0)	(41.2)	(14.6)	(55.8)
Asset impairment	—	—	(30.5)	(30.5)
Provision for North Goonyella equipment loss	(66.4)	—	—	—
Changes in deferred tax asset valuation allowance and reserves and amortization of basis difference related to equity affiliates	18.3	17.3	5.2	22.5
Interest expense	(149.3)	(119.7)	(32.9)	(152.6)
Loss on early debt extinguishment	(2.0)	(20.9)	—	(20.9)
Interest income	33.6	5.6	2.7	8.3
Net mark-to-market adjustment on actuarially determined liabilities	125.5	45.2	—	45.2
Reorganization items, net	12.8	—	(627.2)	(627.2)
Gain on disposal of reclamation liability	—	31.2	—	31.2
Gain on disposal of Burton Mine assets	—	52.2	—	52.2
Break fees related to terminated asset sales	—	28.0	—	28.0
Unrealized gains (losses) on economic hedges	18.3	(23.0)	16.6	(6.4)
Unrealized losses on non-coal trading derivative contracts	(0.7)	(1.5)	—	(1.5)
Fresh start coal inventory revaluation	—	(67.3)	—	(67.3)
Fresh start take-or-pay contract-based intangible recognition	26.7	22.5	—	22.5
Income tax (provision) benefit	(18.4)	161.0	263.8	424.8
Income (loss) from continuing operations, net of income taxes	$ 645.7	$ 713.1	$ (195.5)	$ 517.6

Depreciation, Depletion and Amortization. The following table presents a summary of depreciation, depletion and amortization expense by segment:

	Successor		Predecessor
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)		
Powder River Basin Mining	$ (183.4)	$ (156.6)	$ (32.0)
Midwestern U.S. Mining	(121.5)	(105.2)	(13.3)
Western U.S. Mining	(147.3)	(87.8)	(23.6)
Seaborne Metallurgical Mining	(129.8)	(100.2)	(20.6)
Seaborne Thermal Mining	(88.4)	(62.3)	(24.0)
Corporate and Other	(8.6)	(9.5)	(6.4)
Total	$ (679.0)	$ (521.6)	$ (119.9)

Additionally, the following table presents a summary of our weighted-average depletion rate per ton for active mines in each of our mining segments:

	Successor		Predecessor
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
Powder River Basin Mining	$ 0.81	$ 0.82	$ 0.69
Midwestern U.S. Mining	0.89	0.79	0.61
Western U.S. Mining	2.29	1.06	4.30
Seaborne Metallurgical Mining	0.94	0.72	4.72
Seaborne Thermal Mining	1.79	0.59	2.62

Depreciation, depletion and amortization expense for the year ended December 31, 2018 included depreciation expense ($274.3 million), depletion expense ($193.1 million), amortization of the fair value of certain U.S. coal supply agreements ($93.1 million) and amortization associated with our asset retirement obligation assets ($84.4 million).

Depreciation, depletion and amortization expense for the period April 2 through December 31, 2017 included depreciation expense ($203.3 million), depletion expense ($132.0 million), amortization of the fair value of certain U.S. coal supply agreements ($121.3 million) and amortization associated with our asset retirement obligation assets ($40.3 million).

Depreciation, depletion and amortization expense for the period January 1 through April 1, 2017 reflected additional expense at some of our mines due to changes in the estimated life of mine and at Corporate and Other for leasehold improvements that were vacated in 2017. The additional expense was offset by a decrease at our Metropolitan Mine as the assets were classified as held for sale during the period and depreciation, depletion and amortization was therefore not recorded. The share sale and purchase agreement related to our Metropolitan Mine was terminated in April 2017, as discussed in Note 22. “Other Events” to the accompanying consolidated financial statements.

Asset Impairment. We recognized $30.5 million in aggregate asset impairment charges during the period of January 1 through April 1, 2017. Refer to Note 5. “Asset Impairment” to the accompanying consolidated financial statements for further information regarding the nature and composition of those charges, which information is incorporated herein by reference.

Provision for North Goonyella Equipment Loss. A provision was recorded during the year ended December 31, 2018 for expected equipment losses related to the events at North Goonyella as discussed in Note 22. “Other Events” to the accompanying consolidated financial statements. The provision includes $50.4 million for the estimated cost to replace leased equipment and $16.0 million related to the cost of Company-owned equipment. This provision represents the best estimate of potential loss associated with these events based on assessments made to date.

Interest Expense. Interest expense for the year ended December 31, 2018 primarily related to the 6.000% Senior Secured Notes due March 2022, the 6.375% Senior Secured Notes due March 2025 and the Senior Secured Term Loan due 2025 ($98.7 million). For additional details on debt, refer to Note 14. “Long-term Debt” to the accompanying consolidated financial statements. The remainder of the interest expense ($50.6 million) was primarily related to our surety program, additional letters of credit issued under the revolver, fees for the accounts receivable securitization program and non-cash interest related to certain contractual arrangements.

Interest expense for the period April 2 through December 31, 2017 primarily related to the 6.000% Senior Secured Notes due March 2022, the 6.375% Senior Secured Notes due March 2025 and the Senior Secured Term Loan due 2025 (Senior Secured Term Loan). For additional details on debt, refer to Note 2. “Emergence from the Chapter 11 Cases and Fresh Start Reporting” and Note 14. “Long-term Debt” to the accompanying consolidated financial statements.

Interest expense for the period January 1 through April 1, 2017 was impacted by our filing of the Bankruptcy Petitions, which resulted in only accruing adequate protection payments subsequent to the Petition Date to certain secured lenders and other parties in accordance with Section 502(b)(2) of the Bankruptcy Code.

Loss on Early Debt Extinguishment. The loss on early debt extinguishment recorded during the year ended December 31, 2018, related to the April 11, 2018 amendment of the Senior Secured Term Loan as described in Note 14. “Long-term Debt” to the accompanying consolidated financial statements. The loss on early debt extinguishment recorded during the the period April 2 through December 31, 2017 related to the voluntary prepayments and amendment of the Senior Secured Term Loan as described in Note 14. “Long-term Debt” to the accompanying consolidated financial statements.

Interest Income. Interest income recorded during the year ended December 31, 2018 was driven by higher interest rates and cash balances, as well as the Company's adoption of ASC Topic 606, "Revenue from Contracts with Customers" (ASC 606) on January 1, 2018. As a result of the adoption, the Company is prospectively required to recognize a portion of consideration received for the reimbursement of certain post-mining costs as interest income rather than revenue, due to the embedded financing element within the related contract. For additional details on the adoption of ASC 606, refer to Note 1. "Summary of Significant Accounting Policies" and Note 4. "Revenue Recognition" to the accompanying consolidated financial statements.

Net Mark-to-Market Adjustment on Actuarially Determined Liabilities. In connection with fresh start reporting, an accounting policy election was made to record amounts attributable to actuarial valuation changes for our pension and postretirement plans in earnings rather than accumulated other comprehensive income. The gain recorded during the year ended December 31, 2018 was driven by increases to the discount rates ($46.2 million), changes related to claims ($54.2 million), the new Medicare law ($20.0 million) and an update to our census data ($7.7 million) for the postretirement benefit plans. The impact on our pension plans was small as actuarial losses on pension assets were largely offset by an increase in discount rates.

During the period April 2 through December 31, 2017 a gain was recorded that was driven by actuarial gains on pension assets ($46.7 million), changes to demographic assumptions, including terminations, retirement and morbidity rates, for our postretirement plans ($34.9 million) and mortality rates for both the pension and postretirement plans ($32.7 million). These gains were offset by decreases to the discount rates for all plans ($71.1 million).

Reorganization Items, Net. The reorganization items recorded during year ended December 31, 2018 were impacted by a favorable adjustment of the bankruptcy claims accrual. The reorganization items recorded during the period January 1 through April 1, 2017 reflected the impact of the Plan provisions and the application of fresh start reporting and other expenses recorded in connection with our Chapter 11 Cases. Refer to Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting" to the accompanying consolidated financial statements for further information regarding our reorganization items.

Gain on Disposal of Reclamation Liability. During the period April 2 through December 31, 2017, we recorded a gain of $31.2 million on the extinguishment of a guarantee liability for reclamation and bonding commitments which is further described in Note 22. "Other Events" to the accompanying consolidated financial statements.

Gain on Disposal of Burton Mine Assets. During the period April 2 through December 31, 2017, we recorded a gain of $52.2 million on the sale of our majority of the Burton Mine and related infrastructure which is further described in Note 22. "Other Events" to the accompanying consolidated financial statements.

Break Fees Related to Terminated Asset Sales. During the period April 2 through December 31, 2017 we received break fees of $28.0 million related to terminated asset sale agreements which are further described in Note 22. "Other Events" to the accompanying consolidated financial statements.

Unrealized Gains (Losses) on Economic Hedges. Unrealized gains (losses) primarily relate to mark-to-market activity from economic hedge activities intended to hedge future coal sales. For additional information, refer to Note 9. "Derivatives and Fair Value Measurements" to the accompanying consolidated financial statements.

Fresh Start Coal Inventory Revaluation. As a part of the fresh start reporting adjustments, the book value of coal inventories was increased to reflect the estimated fair value, less costs to sell the inventories. During the period April 2 through December 31, 2017, this adjustment was fully amortized as the inventory was sold. For additional details, refer to Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting" to the accompanying consolidated financial statements.

Fresh Start Take-or-Pay Contract-Based Intangible Recognition. Included in the fresh start reporting adjustments were contract-based intangible liabilities for port and rail take-or-pay contracts. During the year ended December 31, 2018 and the period April 2 through December 31, 2017 we ratably recognized these contract-based intangible liabilities. For additional details, refer to Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting" and Note 10. "Intangible Contract Assets and Liabilities" to the accompanying consolidated financial statements.

Income Tax (Provision) Benefit. The income tax provision recorded for the year ended December 31, 2018 was comprised primarily of the impact from a single operation outside of our Australian consolidated tax group. This was partially offset by a tax benefit related to the release of valuation allowance on refundable alternative minimum tax credits due to non-applicability of sequestration reduction, as well as a tax benefit that was allocated to continuing operations related to the tax effect of items credited directly to other comprehensive income and discontinued operations.

The income tax benefit recorded for the period April 2 through December 31, 2017 reflected the estimated benefit for the newly enacted tax legislation primarily related to alternative minimum tax credits and expected refunds for U.S. net operating loss carrybacks.

The income tax benefit recorded for the period January 1 through April 1, 2017, was primarily comprised of benefits related to Predecessor deferred tax liabilities ($177.8 million), accumulated other comprehensive income ($81.5 million) and unrecognized tax benefits ($6.7 million). Refer to Note 12. "Income Taxes" to the accompanying consolidated financial statements for additional information.

Net Income (Loss) Attributable to Common Stockholders

The following table presents net income (loss) attributable to common stockholders:

	Successor		Predecessor
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)		
Income (loss) from continuing operations, net of income taxes	$ 645.7	$ 713.1	$ (195.5)
Income (loss) from discontinued operations, net of income taxes	18.1	(19.8)	(16.2)
Net income (loss)	663.8	693.3	(211.7)
Less: Series A Convertible Preferred Stock dividends	102.5	179.5	—
Less: Net income attributable to noncontrolling interests	16.9	15.2	4.8
Net income (loss) attributable to common stockholders	$ 544.4	$ 498.6	$ (216.5)

Income (Loss) from Discontinued Operations, Net of Income Taxes. The income from discontinued operations, net of income taxes for the year ended December 31, 2018 primarily consisted of actuarial gains associated with black lung liabilities. The loss from discontinued operations for the period January 1 through April 1, 2017 primarily consisted of fresh start tax adjustments ($12.1 million) as discussed in Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting" to the accompanying consolidated financial statements.

Series A Convertible Preferred Stock Dividends. The Series A Convertible Preferred Stock dividends for the year ended December 31, 2018 were comprised of the deemed dividends granted for all remaining Convertible Preferred Stock shares that were converted as of January 31, 2018. The Series A Convertible Preferred Stock dividends for the period April 2 through December 31, 2017 were comprised of the deemed dividends ($160.7 million) granted for the preferred stock shares that were converted during the period and the semi-annual payable in-kind preferred dividends ($18.8 million).

Diluted EPS

The following table presents diluted EPS:

	Successor		Predecessor
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
Diluted EPS attributable to common stockholders:			
Income (loss) from continuing operations	$ 4.28	$ 3.81	$ (10.93)
Income (loss) from discontinued operations	0.15	(0.14)	(0.88)
Net income (loss) attributable to common stockholders	$ 4.43	$ 3.67	$ (11.81)

Diluted EPS is commensurate with the changes in results from continuing operations and discontinued operations during that period. Diluted EPS reflects weighted average diluted common shares outstanding of 121.0 million, 102.5 million and 18.3 million for the year ended December 31, 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017, respectively.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Summary

Spot pricing for Premium HCC, Premium PCI coal, Newcastle index thermal coal and API 5 thermal coal, and prompt month pricing for PRB 8,880 Btu/Lb coal and Illinois Basin 11,500 Btu/Lb coal during the year ended December 31, 2017 is set forth in the table below. Pricing for our Western U.S. Mining segment is not included as there is no similar spot or prompt pricing data available.

In the U.S., the pricing included in the table below is not necessarily indicative of the pricing we realized during the year ended December 31, 2017 since we generally sell coal under long-term contracts where pricing is determined based on various factors. Such long-term contracts in the U.S. may 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. Competition from alternative fuels such as natural gas and other coal producers may also impact our realized pricing.

The seaborne pricing included in the table below is also not necessarily indicative of the pricing we realized during the year ended December 31, 2017 due to quality differentials and the majority of our seaborne sales being executed through annual and multi-year international coal supply agreements that contain provisions requiring both parties to renegotiate pricing periodically. 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.

	High	Low	Average	December 31, 2017
Premium HCC [(1)]	$ 304.00	$ 139.50	$ 188.00	$ 262.25
Premium PCI coal [(1)]	$ 185.00	$ 101.15	$ 119.10	$ 147.05
Newcastle index thermal coal [(1)]	$ 101.20	$ 73.25	$ 88.15	$ 100.80
API 5 thermal coal [(1)]	$ 78.60	$ 61.25	$ 70.63	$ 75.25
PRB 8,800 Btu/Lb coal [(2)]	$ 12.60	$ 10.95	$ 11.75	$ 12.60
Illinois Basin 11,500 Btu/Lb coal [(2)]	$ 36.75	$ 32.50	$ 34.35	$ 36.75

(1) Prices expressed per tonne.

(2) Prices expressed per ton.

Demand for seaborne metallurgical coal for the year ended December 31, 2017 increased 11 million tonnes or 4% compared to 2016, driven by a 5% increase in worldwide steel production, according to data published by the World Steel Association (WSA). Growth in seaborne metallurgical coal imports was driven by increased steel production in China and India compared to 2016. Global metallurgical coal supply and demand fundamentals were tight as total Australian metallurgical exports declined more than 15 million tonnes year-over-year through December due to cyclone impacts, logistical constraints and industry-wide operational challenges.

Demand for seaborne thermal coal for the year ended December 31, 2017 increased approximately 25 million tonnes or 3% compared to the prior year period, supported by a 5% increase in Chinese thermal electricity generation, according to data published by China Electricity Council. Growth in thermal coal imports in the Pacific region, led by China, South Korea and countries comprising the Association of Southeast Asian Nations (ASEAN), more than offset declining Atlantic basin demand. Lower year-over-year exports from Australia, Indonesia and Colombia resulted in an increase in higher-cost U.S. thermal exports to meet demand.

In the U.S., electricity generation from coal decreased 3% during the year ended December 31, 2017 compared to 2016 according to the U.S. Energy Information Administration (EIA). U.S. electricity generation from coal was unfavorably affected during that period by mild weather and weaker total electricity generation, coal plant retirements, stronger hydro generation and continued gains by renewables in the electricity generation mix. Conversely, coal benefited from higher average natural gas prices, which increased 18% year-over-year to $3.02/mmBtu from $2.55/mmBtu in 2016. Coal's relative share of the electricity generation mix in 2017 was roughly flat at 30% of the total, while the relative share of natural gas declined from 34% in 2016 to 32% in 2017.

Income from continuing operations, net of income taxes of $713.1 million for the period April 2 through December 31, 2017 included revenues of $4,252.6 million, a tax benefit of $161.0 million and net gain on disposals of $84.0 million. These were offset by operating costs of $3,052.7 million, depreciation, depletion and amortization of $521.6 million, interest expense of $119.7 million and selling and administrative expenses of $106.3 million. Adjusted EBITDA for the period April 2 through December 31, 2017 was $1,145.3 million.

For the period January 1 through April 1, 2017, loss from continuing operations, net of income taxes of $195.5 million included revenues of $1,326.2 million and a tax benefit of $263.8 million. These were offset by operating costs of $950.2 million, depreciation, depletion and amortization of $119.9 million, interest expense of $32.9 million and reorganization items, net of $627.2 million which included the impact of the Plan provisions and the application of fresh start reporting. Adjusted EBITDA for the period January 1 through April 1, 2017 was $341.3 million.

Loss from continuing operations, net of income taxes of $663.8 million for the year ended December 31, 2016 included revenues of $4,715.3 million, which were offset by operating costs of $4,070.0 million, depreciation, depletion and amortization of $465.4 million, interest expense of $298.6 million, asset impairment charges of $247.9 million, reorganization items, net of $159.0 million and selling and administrative expenses of $149.4 million. The Adjusted EBITDA for the year ended December 31, 2016 was $532.0 million.

Tons Sold

The following table presents tons sold by operating segment:

	Successor	Predecessor	Combined	Predecessor	Increase (Decrease) to Tons Sold	
	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	Year Ended December 31, 2016	Tons	%
			(Tons in millions)			
Powder River Basin Mining	94.0	31.0	125.0	113.1	11.9	10.5 %
Midwestern U.S. Mining	14.0	4.5	18.5	18.3	0.2	1.1 %
Western U.S. Mining	11.3	3.4	14.7	13.7	1.0	7.3 %
Seaborne Metallurgical Mining	9.5	2.2	11.7	13.4	(1.7)	(12.7)%
Seaborne Thermal Mining	14.6	4.6	19.2	21.3	(2.1)	(9.9)%
Total tons sold from mining segments	143.4	45.7	189.1	179.8	9.3	5.2 %
Corporate and Other	2.0	0.4	2.4	7.0	(4.6)	(65.7)%
Total tons sold	145.4	46.1	191.5	186.8	4.7	2.5 %

Supplemental Financial Data

The following table presents supplemental financial data by operating segment:

	Successor	Predecessor	Combined	Predecessor	(Decrease) Increase	
	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	Year Ended December 31, 2016	$	%
Revenues per Ton - Mining Operations [1]						
Powder River Basin	$ 12.54	$ 12.70	$ 12.58	$ 13.02	$ (0.44)	(3.4)%
Midwestern U.S.	42.45	42.96	42.58	43.39	(0.81)	(1.9)%
Western U.S.	38.75	44.68	40.10	38.30	1.80	4.7 %
Seaborne Metallurgical	128.14	150.22	132.29	81.41	50.88	62.5 %
Seaborne Thermal	52.84	48.65	51.83	38.79	13.04	33.6 %
Costs per Ton - Mining Operations [1][2]						
Powder River Basin	$ 9.57	$ 9.75	$ 9.62	$ 9.66	$ (0.04)	(0.4)%
Midwestern U.S.	33.53	31.84	33.13	31.49	1.64	5.2 %
Western U.S.	27.16	29.76	27.75	30.90	(3.15)	(10.2)%
Seaborne Metallurgical	84.60	100.16	87.52	82.63	4.89	5.9 %
Seaborne Thermal	31.87	32.27	31.97	28.56	3.41	11.9 %
Adjusted EBITDA Margin per Ton - Mining Operations [1][2]						
Powder River Basin	$ 2.97	$ 2.95	$ 2.96	$ 3.36	$ (0.40)	(11.9)%
Midwestern U.S.	8.92	11.12	9.45	11.90	(2.45)	(20.6)%
Western U.S.	11.59	14.92	12.35	7.40	4.95	66.9 %
Seaborne Metallurgical	43.54	50.06	44.77	(1.22)	45.99	3,769.7 %
Seaborne Thermal	20.97	16.38	19.86	10.23	9.63	94.1 %

(1) This is an operating/statistical measure not recognized in accordance with U.S. GAAP. Refer to the "Reconciliation of Non-GAAP Financial Measures" section below for definitions and reconciliations to the most comparable measures under U.S. GAAP.

(2) Includes revenue-based production taxes and royalties; excludes depreciation, depletion and amortization; asset retirement obligation expenses; selling and administrative expenses; restructuring charges; asset impairment; amortization of fresh start reporting adjustments related to coal inventory revaluation and take-or-pay contract-based intangibles; and certain other costs related to post-mining activities.

Revenues

The following table presents revenues by reporting segment:

	Successor	Predecessor	Combined	Predecessor	Increase (Decrease) to Revenues	
	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	Year Ended December 31, 2016	$	%
			(Dollars in millions)			
Powder River Basin Mining	$ 1,178.7	$ 394.3	$ 1,573.0	$ 1,473.3	$ 99.7	6.8 %
Midwestern U.S. Mining	592.3	193.2	785.5	792.5	(7.0)	(0.9)%
Western U.S. Mining	440.7	149.7	590.4	526.0	64.4	12.2 %
Seaborne Metallurgical Mining	1,221.0	328.9	1,549.9	1,090.4	459.5	42.1 %
Seaborne Thermal Mining	772.5	224.8	997.3	824.9	172.4	20.9 %
Corporate and Other	47.4	35.3	82.7	8.2	74.5	908.5 %
Total revenues	$ 4,252.6	$ 1,326.2	$ 5,578.8	$ 4,715.3	$ 863.5	18.3 %

Powder River Basin Mining. The increase in Powder River Basin Mining segment revenues during the year ended December 31, 2017 compared to the prior year was due to demand-based volume increases of 11.9 million tons across the region as the result of increased natural gas pricing ($159.7 million) which drove a switch from natural gas to coal by customers. This increase was partially offset by lower realized coal pricing ($60.0 million).

Midwestern U.S. Mining. Revenues from our Midwestern U.S. Mining segment were adversely impacted during the year ended December 31, 2017 compared to the prior year by lower realized coal pricing ($8.6 million) which was slightly offset by favorable volume and mix variances ($1.6 million).

Western U.S. Mining. The increase in Western U.S. Mining segment revenues for the year ended December 31, 2017 compared to the prior year was predominately driven by favorable volume and mix variances ($46.8 million) and collection of liquidated damage settlements ($21.5 million).

Seaborne Metallurgical Mining. The increase in our Seaborne Metallurgical Mining segment revenues for the year ended December 31, 2017 compared to the prior year was primarily due to significantly improved realized coal pricing ($590.6 million) which was partially offset by an unfavorable volume and mix variance ($131.1 million). The volume decrease which reflected the cessation of mining activities at our Burton Mine during the fourth quarter of 2016, the impact of Cyclone Debbie and an extended longwall move at the Metropolitan Mine during the first half of 2017, was partially offset by increased productivity at the North Goonyella Mine during 2017.

Seaborne Thermal Mining. The increase in our Seaborne Thermal Mining segment revenues for the year ended December 31, 2017 compared to the prior year was primarily driven by significantly improved realized coal pricing ($240.0 million). The increase was partially offset by the unfavorable impact of changes in volume and mix ($67.6 million) which was attributable to lower sales volumes from our Wambo Mine as the result of temporary geological issues and an extended longwall move.

Corporate and Other. The increase in Corporate and Other revenues for the year ended December 31, 2017 compared to the prior year was due to improved results on economic hedges, the receipt of break fees related to terminated asset sale agreements which are further described in Note 22. “Other Events” to the accompanying consolidated financial statements and favorable results from our trading and brokerage activities due to increased prices.

Adjusted EBITDA

The following table presents Adjusted EBITDA for each of our reporting segments:

	Successor	Predecessor	Combined	Predecessor	(Decrease) Increase to Adjusted EBITDA	
	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	Year Ended December 31, 2016	$	%
			(Dollars in millions)			
Powder River Basin Mining	$ 278.8	$ 91.7	$ 370.5	$ 379.9	$ (9.4)	(2.5)%
Midwestern U.S. Mining	124.4	50.0	174.4	217.3	(42.9)	(19.7)%
Western U.S. Mining	131.8	50.0	181.8	101.6	80.2	78.9 %
Seaborne Metallurgical Mining	414.9	109.6	524.5	(16.3)	540.8	3,317.8 %
Seaborne Thermal Mining	306.6	75.6	382.2	217.6	164.6	75.6 %
Corporate and Other	(111.2)	(35.6)	(146.8)	(368.1)	221.3	60.1 %
Adjusted EBITDA [1]	$ 1,145.3	$ 341.3	$ 1,486.6	$ 532.0	$ 954.6	179.4 %

(1) This is a financial measure not recognized in accordance with U.S. GAAP. Refer to the “Reconciliation of Non-GAAP Financial Measures” section below for definitions and reconciliations to the most comparable measures under U.S. GAAP.

Powder River Basin Mining. The decrease in Powder River Basin Mining segment Adjusted EBITDA for the year ended December 31, 2017 compared to the prior year was due to lower realized coal pricing, net of sales-related costs ($64.9 million), increased pricing for fuel and explosives ($13.9 million) and higher materials, services and repairs costs ($13.0 million). This was partially offset by improved volumes driven by increased natural gas pricing ($44.3 million), reduced expenses for leases due to early lease buyouts ($21.9 million) and favorable labor spending ($8.3 million).

Midwestern U.S. Mining. The decrease in Midwestern U.S. Mining segment Adjusted EBITDA for the year ended December 31, 2017 compared to the prior year was due to higher materials, services and repairs costs ($19.2 million), lower realized coal pricing, net of sales-related costs ($11.4 million), increased pricing for fuel and explosives ($10.9 million) and higher labor spending ($9.0 million), partially offset by improved volumes primarily at our Gateway North Mine ($11.6 million).

Western U.S. Mining. The increase in Western U.S. Mining segment Adjusted EBITDA for the year ended December 31, 2017 compared to the prior year was driven by improved sales volumes from higher margin operations ($42.0 million), liquidated damage settlements collected during 2017 ($21.5 million), the favorable impact of mine sequencing at our Kayenta Mine ($10.7 million) and decreased spending for materials, services and repairs costs ($10.3 million).

Seaborne Metallurgical Mining. The improvement in Seaborne Metallurgical Mining segment Adjusted EBITDA for the year ended December 31, 2017 compared to the prior year reflected improved realized coal pricing, net of sales-related costs ($544.4 million), improved production volumes at our North Goonyella Mine ($87.6 million) primarily due to longwall moves in the prior year and lower contractor and rail costs due to the cessation of mining activities at our Burton Mine during the fourth quarter of 2016 ($10.6 million). The increases were offset by lower production at our Metropolitan Mine due to an extended longwall move in the first half of 2017 ($40.4 million), higher fuel pricing and cost escalations ($32.6 million), unfavorable foreign exchange rate movements ($16.0 million) and increased demurrage costs ($9.1 million) due to the impact of Cyclone Debbie, logistical constraints and scheduled port maintenance.

Seaborne Thermal Mining. The increase in Seaborne Thermal Mining segment Adjusted EBITDA for the year ended December 31, 2017 compared to the prior year reflected improved realized coal pricing, net of sales-related costs ($221.2 million), offset by lower sales volumes primarily at our Wambo Mine as the result of temporary geological issues and an extended longwall move ($27.2 million) and higher fuel pricing and other cost escalations ($17.6 million).

Corporate and Other Adjusted EBITDA. The following table presents a summary of the components of Corporate and Other Adjusted EBITDA:

	Successor	Predecessor	Combined	Predecessor	(Decrease) Increase to Income	
	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	Year Ended December 31, 2016	$	%
	(Dollars in millions)					
Resource management activities [(1)]	$ 2.5	$ 2.9	$ 5.4	$ 19.0	$ (13.6)	(71.6)%
Selling and administrative expenses (excluding debt restructuring)	(106.3)	(36.3)	(142.6)	(127.9)	(14.7)	(11.5)%
UMWA voluntary employee beneficiary association settlement	—	—	—	68.1	(68.1)	(100.0)%
Gain on sale of interest in Dominion Terminal Associates	—	19.7	19.7	—	19.7	n.m.
Other items, net [(2)]	(7.4)	(21.9)	(29.3)	(327.3)	298.0	91.0 %
Corporate and Other Adjusted EBITDA	$ (111.2)	$ (35.6)	$ (146.8)	$ (368.1)	$ 221.3	60.1 %

(1) Includes gains (losses) on certain surplus coal reserve and surface land sales and property management costs and revenues.

(2) Includes results from equity affiliates (before the impact of related changes in deferred tax asset valuation allowance and reserves and amortization of basis difference), trading and brokerage activities, costs associated with post mining activities, certain coal royalty expenses, gains (losses) on certain asset disposals, minimum charges on certain transportation-related contracts and expenses related to our other commercial activities.

The increase associated with “Other items, net” was primarily attributable to a decrease in realized losses associated with our corporate hedging results ($216.6 million), which included foreign currency and commodity hedging, during the year ended December 31, 2017 as compared to the prior year due to changes in our hedging activity and elimination of amounts previously deferred in “Accumulated other comprehensive income” resulting from the application of fresh start reporting. “Other items, net” was also favorably impacted by our trading and brokerage activities ($34.3 million) which reflected normalization of business and overall market opportunities, improved Middlemount results ($29.4 million) driven by higher pricing as compared to the prior year and a reduction in restructuring charges ($7.9 million) driven by workforce reductions made during 2016 at multiple mines in our Powder River Basin Mining and Midwestern U.S. Mining segments, partially offset by a provision recorded during 2017 for the expected closure of the Millennium Mine in the second half of 2019. During the first quarter of 2017, a $19.7 million gain was recorded in connection with the sale of our interest in Dominion Terminal Associates. During 2016, a gain of $68.1 million was recognized for the voluntary employee beneficiary association (VEBA) settlement with the United Mine Workers of America (UMWA) as further described in Note 6. “Discontinued Operations” to the accompanying consolidated financial statements. Resource management results decreased during the year ended December 31, 2017 as compared to the prior year due to higher gains from the disposal of surplus lands during 2016. The increase in selling and administrative expenses was driven by charges for share-based compensation expense.

Income (Loss) From Continuing Operations, Net of Income Taxes

The following table presents income (loss) from continuing operations, net of income taxes:

	Successor	Predecessor	Combined	Predecessor
	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Adjusted EBITDA [(1)]	$ 1,145.3	$ 341.3	$ 1,486.6	$ 532.0
Depreciation, depletion and amortization	(521.6)	(119.9)	(641.5)	(465.4)
Asset retirement obligation expenses	(41.2)	(14.6)	(55.8)	(41.8)
Selling and administrative expenses related to debt restructuring	—	—	—	(21.5)
Asset impairment	—	(30.5)	(30.5)	(247.9)
Changes in deferred tax asset valuation allowance and reserves and amortization of basis difference related to equity affiliates	17.3	5.2	22.5	7.5
Interest expense	(119.7)	(32.9)	(152.6)	(298.6)
Loss on early debt extinguishment	(20.9)	—	(20.9)	(29.5)
Interest income	5.6	2.7	8.3	5.7
Net mark-to-market adjustment on actuarially determined liabilities	45.2	—	45.2	—
Reorganization items, net	—	(627.2)	(627.2)	(159.0)
Gain on disposal of reclamation liability	31.2	—	31.2	—
Gain on disposal of Burton Mine assets	52.2	—	52.2	—
Break fees related to terminated asset sales	28.0	—	28.0	—
Unrealized (losses) gains on economic hedges	(23.0)	16.6	(6.4)	(39.8)
Unrealized losses on non-coal trading derivative contracts	(1.5)	—	(1.5)	—
Fresh start coal inventory revaluation	(67.3)	—	(67.3)	—
Fresh start take-or-pay contract-based intangible recognition	22.5	—	22.5	—
Income tax benefit	161.0	263.8	424.8	94.5
Income (loss) from continuing operations, net of income taxes	$ 713.1	$ (195.5)	$ 517.6	$ (663.8)

(1) This is a financial measure not recognized in accordance with U.S. GAAP. Refer to the “Reconciliation of Non-GAAP Financial Measures” section below for definitions and reconciliations to the most comparable measures under U.S. GAAP.

Depreciation, Depletion and Amortization. The following table presents a summary of depreciation, depletion and amortization expense by segment:

	Successor	Predecessor	
	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)		
Powder River Basin Mining	$ (156.6)	$ (32.0)	$ (123.4)
Midwestern U.S. Mining	(105.2)	(13.3)	(56.2)
Western U.S. Mining	(87.8)	(23.6)	(45.2)
Seaborne Metallurgical Mining	(100.2)	(20.6)	(118.7)
Seaborne Thermal Mining	(62.3)	(24.0)	(102.5)
Corporate and Other	(9.5)	(6.4)	(19.4)
Total	$ (521.6)	$ (119.9)	$ (465.4)

Additionally, the following table presents a summary of our weighted-average depletion rate per ton for active mines in each of our mining segments:

	Successor	Predecessor	
	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
Powder River Basin Mining	$ 0.82	$ 0.69	$ 0.71
Midwestern U.S. Mining	0.79	0.61	0.53
Western U.S. Mining	1.06	4.30	0.92
Seaborne Metallurgical Mining	0.72	4.72	4.36
Seaborne Thermal Mining	0.59	2.62	2.53

Depreciation, depletion and amortization expense for the period April 2 through December 31, 2017 included depreciation expense ($203.3 million), depletion expense ($132.0 million), amortization of the fair value of certain U.S. coal supply agreements ($121.3 million) and amortization associated with our asset retirement obligation assets ($40.3 million).

Depreciation, depletion and amortization expense for the period January 1 through April 1, 2017 reflected additional expense at some of our mines due to changes in the estimated life of mine and at Corporate and Other for leasehold improvements that were vacated in 2017. The additional expense was offset by a decrease at our Metropolitan Mine as the assets were classified as held for sale during the period and depreciation, depletion and amortization was therefore not recorded. The share sale and purchase agreement related to our Metropolitan Mine was terminated in April 2017, as discussed in Note 22. "Other Events" to the accompanying consolidated financial statements. Depreciation, depletion and amortization expense for the year ended December 31, 2016 was impacted by a reduction in the asset bases at several of our mines due to impairment charges that had been recognized during 2015.

Asset Retirement Obligation Expenses. Included in the asset retirement obligation expenses recorded during the period April 2 through December 31, 2017 were unfavorable closed mine true-ups and increased ongoing reclamation adjustments related to rate increases at various locations. During the year ended December 31, 2016, credits were recorded for ongoing reclamation due to accelerated work which lowered the overall expense.

Selling and Administrative Expenses Related to Debt Restructuring. The general and administrative expenses related to debt restructuring recorded during the year ended December 31, 2016 related to legal and other expenditures made in connection with debt restructuring initiatives prior to the Debtors' filing of the Bankruptcy Petitions.

Asset Impairment. We recognized $30.5 million and $247.9 million in aggregate asset impairment charges during the period January 1 through April 1, 2017 and the year ended December 31, 2016, respectively. Refer to Note 5. "Asset Impairment" to the accompanying consolidated financial statements for further information regarding the nature and composition of those charges, which information is incorporated herein by reference.

Interest Expense. Interest expense for the period April 2 through December 31, 2017 primarily related to the 6.000% Senior Secured Notes due March 2022, the 6.375% Senior Secured Notes due March 2025 and the Senior Secured Term Loan. For additional details on debt, refer to Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting" and Note 14. "Long-term Debt" to the accompanying consolidated financial statements.

Interest expense for the period January 1 through April 1, 2017 and the year ended December 31, 2016, was impacted by our filing of the Bankruptcy Petitions, which resulted in only accruing adequate protection payments subsequent to the Petition Date to certain secured lenders and other parties in accordance with Section 502(b)(2) of the Bankruptcy Code.

Loss on Early Debt Extinguishment. The loss on early debt extinguishment recorded during the period April 2 through December 31, 2017 related to the voluntary prepayments and amendment of the Senior Secured Term Loan as described in Note 14. "Long-term Debt" to the accompanying consolidated financial statements. The loss on early debt extinguishment recorded during the Predecessor year ended December 31, 2016 was related to the repayment of our Debtor-In-Possession Term Loan Facility.

Net Mark-to-Market Adjustment on Actuarially Determined Liabilities. In connection with fresh start reporting, an accounting policy election was made to record amounts attributable to actuarial valuation changes for our pension and postretirement plans in earnings rather than accumulated other comprehensive income. During the period April 2 through December 31, 2017 a gain was recorded that was driven by actuarial gains on pension assets ($46.7 million), changes to demographic assumptions, including terminations, retirement and morbidity rates, for our postretirement plans ($34.9 million) and mortality rates for both the pension and postretirement plans ($32.7 million). These gains were offset by decreases to the discount rates for all plans ($71.1 million).

Reorganization Items, Net. The reorganization items recorded during the period January 1 through April 1, 2017 reflected the impact of the Plan provisions and the application of fresh start reporting and other expenses recorded in connection with our Chapter 11 Cases. Expense recorded during the year ended December 31, 2016 related to expenses recorded in connection with our Chapter 11 Cases. Refer to Note 2. “Emergence from the Chapter 11 Cases and Fresh Start Reporting” to the accompanying consolidated financial statements for further information regarding our reorganization items.

Gain on Disposal of Reclamation Liability. During the period April 2 through December 31, 2017, we recorded a gain of $31.2 million on the extinguishment of a guarantee liability for reclamation and bonding commitments which is further described in Note 22. “Other Events” to the accompanying consolidated financial statements.

Gain on Disposal of Burton Mine Assets. During the period April 2 through December 31, 2017, we recorded a gain of $52.2 million on the sale of our majority of the Burton Mine and related infrastructure which is further described in Note 22. “Other Events” to the accompanying consolidated financial statements.

Break Fees Related to Terminated Asset Sales. During the period April 2 through December 31, 2017 we received break fees of $28.0 million related to terminated asset sale agreements which are further described in Note 22. “Other Events” to the accompanying consolidated financial statements.

Unrealized (Losses) Gains on Economic Hedges. Unrealized (losses) gains primarily related to mark-to-market activity from economic hedge activities intended to hedge future coal sales. For additional information, refer to Note 9. “Derivatives and Fair Value Measurements” to the accompanying consolidated financial statements.

Fresh Start Coal Inventory Revaluation. As a part of the fresh start reporting adjustments, the book value of coal inventories was increased to reflect the estimated fair value, less costs to sell the inventories. During the period April 2 through December 31, 2017, this adjustment was fully amortized as the inventory was sold. For additional details, refer to Note 2. “Emergence from the Chapter 11 Cases and Fresh Start Reporting” to the accompanying consolidated financial statements.

Fresh Start Take-or-Pay Contract-Based Intangible Recognition. Included in the fresh start reporting adjustments were contract-based intangible liabilities for port and rail take-or-pay contracts. During the period April 2 through December 31, 2017 we ratably recognized these contract-based intangible liabilities. For additional details, refer to Note 2. “Emergence from the Chapter 11 Cases and Fresh Start Reporting” and Note 10. “Intangible Contract Assets and Liabilities” to the accompanying consolidated financial statements.

Income Tax Benefit. The income tax benefit recorded for the period April 2 through December 31, 2017 reflected the estimated benefit for the newly enacted tax legislation primarily related to alternative minimum tax credits and expected refunds for U.S. net operating loss carrybacks.

The income tax benefit recorded for the period January 1 through April 1, 2017, was primarily comprised of benefits related to Predecessor deferred tax liabilities ($177.8 million), accumulated other comprehensive income ($81.5 million) and unrecognized tax benefits ($6.7 million). Refer to Note 12. “Income Taxes” to the accompanying consolidated financial statements for additional information.

Net Income (Loss) Attributable to Common Stockholders

The following table presents net income (loss) attributable to common stockholders:

	Successor	Predecessor	
	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)		
Income (loss) from continuing operations, net of income taxes	$ 713.1	$ (195.5)	$ (663.8)
Loss from discontinued operations, net of income taxes	(19.8)	(16.2)	(57.6)
Net income (loss)	693.3	(211.7)	(721.4)
Less: Series A Convertible Preferred Stock dividends	179.5	—	—
Less: Net income attributable to noncontrolling interests	15.2	4.8	7.9
Net income (loss) attributable to common stockholders	$ 498.6	$ (216.5)	$ (729.3)

Loss from Discontinued Operations, Net of Income Taxes. The loss from discontinued operations for the period January 1 through April 1, 2017 primarily consisted of fresh start tax adjustments ($12.1 million) as discussed in Note 2. “Emergence from the Chapter 11 Cases and Fresh Start Reporting” to the accompanying consolidated financial statements. The loss from discontinued operations for the year ended December 31, 2016 included a charge of $54.3 million associated with the UMWA 1974 Pension Plan which is further described in Note 6. “Discontinued Operations” to the accompanying consolidated financial statements.

Series A Convertible Preferred Stock Dividends. The Series A Convertible Preferred Stock dividends for the period April 2 through December 31, 2017 were comprised of the deemed dividends ($160.7 million) granted for the preferred stock shares that were converted during the period and the semi-annual payable in-kind preferred dividends ($18.8 million).

Diluted EPS

The following table presents diluted EPS:

	Successor	Predecessor	
	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
Diluted EPS attributable to common stockholders:			
Income (loss) from continuing operations	$ 3.81	$ (10.93)	$ (36.72)
Loss from discontinued operations	(0.14)	(0.88)	(3.15)
Net income (loss) attributable to common stockholders	$ 3.67	$ (11.81)	$ (39.87)

Diluted EPS is commensurate with the changes in results from continuing operations and discontinued operations during that period. Diluted EPS reflects weighted average diluted common shares outstanding of 102.5 million for the period April 2 through December 31, 2017. Diluted EPS for the period January 1 through April 1, 2017 and the year ended December 31, 2016 reflects weighted average diluted common shares outstanding of 18.3 million, respectively.

Reconciliation of Non-GAAP Financial Measures

Adjusted EBITDA is defined as income (loss) from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expenses, depreciation, depletion and amortization and reorganization items, net. Adjusted EBITDA is also adjusted for the discrete items that management excluded in analyzing each of our segment's operating performance, as displayed in the reconciliations below.

	Successor		Predecessor	Combined	Predecessor
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	Year Ended December 31, 2016
	(Dollars in millions)				
Income (loss) from continuing operations, net of income taxes	$ 645.7	$ 713.1	$ (195.5)	$ 517.6	$ (663.8)
Depreciation, depletion and amortization	679.0	521.6	119.9	641.5	465.4
Asset retirement obligation expenses	53.0	41.2	14.6	55.8	41.8
Selling and administrative expenses related to debt restructuring	—	—	—	—	21.5
Asset impairment	—	—	30.5	30.5	247.9
Provision for North Goonyella equipment loss	66.4	—	—	—	—
Changes in deferred tax asset valuation allowance and reserves and amortization of basis difference related to equity affiliates	(18.3)	(17.3)	(5.2)	(22.5)	(7.5)
Interest expense	149.3	119.7	32.9	152.6	298.6
Loss on early debt extinguishment	2.0	20.9	—	20.9	29.5
Interest income	(33.6)	(5.6)	(2.7)	(8.3)	(5.7)
Net mark-to-market adjustment on actuarially determined liabilities	(125.5)	(45.2)	—	(45.2)	—
Reorganization items, net	(12.8)	—	627.2	627.2	159.0
Gain on disposal of reclamation liability	—	(31.2)	—	(31.2)	—
Gain on disposal of Burton Mine assets	—	(52.2)	—	(52.2)	—
Break fees related to terminated asset sales	—	(28.0)	—	(28.0)	—
Unrealized (gains) losses on economic hedges	(18.3)	23.0	(16.6)	6.4	39.8
Unrealized losses on non-coal trading derivative contracts	0.7	1.5	—	1.5	—
Fresh start coal inventory revaluation	—	67.3	—	67.3	—
Fresh start take-or-pay contract-based intangible recognition	(26.7)	(22.5)	—	(22.5)	—
Income tax provision (benefit)	18.4	(161.0)	(263.8)	(424.8)	(94.5)
Adjusted EBITDA	$ 1,379.3	$ 1,145.3	$ 341.3	$ 1,486.6	$ 532.0

Revenues per Ton and Adjusted EBITDA Margin per Ton are equal to revenues by segment and Adjusted EBITDA by segment, respectively, divided by segment tons sold. Costs per Ton is equal to Revenues per Ton less Adjusted EBITDA Margin per Ton, and are reconciled to operating costs and expenses as follows:

	Successor		Predecessor	Combined	Predecessor
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	Year Ended December 31, 2016
	(Dollars in millions)				
Operating costs and expenses	$ 4,072.6	$ 3,052.7	$ 950.2	$ 4,002.9	$ 4,070.0
Break fees related to terminated asset sales	—	28.0	—	28.0	—
Unrealized losses on non-coal trading derivative contracts	(0.7)	(1.5)	—	(1.5)	—
Fresh start coal inventory revaluation	—	(67.3)	—	(67.3)	—
Fresh start take-or-pay contract-based intangible recognition	26.7	22.5	—	22.5	—
Net periodic benefit costs, excluding service cost	18.1	21.9	14.4	36.3	57.1
Total Reporting Segment Costs	$ 4,116.7	$ 3,056.3	$ 964.6	$ 4,020.9	$ 4,127.1

The following table presents Reporting Segment Costs by reporting segment:

	Successor		Predecessor	Combined	Predecessor
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2017	Year Ended December 31, 2016
	(Dollars in millions)				
Powder River Basin Mining	$ 1,140.3	$ 899.9	$ 302.6	$ 1,202.5	$ 1,093.4
Midwestern U.S. Mining	655.8	467.9	143.2	611.1	575.2
Western U.S. Mining	446.6	308.9	99.7	408.6	424.4
Seaborne Metallurgical Mining	1,111.6	806.1	219.3	1,025.4	1,106.7
Seaborne Thermal Mining	647.2	465.9	149.2	615.1	607.3
Corporate and Other	115.2	107.6	50.6	158.2	320.1
Total Reporting Segment Costs	$ 4,116.7	$ 3,056.3	$ 964.6	$ 4,020.9	$ 4,127.1

The following tables present revenues, Reporting Segment Costs, Adjusted EBITDA and tons sold by reporting segment:

	Successor				
	Year Ended December 31, 2018				
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining
	(Amounts in millions, except per ton data)				
Revenues	$ 1,424.8	$ 801.0	$ 592.0	$ 1,553.0	$ 1,099.2
Reporting Segment Costs	1,140.3	655.8	446.6	1,111.6	647.2
Adjusted EBITDA	284.5	145.2	145.4	441.4	452.0
Tons sold	120.3	18.9	14.7	11.0	19.1
Revenues per Ton	$ 11.84	$ 42.44	$ 40.20	$ 141.06	$ 57.58
Costs per Ton	9.47	34.75	30.33	100.97	33.90
Adjusted EBITDA Margin per Ton	2.37	7.69	9.87	40.09	23.68

	Successor				
	April 2 through December 31, 2017				
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining
	(Amounts in millions, except per ton data)				
Revenues	$ 1,178.7	$ 592.3	$ 440.7	$ 1,221.0	$ 772.5
Reporting Segment Costs	899.9	467.9	308.9	806.1	465.9
Adjusted EBITDA	278.8	124.4	131.8	414.9	306.6
Tons sold	94.0	14.0	11.3	9.5	14.6
Revenues per Ton	$ 12.54	$ 42.45	$ 38.75	$ 128.14	$ 52.84
Costs per Ton	9.57	33.53	27.16	84.60	31.87
Adjusted EBITDA Margin per Ton	2.97	8.92	11.59	43.54	20.97

	Predecessor				
	January 1 through April 1, 2017				
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining
	(Amounts in millions, except per ton data)				
Revenues	$ 394.3	$ 193.2	$ 149.7	$ 328.9	$ 224.8
Reporting Segment Costs	302.6	143.2	99.7	219.3	149.2
Adjusted EBITDA	91.7	50.0	50.0	109.6	75.6
Tons sold	31.0	4.5	3.4	2.2	4.6
Revenues per Ton	$ 12.70	$ 42.96	$ 44.68	$ 150.22	$ 48.65
Costs per Ton	9.75	31.84	29.76	100.16	32.27
Adjusted EBITDA Margin per Ton	2.95	11.12	14.92	50.06	16.38

	Combined				
	Year Ended December 31, 2017				
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining
	(Amounts in millions, except per ton data)				
Revenues	$ 1,573.0	$ 785.5	$ 590.4	$ 1,549.9	$ 997.3
Reporting Segment Costs	1,202.5	611.1	408.6	1,025.4	615.1
Adjusted EBITDA	370.5	174.4	181.8	524.5	382.2
Tons sold	125.0	18.5	14.7	11.7	19.2
Revenues per Ton	$ 12.58	$ 42.58	$ 40.10	$ 132.29	$ 51.83
Costs per Ton	9.62	33.13	27.75	87.52	31.97
Adjusted EBITDA Margin per Ton	2.96	9.45	12.35	44.77	19.86

	Predecessor				
	Year Ended December 31, 2016				
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining
	(Amounts in millions, except per ton data)				
Revenues	$ 1,473.3	$ 792.5	$ 526.0	$ 1,090.4	$ 824.9
Reporting Segment Costs	1,093.4	575.2	424.4	1,106.7	607.3
Adjusted EBITDA	379.9	217.3	101.6	(16.3)	217.6
Tons sold	113.1	18.3	13.7	13.4	21.3
Revenues per Ton	$ 13.02	$ 43.39	$ 38.30	$ 81.41	$ 38.79
Costs per Ton	9.66	31.49	30.90	82.63	28.56
Adjusted EBITDA Margin per Ton	3.36	11.90	7.40	(1.22)	10.23

Free Cash Flow is defined as net cash provided by operating activities less net cash used in investing activities and excludes cash outflows related to business combinations. See the table below for a reconciliation of Free Cash Flow to its most comparable measure under U.S. GAAP.

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Net cash provided by (used in) operating activities	$ 1,489.7	$ 813.4	$ (813.0)	$ 3.7
Net cash (used in) provided by investing activities	(517.3)	(93.4)	15.1	(244.1)
Add back: Acquisition of Shoal Creek Mine	387.4	—	—	—
Free Cash Flow	$ 1,359.8	$ 720.0	$ (797.9)	$ (240.4)

Outlook

As part of its normal planning and forecasting process, Peabody utilizes a broad approach to develop macroeconomic assumptions for key variables, including country-level gross domestic product (GDP), industrial production, fixed asset investment and third-party inputs, driving detailed supply and demand projections for key demand centers for coal, electricity generation and steel. Specific to the U.S., the Company evaluates individual plant needs, including expected retirements, on a plant by plant basis in developing its demand models. Supply models and cost curves concentrate on major supply regions/countries that impact the regions in which the Company operates.

Our estimates involve risks and uncertainties and are subject to change based on various factors as described more fully in the “Cautionary Notice Regarding Forward-Looking Statements” section contained within this Item 2.

Our near-term outlook is intended to coincide with the next 12 to 24 months, with subsequent periods addressed in our long-term outlook.

Near-Term Outlook

Seaborne Thermal Coal. Continued tightness in seaborne thermal supply-demand dynamics in 2018 contributed to strength in the 6,000-specification Newcastle thermal price. The fourth quarter average prompt Newcastle thermal price eased 10% from the third quarter 2018 to $105 per tonne. The spread between the 6,000 Newcastle specification product and the lower-quality 5,500 product tightened during the quarter to an average of approximately $42 per tonne in the fourth quarter compared to an average of approximately $48 per tonne in the third quarter.

The importance of the Asia/Pacific region continued in 2018. Even with import restrictions enacted by the Chinese government in November, Chinese thermal coal imports rose some 23 million tonnes in 2018, driven by a seven-year high in domestic power consumption amid lagging domestic supply. India thermal coal imports increased 18% to 167 million tonnes as rising domestic coal production fell short of continued strong domestic demand. In addition, ASEAN nations expanded imports by 17 million tonnes in 2018 to support ongoing urbanization and the addition of approximately 56 gigawatts of new coal-fueled generation that came online during the year, with another some 60 gigawatts expected to come online in 2019.

On the supply-side, lower-quality Indonesia exports rose 31 million tonnes in 2018 over the prior year primarily in response to increased demand from China and India. Both Australian and U.S. thermal coal exports remained strong, up 4% and 34%, respectively, year-over-year.

Seaborne Metallurgical Coal. Regarding metallurgical coal, low-vol hard coking coal spot pricing remained high in the fourth quarter, averaging $221 per tonne. The fourth-quarter index settlement price for premium low-vol hard coking coal was $212 per tonne compared to $192 per tonne in the prior year. Pricing for the low-vol PCI product also continued its strength, with a fourth quarter benchmark settlement of $139 per tonne compared to $127 per tonne in the prior year. Looking ahead to the first quarter 2019, the low-vol PCI benchmark price was set at $141 per tonne.

Seaborne metallurgical coal supply/demand balance remains favorable, with blast furnace steel production growth expected to counter new sources of supply coming online to offset depletion and serve growing imports. India continues to demand high-quality metallurgical coal to meet its steel making needs, with metallurgical coal imports rising 3 million tonnes in 2018, or 5%, over the prior year. Increased steel production from ASEAN nations also continues to support seaborne metallurgical coal demand. Chinese metallurgical coal imports eased 2 million tonnes due to an increased reliance on domestic supplies and scrap steel usage.

Even with continued strength in pricing, supply growth remains muted with metallurgical exports from Australia and the U.S. rising 7 million tonnes and 4 million tonnes, respectively in 2018.

U.S. Thermal Coal. Within the U.S., even with substantial plant retirements in 2018, higher seasonal demand, increased fourth quarter natural gas prices and ongoing strength in exports resulted in continued stockpile reductions and increased Eastern coal prices.

Total U.S. electricity generation rose 4% in 2018, while coal demand fell 4%. However, a 16 million ton decline in U.S. coal production and a 22 million ton increase in U.S. exports led to utility coal stockpiles falling 37 million tons since 2017 to the lowest levels since 2005. As a result of continued strength in seaborne thermal coal pricing, the Illinois Basin is now the largest thermal exporting region in the U.S.

Long-Term Outlook

Seaborne Fundamentals. Peabody anticipates that seaborne metallurgical coal demand will continue to grow as India increases steel production and China continues to have a significant influence on seaborne balances. On the supply side, we expect Australia to maintain its leading metallurgical coal export position, followed by other key seaborne suppliers U.S., Canada and Russia, among others.

For seaborne thermal, Peabody expects demand to remain relatively stable as demand growth from ASEAN nations helps offset demand decline elsewhere, including, notably, in the Atlantic markets. Over 80% of seaborne thermal coal demand is projected to come from Asia-Pacific region as Europe’s coal generation continues its secular decline. Seaborne thermal coal will continue to be sourced primarily from seaborne exporters Indonesia and Australia, along with Russia, Colombia, South Africa and the U.S., among others.

U.S. Fundamentals. Coal is expected to remain an important piece of the U.S. electric generation mix, albeit declining from current levels. Peabody expects coal-fueled plant retirements to continue to negatively impact future coal demand. The combination of fluctuations in natural gas prices, growth in renewable generation and other competing fuels, and policy and regulations, among other things, are expected to continue to be a key determinant of future U.S. coal demand.

Liquidity and Capital Resources

Overview

Our primary source of cash is proceeds from the sale of our coal production to customers. We have also generated cash from the sale of non-strategic assets, including coal reserves and surface lands, borrowings under our credit facilities and, from time to time, the issuance of securities. Our primary uses of cash include the cash costs of coal production, capital expenditures, coal reserve lease and royalty payments, debt service costs, capital and operating lease payments, postretirement plans, take-or-pay obligations, post-mining retirement obligations, and selling and administrative expenses. We have also used cash for dividends and share repurchases. We believe that our capital structure allows us to satisfy our working capital requirements and fund capital expenditures and debt-service obligations with cash generated from operations and cash on hand.

Any future determinations to return capital to stockholders, such as dividends or share repurchases will be at the discretion of our Board of Directors and will depend on a variety of factors, including the restrictions set forth under our debt agreements, our net income or other sources of cash, liquidity position and potential alternative uses of cash, such as internal development projects or acquisitions, as well as economic conditions and expected future financial results. Our ability to declare dividends or repurchase shares in the future will depend on our future financial performance, which in turn depends on the successful implementation of our strategy and on financial, competitive, regulatory, technical and other factors, general economic conditions, demand for and selling prices of coal and other factors specific to our industry, many of which are beyond our control.

Total Indebtedness. Our total indebtedness as of December 31, 2018 and 2017 consisted of the following:

	December 31,	
	2018	2017
	(Dollars in millions)	
6.000% Senior Secured Notes due March 2022	$ 500.0	$ 500.0
6.375% Senior Secured Notes due March 2025	500.0	500.0
Senior Secured Term Loan due 2025, net of original issue discount	395.9	444.2
Capital lease and other obligations	40.0	76.0
Less: Debt issuance costs	(68.9)	(59.4)
	1,367.0	1,460.8
Less: Current portion of long-term debt	36.5	42.1
Long-term debt	$ 1,330.5	$ 1,418.7

Refer to Note 14. “Long-term Debt” to the accompanying consolidated financial statements for further information regarding our indebtedness.

Liquidity

As of December 31, 2018, our available liquidity was $1,319.1 million, which was comprised of cash and cash equivalents and availability under our revolving credit facility and receivables securitization program described below. As of December 31, 2018, our cash balances totaled $981.9 million, including approximately $441.5 million held by U.S. entities, $519.2 held by Australian subsidiaries, and the remaining balance held by other foreign subsidiaries. A significant majority of the cash held by our foreign subsidiaries is in accounts domiciled in the U.S. and denominated in U.S. dollars. This cash is generally used to support non-U.S. liquidity needs, including capital and operating expenditures in Australia. During 2018, we repatriated to the U.S. approximately $1.1 billion previously held by foreign subsidiaries. If we repatriate additional foreign-held cash in the future, we do not expect restrictions or potential taxes to have a material effect on our overall liquidity.

During 2018, collateral balances of $323.1 million related primarily to reclamation assurance for our Australian mines, and various port, rail and other contract performance requirements in Australia were returned to the Company as a result of implementing third-party surety bonding in Australia.

Our ability to maintain adequate liquidity depends on the successful operation of our business and appropriate management of operating expenses and capital spending. Our anticipated liquidity needs are highly sensitive to changes in these and other factors.

The Senior Notes and Credit Agreement

As described in Note 2. “Emergence from the Chapter 11 Cases and Fresh Start Reporting” and Note 14. “Long-term Debt” of the accompanying consolidated financial statements, on the Effective Date, the proceeds from the 6.000% Senior Secured Notes due March 2022 and the 6.375% Senior Secured Notes due March 2025 (collectively, the Senior Notes) and the Senior Secured Term Loan under the Credit Agreement (the Credit Agreement) were used to repay the Predecessor company first lien obligations. The proceeds from the Senior Notes and the Senior Secured Term Loan, net of debt issuance costs and an original issue discount, as applicable, were $950.5 million and $912.7 million, respectively.

Since entering into the Credit Agreement, we have repaid $553.0 million of the original $950.0 million loan principal on the Senior Secured Term Loan in various installments. The Credit Agreement has been amended at various dates since its inception primarily to (i) lower the interest rate on the Senior Secured Term Loan from LIBOR plus 4.50% per annum with a 1.00% LIBOR floor to LIBOR plus 2.75% with no floor, (ii) extend the maturity of the Senior Secured Term Loan by three years to 2025, (iii) allow for an incremental revolving credit facility and one or more incremental term loans in an aggregate principal amount of up to $350.0 million plus additional amounts so long as the Company maintains compliance with the Total Leverage Ratio, as defined in the Credit Agreement, (iv) make available an additional restricted payment basket that permits additional repurchases, dividends or other distributions with respect to our capital stock in an aggregate amount up to $450.0 million so long as our Fixed Charge Coverage Ratio, as defined in the Credit Agreement, is at least 2.00:1.00 on a pro forma basis, and (v) eliminate the previous capital expenditure restriction covenants on both the Senior Secured Term Loan and the Revolver (as defined below).

Interest payments on the Senior Notes are scheduled to occur each year on March 31 and September 30 until maturity. We may redeem the 6.000% Senior Secured Notes beginning in 2019 and the 6.375% Senior Secured Notes beginning in 2020, in whole or in part, and subject to periodically decreasing redemption premiums, through maturity. We may also redeem some or all of the Senior Notes by means of a tender offer or open market repurchases.

The Senior Secured Term Loan principal is payable in quarterly installments plus accrued interest through December 2024 with the remaining balance due in March 2025. The loan principal was voluntarily prepayable at 101% of the principal amount repaid if voluntarily prepaid prior to October 2018 (subject to certain exceptions, including prepayments made with internally generated cash) and is voluntarily prepayable at any time thereafter without premium or penalty. The Senior Secured Term Loan may require mandatory principal prepayments of up to 75% of Excess Cash Flow (as defined in the Credit Agreement) for any fiscal year if our Total Leverage Ratio (as defined in the Credit Agreement and calculated at December 31, net of any unrestricted cash) is greater than 2.00:1.00. The mandatory principal prepayment requirement is (i) 50% of Excess Cash Flow if our Total Leverage Ratio is less than or equal to 2.00:1.00 and greater than 1.50:1.00, (ii) 25% of Excess Cash Flow if our Total Leverage Ratio is less than or equal to 1.50:1.00 and greater than 1.00:1.00, or (iii) zero if the our Total Leverage Ratio is less than or equal to 1.00:1.00. If required, mandatory prepayments resulting from Excess Cash Flows are payable within 100 days after the end of each fiscal year. The calculation of mandatory prepayments would be reduced commensurately by the amount of previous voluntary prepayments. In certain circumstances, the Senior Secured Term Loan also requires that Excess Proceeds (as defined in the Credit Agreement) of $10 million or greater from sales of our assets be applied against the loan principal, unless such proceeds are reinvested within one year.

During the fourth quarter of 2017, we entered into the incremental revolving credit facility permitted under the Credit Agreement (the Revolver) for an aggregate commitment of $350.0 million for general corporate purposes. The Revolver matures in November 2020 and permits loans which bear interest at LIBOR plus 3.25%. The Revolver is subject to a 2.00:1.00 First Lien Leverage Ratio requirement, modified to limit unrestricted cash netting to $800.0 million. Capacity under the Revolver may also be utilized for letters of credit which incur combined fees of 3.375% per annum. Unused capacity under the Revolver bears a commitment fee of 0.5% per annum. As of December 31, 2018, the Revolver was utilized for letters of credit amounting to $106.4 million. Such letters of credit were primarily in support of our reclamation obligations.

In addition to the $450.0 million restricted payment basket provided for under the amendments described above, the Credit Agreement provides a builder basket for additional restricted payments subject to a maximum Total Leverage Ratio of 2.00:1.00 (as defined in the Credit Agreement).

The Indenture provides a builder basket for restricted payments that is calculated based upon our Consolidated Net Income, and is subject to a Fixed Charge Coverage Ratio of at least 2.25:1.00 (as defined in the Indenture).

Under both the indenture related to the Senior Notes (the Indenture) and Credit Agreement, additional restricted payments are permitted through a $50.0 million general basket and an annual aggregate $25.0 million basket which allows dividends and common stock repurchases. The payment of dividends and purchases of common stock under this latter basket are permitted so long as our Total Leverage Ratio would not exceed 1.25:1.00 on a pro forma basis (as defined in the Credit Agreement and Indenture).

On August 9, 2018, we executed a supplement to the Indenture following the solicitation of consents from the requisite majorities of holders of each series of Senior Notes. The amendment provided for in the supplemented Indenture permits an additional category of restricted payments at any time not to exceed the sum of $650.0 million, plus an additional $150.0 million per calendar year, commencing with calendar year 2019, with unused amounts in any calendar year carrying forward to and available for restricted payments in any subsequent calendar year. We paid consenting Senior Note holders $10.00 in cash per $1,000 principal amount of 2022 Notes and $30.00 in cash per $1,000 principal amount of 2025 Notes, which amounted to $19.8 million.

Accounts Receivable Securitization Program

As described in Note 25. “Financial Instruments, Guarantees With Off-Balance-Sheet Risk and Other Guarantees” to the accompanying consolidated financial statements, on the Effective Date, we entered into an amended Receivables Purchase Agreement to extend the receivables securitization facility previously in place and expand that facility to include certain receivables from the Company’s Australian operations. The term of the receivables securitization program (Securitization Program) ends on April 3, 2020, subject to certain liquidity requirements and other customary events of default. The Securitization Program provides for up to $250 million in funding, limited to the availability of eligible receivables, accounted for as a secured borrowing and may be secured by a combination of cash collateral and the trade receivables underlying the program. Funding capacity under the Securitization Program may also be drawn upon for letters of credit in support of other obligations.

At December 31, 2018, we had no outstanding borrowings and $137.1 million of letters of credit drawn under the Securitization Program. The letters of credit were primarily in support of portions of our obligations for reclamation, workers’ compensation and postretirement benefits. There was no cash collateral requirement under the Securitization Program at December 31, 2018.

Capital Requirements

Additions to Property, Plant, Equipment and Mine Development. We have sought to maintain a controlled, disciplined approach to capital spending. For 2019, we are targeting capital expenditures of $375 million to $425 million, which includes approximately $200 million related to ongoing extension projects at our North Goonyella and Wilpinjong Mines and a joint venture project to expand our Wambo Mine, and approximately $175 million to $225 million in sustaining capital across our platforms. We plan to consider other significant growth and development projects across our global platform beyond 2019 and will continue to evaluate the timing associated with those projects based on changes in global coal supply and demand. We have no substantial future payment requirements under U.S. federal coal reserve leases, which was formerly a significant use of capital.

Pension and Postretirement Benefit Contributions. Annual contributions to qualified pension plans are made in accordance with minimum funding standards and our agreement with the Pension Benefit Guaranty Corporation. Funding decisions also consider certain funded status thresholds defined by the Pension Protection Act of 2006 (generally 80%). Subsequent to the Effective Date, we no longer sponsor any non-qualified plans. During 2018, we made discretionary contributions of $62.0 million to our qualified pension plans and $15.0 million to our postretirement benefit plans. Based upon our current funding status, we have no minimum funding requirement for 2019. From time to time, Peabody may make discretionary contributions to its qualified pension and postretirement benefit plans.

Historical Cash Flows and Free Cash Flow

The following table summarizes our cash flows for the year ended December 31, 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017, as reported in the accompanying consolidated financial statements:

	Successor		Predecessor
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)		
Net cash provided by (used in) operating activities	$ 1,489.7	$ 813.4	$ (813.0)
Net cash (used in) provided by investing activities	(517.3)	(93.4)	15.1
Net cash (used in) provided by financing activities	(1,025.2)	(745.4)	952.3
Net change in cash, cash equivalents and restricted cash	(52.8)	(25.4)	154.4
Cash, cash equivalents and restricted cash at beginning of period	1,070.2	1,095.6	941.2
Cash, cash equivalents and restricted cash at end of period	$ 1,017.4	$ 1,070.2	$ 1,095.6
Net cash provided by (used in) operating activities	$ 1,489.7	$ 813.4	$ (813.0)
Net cash (used in) provided by investing activities	(517.3)	(93.4)	15.1
Add back: Acquisition of Shoal Creek Mine	387.4	—	—
Free Cash Flow	$ 1,359.8	$ 720.0	$ (797.9)

Cash Flow - Successor

Cash provided by operating activities for the year ended December 31, 2018 resulted from cash generated from our mining operations and $323.1 million of collateral returned as we replaced collateral with other forms of financial assurance. These factors were partially offset by $62.0 million of discretionary contributions to our qualified pension plans.

Cash provided by operating activities in the period April 2 through December 31, 2017 primarily resulted from cash from our mining operations. In addition, $274.2 million of restricted cash collateral became unrestricted, largely as a result of our improved liquidity subsequent to emergence from the Chapter 11 Cases and our ability to replace the cash collateral required to support reclamation and other obligations with letters of credit issued under our Revolver and Securitization Program. These factors were partially offset by the greater use of working capital related to coal stockpile increases and the payment of claims and professional fees related to the Chapter 11 Cases.

Cash used in investing activities for the year ended December 31, 2018 resulted primarily from our acquisition of the Shoal Creek Mine for $387.4 million and $300.9 million of additions to property, plant, equipment and mine development, which was partially offset by $106.7 million of cash receipts from Middlemount and proceeds from disposals of assets of $76.4 million.

Cash used in investing activities in the period April 2 through December 31, 2017 resulted from $166.6 million of additions to property, plant, equipment and mine development, partially offset by $48.1 million of cash receipts from Middlemount.

Cash used in financing activities for the year ended December 31, 2018 resulted primarily from $834.7 million of repurchases of Common Stock, $59.6 million of dividends paid, $85.0 million of repayments of long-term debt and $21.2 million of debt issuance costs, primarily related to a supplement to the Indenture.

Cash used in financing activities in the period April 2 through December 31, 2017 primarily resulted primarily from $541.8 million of repayments of long-term debt, including $504.0 million related to the Senior Secured Term Loan and $175.7 million of repurchases of Common Stock.

Cash Flow - Predecessor

Cash used in operating activities in the period January 1 through April 1, 2017 resulted from cash used in settlement of bankruptcy claims, partially offset by cash generated from our operations from improved supply and demand conditions.

Cash provided by investing activities in the period January 1 through April 1, 2017 resulted from $31.1 million of cash receipts from Middlemount and proceeds from disposals of assets of $24.3 driven by the sale of Dominion Terminal Associates, which was offset by $34.2 million of payments for additions to property, plant, equipment and mine development.

Cash provided by financing activities in the period January 1 through April 1, 2017 resulted from $1.0 billion of debt proceeds related to our recapitalization upon emergence from the Chapter 11 cases, partially offset by $45.4 million of related deferred financing costs.

Contractual Obligations

The following is a summary of our contractual obligations as of December 31, 2018:

	Payments Due By Year				
	Total	Less than 1 Year	2 - 3 Years	4 - 5 Years	More than 5 Years
	(Dollars in millions)				
Long-term debt obligations (principal and interest) [1]	$ 1,852.4	$ 87.0	$ 173.4	$ 650.1	$ 941.9
Capital lease obligations (principal and interest)	46.3	28.2	8.4	0.9	8.8
Operating lease obligations [2]	127.1	47.6	43.5	23.9	12.1
Unconditional purchase obligations [3]	110.3	94.2	16.1	—	—
Coal reserve lease and royalty obligations	63.6	5.4	11.1	10.9	36.2
Take-or-pay obligations [4]	1,252.7	148.2	258.8	208.2	637.5
Other long-term liabilities [5]	2,877.9	233.6	442.1	309.7	1,892.5
Total contractual cash obligations	$ 6,330.3	$ 644.2	$ 953.4	$ 1,203.7	$ 3,529.0

(1) Represents the original contractual maturities of our long-term debt obligations. The related interest on long-term debt was calculated using rates in effect at December 31, 2018 for the remaining contractual term of the outstanding borrowings.

(2) Excludes contingent rents. Refer to Note 15. "Leases" to the accompanying consolidated financial statements for additional discussion of contingent rental agreements.

(3) We routinely enter into purchase agreements with approved vendors for most types of operating expenses in the ordinary course of business. Our specific open purchase orders (which have not been recognized as a liability) under these purchase agreements, combined with any other open purchase orders, are not material and though they are considered enforceable and legally binding, the related terms generally allow us the option to cancel, reschedule or adjust our requirements based on our business needs prior to the delivery of goods or performance of services. Accordingly, the commitments in the table above relate to orders to suppliers for capital purchases.

(4) Represents various short- and long-term take or pay arrangements in Australia and the U.S. associated with rail and port commitments for the delivery of coal, including amounts relating to export facilities.

(5) Represents estimated cash outflows for long-term liabilities relating to our postretirement benefit plans, work-related injuries and illnesses, defined benefit pension plans, mine reclamation and end-of-mine closure costs and exploration obligations. Also includes $6 million of required payments to the VEBA established in connection with Patriot's bankruptcy, as well as $45 million related to the settlement of the UMWA 1974 Pension Plan Litigation described in Note 6. "Discontinued Operations" to the accompanying consolidated financial statements.

We do not expect any of the $14.0 million of net unrecognized tax benefits reported in our consolidated financial statements to require cash settlement within the next year. Beyond that, we are unable to make reasonably reliable estimates of periodic cash settlements with respect to such unrecognized tax benefits.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to various guarantees and financial instruments that carry off-balance-sheet risk and are not reflected in the accompanying consolidated balance sheets. At December 31, 2018, such instruments included $1,589.8 million of surety bonds and $245.0 million of letters of credit. Such financial instruments provide support for our reclamation bonding requirements, lease obligations, insurance policies and various other performance guarantees. We periodically evaluate the instruments for on-balance-sheet treatment based on the amount of exposure under the instrument and the likelihood of required performance. We do not expect any material losses to result from these guarantees or off-balance-sheet instruments in excess of liabilities provided for in our consolidated balance sheets.

We could experience a decline in our liquidity as financial assurances associated with reclamation bonding requirements, surety bonds or other obligations are required to be collateralized by cash or letters of credit.

As described in Note 25. "Financial Instruments, Guarantees With Off-Balance-Sheet Risk and Other Guarantees" to the accompanying consolidated financial statements, we are required to provide various forms of financial assurance in support of our mining reclamation obligations in the jurisdictions in which we operate. Such requirements are typically established by statute or under mining permits. Historically, such assurances have taken the form of third-party instruments such as surety bonds, bank guarantees and letters of credit, as well as self-bonding arrangements in the U.S. Following our emergence from the Chapter 11 Cases, we shifted away from extensive self-bonding in the U.S. in favor of increased usage of surety bonds and similar third-party instruments. However, we may utilize self-bonding in the future, dependent upon state-by-state approval and internal cost-benefit considerations. This divergence in practice may impact our liquidity in the future due to increased collateral requirements and surety and related fees.

At December 31, 2018, we had total asset retirement obligations of $750.2 million which were backed by a combination of surety bonds, bank guarantees and letters of credit.

Bonding requirement amounts may differ significantly from the related asset retirement obligation because such requirements are calculated under the assumption that reclamation begins currently, whereas our accounting liabilities are discounted from the end of a mine's economic life (when final reclamation work would begin) to the balance sheet date.

Guarantees and Other Financial Instruments with Off-Balance Sheet Risk. See Note 25. "Financial Instruments, Guarantees With Off-Balance-Sheet Risk and Other Guarantees" to our accompanying consolidated financial statements for a discussion of our accounts receivable securitization program and guarantees and other financial instruments with off-balance sheet risk.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based upon our financial statements, which have been prepared in accordance with U.S. GAAP. We are also required under U.S. GAAP to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. On an ongoing basis, we evaluate our estimates. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

Business Combinations. We account for business combinations using the purchase method of accounting. The purchase method requires us to determine the fair value of all acquired assets, including identifiable intangible assets, and all assumed liabilities. The total cost of acquisitions is allocated to the underlying identifiable net assets, based on their respective estimated fair values. Determining the fair value of assets acquired and liabilities assumed requires management's judgment, and the utilization of independent valuation experts, and often involves the use of significant estimates and assumptions, including assumptions with respect to future cash inflows and outflows, discount rates, and asset lives, among other items. Due to the unobservable inputs to the valuation, the fair value would be considered Level 3 in the fair value hierarchy.

Subsequent to the finalization of the purchase price allocation, any adjustments to the recorded values of acquired assets and liabilities would be reflected in the consolidated statements of operations. Once final, it is not permitted to revise the allocation of the original purchase price, even if subsequent events or circumstances prove the original judgments and estimates to be incorrect. The assumptions and judgments made when recording business combinations will have an impact on reported results of operations for many years into the future. See Note 3. "Acquisition of Shoal Creek Mine" to our accompanying consolidated financial statements for additional information regarding business combinations.

Impairment of Long-Lived Assets. We evaluate our long-lived assets held and used in operations for impairment as events and changes in circumstances indicate that the carrying amount of such assets might not be recoverable. Factors that would indicate potential impairment to be present include, but are not limited to, a sustained history of operating or cash flow losses, an unfavorable change in earnings and cash flow outlook, prolonged adverse industry or economic trends and a significant adverse change in the extent or manner in which a long-lived asset is being used or in its physical condition. We generally do not view short-term declines in thermal and metallurgical coal prices as a triggering event for conducting impairment tests because of historic price volatility. However, we generally view a sustained trend of depressed coal pricing (for example, over periods exceeding one year) as an indicator of potential impairment.

Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. For our active mining operations, we generally group such assets at the mine level, or the mining complex level for mines that share infrastructure, with the exception of impairment evaluations triggered by mine closures. In those cases involving mine closures, the related assets are evaluated at the individual asset level for remaining economic life based on transferability to ongoing operating sites and for use in reclamation-related activities, or for expected salvage. For our development and exploration properties and portfolio of surface land and coal reserve holdings, we consider several factors to determine whether to evaluate those assets individually or on a grouped basis for purposes of impairment testing. Such factors include geographic proximity to one another, the expectation of shared infrastructure upon development based on future mining plans and whether it would be most advantageous to bundle such assets in the event of a sale to a third party.

When indicators of impairment are present, we evaluate our long-lived assets for recoverability by comparing the estimated undiscounted cash flows expected to be generated by those assets under various assumptions to their carrying amounts. If such undiscounted cash flows indicate that the carrying value of the asset group is not recoverable, impairment losses are measured by comparing the estimated fair value of the asset group to its carrying amount. As quoted market prices are unavailable for our individual mining operations, fair value is determined through the use of an expected present value technique based on the income approach, except for non-strategic coal reserves, surface lands and undeveloped coal properties excluded from our long-range mine planning. In those cases, a market approach is utilized based on the most comparable market multiples available. The estimated future cash flows and underlying assumptions used to assess recoverability and, if necessary, measure the fair value of our long-lived mining assets are derived from those developed in connection with our planning and budgeting process. We believe our assumptions to be consistent with those a market participant would use for valuation purposes. The most critical assumptions underlying our projections and fair value estimates include those surrounding future tons sold, coal prices for unpriced coal, production costs (including costs for labor, commodity supplies and contractors), transportation costs, foreign currency exchange rates and a risk-adjusted, after-tax cost of capital (all of which generally constitute unobservable Level 3 inputs under the fair value hierarchy), in addition to market multiples for non-strategic coal reserves, surface lands and undeveloped coal properties excluded from our long-range mine planning (which generally constitute Level 2 inputs under the fair value hierarchy).

No impairment of long-lived assets was recorded for the year ended December 31, 2018. The assumptions used are based on our best knowledge at the time we prepare our analysis but can vary significantly due to the volatile and cyclical nature of coal prices and demand, regulatory issues, unforeseen mining conditions, commodity prices and cost of labor. These types of changes may cause us to be unable to recover all or a portion of the carrying value of our long-lived assets. We conducted a review of long-lived assets for recoverability as of December 31, 2018 and determined that no further impairment charge was necessary as of that date.

See Note 5. “Asset Impairment” to our accompanying consolidated financial statements for additional information regarding impairment charges.

Income Taxes. We account for income taxes in accordance with accounting guidance which requires deferred tax assets and liabilities to be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. The guidance also requires that deferred tax assets be reduced by a valuation allowance if it is “more likely than not” that some portion or all of the deferred tax asset will not be realized. In our evaluation of the need for a valuation allowance, we take into account various factors, including the expected level of future taxable income, available tax planning strategies, reversals of existing taxable temporary differences and taxable income in carryback years. As of December 31, 2018, we had valuation allowances for income taxes totaling $2,094.3 million. If actual results differ from the assumptions made in our annual evaluation of our valuation allowance, we may record a change in valuation allowance through income tax expense in the period such determination is made.

Our liability for unrecognized tax benefits contains uncertainties because management is required to make assumptions and to apply judgment to estimate the exposures associated with our various filing positions. We recognize the tax benefit from an uncertain tax position only if it is “more likely than not” that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position must be measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. As of December 31, 2018, we had net unrecognized tax benefits of $14.0 million included in recorded liabilities in the consolidated balance sheet. We believe that our judgments and estimates are reasonable; however, to the extent we prevail in matters for which liabilities have been established, or are required to pay amounts in excess of our recorded liabilities, our effective tax rate in a given period could be materially affected.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Act) was signed into law making significant changes to the Internal Revenue Code. Key provisions of the Act that impact the Company include: (i) repeal of the corporate alternative minimum tax system, (ii) reduction of the U.S. federal corporate tax rate from 35% to 21%, (iii) further limitation on the deductibility of certain executive compensation and (iv) the inclusion of foreign income from the new global intangible low-taxed income provision of the Act.

See Note 12. “Income Taxes” to the accompanying consolidated financial statements for additional information regarding valuation allowances, unrecognized tax benefits and the Act.

Postretirement Benefit and Pension Liabilities. We have long-term liabilities for our employees’ postretirement benefit costs and defined benefit pension plans. Our pension obligations are funded in accordance with the provisions of applicable laws and our policies. Liabilities for postretirement benefit costs are funded at our discretion. In connection with fresh start reporting, we made an accounting policy election to prospectively record amounts attributable to actuarial valuation changes currently in earnings rather than recording such amounts within accumulated other comprehensive income and amortizing to expense over applicable time periods. Expense for the year ended December 31, 2018 for postretirement benefit costs and pension liabilities totaled $27.4 million, while employer contributions were $121.3 million. An actuarial gain of $124.2 million was recorded for the year ended December 31, 2018.

Each of these liabilities is actuarially determined and we use various actuarial assumptions, including the discount rate, future cost trends, demographic assumptions and expected asset returns 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. We make assumptions related to future trends for medical care costs in the estimates of postretirement benefit costs. Our medical trend assumption is developed by annually examining the historical trend of cost per claim data. In addition, we make assumptions related to rates of return on plan assets. 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 could affect our obligation to satisfy these or additional obligations.

For our postretirement benefit obligation, assumed discount rates and health care cost trend rates have a significant effect on the expense and liability amounts reported for our health care plans. Below we have provided two separate sensitivity analyses to demonstrate the significance of these assumptions in relation to reported amounts.

	For Year Ended December 31, 2018	
	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Dollars in millions)	
Health care cost trend rate:		
Effect on total net periodic postretirement benefit cost	$ 2.9	$ (2.6)
Effect on total postretirement benefit obligation	$ 50.2	$ (45.7)

	For Year Ended December 31, 2018	
	One-Half Percentage-Point Increase	One-Half Percentage-Point Decrease
	(Dollars in millions)	
Discount rate:		
Effect on total net periodic postretirement benefit cost	$ 1.8	$ (1.9)
Effect on total postretirement benefit obligation	$ (27.2)	$ 30.8

For our pension obligation, assumed discount rates and expected returns on assets have a significant effect on the expense and funded status amounts reported for our defined benefit pension plans. Below we have provided two separate sensitivity analyses to demonstrate the significance of these assumptions in relation to reported amounts.

	For Year Ended December 31, 2018	
	One-Half Percentage-Point Increase	One-Half Percentage-Point Decrease
	(Dollars in millions)	
Discount rate:		
Effect on total net periodic pension cost	$ 2.2	$ (2.5)
Effect on defined benefit pension plans' projected benefit obligation	$ (37.0)	$ 40.4
Expected return on assets:		
Effect on total net periodic pension cost	$ (3.8)	$ 3.8

As a result of discretionary contributions made in recent years, our defined benefit pension plans have become nearly fully funded. As a result of the funding level, the asset allocation mix reflected Peabody's target asset mix of 100% fixed income investments and the pensions plans' assets provide a significant hedge to the funded status against interest rate movements. If the discount rate moves, Peabody's actual results would be different than those shown above as substantially all of the change in the discount rate should be offset by changes to the expected return on plan assets.

See Note 17. "Postretirement Health Care and Life Insurance Benefits" and Note 18. "Pension and Savings Plans" to the accompanying consolidated financial statements for additional information regarding postretirement benefit and pension plans.

Asset Retirement Obligations. 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 applicable reclamation laws and regulations in the U.S. and Australia as defined by each mining permit. Asset retirement 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, discounted using a credit-adjusted, risk-free rate. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free rate. 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 and mine closing activities. In connection with fresh start reporting, we made an accounting policy election to classify the amortization associated with our asset retirement obligation assets within "Depreciation, depletion and amortization" in the consolidated statements of operations, rather than within "Asset retirement obligation expenses", as in Predecessor periods. Amortization associated with our asset retirement obligation assets was $84.4 million for the year ended December 31, 2018. Asset retirement obligation expenses for the year ended December 31, 2018 was $53.0 million and payments totaled $44.4 million. See Note 16. "Asset Retirement Obligations" to the accompanying consolidated financial statements for additional information regarding our asset retirement obligations.

Contingent liabilities. From time to time, we are subject to legal and environmental matters related to our continuing and discontinued operations and certain historical, non-coal producing operations. In connection with such matters, we are required to assess the likelihood of any adverse judgments or outcomes, as well as potential ranges of probable losses.

A determination of the amount of reserves required for these matters is made after considerable analysis of each individual issue. We accrue for legal and environmental matters within "Operating costs and expenses" when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. We provide disclosure surrounding loss contingencies when we believe that it is at least reasonably possible that a material loss may be incurred or an exposure to loss in excess of amounts already accrued may exist. Adjustments to contingent liabilities are made when additional information becomes available that affects the amount of estimated loss, which information may include changes in facts and circumstances, changes in interpretations of law in the relevant courts, the results of new or updated environmental remediation cost studies and the ongoing consideration of trends in environmental remediation costs.

Accrued contingent liabilities exclude claims against third parties and are not discounted. The current portion of these accruals is included in "Accounts payables and accrued expenses" and the long-term portion is included in "Other noncurrent liabilities" in our consolidated balance sheets. In general, legal fees related to environmental remediation and litigation are charged to expense. We include the interest component of any litigation-related penalties within "Interest expense" in our consolidated statements of operations. See Note 26. "Commitments and Contingencies" to the accompanying consolidated financial statements for further discussion of our contingent liabilities.

Newly Adopted Accounting Standards and Accounting Standards Not Yet Implemented

See Note 1. "Summary of Significant Accounting Policies" to the accompanying consolidated financial statements for a discussion of newly adopted accounting standards and accounting standards not yet implemented.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

The potential for changes in the market value of our coal and freight-related trading, crude oil, diesel fuel, natural gas and foreign currency contract portfolios, as applicable, is referred to as "market risk." Market risk related to our coal trading and freight-related contract portfolio, which includes bilaterally-settled and over-the-counter (OTC) exchange-settled trading, in addition to, from time to time, the brokered trading of coal, is evaluated using a value at risk (VaR) analysis. VaR analysis is not used to evaluate our non-trading diesel fuel or foreign currency hedging portfolios, as applicable, or coal trading activities we employ in support of coal production (as discussed below). We attempt to manage market price risks through diversification, controlling position sizes and executing hedging strategies. Due to a lack of quoted market prices and the long-term, illiquid nature of the positions, we have not quantified market price risk related to our non-trading, long-term coal supply agreement portfolio.

Coal Trading Activities and Related Commodity Price Risk

Coal Price Risk Monitored Using VaR. We engage in direct and brokered trading of physical coal and freight-related commodities in OTC markets. These activities give rise to commodity price risk, which represents the potential loss that can be caused by an adverse change in the market value of a particular commitment. We actively measure, monitor, manage and hedge market price risk due to current and anticipated trading activities to remain within risk limits prescribed by management. For example, we have policies in place that limit the amount of market price risk, as measured by VaR, that we may assume at any point in time from our trading and brokerage activities.

We generally account for our coal trading activities using the fair value method, which requires us to reflect contracts with third parties that meet the definition of a derivative at market value in our consolidated financial statements, with the exception of contracts for which we have elected to apply the normal purchases and normal sales exception. Our trading portfolio included futures, forwards, and options as of December 31, 2018. The use of VaR allows us to quantify in dollars, on a daily basis, a measure of price risk inherent in our trading portfolio. VaR represents the expected loss in portfolio value due to adverse market price movements over a defined time horizon (liquidation period) within a specified confidence level. Our VaR model is based on a variance/co-variance approach, which captures our potential loss exposure related to future, forward, swap and option positions. Our VaR model assumes a 15-day holding period at the time of VaR measurement and produces an output corresponding with a 95% one-tailed confidence interval, which means that there is a one in 20 statistical chance that our portfolio could lose more than the VaR estimates during the assumed liquidation period. Our volatility calculation incorporates an exponentially weighted moving average algorithm based on price movements during the previous 60 market days, which makes our volatility more representative of recent market conditions while still reflecting an awareness of historical price movements. VaR does not estimate the maximum potential loss expected in the 5% of the time that changes in the portfolio value during the assumed liquidation period is expected to exceed measured VaR. We use stress testing and scenario analysis to help provide visibility in such cases, as discussed further below.

VaR analysis allows us to aggregate market price risk across products in the portfolio, compare market price risk on a consistent basis and identify the drivers of risk and changes thereto over time. We use historical data to estimate price volatility as an input to VaR. Given our reliance on historical data, we believe VaR is reasonably effective in characterizing market price risk exposures in markets in which there are not sudden fundamental changes or shifts in market conditions. Nonetheless, an inherent limitation of VaR is that past changes in market price risk factors may not produce accurate predictions of future market price risk. Due to that limitation, combined with the subjectivity in the choice of the liquidation period and reliance on historical data to calibrate our models, we perform stress and scenario analyses as needed to estimate the impacts of market price changes on the value of the portfolio. Additionally, back-testing is regularly performed to monitor the effectiveness of our VaR measure. The results of these analyses are used to supplement the VaR methodology and identify additional market price-related risks.

During the year ended December 31, 2018, the actual low, high and average VaR was $2.8 million, $13.1 million and $7.2 million, respectively.

Other Risk Exposures. We also use our coal trading and brokerage platform to support various coal production-related activities. These transactions may involve coal to be produced from our mines, coal sourcing arrangements with third-party mining companies, joint venture positions with producers or offtake agreements with producers. While the support activities (such as the forward sale of coal to be produced and/or purchased) may ultimately involve instruments sensitive to market price risk, the sourcing of coal in these arrangements does not involve market risk sensitive instruments and does not encompass the commodity price risks that we monitor through VaR analysis, as discussed above.

Future Realization. As of December 31, 2018, the total estimated future realization of the value of our trading portfolio is expected to occur in 2019.

We also monitor other types of risk associated with our coal trading activities, including credit, market liquidity and counterparty nonperformance.

Credit and Nonperformance Risk

The fair values of our derivative instruments utilized for corporate hedging and coal trading activities reflect adjustments for credit risk, as necessary. Our exposure is substantially with electric utilities, energy marketers, steel producers and nonfinancial trading houses. Our policy is to independently evaluate each counterparty's creditworthiness prior to entering into transactions and to regularly monitor exposures. We manage our counterparty risk from our hedging activities related to foreign currency and fuel exposures, as applicable, through established credit standards, diversification of counterparties, utilization of investment grade commercial banks, adherence to established tenor limits based on counterparty creditworthiness and continual monitoring of that creditworthiness. If we engage in a transaction with a counterparty that does not meet our credit standards, we seek to protect our position by requiring the counterparty to provide an appropriate credit enhancement. Also, when appropriate (as determined by our credit management function), we have taken steps to reduce our exposure to customers or counterparties whose credit has deteriorated and who may pose a higher risk of failure to perform under their contractual obligations. These steps include obtaining letters of credit or cash collateral (margin), requiring prepayments for shipments or the creation of customer trust accounts held for our benefit to serve as collateral in the event of a failure to pay or perform. To reduce our credit exposure related to trading and brokerage activities, we seek to enter into netting agreements with counterparties that permit us to offset asset and liability positions with such counterparties and, to the extent required, we will post or receive margin amounts associated with exchange-cleared and certain OTC positions. We also continually monitor counterparty and contract nonperformance risk, if present, on a case-by-case basis.

Foreign Currency Risk

We have historically utilized currency forwards and options to hedge currency risk associated with anticipated Australian dollar expenditures. The accounting for these derivatives is discussed in Note 9. "Derivatives and Fair Value Measurements" to the accompanying consolidated financial statements. As of December 31, 2018, we had currency options outstanding with an aggregate notional amount of $875.0 million Australian dollars to hedge currency risk associated with anticipated Australian dollar expenditures during the first nine months of 2019. Assuming we had no foreign currency hedging instruments in place, our exposure in operating costs and expenses due to a $0.05 change in the Australian dollar/U.S. dollar exchange rate is approximately $70 to $80 million for the next twelve months. Based upon the Australian dollar/U.S. dollar exchange rate at December 31, 2018, the currency option contracts outstanding at that date would not limit our net exposure to a $0.05 unfavorable change in the exchange rate for the next twelve months.

Other Non-Coal Trading Activities — Commodity Price Risk

Long-Term Coal Contracts. We predominantly manage our commodity price risk for our non-trading, long-term coal contract portfolio through the use of long-term coal supply agreements (those with terms longer than one year) to the extent possible, rather than through the use of derivative instruments. Sales under such agreements comprised approximately 87%, 83% and 86% of our worldwide sales (by volume) for the years ended December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018, approximately 90% - 95% of our projected 2019 U.S. thermal coal production is priced at planned production levels of approximately 140 million tons. We are estimating 2019 thermal coal sales volumes from our Seaborne Thermal Mining segment of approximately 20 million tons. We are targeting full year 2019 metallurgical coal sales from our Seaborne Metallurgical Mining segment of approximately 10 million tons. Sales commitments in the metallurgical coal market are typically not long-term in nature, and we are therefore subject to fluctuations in market pricing.

Diesel Fuel Hedges. Previously, we managed price risk of the diesel fuel used in our mining activities through the use of derivatives, primarily swaps. As of December 31, 2018, we did not have any diesel fuel derivative instruments in place. We also manage the price risk of diesel fuel through the use of cost pass-through contacts with certain customers.

We expect to consume 110 to 120 million gallons of diesel fuel during the next twelve months. A $10 per barrel change in the price of crude oil (the primary component of a refined diesel fuel product) would increase or decrease our annual diesel fuel costs by approximately $27 million based on our expected usage.

Interest Rate Risk

Our objectives in managing exposure to interest rate changes are to limit the impact of interest rate changes on earnings and cash flows and to lower overall borrowing costs. From time to time, we manage our debt to achieve a certain ratio of fixed-rate debt and variable-rate debt as a percent of net debt through the use of various hedging instruments. As of December 31, 2018, we had approximately $1.0 billion of fixed-rate borrowings and $0.4 billion of variable-rate borrowings outstanding and had no interest rate swaps in place. A one percentage point increase in interest rates would result in an annualized increase to interest expense of approximately $4.0 million on our variable-rate borrowings. With respect to our fixed-rate borrowings, a one percentage point increase in interest rates would result in a decrease of approximately $38.2 million in the estimated fair value of these borrowings.

Item 8. *Financial Statements and Supplementary Data.*

See Part IV, Item 15. “Exhibits and Financial Statement Schedules” of this report for the information required by this Item 8, which information is incorporated by reference herein.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.*

None.

Item 9A. *Controls and Procedures.*

Evaluation of Disclosure Controls and Procedures

Our disclosure controls and procedures are designed to, among other things, provide reasonable assurance that material information, both financial and non-financial, and other information required under the securities laws to be disclosed is accumulated and communicated to senior management, including the principal executive officer and principal accounting officer, on a timely basis. As of December 31, 2018, the end of the period covered by this Annual Report on Form 10-K, we carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act as of December 31, 2018 were effective to provide reasonable assurance that the desired control objectives were achieved.

Changes in Internal Control Over Financial Reporting

We periodically review our internal control over financial reporting as part of our efforts to ensure compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002. In addition, we routinely review our system of internal control over financial reporting to identify potential changes to our processes and systems that may improve controls and increase efficiency, while ensuring that we maintain an effective internal control environment. Changes may include such activities as implementing new systems, consolidating the activities of acquired business units, migrating certain processes to our shared services organizations, formalizing and refining policies, procedures and control documentation requirements, improving segregation of duties and adding monitoring controls. In addition, when we acquire new businesses, we incorporate our controls and procedures into the acquired business as part of our integration activities.

On December 3, 2018, we acquired the Shoal Creek Mine. As a result of the acquisition, we are in the process of reviewing the internal control structure of the Shoal Creek Mine and, if necessary, will make appropriate changes as we incorporate our controls and procedures into the acquired business.

Except for the acquisition, there have been no changes in our internal control over financial reporting that occurred during the three months ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management’s Report on Internal Control Over Financial Reporting

Management is responsible for maintaining and establishing adequate internal control over financial reporting. An evaluation of the effectiveness of the design and operation of our internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act, as of the end of the period covered by this report was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer. This evaluation is performed to determine if our internal controls over financial reporting provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management conducted an assessment of the effectiveness of our internal control over financial reporting using the criteria set by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control - Integrated Framework (2013).* Based on this assessment, management concluded that the Company's internal control over financial reporting was effective to provide reasonable assurance that the desired control objectives were achieved as of December 31, 2018.

Management's assessment of the effectiveness of our internal control over financial reporting did not include the internal controls of Shoal Creek, which was acquired on December 3, 2018. In accordance with SEC guidance regarding the reporting of internal control over financial reporting in connection with an acquisition, management may omit an assessment of an acquired business' internal control over financial reporting from management's assessment of internal control over financial reporting for a period not to exceed one year from the date of acquisition. Management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2019 will include the internal controls of Shoal Creek. Shoal Creek is included in our consolidated financial statements and constituted $404.8 million of total assets as of December 31, 2018.

Our Independent Registered Public Accounting Firm, Ernst & Young LLP, has audited our internal control over financial reporting, as stated in their unqualified opinion report included herein.

/s/ Glenn L. Kellow	/s/ Amy B. Schwetz
Glenn L. Kellow *President and Chief Executive Officer*	Amy B. Schwetz *Executive Vice President and Chief Financial Officer*

February 27, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Peabody Energy Corporation

Opinion on Internal Control over Financial Reporting

We have audited Peabody Energy Corporation's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Peabody Energy Corporation (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

As indicated in the accompanying Management's Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Shoal Creek, which is included in the 2018 consolidated financial statements of the Company and constituted approximately $404.8 million of total assets as of December 31, 2018. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of Shoal Creek.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of Peabody Energy Corporation as of December 31, 2018 and 2017 (Successor), the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity and cash flows for the year ended December 31, 2018 (Successor), the period from April 2, 2017 through December 31, 2017 (Successor), the period from January 1, 2017 through April 1, 2017 (Predecessor), and the year ended December 31, 2016 (Predecessor) and the related notes and financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "consolidated financial statements") of the Company, and our report dated February 27, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Ernst & Young LLP

St. Louis, Missouri

February 27, 2019

Item 9B. *Other Information.*

On February 21, 2019, the Company's Board of Directors adopted the Peabody Energy Corporation 2019 Executive Severance Plan, effective as of January 1, 2019 (the Severance Plan). The Severance Plan revises and replaces the Peabody Energy Corporation 2015 Amended and Restated Executive Severance Plan (the Prior Plan). In general, the Severance Plan provides for severance payments and benefits to certain U.S. officers and executives of the Company upon certain qualifying terminations of employment by the Company without Cause, or by the officer or executive for Good Reason (as such key terms are defined in the Severance Plan), including with respect to the Company's current named executive officers. As of the date of this report, there were nine eligible participants in the Severance Plan.

In general, the Severance Plan amends the Prior Plan with respect to the Company's named executive officers by:

- revising the severance benefits to include payment of a pro-rata, current-year annual incentive based upon actual performance for the year in which termination occurs;
- reducing the advance written notice period for plan amendments from 12 months to six months; and
- revising the definitions of "Change in Control," "Disability," "Cause" and "Confidential Information" to generally conform to or coordinate with the definitions in the Peabody Energy Corporation 2017 Incentive Plan.

The foregoing summary is qualified in its entirety by reference to the Severance Plan, a copy of which is filed as Exhibit 10.32 hereto and incorporated by reference herein.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance.*

The information required by Item 401 of Regulation S-K is included under the caption Proposal I - "Election of Directors" in our 2019 Proxy Statement and in Part I, Item 1. "Business" of this report under the caption "Executive Officers of the Company." The information required by Items 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K is included under the captions "Stock Ownership — Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance - Code of Business Conduct and Ethics" and "Additional Information Concerning the Board of Directors - Committee Overview - Audit Committee" in our 2019 Proxy Statement. Such information is incorporated herein by reference.

Item 11. *Executive Compensation.*

The information required by Items 402 and 407(e)(4) and (e)(5) of Regulation S-K is included under the captions "Additional Information Concerning the Board of Directors - Director Compensation," "Compensation Discussion and Analysis," "Compensation Committee Interlocks and Insider Participation" and "Compensation Committee Report" in our 2019 Proxy Statement and is incorporated herein by reference.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

The information required by Item 403 of Regulation S-K is included under the caption "Stock Ownership - Security Ownership of Directors and Management and Certain Beneficial Owners" in our 2019 Proxy Statement and is incorporated herein by reference.

Equity Compensation Plan Information

As required by Item 201(d) of Regulation S-K, the following table provides information regarding our equity compensation plans as of December 31, 2018:

Plan Category	(a) Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by security holders	262,222 [1]	$ — [2]	9,901,276
Equity compensation plans not approved by security holders	—	—	—
Total	262,222	$ —	9,901,276

(1) Shares issuable pursuant to outstanding performance units and vested but not issued deferred stock units. Performance units are shown at target and could change based on actual metrics achieved.

(2) The weighted-average exercise price shown in the table does not take into account outstanding deferred stock units or performance awards.

Refer to Note 20. "Share-Based Compensation" to the accompanying consolidated financial statements for additional information regarding the material features of our current equity compensation plans.

Item 13. *Certain Relationships and Related Transactions, and Director Independence.*

The information required by Items 404 and 407(a) of Regulation S-K is included under the captions "Review of Related Person Transactions" and "Additional Information Concerning the Board of Directors - Board Independence" in our 2019 Proxy Statement and is incorporated herein by reference.

Item 14. *Principal Accountant Fees and Services.*

The information required by Item 9(e) of Schedule 14A is included under the caption "Audit Fees" in our 2019 Proxy Statement and is incorporated herein by reference.

PART IV

Item 15. *Exhibits and Financial Statement Schedules.*

(a) Documents Filed as Part of the Report

(1) Financial Statements.

The following consolidated financial statements of Peabody Energy Corporation and the report thereon of the independent registered public accounting firm are included herein on the pages indicated:

(2) Financial Statement Schedules.

The following financial statement schedule of Peabody Energy Corporation is at the page indicated:

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions or are not applicable and, therefore, have been omitted.

(3) Exhibits.

See Exhibit Index hereto.

Pursuant to the Instructions to Exhibits, certain instruments defining the rights of holders of long-term debt securities of the Company and its consolidated subsidiaries are not filed because the total amount of securities authorized under any such instrument does not exceed 10% of the total assets of the Company and its subsidiaries on a consolidated basis. A copy of such instrument will be furnished to the Securities and Exchange Commission upon request.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PEABODY ENERGY CORPORATION

/s/ GLENN L. KELLOW

Glenn L. Kellow
President and Chief Executive Officer

Date: February 27, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons, on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ GLENN L. KELLOW Glenn L. Kellow	President and Chief Executive Officer, Director (principal executive officer)	February 27, 2019
/s/ AMY B. SCHWETZ Amy B. Schwetz	Executive Vice President and Chief Financial Officer (principal financial and accounting officer)	February 27, 2019
/s/ ANDREA BERTONE Andrea Bertone	Director	February 27, 2019
/s/ NICHOLAS CHIREKOS Nicholas Chirekos	Director	February 27, 2019
/s/ STEPHEN GORMAN Stephen Gorman	Director	February 27, 2019
/s/ JOE LAYMON Joe Laymon	Director	February 27, 2019
/s/ TERESA MADDEN Teresa Madden	Director	February 27, 2019
/s/ ROBERT MALONE Robert Malone	Chairman	February 27, 2019
/s/ KENNETH MOORE Kenneth Moore	Director	February 27, 2019
/s/ MICHAEL SUTHERLIN Michael Sutherlin	Director	February 27, 2019
/s/ SHAUN USMAR Shaun Usmar	Director	February 27, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Peabody Energy Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Peabody Energy Corporation (the Company) as of December 31, 2018 and 2017 (Successor), the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity and cash flows for the year ended December 31, 2018 (Successor), the period from April 2, 2017 through December 31, 2017 (Successor), the period from January 1, 2017 through April 1, 2017 (Predecessor), and the year ended December 31, 2016 (Predecessor), and the related notes and financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2018 and 2017 (Successor), and the results of its operations and its cash flows for the year ended December 31, 2018 (Successor), the period from April 2, 2017 through December 31, 2017 (Successor), the period from January 1, 2017 through April 1, 2017 (Predecessor), and the year ended December 31, 2016 (Predecessor), in conformity with US generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 27, 2019 expressed an unqualified opinion thereon.

Company Reorganization

As discussed in Notes 1 and 2 to the consolidated financial statements, on March 17, 2017, the Bankruptcy Court entered an order confirming the plan of reorganization, which became effective on April 3, 2017. Accordingly, the accompanying consolidated financial statements have been prepared in conformity with Accounting Standards Codification 852-10, Reorganizations, for the Successor Company as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with prior periods (Predecessor) as described in Notes 1 and 2.

Basis for Opinion

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

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

/s/ Ernst & Young LLP

We have served as the Company's auditor since 1991.

St. Louis, Missouri

February 27, 2019

PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions, except per share data)			
Revenues	$ 5,581.8	$ 4,252.6	$ 1,326.2	$ 4,715.3
Costs and expenses				
Operating costs and expenses (exclusive of items shown separately below)	4,072.6	3,052.7	950.2	4,070.0
Depreciation, depletion and amortization	679.0	521.6	119.9	465.4
Asset retirement obligation expenses	53.0	41.2	14.6	41.8
Selling and administrative expenses	158.1	106.3	36.3	149.4
Acquisition costs related to Shoal Creek Mine	7.4	—	—	—
Other operating (income) loss:				
Net gain on disposals	(48.2)	(84.0)	(22.8)	(23.2)
Asset impairment	—	—	30.5	247.9
Provision for North Goonyella equipment loss	66.4	—	—	—
Income from equity affiliates	(68.1)	(49.0)	(15.0)	(16.2)
Operating profit (loss)	661.6	663.8	212.5	(219.8)
Interest expense	149.3	119.7	32.9	298.6
Loss on early debt extinguishment	2.0	20.9	—	29.5
Interest income	(33.6)	(5.6)	(2.7)	(5.7)
Net periodic benefit costs, excluding service cost	18.1	21.9	14.4	57.1
Net mark-to-market adjustment on actuarially determined liabilities	(125.5)	(45.2)	—	—
Reorganization items, net	(12.8)	—	627.2	159.0
Income (loss) from continuing operations before income taxes	664.1	552.1	(459.3)	(758.3)
Income tax provision (benefit)	18.4	(161.0)	(263.8)	(94.5)
Income (loss) from continuing operations, net of income taxes	645.7	713.1	(195.5)	(663.8)
Income (loss) from discontinued operations, net of income taxes	18.1	(19.8)	(16.2)	(57.6)
Net income (loss)	663.8	693.3	(211.7)	(721.4)
Less: Series A Convertible Preferred Stock dividends	102.5	179.5	—	—
Less: Net income attributable to noncontrolling interests	16.9	15.2	4.8	7.9
Net income (loss) attributable to common stockholders	$ 544.4	$ 498.6	$ (216.5)	$ (729.3)
Income (loss) from continuing operations:				
Basic income (loss) per share	$ 4.35	$ 3.85	$ (10.93)	$ (36.72)
Diluted income (loss) per share	$ 4.28	$ 3.81	$ (10.93)	$ (36.72)
Net income (loss) attributable to common stockholders:				
Basic income (loss) per share	$ 4.50	$ 3.70	$ (11.81)	$ (39.87)
Diluted income (loss) per share	$ 4.43	$ 3.67	$ (11.81)	$ (39.87)
Dividends declared per share	$ 0.485	$ —	$ —	$ —

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Net income (loss)	$ 663.8	$ 693.3	$ (211.7)	$ (721.4)
Other comprehensive income, net of income taxes:				
Reclassification for realized losses on cash flow hedges (net of respective net tax provision of $0.0, $0.0, $9.1, and $85.9) included in net income	—	—	18.6	146.3
Postretirement plans and workers' compensation obligations (net of respective net tax provision (benefit) of $7.1, $0.0, $2.5, and ($1.5))				
Prior service credit (cost) for the period	44.6	—	—	(4.5)
Net actuarial loss for the period	—	—	—	(13.5)
Amortization of actuarial loss and prior service cost included in net income (loss)	—	—	4.4	15.4
Postretirement plans and workers' compensation obligations	44.6	—	4.4	(2.6)
Foreign currency translation adjustment	(5.9)	1.4	5.5	(1.8)
Other comprehensive income, net of income taxes	38.7	1.4	28.5	141.9
Comprehensive income (loss)	702.5	694.7	(183.2)	(579.5)
Less: Series A Convertible Preferred Stock dividends	102.5	179.5	—	—
Less: Net income attributable to noncontrolling interests	16.9	15.2	4.8	7.9
Comprehensive income (loss) attributable to common stockholders	$ 583.1	$ 500.0	$ (188.0)	$ (587.4)

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2018	2017
	(Amounts in millions, except per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 981.9	$ 1,012.1
Restricted cash	—	40.1
Accounts receivable, net of allowance for doubtful accounts of $4.4 at December 31, 2018 and $4.6 at December 31, 2017	450.4	552.1
Inventories	280.2	291.3
Other current assets	243.1	294.4
Total current assets	1,955.6	2,190.0
Property, plant, equipment and mine development, net	5,207.0	5,111.9
Collateral arrangements	—	323.1
Investments and other assets	212.6	470.6
Deferred income taxes	48.5	85.6
Total assets	$ 7,423.7	$ 8,181.2
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of long-term debt	$ 36.5	$ 42.1
Accounts payable and accrued expenses	1,022.0	1,202.8
Total current liabilities	1,058.5	1,244.9
Long-term debt, less current portion	1,330.5	1,418.7
Deferred income taxes	9.7	5.4
Asset retirement obligations	686.4	657.0
Accrued postretirement benefit costs	547.7	730.0
Other noncurrent liabilities	339.3	469.4
Total liabilities	3,972.1	4,525.4
Stockholders' equity		
Series A Convertible Preferred Stock — $0.01 per share par value; no shares authorized, issued or outstanding as of December 31, 2018 and 50.0 shares authorized, 30.0 issued and 13.5 shares outstanding as of December 31, 2017	—	576.0
Preferred Stock — $0.01 per share par value; 100.0 shares authorized, no shares issued or outstanding as of December 31, 2018 and 50.0 shares authorized, no shares issued or outstanding as of December 31, 2017	—	—
Series Common Stock — $0.01 per share par value; 50.0 shares authorized, no shares issued or outstanding as of December 31, 2018 or December 31, 2017	—	—
Common Stock — $0.01 per share par value; 450.0 shares authorized, 137.7 shares issued and 110.4 shares outstanding as of December 31, 2018 and 111.8 shares issued and 105.2 shares outstanding as of December 31, 2017	1.4	1.0
Additional paid-in capital	3,304.7	2,590.3
Treasury stock, at cost — 27.3 and 5.8 common shares as of December 31, 2018 and December 31, 2017	(1,025.1)	(175.9)
Retained earnings	1,074.5	613.6
Accumulated other comprehensive income	40.1	1.4
Peabody Energy Corporation stockholders' equity	3,395.6	3,606.4
Noncontrolling interests	56.0	49.4
Total stockholders' equity	3,451.6	3,655.8
Total liabilities and stockholders' equity	$ 7,423.7	$ 8,181.2

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Cash Flows From Operating Activities				
Net income (loss)	$ 663.8	$ 693.3	$ (211.7)	$ (721.4)
(Income) loss from discontinued operations, net of income taxes	(18.1)	19.8	16.2	57.6
Income (loss) from continuing operations, net of income taxes	645.7	713.1	(195.5)	(663.8)
Adjustments to reconcile income (loss) from continuing operations, net of income taxes to net cash provided by (used in) operating activities:				
Depreciation, depletion and amortization	679.0	521.6	119.9	465.4
Fresh start noncash coal inventory revaluation	—	67.3	—	—
Noncash interest expense including loss on early extinguishment of debt	19.2	34.0	0.5	61.3
Deferred income taxes	35.5	(99.6)	(262.3)	(97.0)
Noncash share-based compensation	34.9	21.8	1.9	12.8
Asset impairment	—	—	30.5	247.9
Net gain on disposals	(48.2)	(84.0)	(22.8)	(23.2)
Income from equity affiliates	(68.1)	(49.0)	(15.0)	(16.2)
Provision for North Goonyella equipment loss	66.4	—	—	—
Gain on voluntary employee beneficiary association settlement	—	—	—	(68.1)
Foreign currency option contracts	9.1	(0.8)	—	—
Reclassification from other comprehensive earnings for terminated hedge contracts	—	—	27.6	125.2
Settlement of hedge positions	—	—	—	(25.0)
Noncash reorganization items, net	(12.8)	—	(485.4)	90.9
Changes in current assets and liabilities:				
Accounts receivable	171.8	(240.1)	159.3	(101.3)
Change in receivable from accounts receivable securitization program	—	—	—	(168.5)
Inventories	50.2	(36.8)	(47.2)	104.0
Other current assets	(30.6)	(53.1)	0.2	(1.6)
Accounts payable and accrued expenses	(160.2)	(158.5)	(65.5)	142.2
Collateral arrangements	323.1	288.3	(66.4)	(71.4)
Asset retirement obligations	5.7	12.1	10.2	13.1
Workers' compensation obligations	(1.8)	(1.1)	(3.1)	(0.4)
Postretirement benefit obligations	(151.1)	(19.8)	0.8	6.3
Pension obligations	(66.9)	(55.4)	5.4	21.7
Take-or-pay obligation settlement	—	—	(5.5)	(15.5)
Other, net	16.0	(27.8)	7.6	(5.2)
Net cash provided by (used in) continuing operations	1,516.9	832.2	(804.8)	33.6
Net cash used in discontinued operations	(27.2)	(18.8)	(8.2)	(29.9)
Net cash provided by (used in) operating activities	1,489.7	813.4	(813.0)	3.7

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS - (Continued)

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Cash Flows From Investing Activities				
Additions to property, plant, equipment and mine development	(301.0)	(166.6)	(32.8)	(126.6)
Changes in accrued expenses related to capital expenditures	0.1	16.2	(1.4)	(6.1)
Federal coal lease expenditures	(0.5)	—	(0.5)	(249.0)
Proceeds from disposal of assets, net of receivables	76.4	17.9	24.3	144.4
Investment in equity securities	(10.0)	—	—	—
Acquisition of Shoal Creek Mine	(387.4)	—	—	—
Contributions to joint ventures	(475.3)	(305.8)	(95.4)	(309.5)
Distributions from joint ventures	483.7	307.0	90.5	312.4
Advances to related parties	(13.8)	(3.0)	(0.4)	(40.4)
Cash receipts from Middlemount Coal Pty Ltd	106.7	48.1	32.7	48.5
Other, net	3.8	(7.2)	(1.9)	(17.8)
Net cash (used in) provided by investing activities	(517.3)	(93.4)	15.1	(244.1)
Cash Flows From Financing Activities				
Proceeds from long-term debt	—	—	1,000.0	1,458.4
Repayments of long-term debt	(85.0)	(541.8)	(2.1)	(513.7)
Payment of deferred financing costs	(21.2)	(10.8)	(45.4)	(31.0)
Common stock repurchases	(834.7)	(175.7)	—	—
Repurchase of employee common stock relinquished for tax withholding	(14.5)	(0.2)	(0.1)	(0.1)
Dividends paid	(59.6)	—	—	—
Distributions to noncontrolling interests	(10.3)	(16.7)	(0.1)	(1.9)
Other, net	0.1	(0.2)	—	(3.8)
Net cash (used in) provided by financing activities	(1,025.2)	(745.4)	952.3	907.9
Net change in cash, cash equivalents and restricted cash	(52.8)	(25.4)	154.4	667.5
Cash, cash equivalents and restricted cash at beginning of period [1]	1,070.2	1,095.6	941.2	273.7
Cash, cash equivalents and restricted cash at end of period [2]	$ 1,017.4	$ 1,070.2	$ 1,095.6	$ 941.2

[1] The following table provides a reconciliation of “Cash, cash equivalents and restricted cash at beginning of period”:

Cash and cash equivalents	$ 1,012.1
Restricted cash	40.1
Restricted cash included in “Investments and other assets”	18.0
Cash, cash equivalents and restricted cash at beginning of period	$ 1,070.2

[2] The following table provides a reconciliation of “Cash, cash equivalents and restricted cash at end of period”:

Cash and cash equivalents	$ 981.9
Restricted cash included in “Investments and other assets”	35.5
Cash, cash equivalents and restricted cash at end of period	$ 1,017.4

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Peabody Energy Corporation Stockholders' Equity							
	Series A Convertible Preferred Stock	Common Stock	Additional Paid-in Capital	Treasury Stock	(Accumulated Deficit) Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Stockholders' Equity
	(Dollars in millions)							
December 31, 2015 - Predecessor	$ —	$ 0.2	$ 2,410.7	$ (371.7)	$ (670.2)	$ (618.9)	$ 1.6	$ 751.7
Net (loss) income	—	—	—	—	(729.3)	—	7.9	(721.4)
Net unrealized gains on cash flow hedges (net of $85.9 tax provision)	—	—	—	—	—	146.3	—	146.3
Postretirement plans and workers' compensation obligations (net of $1.5 tax benefit)	—	—	—	—	—	(2.6)	—	(2.6)
Foreign currency translation adjustment	—	—	—	—	—	(1.8)	—	(1.8)
Share-based compensation for equity-classified awards	—	—	11.3	—	—	—	—	11.3
Repurchase of employee common stock relinquished for tax withholding	—	—	—	(0.1)	—	—	—	(0.1)
Distributions to noncontrolling interests	—	—	—	—	—	—	(1.9)	(1.9)
December 31, 2016 - Predecessor	$ —	$ 0.2	$ 2,422.0	$ (371.8)	$ (1,399.5)	$ (477.0)	$ 7.6	$ 181.5
Net (loss) income	—	—	—	—	(216.5)	—	4.8	(211.7)
Net realized losses on cash flow hedges (net of $9.1 net tax provision)	—	—	—	—	—	18.6	—	18.6
Postretirement plans and workers' compensation obligations (net of $2.5 tax provision)	—	—	—	—	—	4.4	—	4.4
Foreign currency translation adjustment	—	—	—	—	—	5.5	—	5.5
Share-based compensation for equity-classified awards	—	—	1.9	—	—	—	—	1.9
Repurchase of employee common stock relinquished for tax withholding	—	—	—	(0.1)	—	—	—	(0.1)
Distributions to noncontrolling interests	—	—	—	—	—	—	(0.1)	(0.1)
Elimination of Predecessor equity	—	(0.2)	(2,423.9)	371.9	1,616.0	448.5	(12.3)	—
April 1, 2017 - Predecessor	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Issuance of Successor equity	1,305.4	0.7	1,774.9	—	—	—	50.9	3,131.9
April 2, 2017 - Successor	$ 1,305.4	$ 0.7	$ 1,774.9	$ —	$ —	$ —	$ 50.9	$ 3,131.9
Net income	—	—	—	—	678.1	—	15.2	693.3
Foreign currency translation adjustment	—	—	—	—	—	1.4	—	1.4
Warrant conversions	—	0.1	(0.1)	—	—	—	—	—
Series A Convertible Preferred Stock conversions	(748.2)	0.2	796.7	—	(48.7)	—	—	—
Series A Convertible Preferred Stock dividends	18.8	—	(3.0)	—	(15.8)	—	—	—
Share-based compensation for equity-classified awards	—	—	21.8	—	—	—	—	21.8
Common stock repurchases	—	—	—	(175.7)	—	—	—	(175.7)
Repurchase of employee common stock relinquished for tax withholding	—	—	—	(0.2)	—	—	—	(0.2)
Distributions to noncontrolling interests	—	—	—	—	—	—	(16.7)	(16.7)
December 31, 2017 - Successor	$ 576.0	$ 1.0	$ 2,590.3	$ (175.9)	$ 613.6	$ 1.4	$ 49.4	$ 3,655.8
Impact of adoption of Accounting Standards Update 2014-09	—	—	—	—	(22.5)	—	—	(22.5)
Net income	—	—	—	—	646.9	—	16.9	663.8
Dividends declared	—	—	1.4	—	(61.0)	—	—	(59.6)
Postretirement plans and workers' compensation obligations (net of $7.1 tax provision)	—	—	—	—	—	44.6	—	44.6
Foreign currency translation adjustment	—	—	—	—	—	(5.9)	—	(5.9)
Series A Convertible Preferred Stock conversions	(576.0)	0.4	678.1	—	(102.5)	—	—	—
Share-based compensation for equity-classified awards	—	—	34.9	—	—	—	—	34.9
Common stock repurchases	—	—	—	(834.7)	—	—	—	(834.7)
Repurchase of employee common stock relinquished for tax withholding	—	—	—	(14.5)	—	—	—	(14.5)
Distributions to noncontrolling interests	—	—	—	—	—	—	(10.3)	(10.3)
December 31, 2018 - Successor	$ —	$ 1.4	$ 3,304.7	$ (1,025.1)	$ 1,074.5	$ 40.1	$ 56.0	$ 3,451.6

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of Peabody Energy Corporation (PEC) and its affiliates. The Company, or Peabody, are used interchangeably to refer to Peabody Energy Corporation, to Peabody Energy Corporation and its subsidiaries, or to such subsidiaries, as appropriate to the context. Interests in subsidiaries controlled by the Company are consolidated with any outside stockholder interests reflected as noncontrolling interests, except when the Company has an undivided interest in an unincorporated joint venture. In those cases, the Company includes its proportionate share in the assets, liabilities, revenues and expenses of the jointly controlled entities within each applicable line item of the consolidated financial statements. All intercompany transactions, profits and balances have been eliminated in consolidation. Certain amounts from prior years have been reclassified to conform with the 2018 presentation.

Description of Business

The Company is engaged in the mining of thermal coal for sale primarily to electric utilities and metallurgical coal for sale to industrial customers. The Company's mining operations are located in the United States (U.S.) and Australia, including an equity-affiliate mining operation in Australia. The Company also markets and brokers coal from other coal producers and trades coal and freight-related contracts through trading and business offices in the U.S., Australia, China, and the United Kingdom. The Company's other commercial activities include managing its coal reserve and real estate holdings, and supporting the development of clean coal technologies.

Plan of Reorganization and Emergence from Chapter 11 Cases

On April 13, 2016, (the Petition Date), PEC and a majority of its wholly owned domestic subsidiaries, as well as one international subsidiary in Gibraltar (collectively with PEC, the Debtors), filed voluntary petitions (the Bankruptcy Petitions) under Chapter 11 of Title 11 of the U.S. Code (the Bankruptcy Code) in the U.S. Bankruptcy Court for the Eastern District of Missouri (the Bankruptcy Court). The Debtors' Chapter 11 cases (the Chapter 11 Cases) were jointly administered under the caption *In re Peabody Energy Corporation, et al.*, Case No. 16-42529.

For periods subsequent to filing the Bankruptcy Petitions, the Company applied the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 852, "Reorganizations", in preparing its consolidated financial statements. ASC 852 requires that financial statements distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain revenues, expenses, realized gains and losses and provisions for losses that were realized or incurred in the bankruptcy proceedings were recorded in "Reorganization items, net" in the consolidated statements of operations.

On March 17, 2017, the Bankruptcy Court entered an order, Docket No. 2763 (the Confirmation Order), confirming the Debtors' Second Amended Joint Plan of Reorganization of Debtors and Debtors in Possession (as further modified, 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.

On the Effective Date, in accordance with ASC 852, the Company applied fresh start reporting which requires the Company to allocate its reorganization value to the fair value of assets and liabilities in conformity with the guidance for the acquisition method of accounting for business combinations. The Company was permitted to use fresh start reporting because (i) the holders of existing voting shares of the Predecessor (as defined below) company received less than 50% of the voting shares of the emerging entity upon reorganization and (ii) the reorganization value of the Company's assets immediately prior to Plan confirmation was less than the total of all postpetition liabilities and allowed claims.

Upon adoption of fresh start reporting, the Company became a new entity for financial reporting purposes, reflecting the Successor (as defined below) capital structure. As a result, a new accounting basis in the identifiable assets and liabilities assumed was established with no retained earnings or accumulated other comprehensive income (loss) for financial reporting purposes. The Company selected an accounting convenience date of April 1, 2017 for purposes of applying fresh start reporting as the activity between the convenience date and the Effective Date did not result in a material difference in the results. References to “Successor” in the financial statements and accompanying footnotes are in reference to reporting dates on or after April 2, 2017; references to “Predecessor” in the financial statements and accompanying footnotes are in reference to reporting dates through April 1, 2017 which includes the impact of the Plan provisions and the application of fresh start reporting. As such, the Company’s financial statements for the Successor will not be comparable in many respects to its financial statements for periods prior to the adoption of fresh start reporting and prior to the accounting for the effects of the Plan. For further information on the Plan and fresh start reporting, see Note 2. “Emergence from the Chapter 11 Cases and Fresh Start Reporting.”

In connection with fresh start reporting, the Company made certain prospective accounting policy elections that impact the Successor periods presented herein. The Company now classifies the amortization associated with its asset retirement obligation assets within “Depreciation, depletion and amortization” in its consolidated statements of operations, rather than within “Asset retirement obligation expenses”, as in Predecessor periods. With respect to its accrued postretirement benefit and pension obligations, the Company now records amounts attributable to actuarial valuation changes currently in earnings rather than recording such amounts within accumulated other comprehensive income and amortizing to expense over the applicable time periods.

Newly Adopted Accounting Standards

Revenue Recognition. In May 2014, the FASB issued Accounting Standards Update (ASU) 2014-09, “Revenue from Contracts with Customers” (Topic 606), that requires recognition of revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which a company expects to be entitled in exchange for those goods or services. The FASB has also issued several updates to ASU 2014-09. On January 1, 2018, the Company adopted ASU 2014-09 using the modified retrospective method. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers, which steps are to (1) identify the contract(s) with the customer, (2) identify the performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract and (5) recognize revenue when each performance obligation is satisfied. The Company recognized the cumulative effect of initially applying ASU 2014-09 as an adjustment to the opening balance of retained earnings. Revenue previously recognized under contracts completed prior to January 1, 2018 was not impacted by adoption and comparative information has not been restated. The impact of the adoption of ASU 2014-09 was immaterial to the Company’s results of operations, financial condition and cash flows.

The majority of the Company’s coal sales revenue will continue to be recognized as title and risk of loss transfer to the customer at mines and ports when coal is loaded to the transportation source, as further described below under the heading *Revenues*. The impact of the adoption of ASU 2014-09 was limited to a long-term contract in which consideration related to the reimbursement of certain post-mining costs was recognized as costs were incurred, which differs in timing compared to the five-step model described above. The cumulative effects to the Company’s consolidated January 1, 2018 balance sheet were to reduce retained earnings for the amount of revenue that would have been deferred and to reduce long-term customer receivables, as noted in the table below:

	Balance at December 31, 2017	Adjustments due to ASU 2014-09	Balance at January 1, 2018
		(Dollars in millions)	
ASSETS			
Investments and other assets	$ 470.6	$ (22.5)	$ 448.1
STOCKHOLDERS’ EQUITY			
Retained earnings	613.6	(22.5)	591.1

ASU 2014-09 also requires entities to disclose sufficient qualitative and quantitative information to enable financial statement users to understand the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. Such disclosures are included below under the heading *Revenues* and in Note 4. “Revenue Recognition.”

Classification of Certain Cash Receipts and Cash Payments. In August 2016, the FASB issued ASU 2016-15 to amend the classification of certain cash receipts and cash payments in the statement of cash flows to reduce diversity in practice. The Company retrospectively adopted all the provisions of this new standard in the first quarter of 2018. The classification requirements under the new guidance are either consistent with the Company's current practices or are not applicable to its activities, and as such, did not have a material impact on classification of cash receipts and cash payments in the Company's consolidated statements of cash flows.

Restricted Cash. In November 2016, the FASB issued ASU 2016-18, which reduces diversity in the presentation of restricted cash and restricted cash equivalents in the statement of cash flows. The Company retrospectively adopted all the provisions of this new accounting standard in the first quarter of 2018 and as a result of the new guidance, the Company combines restricted cash with unrestricted cash and cash equivalents when reconciling the beginning and end of period balances on its statements of cash flows. The amendments also require a company to disclose information about the nature of the restrictions and amounts described as restricted cash and restricted cash equivalents. Such disclosures are included in Note 25. "Financial Instruments, Guarantees With Off-Balance-Sheet Risk and Other Guarantees." Further, as cash, cash equivalents, restricted cash and restricted cash equivalents are presented in more than one line item on the balance sheet, the Company reconciled these amounts to the total shown in the statement of cash flows in a tabular format within the Company's consolidated statements of cash flows.

Compensation - Retirement Benefits. In March 2017, the FASB issued ASU 2017-07, which requires employers that sponsor defined benefit pension and other postretirement plans to report the service cost component in the same line item as other compensation costs and to report the other components of net periodic benefit costs (which include interest costs, expected return on plan assets, amortization of prior service cost or credits and actuarial gains and losses) separately and outside a subtotal of operating income on a retrospective basis. The guidance limiting the capitalization of net periodic benefit cost in assets to the service cost component will be applied prospectively. The Company adopted all the provisions of this new accounting standard in the first quarter of 2018. While adoption of this guidance did impact financial statement presentation, it did not materially impact the Company's results of operations, financial condition or cash flows. The retrospective impacts to the consolidated statements of operations were as follows:

	Successor		
	April 2 through December 31, 2017		
	Before Application of Accounting Guidance	Adjustment	After Application of Accounting Guidance
	(Dollars in millions)		
Results of Operations Amounts			
Operating costs and expenses	$ 3,075.5	$ (22.8)	$ 3,052.7
Selling and administrative expenses	105.4	0.9	106.3
Net mark-to-market adjustment on actuarially determined liabilities	(45.2)	45.2	—
Operating profit	687.1	(23.3)	663.8
Net periodic benefit costs, excluding service cost	—	21.9	21.9
Net mark-to-market adjustment on actuarially determined liabilities	—	(45.2)	(45.2)
Income from continuing operations before income taxes	552.1	—	552.1

	Predecessor		
	January 1 through April 1, 2017		
	Before Application of Accounting Guidance	Adjustment	After Application of Accounting Guidance
	(Dollars in millions)		
Results of Operations Amounts			
Operating costs and expenses	$ 963.7	$ (13.5)	$ 950.2
Selling and administrative expenses	37.2	(0.9)	36.3
Operating profit	198.1	14.4	212.5
Net periodic benefit costs, excluding service cost	—	14.4	14.4
Loss from continuing operations before income taxes	(459.3)	—	(459.3)

	Predecessor		
	Year Ended December 31, 2016		
	Before Application of Accounting Guidance	Adjustment	After Application of Accounting Guidance
	(Dollars in millions)		
Results of Operations Amounts			
Operating costs and expenses	$ 4,123.1	$ (53.1)	$ 4,070.0
Selling and administrative expenses	153.4	(4.0)	149.4
Operating loss	(276.9)	57.1	(219.8)
Net periodic benefit costs, excluding service cost	—	57.1	57.1
Loss from continuing operations before income taxes	(758.3)	—	(758.3)

Compensation - Stock Compensation. In May 2017, the FASB issued ASU 2017-09 to clarify when to account for a change to the terms or conditions of a share-based payment award as a modification. Under the new guidance, modification accounting is required only if the fair value, the vesting conditions or the classification of the award (as equity or liability) changes as a result of the change in terms or conditions. The Company prospectively applied all the provisions of this new accounting standard on January 1, 2018, and there was no material impact to the Company's results of operations, financial condition or cash flows.

Cloud Computing Arrangements. In August 2018, the FASB issued ASU 2018-15 to provide new guidance on a customer's accounting for implementation, set-up and other upfront costs incurred in a cloud computing arrangement that is hosted by the vendor. Under the new guidance, customers will apply the same criteria for capitalizing implementation costs as they would for an arrangement that has a software license. The new guidance also prescribes the balance sheet, income statement and cash flow classification of the capitalized implementation costs and related amortization expense, and requires additional quantitative and qualitative disclosures. The Company retrospectively adopted all the provisions of this new accounting standard pertaining to multiple ongoing cloud implementation projects. The adoption of this guidance did not materially impact the Company's results of operations, financial condition or cash flows.

Accounting Standards Not Yet Implemented

Leases. In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)," which requires a lessee to recognize on its balance sheet a liability to make lease payments and a right-of-use (ROU) asset representing its right to use the underlying asset for the lease term for leases with lease terms of more than 12 months. Consistent with current accounting principles generally accepted in the United States (U.S. GAAP), the recognition, measurement and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. Additional qualitative disclosures along with specific quantitative disclosures will also be required. The new guidance will take effect for public companies for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018 (January 1, 2019 for the Company). In July 2018, the FASB issued the new transition method and practical expedient to simplify the application of the new leasing standard. Under the new transition method, comparative periods presented in the financial statements in the period of adoption will not need to be restated. Instead, a Company would initially apply the new lease requirements at the effective date, and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The Company would continue to report comparative periods presented in the financial statements in the period of adoption under current U.S. GAAP and provide the applicable required disclosures for such periods. The new practical expedient allows lessors to avoid separating lease and associated nonlease components within a contract if certain criteria are met. If elected, lessors will be able to aggregate nonlease components that otherwise would be accounted for under the new revenue standard with the associated lease component if the following conditions are met: (1) the timing and pattern of transfer for the nonlease component and the associated lease component are the same and (2) the stand-alone lease component would be classified as an operating lease if accounted for separately. The Company intends to elect the package of practical expedients offered under ASC 842 that allows it to forgo reassessing the classification for leases that have already commenced. The Company will also elect to adopt the additional expedients to transition without restating comparatives, to not capitalize a lease where the term is shorter than 12 months, and to not split out non-lease components for lessees.

The Company has implemented key systems functionality and internal control processes in order to comply with the new reporting requirements of ASU 2016-02 and estimates that adoption of the standard will result in the recognition of additional ROU assets and corresponding lease liabilities on January 1, 2019 of approximately $100 million to $200 million. The adoption of ASU 2016-02 is not expected to have a material impact on the Company's results of operations or its cash flows, or to affect the Company's compliance with the terms of its existing debt agreements.

Financial Instruments - Credit Losses. In June 2016, the FASB issued ASU 2016-13 related to the measurement of credit losses on financial instruments. The pronouncement replaces the incurred loss methodology to record credit losses with a methodology that reflects the expected credit losses for financial assets not accounted for at fair value with gains and losses recognized through net income. This standard is effective for fiscal years beginning after December 15, 2019 (January 1, 2020 for the Company) and interim periods therein, with early adoption permitted for fiscal years, and interim periods therein, beginning after December 15, 2018. The Company is in the process of evaluating the impact that the adoption of this guidance will have on its results of operations, financial condition, cash flows and financial statement presentation.

Leases - Land Easements. In January 2018, the FASB issued ASU 2018-01 to provide an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under current leasing guidance. An entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 beginning at the date that the entity adopts Topic 842. An entity that does not elect this practical expedient should evaluate all existing or expired land easements in connection with the adoption of the new leases requirements in Topic 842 to assess whether they meet the definition of a lease. The amendments in this update affect the amendments in ASU 2016-02. The effective date and transition requirements for the amendments are the same as the effective date and transition requirements in ASU 2016-02. The Company plans to adopt the expedient effective January 1, 2019 and the adoption of this guidance will not have a material impact on its results of operations, financial condition, cash flows and financial statement presentation.

Fair Value Measurement. In August 2018, the FASB issued ASU 2018-13, which amended the fair value measurement guidance by removing and modifying certain disclosure requirements, while also adding new disclosure requirements. The amendments on changes in unrealized gains and losses, the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements, and the narrative description of measurement uncertainty should be applied prospectively for only the most recent interim or annual period presented in the initial fiscal year of adoption. All other amendments should be applied retrospectively to all periods presented upon their effective date. The amendments are effective for all companies for fiscal years, and interim periods within those years, beginning after December 15, 2019. Early adoption is permitted for all amendments. Further, a company may elect to early adopt the removal or modification of disclosures immediately and delay adoption of the new disclosure requirements until the effective date. The Company plans to adopt all disclosure requirements effective January 1, 2020.

Compensation - Retirement Benefits. In August 2018, the FASB issued ASU 2018-14 to add, remove and clarify disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. ASU 2018-14 is effective for fiscal years ending after December 15, 2020 for public companies and early adoption is permitted. The Company plans to adopt the disclosure requirements effective January 1, 2021.

Collaborative Arrangements - Clarifying the Interaction Between Topic 808 and Topic 606. In November 2018, the FASB issued ASU 2018-18 to provide guidance on how to assess whether certain arrangements between participants in collaborative arrangements should be accounted for within the revenue recognition standard. In a collaborative arrangement, two or more parties actively participate under contract in a joint operating activity and are exposed to significant risks and rewards that depend on the activity's commercial success. The standard allows companies to present units of account in collaborative arrangements that are within the scope of the revenue recognition standard together with revenue accounted for under the revenue recognition standard. The amendments in the new standard take effect for public companies for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted. The Company is in the process of evaluating the impact that the adoption of this guidance will have on its financial statement presentation.

Revenues

The majority of the Company's revenue is derived from the sale of coal 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) and contracts with terms of less than one year, including sales made on a spot basis. The Company's revenue from coal sales is realized and earned when control passes to the customer. Under the typical terms of the Company's coal supply agreements, title and risk of loss transfer to the customer at the mine or port, where coal is loaded to the transportation source(s) that serves each of the Company's mines. The Company incurs certain "add-on" taxes and fees on coal sales. Reported coal sales include taxes and fees charged by various federal and state governmental bodies and the freight charged on destination customer contracts.

The Company's U.S. thermal operating platform primarily sells thermal coal to electric utilities in the U.S. under long-term contracts, with a portion sold into the seaborne markets as conditions warrant. A significant portion of the coal production from the U.S. thermal mining segments is sold 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 may vary 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.

The Company's seaborne operating platform is primarily export focused with customers spread across several countries, with a portion of the metallurgical and thermal coal 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. A majority of these sales are executed through annual and multi-year international coal supply agreements that contain provisions requiring both parties to renegotiate pricing periodically. Industry commercial practice, and the Company's 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 sales volume under contracts with a duration of less than one year has increased in recent years. In the case of periodically negotiated pricing, the Company may deliver coal under provisional pricing until a final agreed-upon price is determined. The resulting make-whole settlements are recognized when reasonably estimable.

Contract pricing is set forth on a per ton basis, and revenue is generally recorded as the product of price and volume delivered. Many of the Company's coal supply agreements contain provisions that permit the parties to adjust the contract price upward or downward at specified times. These contract prices may be adjusted 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. The Company sometimes experiences a reduction in coal prices in new long-term coal supply agreements replacing some of its expiring contracts. Coal supply agreements also typically contain force majeure provisions allowing temporary suspension of performance by the Company or the customer during the duration of specified events beyond the control of the affected party. Most of the coal supply agreements contain provisions requiring the Company 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 the Company's customers to terminate their contracts in the event of changes in regulations affecting the industry that restrict the use or type of coal permissible at the customer's plant or increase the price of coal beyond specified limits.

Additional revenues may include realized and unrealized gains and losses on coal-related derivative instruments, revenues from customer contract-related payments, and other insignificant items including royalties related to coal lease agreements, sales agency commissions, farm income and property and facility rentals. Royalty income generally results from the lease or sublease of mineral rights to third parties, with payments based upon a percentage of the selling price or an amount per ton of coal produced. The Company previously disclosed such revenue as "Other revenues" in its consolidated statements of operations, but for the current and comparative periods has combined all revenue within the "Revenues" caption.

Discontinued Operations and Assets Held for Sale

The Company classifies items within discontinued operations in the consolidated financial statements when the operations and cash flows of a particular component of the Company have been (or will be) eliminated from the ongoing operations of the Company as a result of a disposal (by sale or otherwise) and represents a strategic shift that has (or will have) a major effect on the entity's operations and financial results. Refer to Note 6. "Discontinued Operations" for additional details related to discontinued operations.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost, which approximates fair value. Cash equivalents consist of highly liquid investments with original maturities of three months or less.

Accounts Receivable

The timing of revenue recognition, billings and cash collections results in accounts receivable from customers. Customers are invoiced as coal is shipped or at periodic intervals in accordance with contractual terms. Invoices typically include customary adjustments for the resolution of price variability related to prior shipments, such as coal quality thresholds. Payments are generally received within thirty days of invoicing.

Inventories

Coal is reported as inventory at the point in time the coal is extracted from the mine. Raw coal represents coal stockpiles that may be sold in current condition or may be further processed prior to shipment to a customer. Saleable coal represents coal stockpiles which require no further processing prior to shipment to a customer.

Coal inventory is valued at the lower of average cost or net realizable value. Coal inventory costs include labor, supplies, equipment (including depreciation thereto) and operating overhead and other related costs incurred at or on behalf of the mining location. Net realizable value considers the projected future sales price of the particular coal product, less applicable selling costs, and, in the case of raw coal, estimated remaining processing costs. The valuation of coal inventory is subject to several additional estimates, including those related to ground and aerial surveys used to measure quantities and processing recovery rates.

Materials and supplies inventory is valued at the lower of average cost or net realizable value, less a reserve for obsolete or surplus items. This reserve incorporates several factors, such as anticipated usage, inventory turnover and inventory levels.

Property, Plant, Equipment and Mine Development

Property, plant, equipment and mine development are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period. There was no capitalized interest in any of the periods presented. Expenditures which extend the useful lives of existing plant and equipment assets are capitalized. Maintenance and repairs are charged to operating costs as incurred. Costs incurred to develop coal mines or to expand the capacity of operating mines are capitalized. Maintenance and repair costs incurred to maintain current production capacity at a mine are charged to operating costs as incurred. Costs to acquire computer hardware and the development and/or purchase of software for internal use are capitalized and depreciated over the estimated useful lives.

Coal reserves are recorded at cost, or at fair value in the case of nonmonetary exchanges of reserves or business acquisitions.

Depletion of coal reserves and amortization of advance royalties is computed using the units-of-production method utilizing only proven and probable reserves (as adjusted for recoverability factors) in the depletion base. Mine development costs are principally amortized over the estimated lives of the mines using the straight-line method. Depreciation of plant and equipment is computed using the straight-line method over the shorter of the asset's estimated useful life or the life of the mine. The estimated useful lives by category of assets are as follows:

	Years
Building and improvements	up to 27
Machinery and equipment	up to 27
Leasehold improvements	Shorter of Useful Life or Remaining Life of Lease

Equity Investments

The Company applies the equity method to investments in joint ventures when it has the ability to exercise significant influence over the operating and financial policies of the joint venture. Investments accounted for under the equity method are initially recorded at cost and any difference between the cost of the Company's investment and the underlying equity in the net assets of the joint venture at the investment date is amortized over the lives of the related assets that gave rise to the difference. The Company's pro-rata share of the operating results of joint ventures and basis difference amortization is reported in the consolidated statements of operations in "Income from equity affiliates." Similarly, the Company's pro-rata share of the cumulative foreign currency translation adjustment of its equity method investments whose functional currency is not the U.S. dollar is reported in the consolidated balance sheet as a component of "Accumulated other comprehensive income," with periodic changes thereto reflected in the consolidated statements of comprehensive income.

The Company monitors its equity method investments for indicators that a decrease in investment value has occurred that is other than temporary. Examples of such indicators include a sustained history of operating losses and adverse changes in earnings and cash flow outlook. In the absence of quoted market prices for an investment, discounted cash flow projections are used to assess fair value, the underlying assumptions to which are generally considered unobservable Level 3 inputs under the fair value hierarchy. If the fair value of an investment is determined to be below its carrying value and that loss in fair value is deemed other than temporary, an impairment loss is recognized. No such impairment losses were recorded in any period presented.

For the remaining investments, the Company will adjust the carrying value of its investments to fair value based on observable market transactions. The Company also monitors such investments for indicators of impairment should no observable market transactions exist.

Asset Retirement Obligations

The Company's asset retirement obligation (ARO) liabilities primarily consist of spending estimates for surface land reclamation and support facilities at both surface and underground mines in accordance with applicable reclamation laws and regulations in the U.S. and Australia as defined by each mining permit.

The Company estimates its ARO liabilities for final reclamation and mine closure based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at the credit-adjusted, risk-free rate. The Company records an ARO asset associated with the discounted liability for final reclamation and mine closure. The obligation and corresponding asset are recognized in the period in which the liability is incurred. The ARO asset is amortized on the units-of-production method over its expected life and the ARO liability is accreted to the projected spending date. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free rate. The Company also recognizes an obligation for contemporaneous reclamation liabilities incurred as a result of surface mining. Contemporaneous reclamation consists primarily of grading, topsoil replacement and re-vegetation of backfilled pit areas.

Contingent Liabilities

From time to time, the Company is subject to legal and environmental matters related to its continuing and discontinued operations and certain historical, non-coal producing operations. In connection with such matters, the Company is required to assess the likelihood of any adverse judgments or outcomes, as well as potential ranges of probable losses.

A determination of the amount of reserves required for these matters is made after considerable analysis of each individual issue. The Company accrues for legal and environmental matters within "Operating costs and expenses" when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. The Company provides disclosure surrounding loss contingencies when it believes that it is at least reasonably possible that a material loss may be incurred or an exposure to loss in excess of amounts already accrued may exist. Adjustments to contingent liabilities are made when additional information becomes available that affects the amount of estimated loss, which information may include changes in facts and circumstances, changes in interpretations of law in the relevant courts, the results of new or updated environmental remediation cost studies and the ongoing consideration of trends in environmental remediation costs.

Accrued contingent liabilities exclude claims against third parties and are not discounted. The current portion of these accruals is included in "Accounts payable and accrued expenses" and the long-term portion is included in "Other noncurrent liabilities" in the consolidated balance sheets. In general, legal fees related to environmental remediation and litigation are charged to expense. The Company includes the interest component of any litigation-related penalties within "Interest expense" in the consolidated statements of operations.

Income Taxes

Income taxes are accounted for using a balance sheet approach. The Company accounts for deferred income taxes by applying statutory tax rates in effect at the reporting date of the balance sheet to differences between the book and tax basis of assets and liabilities. A valuation allowance is established if it is "more likely than not" that the related tax benefits will not be realized. Significant weight is given to evidence that can be objectively verified including history of tax attribute expiration and cumulative income or loss. In determining the appropriate valuation allowance, the Company considers the projected realization of tax benefits based on expected levels of future taxable income, available tax planning strategies, reversals of existing taxable temporary differences and taxable income in carryback years.

The Company recognizes the tax benefit from uncertain tax positions only if it is "more likely than not" the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. To the extent the Company's assessment of such tax positions changes, the change in estimate will be recorded in the period in which the determination is made. Tax-related interest and penalties are classified as a component of income tax expense.

Postretirement Health Care and Life Insurance Benefits

The Company accounts for postretirement benefits other than pensions by accruing the costs of benefits to be provided over the employees' period of active service. These costs are determined on an actuarial basis. The Company's consolidated balance sheets reflect the accumulated postretirement benefit obligations of its postretirement benefit plans. The Company accounts for changes in its postretirement benefit obligations as a settlement when an irrevocable action has been effected that relieves the Company of its actuarially-determined liability to individual plan participants and removes substantial risk surrounding the nature, amount and timing of the obligation's funding and the assets used to effect the settlement. See Note 17. "Postretirement Health Care and Life Insurance Benefits" for information related to postretirement benefits.

Pension Plans

The Company sponsors non-contributory defined benefit pension plans accounted for by accruing the cost to provide the benefits over the employees' period of active service. These costs are determined on an actuarial basis. The Company's consolidated balance sheets reflect the funded status of the defined benefit pension plans. See Note 18. "Pension and Savings Plans" for information related to pension plans.

Restructuring Activities

From time to time, the Company initiates restructuring activities in connection with its repositioning efforts to appropriately align its cost structure or optimize its coal production relative to prevailing market conditions. Costs associated with restructuring actions can include early mine closures, voluntary and involuntary workforce reductions, office closures and other related activities. Costs associated with restructuring activities are recognized in the period incurred.

Included as a component of "Operating costs and expenses" in the Company's consolidated statements of operations for the year ended December 31, 2018, the period April 2 through December 31, 2017 and the year ended December 31, 2016 were aggregate restructuring charges of $1.2 million, $7.6 million and $15.5 million, respectively, primarily associated with voluntary and involuntary workforce reductions. There were no restructuring charges during the period January 1 through April 1, 2017.

Derivatives

The Company recognizes at fair value all contracts meeting the definition of a derivative as assets or liabilities in the consolidated balance sheets, with the exception of certain coal trading contracts for which the Company has elected to apply a normal purchases and normal sales exception.

With respect to derivatives used in hedging activities, the Company assesses, both at inception and at least quarterly thereafter, whether such derivatives are highly effective at offsetting the changes in the anticipated exposure of the hedged item. The effective portion of the change in the fair value of derivatives designated as a cash flow hedge is recorded in "Accumulated other comprehensive income" in the consolidated balance sheets until the hedged transaction impacts reported earnings, at which time any gain or loss is reclassified to earnings. To the extent that periodic changes in the fair value of derivatives deemed highly effective exceeds such changes in the hedged item, the ineffective portion of the periodic non-cash changes are recorded in earnings in the period of the change. If the hedge ceases to qualify for hedge accounting, the Company prospectively recognizes changes in the fair value of the instrument in earnings in the period of the change. The potential for hedge ineffectiveness may be present in the design of certain of the Company's cash flow hedge relationships. Gains or losses from derivative financial instruments designated as fair value hedges are recognized immediately in earnings, along with the offsetting gain or loss related to the underlying hedged item.

The Company's asset and liability derivative positions are offset on a counterparty-by-counterparty basis if the contractual agreement provides for the net settlement of contracts with the counterparty in the event of default or termination of any one contract.

Non-derivative contracts and derivative contracts for which the Company has elected to apply the normal purchases and normal sales exception are accounted for on an accrual basis.

Business Combinations

The Company accounts for business combinations using the purchase method of accounting. The purchase method requires the Company to determine the fair value of all acquired assets, including identifiable intangible assets and all assumed liabilities. The total cost of acquisitions is allocated to the underlying identifiable net assets, based on their respective estimated fair values. Determining the fair value of assets acquired and liabilities assumed requires management's judgment and the utilization of independent valuation experts, and often involves the use of significant estimates and assumptions, including assumptions with respect to future cash inflows and outflows, discount rates and asset lives, among other items.

Impairment of Long-Lived Assets

The Company evaluates its long-lived assets held and used in operations for impairment as events and changes in circumstances indicate that the carrying amount of such assets might not be recoverable. Factors that would indicate potential impairment to be present include, but are not limited to, a sustained history of operating or cash flow losses, an unfavorable change in earnings and cash flow outlook, prolonged adverse industry or economic trends and a significant adverse change in the extent or manner in which a long-lived asset is being used or in its physical condition. The Company generally does not view short-term declines in thermal and metallurgical coal prices as a triggering event for conducting impairment tests because of historic price volatility. However, the Company generally does view a sustained trend of depressed coal pricing (for example, over periods exceeding one year) as an indicator of potential impairment.

Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. For its active mining operations, the Company generally groups such assets at the mine level, or the mining complex level for mines that share infrastructure, with the exception of impairment evaluations triggered by mine closures. In those cases involving mine closures, the related assets are evaluated at the individual asset level for remaining economic life based on transferability to ongoing operating sites and for use in reclamation-related activities, or for expected salvage. For its development and exploration properties and portfolio of surface land and coal reserve holdings, the Company considers several factors to determine whether to evaluate those assets individually or on a grouped basis for purposes of impairment testing. Such factors include geographic proximity to one another, the expectation of shared infrastructure upon development based on future mining plans and whether it would be most advantageous to bundle such assets in the event of sale to a third party.

When indicators of impairment are present, the Company evaluates its long-lived assets for recoverability by comparing the estimated undiscounted cash flows expected to be generated by those assets under various assumptions to their carrying amounts. If such undiscounted cash flows indicate that the carrying value of the asset group is not recoverable, impairment losses are measured by comparing the estimated fair value of the asset group to its carrying amount. As quoted market prices are unavailable for the Company's individual mining operations, fair value is determined through the use of an expected present value technique based on the income approach, except for non-strategic coal reserves, surface lands and undeveloped coal properties excluded from the Company's long-range mine planning. In those cases, a market approach is utilized based on the most comparable market multiples available. The estimated future cash flows and underlying assumptions used to assess recoverability and, if necessary, measure the fair value of the Company's long-lived mining assets are derived from those developed in connection with the Company's planning and budgeting process. The Company believes its assumptions to be consistent with those a market participant would use for valuation purposes. The most critical assumptions underlying the Company's projections and fair value estimates include those surrounding future tons sold, coal prices for unpriced coal, production costs (including costs for labor, commodity supplies and contractors), transportation costs, foreign currency exchange rates and a risk-adjusted, after-tax cost of capital (all of which generally constitute unobservable Level 3 inputs under the fair value hierarchy), in addition to market multiples for non-strategic coal reserves, surface lands and undeveloped coal properties excluded from the Company's long-range mine planning (which generally constitute Level 2 inputs under the fair value hierarchy).

Refer to Note 5. "Asset Impairment" for details regarding impairment charges related to long-lived assets of $30.5 million and $247.9 million recognized during the period January 1 through April 1, 2017 and the year ended December 31, 2016, respectively. There were no impairment charges related to long-lived assets during the year ended December 31, 2018 or the period April 2 through December 31, 2017.

Fair Value

For assets and liabilities that are recognized or disclosed at fair value in the consolidated financial statements, the Company defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Foreign Currency

Functional currency is determined by the primary economic environment in which an entity operates, which for the Company's foreign operations is generally the U.S. dollar because sales prices in international coal markets and the Company's sources of financing those operations are denominated in that currency. Accordingly, substantially all of the Company's consolidated foreign subsidiaries utilize the U.S. dollar as their functional currency. Monetary assets and liabilities are remeasured at year-end exchange rates while non-monetary items are remeasured at historical rates. Income and expense accounts are remeasured at the average rates in effect during the year, except for those expenses related to balance sheet amounts that are remeasured at historical exchange rates. Gains and losses from foreign currency remeasurement related to tax balances are included as a component of "Income tax provision (benefit)," while all other remeasurement gains and losses are included in "Operating costs and expenses" in the consolidated statements of operations. The total impact of foreign currency remeasurement on the consolidated statements of operations was a net gain of $1.4 million, $0.7 million and $10.6 million for the year ended December 31, 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017, respectively, and a net loss of $7.4 million for the year ended December 31, 2016.

The Company owns a 50% equity interest Middlemount Coal Pty Ltd. (Middlemount), which owns the Middlemount Mine in Queensland, Australia. Middlemount utilizes the Australian dollar as its functional currency. Accordingly, the assets and liabilities of that equity investee are translated to U.S. dollars at the year-end exchange rate and income and expense accounts are translated at the average rate in effect during the year. The Company's pro-rata share of the translation gains and losses of the equity investee are recorded as a component of "Accumulated other comprehensive income" in the consolidated balance sheets. Australian dollar denominated stockholder loans to the Middlemount Mine, which are long term in nature, are considered part of the Company's net investment in that operation. Accordingly, foreign currency gains or losses on those loans are recorded as a component of foreign currency translation adjustment. The Company recorded foreign currency translation losses of $5.9 million and $1.8 million for the years ended December 31, 2018 and 2016, respectively, and gains of $1.4 million and $5.5 million for the periods April 2 through December 31, 2017 and January 1 through April 1, 2017, respectively.

Share-Based Compensation

The Company accounts for share-based compensation at the grant date fair value of awards and recognizes the related expense over the service period of the awards. See Note 20. "Share-Based Compensation" for information related to share-based compensation.

Exploration and Drilling Costs

Exploration expenditures are charged to operating costs as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves.

Advance Stripping Costs

Pre-production. At existing surface operations, additional pits may be added to increase production capacity in order to meet customer requirements. These expansions may require significant capital to purchase additional equipment, expand the workforce, build or improve existing haul roads and create the initial pre-production box cut to remove overburden (that is, advance stripping costs) for new pits at existing operations. If these pits operate in a separate and distinct area of the mine, the costs associated with initially uncovering coal (that is, advance stripping costs incurred for the initial box cuts) for production are capitalized and amortized over the life of the developed pit consistent with coal industry practices.

Post-production. Advance stripping costs related to post-production are expensed as incurred. Where new pits are routinely developed as part of a contiguous mining sequence, the Company expenses such costs as incurred. The development of a contiguous pit typically reflects the planned progression of an existing pit, thus maintaining production levels from the same mining area utilizing the same employee group and equipment.

Use of Estimates in the Preparation of the Consolidated Financial Statements

These consolidated financial statements have been prepared in conformity with U.S. GAAP. In doing so, estimates and assumptions are made that affect the amounts reported in the consolidated financial statements and accompanying notes. These estimates are based on historical experience and on various other assumptions deemed reasonable under the circumstances, the results of which form the basis for making judgments about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The Company's actual results may differ materially from these estimates. Significant estimates inherent in the preparation of these consolidated financial statements include, but are not limited to, accounting for sales and cost recognition, postretirement benefit plans, environmental receivables and liabilities, asset retirement obligations, evaluation of long-lived assets for impairment, income taxes including deferred tax assets, fair value measurements and contingencies.

(2) Emergence from the Chapter 11 Cases and Fresh Start Reporting

The following is a summary of certain provisions of the Plan, as confirmed by the Bankruptcy Court pursuant to the Confirmation Order, and is not intended to be a complete description of the Plan, which is included in its entirety as Exhibit 2.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission (SEC) on March 20, 2017.

The consummation of the Plan resulted in the following capital structure on the Effective Date:

- Successor Notes - $1,000.0 million first lien senior secured notes
- Successor Credit Facility - a first lien credit facility of $950.0 million
- Series A Convertible Preferred Stock - $750.0 million for 30.0 million shares of Series A Convertible Preferred Stock
- Common Stock and Warrants - $750.0 million for common stock and warrants issued in connection with a Rights Offering (as defined below), resulting in, together with other issuances of common stock, the issuance of 70.9 million shares of a single class of common stock and warrants to purchase 6.2 million shares of common stock

The new debt and equity instruments comprising the Successor Company's capital structure are further described below.

Treatment of Classified Claims and Interests

The following summarizes the various classes of claimants' recoveries under the Plan. Undefined capitalized terms used in this section, *Treatment of Classified Claims and Interests*, are defined in the Plan.

First Lien Lender Claims (Classes 1A - 1D)	Paid in full in cash.
Second Lien Notes Claims (Classes 2A - 2D)	A combination of (1) $450 million of cash, first lien debt and/or new second lien notes and (2)(a) new common stock, par value $0.01 per share, of the Reorganized Peabody (Common Stock) and (b) subscription rights in the Rights Offering.
Other Secured Claims (Classes 3A - 3E)	At the election of the Debtors, (1) reinstatement, (2) payment in full in cash, (3) receipt of the applicable collateral or (4) such other treatment consistent with section 1129(b) of the Bankruptcy Code.
Other Priority Claims (Classes 4A - 4E)	Paid in full in cash.
General Unsecured Claims	Class 5A: Against Peabody Energy: a pro rata share of $5 million in cash plus an amount of additional cash (up to $2 million) not otherwise paid to holders of Convenience Claims. Class 5B: Against the Encumbered Guarantor Debtors: (1) Common Stock and subscription rights in the Rights Offering or (2) at the election of the claim holder, cash from a pool of $75 million in cash to be paid by the Debtors and the Reorganized Debtors into a segregated account in accordance with the terms set forth in the Plan. Class 5C: Against the Gold Fields Debtors: units in the Gold Fields Liquidating Trust. Class 5D: Against Peabody Holdings (Gibraltar) Limited: no recoveries. Class 5E: Against the Unencumbered Debtors: cash in the amount of such holder's allowed claim, less any amounts attributable to late fees, postpetition interest or penalties.
Convenience Claims	Class 6A: Against Peabody Energy: up to 72.5% of such claim in cash, provided that total payments to Convenience Claims not exceed $2 million. Class 6B: Against the Encumbered Guarantor Debtors: up to 72.5% of such claim in cash, provided that total payments to Convenience Claims not exceed $18 million.
United Mine Workers of America 1974 Pension Plan Claim (Classes 7A - 7E)	$75 million in cash paid over five years. See Note 6. "Discontinued Operations," for additional details.
Unsecured Subordinated Debentures Claims (Class 8A)	(1) Payment of the reasonable and documented fees and expenses of the trustee under the 2066 subordinated indenture up to $350,000; and (2) because this class voted in favor of the Plan and in connection with the settlement of certain potential intercreditor disputes as part of the global settlement embodied therein, and because the trustee under the 2066 subordinated indenture did not object to, and affirmatively supported, the Plan, holders of allowed Unsecured Subordinated Debenture Claims received from specified noteholder co-proponents their pro rata share of penny warrants exercisable for 1.0% of the fully diluted Reorganized Peabody common stock from the pool of penny warrants issued to the noteholder co-proponents under the Rights Offering and/or the terms of the Backstop Commitment Agreement (as defined below).
Section 510(b) Claims (Class 10A)	No recovery.
Peabody Energy Equity Interests (Class 11A)	No recovery, as further described under *Cancellation of Prior Common Stock* below.

Cancellation of Prior Common Stock

In accordance with the Plan and as previously disclosed, each share of the Company's common stock outstanding prior to the Effective Date, including all options and warrants to purchase such stock, was extinguished, canceled and discharged, and each such share, option or warrant has no further force or effect as of the Effective Date. Furthermore, all of the Company's equity award agreements under prior incentive plans, and the awards granted pursuant thereto, were extinguished, canceled and discharged and have no further force or effect as of the Effective Date.

Issuance of Equity Securities

Section 1145 Securities

On the Effective Date and simultaneous with the cancellation of the prior common stock discussed above, in connection with the Company's emergence from the Chapter 11 Cases and in reliance on the exemption from registration requirements of the Securities Act of 1933 (the Securities Act) provided by Section 1145 of the Bankruptcy Code, the Company issued:

- 11.6 million shares of Common Stock to holders of Allowed Claims (as defined in the Plan) in Classes 2A, 2B, 2C, 2D and 5B on account of such claims as provided in the Plan; and
- 51.2 million shares of Common Stock and 2.9 million Warrants (the 1145 Warrants) pursuant to the completed Rights Offering to certain holders of the Company's prepetition indebtedness for total consideration of $704.4 million.

Any shares of Common Stock issued pursuant to the exercise of such 1145 Warrants were similarly issued pursuant to the exemption from registration provided by Section 1145 of the Bankruptcy Code.

Section 4(a)(2) Securities

In addition, on the Effective Date, in connection with the Company's emergence from the Chapter 11 Cases and in reliance on the exemption from registration requirements of the Securities Act provided by Section 4(a)(2) of the Securities Act, the Company issued:

- 30.0 million shares of Series A Convertible Preferred Stock (the Convertible Preferred Stock) to parties to the Private Placement Agreement, dated as of December 22, 2016 (as amended, the Private Placement Agreement), among the Company and the other parties thereto, for total consideration of $750.0 million;
- 3.3 million shares of Common Stock and 0.2 million Warrants (the Private Warrants, and together with the 1145 Warrants, the Warrants) to parties to the Backstop Commitment Agreement, dated as of December 22, 2016 (as amended, the Backstop Commitment Agreement), among the Company and the other parties thereto, on account of their commitments under that agreement, for total consideration of $45.6 million; and
- 4.8 million shares of Common Stock and 3.1 million additional Private Warrants to specified parties to the Private Placement Agreement and Backstop Commitment Agreement on account of commitment premiums contemplated by those agreements.

Any shares of Common Stock issued pursuant to the conversion of the Convertible Preferred Stock or the exercise of such Private Warrants were issued pursuant to the exemption from registration provided by Section 3(a)(9) and/or Section 4(a)(2) of the Securities Act. The securities issued in reliance on Section 4(a)(2) of the Securities Act were subject to restrictions on transfer; however, substantially all such shares were registered with the SEC on a resale Form S-1 effective July 14, 2017.

Other Forms of Equity Authorized under the Company's Certificate of Incorporation

As noted on the accompanying consolidated balance sheets, the Company's Fourth Amended and Restated Certificate of Incorporation authorizes the issuances of additional series of preferred stock, as well as series common stock. No series of preferred stock was outstanding as of December 31, 2018, and other than the Series A Convertible Preferred Stock, no other series of preferred stock was outstanding as of December 31, 2017. Additionally, as of December 31, 2018 and 2017, no series common stock was outstanding. A copy of the Company's Fourth Amended and Restated Certificate of Incorporation is included as Exhibit 3.1 to the Company's Current Report on Form 8-K filed by the Company with the SEC on April 3, 2017.

Convertible Preferred Stock

Prior to the Mandatory Conversion (as defined below), the Convertible Preferred Stock accrued dividends at a rate of 8.5% per year, payable in-kind semi-annually on April 30 and October 31 of each year as additional shares of Series A Convertible Preferred Stock, and could be converted into a number of shares of Common Stock as described below.

The Convertible Preferred Stock was convertible into Common Stock at any time, at the option of the holders at an initial conversion price of $16.25, representing a discount of 35% to the equity value assigned to the Common Stock by the Plan (subject to customary anti-dilution adjustments, the Conversion Price). Beginning on the Effective Date, each outstanding share of Convertible Preferred Stock would automatically convert into a number of shares of Common Stock at the Conversion Price (such conversion, the Mandatory Conversion) if the volume weighted average price of the Common Stock exceeded $32.50 (the Conversion Threshold) for at least 45 trading days in a 60 consecutive trading day period, including each of the last 20 days in such 60 consecutive trading day period (such period, the Mandatory Conversion Period). On January 31, 2018, the requirements for a Mandatory Conversion were met and all remaining outstanding shares of Convertible Preferred Stock were automatically converted into shares of Common Stock.

Upon both the optional and the Mandatory Conversion of the Convertible Preferred Stock, holders of the Convertible Preferred Stock were deemed to have (1) received dividends through the last payment of dividends prior to the conversion, including dividends received on prior dividends, to the extent accrued and not previously paid; and (2) dividends on the shares of Convertible Preferred Stock then outstanding and any shares deemed issued pursuant to the preceding clause accruing from the last dividend date preceding the date of the conversion through, but not including, the three year anniversary of their initial issuance, and all dividends on prior dividends.

As of January 31, 2018, all 30.0 million shares of Convertible Preferred Stock issued upon the Effective Date had been converted into 59.3 million shares of Common Stock, which is inclusive of the shares that had been issued for the payable in-kind preferred stock dividends.

Rights Offering

Pursuant to the Plan and Rights Offering, holders of Allowed Claims in Classes 2A, 2B, 2C, 2D and 5B were offered the opportunity to purchase up to 54.5 million units, each unit being comprised of (1) one share of Common Stock and (2) a fraction of a Warrant. The purchase price for the units offered in the Rights Offering was $13.75 per unit. A total of 51.2 million units were purchased in the Rights Offering. Pursuant to the Backstop Commitment Agreement, the remaining 3.3 million units that were not purchased in the Rights Offering were purchased by the parties to the Backstop Commitment Agreement at the same per-unit price.

Registration Rights Agreement

On the Effective Date, the Company entered into a registration rights agreement (Registration Rights Agreement) with certain parties (together with any person or entity that became a party to the Registration Rights Agreement, the Holders) that received shares of the Company's Common Stock and Convertible Preferred Stock in the Company on the Effective Date, as provided in the Plan. The Registration Rights Agreement provided Holders with registration rights for the Holders' Registrable Securities (as defined in the Registration Rights Agreement). Substantially all of the Holders' Registrable Securities were registered with the SEC on Form S-1 effective July 14, 2017.

Warrant Agreement

On the Effective Date, the Company entered into a warrant agreement (the Warrant Agreement) with American Stock Transfer and Trust Company, LLC. In accordance with the Plan, the Company issued 6.2 million warrants to purchase one share of Common Stock each at an exercise price of $0.01 per share to all Noteholder Co-Proponents (as defined in the Plan) and subscribers in the Rights Offering (as defined in the Plan) and related backstop commitment. All Warrants described above under the heading *Issuance of Equity Securities* were issued under the Warrant Agreement. All unexercised Warrants expired, and the rights of the holders of such Warrants to purchase Common Stock terminated on July 3, 2017, with less than 0.1% of the Warrants unexercised.

6.000% and 6.375% Senior Secured Notes (collectively, the Successor Notes)

On February 15, 2017, one of PEC's subsidiaries entered into an indenture with Wilmington Trust, National Association, as trustee, relating to the issuance by PEC's subsidiary of $500.0 million aggregate principal amount of 6.000% senior secured notes due 2022 (the 2022 Notes) and $500.0 million aggregate principal amount of 6.375% senior secured notes due 2025 (together with the 2022 Notes, the Successor Notes). The Successor Notes were sold on February 15, 2017 in a private transaction exempt from the registration requirements of the Securities Act.

Prior to the Effective Date, PEC's subsidiary deposited the proceeds of the offering of the Successor Notes into an escrow account pending confirmation of the Plan and certain other conditions being satisfied. On the Effective Date, the proceeds from the Successor Notes were used to repay the predecessor first lien obligations. The Successor Notes are further described in Note 14. "Long-term Debt."

Successor Credit Agreement

In connection with an exit facility commitment letter, on the Effective Date, the Company entered into a credit agreement, dated as of April 3, 2017, among the Company, as Borrower, Goldman Sachs Bank USA, as Administrative Agent, and other lenders party thereto (the Successor Credit Agreement). The Successor Credit Agreement originally provided for a $950.0 million senior secured term loan, which prior to the amendments described in Note 14. "Long-term Debt," matured in 2022 and bore interest at LIBOR plus 4.50% per annum with a 1.00% LIBOR floor. Following the amendments the loan matures in 2025 and bears interest at LIBOR plus 2.75% per annum. On the Effective Date, the proceeds from the Successor Credit Agreement were used to repay the predecessor first lien obligations.

Securitization Facility

In connection with a receivables securitization program commitment letter, on the Effective Date, the Company entered into the Sixth Amended and Restated Receivables Purchase Agreement, as amended, dated as of April 3, 2017 (Receivables Purchase Agreement), among P&L Receivables Company, LLC (P&L Receivables), as the Seller, the Company, as the Servicer, the sub-servicers party thereto, the various purchasers and purchaser agents party thereto and PNC Bank, National Association (PNC), as administrator. The Receivables Purchase Agreement extends the receivables securitization facility previously in place and expands that facility to include certain receivables from the Company's Australian operations. The Receivables Purchase Agreement is further described in Note 25. "Financial Instruments, Guarantees With Off-Balance-Sheet Risk and Other Guarantees."

Cancellation of Prepetition Obligations

In accordance with the Plan, on the Effective Date all of the obligations of the Debtors with respect to the following debt instruments were canceled:

- Indenture governing $1,000.0 million outstanding aggregate principal amount of the Company's 10.00% Senior Secured Second Lien Notes due 2022, dated as of March 16, 2015, among the Company, U.S. Bank National Association (U.S. Bank), as trustee and collateral agent, and the guarantors named therein, as supplemented;
- Indenture governing $650.0 million outstanding aggregate principal amount of the Company's 6.50% Senior Notes due 2020, dated as of March 19, 2004, among the Company, U.S. Bank, as trustee, and the guarantors named therein, as supplemented;
- Indenture governing $1,518.8 million outstanding aggregate principal amount of the Company's 6.00% Senior Notes due 2018, dated as of November 15, 2011, among the Company, U.S. Bank, as trustee, and the guarantors named therein, as supplemented;
- Indenture governing $1,339.6 million outstanding aggregate principal amount of the Company's 6.25% Senior Notes due 2021, dated as of November 15, 2011, by and among the Company, U.S. Bank, as trustee, and the guarantors named therein, as supplemented;
- Indenture governing $250.0 million outstanding aggregate principal amount of the Company's 7.875% Senior Notes due 2026, dated as of March 19, 2004, among the Company, U.S. Bank, as trustee, and the guarantors named therein, as supplemented;
- Subordinated Indenture governing $732.5 million outstanding aggregate principal amount of the Company's Convertible Junior Subordinated Debentures due 2066, dated as of December 20, 2006, among the Company and U.S. Bank, as trustee, as supplemented; and
- Amended and Restated Credit Agreement, as amended and restated as of September 24, 2013 (the 2013 Credit Facility), related to $1,170.0 million outstanding aggregate principal amount of term loans under a term loan facility (the 2013 Term Loan Facility) and $1,650.0 million under a revolving credit facility (the 2013 Revolver), which includes approximately $675.0 million of posted but undrawn letters of credit and approximately $947.0 million in outstanding borrowings, by and among the Company, Citibank, N.A., as administrative agent, swing line lender and letter of credit issuer, Citigroup Global Markets, Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, BNP Paribas Securities Corp., Crédit Agricole Corporate and Investment Bank, HSBC Securities (USA) Inc., Morgan Stanley Senior Funding, Inc., PNC Capital Markets LLC and RBS Securities Inc., as joint lead arrangers and joint book managers, and the lender parties thereto, as amended by that certain Omnibus Amendment Agreement, dated as of February 5, 2015.

2017 Incentive Compensation Plan

In accordance with the Plan, the Peabody Energy Corporation 2017 Incentive Plan (the 2017 Incentive Plan) became effective as of the Effective Date. The 2017 Incentive Plan is intended to, among other things, help attract and retain employees and directors upon whom, in large measure, the Company depends for sustained progress, growth and profitability. The 2017 Incentive Plan also permits awards to consultants.

Unless otherwise determined by the Company's Board of Directors (the Board), the compensation committee of the Board will administer the 2017 Incentive Plan. The 2017 Incentive Plan generally provides for the following types of awards:

- options (including non-qualified stock options and incentive stock options);
- stock appreciation rights;
- restricted stock;
- restricted stock units;
- deferred stock;
- performance units;
- dividend equivalents; and
- cash incentive awards.

The aggregate number of shares of Common Stock reserved for issuance pursuant to the 2017 Incentive Plan was approximately 14.0 million. The 2017 Incentive Plan will remain in effect, subject to the right of the Board to terminate the 2017 Incentive Plan at any time, subject to certain restrictions, until the earlier to occur of (a) the date all shares of Common Stock subject to the 2017 Incentive Plan are purchased or acquired and the restrictions on all restricted stock granted under the 2017 Incentive Plan have lapsed, according to the 2017 Incentive Plan's provisions, and (b) ten years from the Effective Date.

Reorganization Value

Fresh start reporting provides, among other things, for a determination of the value to be assigned to the equity of the emerging company as of a date selected for financial reporting purposes. In conjunction with the bankruptcy proceedings, a third-party financial advisor provided an enterprise value of the Company of approximately $4.2 billion to $4.9 billion. The final equity value of $3,081.0 million was based upon the approximate low end of the enterprise value established by the third-party valuation and cash held by the Successor company in connection with the emergence from the Chapter 11 Cases, less the fair value of Successor debt issued on the Effective Date as described above. The final equity value equated to a per share value of $22.03 per equivalent common share issued in accordance with the Plan.

The enterprise value of the Company was estimated using two primary valuation methods: a comparable public company analysis and a discounted cash flow (DCF) analysis. The comparable public company analysis is based on the enterprise value of selected publicly traded companies that have operating and financial characteristics comparable in certain respects to the Company, for example, operational requirements and risk and profitability characteristics. Selected companies were comprised of coal mining companies with primary operations in the United States. Under this methodology, certain financial multiples and ratios that measure financial performance and value were calculated for each selected company and then applied to the Company's financials to imply an enterprise value for the Company.

The DCF analysis is a forward-looking enterprise valuation methodology that estimates the value of an asset or business by calculating the present value of expected future cash flows by that asset or business. The basis of the DCF analysis was the Company's prepared projections which included a variety of estimates and assumptions, such as pricing and demand for coal. The Company's pricing was based on its view of the market taking into account third-party forward pricing curves adjusted for the quality of products sold by the Company. While the Company considers such estimates and assumptions reasonable, they are inherently subject to significant business, economic and competitive uncertainties, many of which are beyond the Company's control and, therefore, may not be realized. Changes in these estimates and assumptions may have a significant effect on the determination of the Company's enterprise value. The assumptions used in the calculations for the DCF analysis included projected revenue, cost and cash flows for the nine months ending December 31, 2017 through each respective mine life and represented the Company's best estimates at the time the analysis was prepared. The DCF analysis was completed using discount rates ranging from 11% to 14.5%. The DCF analysis involves complex considerations and judgments concerning appropriate discount rates. Due to the unobservable inputs to the valuation, the fair value would be considered Level 3 in the fair value hierarchy.

Grant of Emergence Awards

On the Effective Date, the Company granted restricted stock units under the 2017 Incentive Plan and the terms of the relevant restricted stock unit agreement to all employees, including its executive officers (the Emergence Awards). The fair value of the Emergence Awards on the Effective Date was approximately $80 million. The Emergence Awards granted to the Company's executive officers generally will vest ratably on each of the first three anniversaries of the Effective Date, subject to, among other things, each such executive officer's continued employment with the Company. The Emergence Awards will become fully vested upon each such executive officer's termination of employment by the Company and its subsidiaries without Cause or by the executive for Good Reason (each, as defined in the 2017 Incentive Plan or award agreement) or due to a termination of employment with the Company and its subsidiaries by reason of death or Disability (as defined in the 2017 Incentive Plan or award agreement). In order to receive the Emergence Awards, the executive officers were required to execute restrictive covenant agreements protecting the Company's interests.

Effect of Plan and Fresh Start Reporting Adjustments

The following balance sheet illustrates the impacts of the implementation of the Plan and the application of fresh start reporting, which results in the opening balance sheet of the Successor company.

As of April 1, 2017	Predecessor (a)	Effect of Plan (b)		Fresh Start Adjustments (c)		Successor
		(Dollars in millions)				
ASSETS						
Current assets						
Cash and cash equivalents	$ 1,068.1	$ (14.4)	(d)	$ —		$ 1,053.7
Restricted cash	80.7	(54.7)	(d)	—		26.0
Successor Notes issuance proceeds - restricted cash	1,000.0	(1,000.0)	(d)	—		—
Accounts receivable, net	312.1	—		—		312.1
Inventories	250.8	—		70.1	(k)	320.9
Other current assets	494.5	(18.1)	(e)	(333.0)	(l)	143.4
Total current assets	3,206.2	(1,087.2)		(262.9)		1,856.1
Property, plant, equipment and mine development, net.	8,653.9	—		(3,461.4)	(m)	5,192.5
Investments and other assets	976.4	3.9	(f)	238.0	(n)	1,218.3
Total assets	$ 12,836.5	$ (1,083.3)		$ (3,486.3)		$ 8,266.9
LIABILITIES AND STOCKHOLDERS' EQUITY						
Current liabilities						
Current portion of long-term debt	$ 18.2	$ 9.5	(g)	$ —		$ 27.7
Accounts payable and accrued expenses	968.0	257.6	(h)	14.8	(o)	1,240.4
Total current liabilities	986.2	267.1		14.8		1,268.1
Long-term debt, less current portion	950.5	903.2	(g)	—		1,853.7
Deferred income taxes	179.2	—		(177.8)	(p)	1.4
Asset retirement obligations	707.0	—		(73.9)	(q)	633.1
Accrued postretirement benefit costs	753.9	—		(6.9)	(r)	747.0
Other noncurrent liabilities	511.1	—		120.6	(s)	631.7
Total liabilities not subject to compromise	4,087.9	1,170.3		(123.2)		5,135.0
Liabilities subject to compromise	8,416.7	(8,416.7)	(i)	—		—
Total liabilities	12,504.6	(7,246.4)		(123.2)		5,135.0
Stockholders' equity						
Common Stock (Predecessor)	0.2	(0.2)	(j)	—		—
Common Stock (Successor)	—	0.7	(b)	—		0.7
Series A Preferred Stock (Successor)	—	1,305.4	(b)	—		1,305.4
Additional paid-in capital (Predecessor)	2,423.9	(2,423.9)	(j)	—		—
Additional paid-in capital (Successor)	—	1,774.9	(b)	—		1,774.9
Treasury stock, at cost	(371.9)	371.9	(j)	—		—
Accumulated deficit	(1,284.1)	5,134.3	(j)	(3,850.2)	(t)	—
Accumulated other comprehensive loss	(448.5)	—		448.5	(t)	—
Peabody Energy Corporation stockholders' equity	319.6	6,163.1		(3,401.7)		3,081.0
Noncontrolling interests	12.3	—		38.6	(u)	50.9
Total stockholders' equity	331.9	6,163.1		(3,363.1)		3,131.9
Total liabilities and stockholders' equity	$ 12,836.5	$ (1,083.3)		$ (3,486.3)		$ 8,266.9

(a) Represents the Predecessor consolidated balance sheet at April 1, 2017.

(b) Represents amounts recorded for the implementation of the Plan on the Effective Date. This includes the settlement of liabilities subject to compromise through a combination of cash payments, the issuance of new common stock and warrants and the issuance of new debt. The following is the calculation of the total pre-tax gain on the settlement of the liabilities subject to compromise.

		(Dollars in millions)
Liabilities subject to compromise	$	8,416.7
Less amounts issued to settle claims:		
Successor Common Stock (at par)		(0.7)
Successor Series A Convertible Preferred Stock		(1,305.4)
Successor Additional paid-in capital		(1,774.9)
Issuance of Successor Notes		(1,000.0)
Issuance of Successor Term Loan		(950.0)
Cash payments and accruals for claims and professional fees		(336.4)
Other:		
Write-off of Predecessor debt issuance costs, see also (e) below		(18.1)
Total pre-tax gain on plan effects, see also (j) below	$	3,031.2

At the Effective Date, 70.9 million shares of Common Stock were issued and outstanding at a par value of $0.01 per share.

Convertible Preferred Stock was recorded at fair value and was based upon the $750.0 million cash raised upon emergence from bankruptcy through the Private Placement Agreement, plus a premium to account for the fair value of the Convertible Preferred Stocks' conversion and dividend features. Each share of Convertible Preferred Stock was convertible, at the holder's election or upon the occurrence of certain triggering events, into shares of Common Stock at a 35% discount relative to the initial per share purchase price of $25.00 and provided for three years of guaranteed paid-in-kind dividends, payable semiannually, at a rate of 8.5% per annum. The 46.2 million shares of Common Stock issuable upon conversion of the Convertible Preferred Stock issued under the Plan and an additional 13.1 million shares of Common Stock attributable to such Convertible Preferred Stocks' guaranteed paid-in-kind dividend feature constituted approximately 42% ownership of the Plan Equity Value (as defined in the Plan) of $3,105.0 million in the reorganized Company, and thus had a fair value of $1,305.4 million.

Successor Additional paid-in capital was recorded at the Plan Equity Value less the amounts recorded for par value of the Common Stock, the fair value of the Convertible Preferred Stock, and certain fees incurred associated with the Registration Rights Agreement.

(c) Represents the fresh start reporting adjustments required to record the assets and liabilities of the Company at fair value.

(d) The following table reflects the sources and uses of cash and restricted cash at emergence:

		(Dollars in millions)
Sources:		
Private placement and rights offering	$	1,500.0
Net proceeds from Senior Secured Term Loan		912.7
Escrowed interest from Successor Notes offering		8.0
Net impact on collateral requirements		11.6
Uses:		
Payments to secured lenders		(3,489.2)
Professional fees		(8.3)
Securitization facility deferred financing costs		(3.9)
Total cash outflow at emergence	$	(1,069.1)

(e) Primarily represents the write off of deferred financing costs associated with the cancellation and discharge of Predecessor revolving debt obligations.

(f) Represents the payment of deferred financing costs associated with the Receivables Purchase Agreement.

(g) Represents a $950.0 million Senior Secured Term Loan, net of an original issue discount and deferred financing costs of $37.3 million, as contemplated by the Plan. Under the Plan, the Company also issued $1.0 billion of Successor Notes, net of $49.5 million of deferred financing costs. The Successor Notes and the related proceeds held in escrow were included on the Company's unaudited condensed consolidated balance sheet at March 31, 2017. The debt instruments issued in accordance with the Plan, and the subsequent amendments, are further described in Note 14. "Long-term Debt."

(h) Represents an accrual to account for amounts paid subsequent to the Effective Date for professional fees and certain unsecured claims and settlements set forth in the Plan.

(i) Liabilities subject to compromise included secured and unsecured liabilities incurred prior to the Petition Date. These liabilities represented the amounts expected to be allowed on known or potential claims to be resolved through the Chapter 11 Cases and remained subject to future adjustments based on negotiated settlements with claimants, actions of the Bankruptcy Court, rejection of executory contracts, proofs of claims or other events. Additionally, liabilities subject to compromise also included certain items that were assumed under the Plan, and as such, were subsequently reclassified to liabilities not subject to compromise. Generally, actions to enforce or otherwise effect payment of prepetition liabilities were subject to the injunction provisions set forth in the Plan. Liabilities subject to compromise consisted of the following immediately prior to emergence:

	Predecessor	
	April 1, 2017	
	(Dollars in millions)	
Debt [1]	$	8,077.4
Interest payable		172.6
Environmental liabilities		61.9
Trade payables		55.2
Postretirement benefit obligations [2]		23.0
Other accrued liabilities		26.6
Liabilities subject to compromise	$	8,416.7

(1) Includes $7,768.3 million of first lien, second lien and unsecured debt, $257.3 million of derivative contract terminations, and $51.8 million of liabilities secured by prepetition letters of credit at April 1, 2017.

(2) Includes liabilities for unfunded non-qualified pension plans, all the participants of which are former employees.

(j) Reflects the impacts of the reorganization adjustments:

	(Dollars in millions)	
Total pre-tax gain on plan effects, see also (b) above	$	3,031.2
Cancellation of Predecessor Common Stock		0.2
Cancellation of Predecessor Additional paid-in capital		2,423.9
Cancellation of Predecessor Treasury stock		(371.9)
Successor debt issuance costs and other items, see also (f) and (g) above		50.9
Net impact on accumulated deficit	$	5,134.3

(k) Represents adjustment to increase the book value of coal inventories to their estimated fair value, less costs to sell the inventories.

(l) Represents adjustments comprising $228.5 million related to assets classified as held-for-sale at March 31, 2017 which were reclassified as held-for-use and considered in connection with the valuations described in (m) below, $89.5 million to write off certain existing short-term mine development costs, and $15.0 million of various prepaid assets deemed to have no future utility subsequent to the Effective Date.

(m) Represents a $3,461.4 million reduction in property, plant and equipment to estimated fair value as discussed below:

	Predecessor	Fresh Start Adjustments	Successor
		(Dollars in millions)	
Land and coal interests	$ 10,297.7	$ (6,511.8)	$ 3,785.9
Buildings and improvements	1,479.3	(1,013.2)	466.1
Machinery and equipment	2,143.8	(1,203.3)	940.5
Less: Accumulated depreciation, depletion and amortization	(5,266.9)	5,266.9	—
Net impact on accumulated deficit	$ 8,653.9	$ (3,461.4)	$ 5,192.5

The fair value of land and coal interests, excluding the asset related to the Company's asset retirement obligations described below, was established at $3,504.7 million utilizing a DCF model and the market approach. The market approach was used to provide a starting value of the coal mineral reserves without consideration for economic obsolescence. The DCF model was based on assumptions market participants would use in the pricing of these assets as well as projections of revenues and expenditures that would be incurred to mine or maintain these coal reserves through the life of mine. The basis of the DCF analysis was the Company's prepared projections which included a variety of estimates and assumptions, such as pricing and demand for coal. The Company's pricing was based on its view of the market taking into account third-party forward pricing curves adjusted for the quality of products sold by the Company. The fair value of land and coal interests also includes $281.2 million corresponding to the asset retirement obligation discussed in item (q) below.

The fair value of buildings and improvements and machinery and equipment were set at $466.1 million and $940.5 million, respectively, utilizing both market and cost approaches. The market approach was used to estimate the value of assets where detailed information for the asset was available and an active market was identified with a sufficient number of sales of comparable property that could be independently verified through reliable sources. The cost approach was utilized where there were limitations in the secondary equipment market to derive values from. The first step in the cost approach is the estimation of the cost required to replace the asset via construction or purchasing a new asset with similar utility adjusting for depreciation due to physical deterioration, functional obsolescence due to technology changes and economic obsolescence due to external factors such as regulatory changes. Useful lives were assigned to all assets based on remaining future economic benefit of each asset.

(n) Primarily to recognize fair value of $314.9 million inherent in certain U.S. coal supply agreements as a result of favorable differences between contract terms and estimated market terms for the same coal products, partially offset by a reduction in the fair value of certain equity method investments. The intangible asset related to coal supply agreements will be amortized on a per ton shipped basis through 2025. See also Note 10. "Intangible Contract Assets and Liabilities."

(o) Represents $32.6 million to account for the short-term portion of the value of certain contract-based intangibles primarily consisting of unutilized capacity of certain port and rail take-or-pay contracts, partially offset by $15.7 million related to liabilities classified as held-for-sale at March 31, 2017 which were reclassified as held-for-use and considered in connection with the valuations described in (m) above, and various other fair value adjustments. The intangible liabilities related to port and rail take-or-pay contracts will be amortized ratably over the terms of each contact, which vary in duration through 2043.

(p) Represents the tax impact of fresh start reporting. See also Note 12. "Income Taxes."

(q) Represents the fair value adjustment related to the Company's asset retirement obligations which was calculated using DCF models based on current mine plans. The credit-adjusted, risk-free interest rates utilized to estimate the Company's asset retirement obligations were 9.36% for its U.S. reclamation obligations and 4.36% for its Australia reclamation obligations.

(r) Represents the remeasurement of liabilities associated with the Company's postretirement benefits obligations as of the Effective Date as the reorganization of the Company pursuant to the Plan represented a remeasurement event under ASC 715 "Compensation - Retirement Benefits." The relevant discount rate was adjusted to 4.1% from 4.15% used in the Company's remeasurement process for the year ended December 31, 2016.

(s) Represents $83.6 million to account for the long-term portion of the value of contract-based intangibles related to unutilized capacity of port and rail take-or-pay contracts as described in (o) above and $58.7 million to account for the fair value inherent in certain U.S. coal supply agreements as a result of unfavorable differences between contract terms and estimated market terms for the same coal products as described in (n) above, partially offset by a remeasurement reduction of $9.2 million of the Company's pension liabilities in accordance with ASC 715 as described in (r) above, as the relevant discount rate was adjusted to 4.1% from 4.15% used in the Company's remeasurement process for the year ended December 31, 2016, and certain other valuation adjustments.

(t) Represents the elimination of remaining equity balances in accordance with fresh start reporting requirements.

(u) Represents adjustment to increase the book value of noncontrolling interests to fair value based on an estimate of the rights of the noncontrolling interests.

Reorganization Items, Net

The Company's reorganization items consisted of the following for the periods presented below:

	Successor	Predecessor	
	Year Ended December 31, 2018	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)		
Gain on settlement of claims	$ (12.8)	$ (3,031.2)	$ —
Fresh start adjustments, net	—	3,363.1	—
Fresh start income tax adjustments, net	—	253.9	—
Loss on termination of derivative contracts	—	—	75.2
Professional fees	—	42.5	88.4
Accounts payable settlement gains	—	(0.7)	(1.8)
Interest income	—	(0.4)	(1.8)
Other	—	—	(1.0)
Reorganization items, net	$ (12.8)	$ 627.2	$ 159.0
Cash paid for "Reorganization items, net"	$ —	$ 45.8	$ 68.1

Refer to the above section, *Effect of Plan and Fresh Start Reporting Adjustments*, for further information related to the gain on settlement of claims and fresh start adjustments, net recorded in the period January 1 through April 1, 2017.

The fresh start income tax adjustments included in the above table are comprised of tax benefits related to Predecessor deferred tax liabilities of $177.8 million, accumulated other comprehensive income of $81.5 million and unrecognized tax benefits of $6.7 million, partially offset by $12.1 million of tax expense related to the deferred tax assets of Predecessor discontinued operations.

Professional fees are only those that were directly related to the reorganization including, but not limited to, fees associated with advisors to the Debtors, the unsecured creditors' committee and certain other secured and unsecured creditors.

(3) Acquisition of Shoal Creek Mine

On December 3, 2018, the Company completed an acquisition of the Shoal Creek metallurgical coal mine, preparation plant and supporting assets located in Alabama (Shoal Creek Mine) from Drummond Company, Inc. for a purchase price of $387.4 million. The purchase price was funded with available cash on hand and reflected customary purchase price adjustments. The acquisition expands the Company's metallurgical mining platform to serve seaborne coal customers.

The acquisition excluded legacy liabilities other than reclamation and the Company is not responsible for other liabilities arising out of or relating to the operation of the Shoal Creek Mine prior to the acquisition date, including with respect to employee benefit plans and post-employment benefits. In connection with completing the acquisition, a new collective bargaining agreement was reached with the union-represented workforce that eliminates participation in the multi-employer pension plan and replaces it with a 401(k) retirement plan.

The preliminary purchase accounting allocations have been recorded in the accompanying consolidated financial statements as of, and for the period subsequent to the acquisition date. Subsequent to December 31, 2018, the Company agreed to pay an additional $2.4 million, which is reflected as a current liability in the table below, to settle a working capital adjustment. The following table summarizes the preliminary estimated fair values of assets acquired and liabilities assumed that were recognized at the acquisition and control date (in millions):

Inventories	$	39.7
Property, plant, equipment and mine development		364.7
Current liabilities		(6.5)
Asset retirement obligations		(10.5)
Total purchase price	$	387.4

Determining the fair value of assets acquired and liabilities assumed required judgment and the utilization of independent valuation experts, and included the use of significant estimates and assumptions, including assumptions with respect to future cash inflows and outflows, discount rates and asset lives, among other items. Due to the unobservable inputs to the valuation, the fair value would be considered Level 3 in the fair value hierarchy.

The Company is evaluating the mine plan, assessing the equipment and inventories, and reviewing coal reserve studies on the Shoal Creek Mine, the outcome of which will determine the fair value allocated to the asset retirement obligation, coal reserve assets, and equipment. The final valuation of the net assets acquired is expected to be finalized once those assessments and third-party valuation appraisals are completed. In connection with the acquisition, the Company recorded a contract based intangible liability of $3.5 million to reflect the fair value of a coal supply agreement. The liability was amortized to income in January 2019 and the related contract was renegotiated on market terms.

The Shoal Creek Mine contributed revenues of $12.8 million and less than $0.1 million of net income from December 4, 2018 through December 31, 2018. Such results are included in the consolidated statements of operations and are reported in the Seaborne Metallurgical Mining segment. This excludes acquisition costs recorded during the year ended December 31, 2018 of $7.4 million, which primarily consisted of professional fees. These acquisition costs are recorded in the “Acquisition costs related to Shoal Creek Mine” line item in the consolidated statements of operations.

As a result of Peabody's reorganization and change in reporting entity as described in Note 2. “Emergence from the Chapter 11 Cases and Fresh Start Reporting,” the following unaudited pro forma financial information presents the combined results of operations of the Company and the Shoal Creek Mine, on a pro forma basis, as though the acquisition was completed on April 2, 2017. The pro forma financial information does not necessarily reflect the results of operations that would have occurred had the Company and the Shoal Creek Mine constituted a single entity during those periods or that may be attained in the future.

	Successor			
	Year Ended December 31, 2018		April 2 through December 31, 2017	
	(Dollars in millions, except per share data)			
Revenue	$	6,008.4	$	4,506.2
Income from continuing operations, net of income taxes		826.6		783.3
Basic earnings per share from continuing operations	$	5.84	$	4.37
Diluted earnings per share from continuing operations	$	5.75	$	4.33

The pro forma income from continuing operations, net of income taxes includes adjustments to operating costs to reflect the additional expense for the estimated impact of the fair value adjustment for coal inventory, a reduction in postretirement benefit costs resulting from the new collective bargaining agreement described above, and the estimated impact on depreciation, depletion and amortization for the fair value adjustment for property, plant and equipment (including coal reserve assets). On a pro forma basis, the acquisition would have had no impact on taxable income due to the Company’s federal net operating losses (NOLs), as further described in Note 12. “Income Taxes.”

(4) Revenue Recognition

The Company accounts for revenue in accordance with ASC Topic 606, "Revenue from Contracts with Customers," (ASC 606) which the Company adopted on January 1, 2018, using the modified retrospective approach. See Note 1. "Summary of Significant Accounting Policies," for further discussion of the adoption, including the transition impact on the Company's accompanying consolidated balance sheets.

Disaggregation of Revenues

Revenue by product type and market is set forth in the following tables. With respect to its seaborne mining segments, the Company classifies as "Export" certain revenue from domestically-delivered coal under contracts in which the price is derived on a basis similar to export contracts.

	Successor						
	Year Ended December 31, 2018						
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining	Corporate and Other [(1)]	Consolidated
	(Dollars in millions)						
Thermal coal							
Domestic	$ 1,424.8	$ 799.4	$ 543.1	$ —	$ 153.0	$ —	$ 2,920.3
Export	—	1.3	22.1	—	945.0	—	968.4
Total thermal	1,424.8	800.7	565.2	—	1,098.0	—	3,888.7
Metallurgical coal							
Export	—	—	—	1,548.6	—	—	1,548.6
Total metallurgical	—	—	—	1,548.6	—	—	1,548.6
Other	—	0.3	26.8	4.4	1.2	111.8	144.5
Total revenues	$ 1,424.8	$ 801.0	$ 592.0	$ 1,553.0	$ 1,099.2	$ 111.8	$ 5,581.8

	Successor						
	April 2 through December 31, 2017						
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining	Corporate and Other [(1)]	Consolidated
	(Dollars in millions)						
Thermal coal							
Domestic	$ 1,174.3	$ 586.7	$ 409.8	$ —	$ 87.9	$ —	$ 2,258.7
Export	—	5.3	19.2	—	684.1	—	708.6
Total thermal	1,174.3	592.0	429.0	—	772.0	—	2,967.3
Metallurgical coal							
Export	—	—	—	1,221.0	—	—	1,221.0
Total metallurgical	—	—	—	1,221.0	—	—	1,221.0
Other	4.4	0.3	11.7	—	0.5	47.4	64.3
Total revenues	$ 1,178.7	$ 592.3	$ 440.7	$ 1,221.0	$ 772.5	$ 47.4	$ 4,252.6

	Predecessor						
	January 1 through April 1, 2017						
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining	Corporate and Other (1)	Consolidated
	(Dollars in millions)						
Thermal coal							
Domestic	$ 394.3	$ 193.2	$ 133.5	$ —	$ 27.3	$ —	$ 748.3
Export	—	—	—	—	197.2	—	197.2
Total thermal	394.3	193.2	133.5	—	224.5	—	945.5
Metallurgical coal							
Export	—	—	—	324.6	—	—	324.6
Total metallurgical	—	—	—	324.6	—	—	324.6
Other	—	—	16.2	4.3	0.3	35.3	56.1
Total revenues	$ 394.3	$ 193.2	$ 149.7	$ 328.9	$ 224.8	$ 35.3	$ 1,326.2

	Predecessor						
	Year Ended December 31, 2016						
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining	Corporate and Other (1)	Consolidated
	(Dollars in millions)						
Thermal coal							
Domestic	$ 1,472.5	$ 793.4	$ 516.1	$ —	$ 108.1	$ —	$ 2,890.1
Export	—	—	—	—	715.3	—	715.3
Total thermal	1,472.5	793.4	516.1	—	823.4	—	3,605.4
Metallurgical coal							
Export	—	—	—	1,089.6	—	—	1,089.6
Total metallurgical	—	—	—	1,089.6	—	—	1,089.6
Other	0.8	(0.9)	9.9	0.8	1.5	8.2	20.3
Total revenues	$ 1,473.3	$ 792.5	$ 526.0	$ 1,090.4	$ 824.9	$ 8.2	$ 4,715.3

Revenue by contract duration was as follows:

	Successor						
	Year Ended December 31, 2018						
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining	Corporate and Other (1)	Consolidated
	(Dollars in millions)						
One year or longer	$ 1,283.9	$ 775.4	$ 531.8	$ 1,036.7	$ 799.5	$ —	$ 4,427.3
Less than one year	140.9	25.3	33.4	511.9	298.5	—	1,010.0
Other (2)	—	0.3	26.8	4.4	1.2	111.8	144.5
Total revenues	$ 1,424.8	$ 801.0	$ 592.0	$ 1,553.0	$ 1,099.2	$ 111.8	$ 5,581.8

	Successor						
	April 2 through December 31, 2017						
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining	Corporate and Other [1]	Consolidated
	(Dollars in millions)						
One year or longer	$ 1,023.1	$ 560.5	$ 404.6	$ 867.1	$ 503.0	$ —	$ 3,358.3
Less than one year	151.2	31.5	24.4	353.9	269.0	—	830.0
Other [2]	4.4	0.3	11.7	—	0.5	47.4	64.3
Total revenues	$ 1,178.7	$ 592.3	$ 440.7	$ 1,221.0	$ 772.5	$ 47.4	$ 4,252.6

	Predecessor						
	January 1 through April 1, 2017						
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining	Corporate and Other [1]	Consolidated
	(Dollars in millions)						
One year or longer	$ 357.7	$ 193.2	$ 129.3	$ 240.6	$ 134.1	$ —	$ 1,054.9
Less than one year	36.6	—	4.2	84.0	90.4	—	215.2
Other [2]	—	—	16.2	4.3	0.3	35.3	56.1
Total revenues	$ 394.3	$ 193.2	$ 149.7	$ 328.9	$ 224.8	$ 35.3	$ 1,326.2

	Predecessor						
	Year Ended December 31, 2016						
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining	Corporate and Other [1]	Consolidated
	(Dollars in millions)						
One year or longer	$ 1,364.0	$ 791.8	$ 478.8	$ 686.1	$ 464.2	$ —	$ 3,784.9
Less than one year	108.5	1.6	37.3	403.5	359.2	—	910.1
Other [2]	0.8	(0.9)	9.9	0.8	1.5	8.2	20.3
Total revenues	$ 1,473.3	$ 792.5	$ 526.0	$ 1,090.4	$ 824.9	$ 8.2	$ 4,715.3

(1) Corporate and Other revenue includes realized and unrealized gains and losses related to mark-to-market activity from economic hedge activities intended to hedge future coal sales. Refer to Note 9. “Derivatives and Fair Value Measurements” for additional information regarding the economic hedge activities.

(2) Other includes revenues from arrangements such as customer contract-related payments, royalties related to coal lease agreements, sales agency commissions, farm income and property and facility rentals, for which contract duration is not meaningful.

Committed Revenue from Contracts with Customers

The Company expects to recognize revenue subsequent to December 31, 2018 of approximately $5.8 billion related to contracts with customers in which volumes and prices per ton were fixed or reasonably estimable at December 31, 2018. Approximately 51% of such amount is expected to be recognized over the next twelve months and the remainder thereafter. Actual revenue related to such contracts may differ materially for various reasons, including price adjustment features for coal quality and cost escalations, volume optionality provisions and potential force majeure events. This estimate of future revenue does not include any revenue related to contracts with variable prices per ton that cannot be reasonably estimated, such as the majority of seaborne metallurgical and seaborne thermal coal contracts where pricing is negotiated or settled quarterly or annually.

Accounts Receivable

"Accounts receivable, net" at December 31, 2018 and 2017 consisted of the following:

	December 31, 2018	December 31, 2017
	(Dollars in millions)	
Trade receivables, net	$ 345.5	$ 504.2
Miscellaneous receivables, net	104.9	47.9
Accounts receivable, net	$ 450.4	$ 552.1

Trade receivables, net presented above have been shown net of reserves of $0.1 million and $0.3 million as of December 31, 2018 and 2017, respectively. Miscellaneous receivables, net presented above have been shown net of reserves of $4.3 million as of both December 31, 2018 and 2017. Included in "Operating costs and expenses" in the consolidated statements of operations was a credit of $0.2 million for the year ended December 31, 2018, and charges of $4.3 million and $0.8 million for the period April 2 through December 31, 2017 and the year ended December 31, 2016, respectively. No charges for doubtful accounts were recognized during the period January 1 through April 1, 2017.

The Company also records long-term customer receivables related to the reimbursement of certain post-mining costs which are included within "Investments and other assets" in the accompanying consolidated balance sheets. The balance of such receivables was $11.1 million and $139.3 million as of December 31, 2018 and 2017, respectively. The balance was adjusted in connection with the adoption of ASC 606, as described in Note 1. "Summary of Significant Accounting Policies." Also in connection with the adoption of ASC 606, the Company prospectively records a portion of the consideration received as "Interest income" rather than "Revenues" in the accompanying consolidated statements of operations, due to the embedded financing element within the related contract. Interest income related to these arrangements amounted to $8.4 million during the year ended December 31, 2018.

(5) Asset Impairment

The Company's mining and exploration assets and mining-related investments may be adversely affected by numerous uncertain factors that may cause the Company to be unable to recover all or a portion of the carrying value of those assets. The Company generally does not view short-term declines in thermal and metallurgical coal prices as an indicator of impairment. However, the Company generally views a sustained trend (for example, over periods exceeding one year) of adverse coal pricing or unfavorable changes thereto as a potential indicator of impairment. Because of the volatile and cyclical nature of coal prices and demand, it is reasonably possible that coal prices may decrease and/or fail to improve in the near term, which, absent sufficient mitigation such as an offsetting reduction in the Company's operating costs, may result in the need for future adjustments to the carrying value of the Company's long-lived mining assets and mining-related investments.

The Company's assets whose recoverability and values are most sensitive to near-term pricing include certain Australian metallurgical assets with an aggregate carrying value of $177.2 million as of December 31, 2018. The Company conducted a review of those assets for recoverability as of December 31, 2018 and determined that no further impairment charge was necessary as of that date.

The fair value estimates made during the Company's impairment assessments were determined in accordance with the methods outlined in Note 1. "Summary of Significant Accounting Policies," except in certain instances where indicative bids were received related to non-strategic assets being marketed for divestiture. In those instances, the indicative bids were also considered in estimating fair value. As described in Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting," the Company adjusted the book values of its property, plant, equipment and mine development assets to estimated fair value in connection with fresh start reporting.

During the year ended December 31, 2018 and the period April 2 through December 31, 2017, the Company recognized no impairment charges. During the period January 1 through April 1, 2017, the Company recognized impairment charges of $30.5 million related to terminated coal lease contracts in the Midwestern United States.

During 2016, the Company recorded an impairment charge of $193.2 million related to its Metropolitan Mine in New South Wales, Australia as a result of entering into a definitive agreement to sell the mine for an amount less than the carrying value of the related assets. The agreement was subsequently terminated during 2017 as the parties were unable to obtain the necessary Australian regulatory approvals, but the agreed-upon selling price was deemed the best estimate of fair value for the related assets. Also during 2016, during a review of its asset portfolio and prepetition leases, the Company identified certain non-strategic Midwestern coal reserves held under lease that were determined to be uneconomical to be mined in the future. As a result, the Company rejected certain leases and recognized an aggregate impairment charge of $37.5 million. The Company also recognized a $17.2 million impairment charge to record at fair value certain non-strategic Australian metallurgical assets classified as held for sale. For additional information regarding divested assets, refer to Note 22. “Other Events.”

(6) Discontinued Operations

Discontinued operations include certain former Seaborne Thermal Mining and Midwestern U.S. Mining segment assets that have ceased production and other previously divested legacy operations, including Patriot Coal Corporation and certain of its wholly-owned subsidiaries (Patriot).

Summarized Results of Discontinued Operations

Results from discontinued operations were as follows during the years ended December 31, 2018, 2017 and 2016:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Income (loss) from discontinued operations, net of income taxes	$ 18.1	$ (19.8)	$ (16.2)	$ (57.6)

There were no significant revenues from discontinued operations during the years ended December 31, 2018, 2017 and 2016.

Assets and Liabilities of Discontinued Operations

Assets and liabilities classified as discontinued operations included in the Company’s consolidated balance sheets were as follows:

	December 31, 2018	December 31, 2017
	(Dollars in millions)	
Assets:		
Other current assets	$ —	$ 0.3
Total assets classified as discontinued operations	$ —	$ 0.3
Liabilities:		
Accounts payable and accrued expenses	$ 54.0	$ 70.6
Other noncurrent liabilities	141.1	170.0
Total liabilities classified as discontinued operations	$ 195.1	$ 240.6

Patriot-Related Matters

A significant portion of the liabilities in the table above relate to Patriot. In 2012, Patriot filed voluntary petitions for relief under the Bankruptcy Code. In 2013, the Company entered into a definitive settlement agreement (2013 Agreement) with Patriot and the United Mine Workers of America (UMWA), on behalf of itself, its represented Patriot employees and its represented Patriot retirees, to resolve all then disputed issues related to Patriot’s bankruptcy. In May 2015, Patriot again filed voluntary petitions for relief under the Bankruptcy Code in the Eastern District of Virginia and subsequently initiated a process to sell some or all of its assets to qualified bidders. On October 9, 2015, Patriot’s bankruptcy court entered an order confirming Patriot’s plan of reorganization, which provided, among other things, for the sale of substantially all of Patriot’s assets to two different buyers.

Black Lung Occupational Disease Liabilities. Patriot had federal and state black lung occupational disease liabilities related to workers employed in periods prior to Patriot's spin-off from the Company in 2007. Upon spin-off, Patriot indemnified the Company against any claim relating to these liabilities, which amounted to approximately $150 million at that time. The indemnification included any claim made by the U.S. Department of Labor (DOL) against the Company with respect to these obligations as a potentially liable operator under the Federal Coal Mine Health and Safety Act of 1969. The 2013 Agreement included Patriot's affirmance of indemnities provided in the spin-off agreements, including the indemnity relating to such black lung liabilities; however, Patriot rejected this indemnity in its May 2015 bankruptcy.

By statute, the Company had secondary liability for the black lung liabilities related to Patriot's workers employed by former subsidiaries of the Company. The Company's accounting for the black lung liabilities related to Patriot is based on an interpretation of applicable statutes. Management believes that inconsistencies exist among the applicable statutes, regulations promulgated under those statutes and the DOL's interpretative guidance. The Company has sought clarification from the DOL regarding these inconsistencies and the accounting for these liabilities could be reduced in the future depending on the DOL's responses. Whether the Company will ultimately be required to fund certain of those obligations in the future as a result of Patriot's May 2015 bankruptcy remains uncertain. The amount of the liability, which was determined on an actuarial basis based on the best information available to the Company was $102.7 million and $134.0 million at December 31, 2018 and 2017, respectively. In connection with the actuarial valuation, the Company recorded a mark-to-market adjustment of $33.7 million and $7.9 million to decrease the liability during the period ended December 31, 2018 and increase the liability during the period April 2 through December 31, 2017. While the Company has recorded a liability, it intends to review each claim on a case-by-case basis and contest liability estimates as appropriate. The amount of the Company's recorded liability reflects only Patriot workers employed by former subsidiaries of the Company that are presently retired, disabled or otherwise not actively employed. The Company cannot reliably estimate the potential liabilities for Patriot's workers employed by former subsidiaries of the Company that are presently active in the workforce because of the potential for such workers to continue to work for another coal operator that is a going concern.

Combined Benefit Fund (Combined Fund). The Combined Fund was created by the Coal Act in 1992 as a multi-employer plan to provide health care benefits to a closed group of retirees who last worked prior to 1976, as well as orphaned beneficiaries of bankrupt companies who were receiving benefits as orphans prior to the passage of the Coal Act. No new retirees will be added to this group, which includes retirees formerly employed by certain Patriot subsidiaries and their predecessors. Former employers are required to contribute to the Combined Fund according to a formula.

Under the terms of the Patriot spin-off, Patriot was primarily liable to the Combined Fund for the approximately $40.0 million of its subsidiaries' obligations at that time. Once Patriot ceased meeting its obligations, the Company was held responsible for these costs and, as a result, recorded "Income (loss) from discontinued operations, net of income taxes" charges of $0.7 million, $0.6 million, and $0.2 million and $1.2 million during the year ended December 31, 2018, the period April 2 through December 31, 2017, the period January 1 through April 1, 2017 and the year ended December 31, 2016, respectively. The Company made payments into the fund of $2.2 million and $1.7 million and $0.6 million during the year ended December 31, 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017 and estimates that the annual cash cost to fund these potential Combined Fund liabilities will range between $1 million and $2 million in the near-term, with those premiums expected to decline over time because the fund is closed to new participants. The liability related to the fund was $16.4 million and $20.2 million at December 31, 2018 and 2017, respectively.

UMWA 1974 Pension Plan (UMWA Plan) Litigation. On July 16, 2015, a lawsuit was filed by the UMWA Plan, the UMWA 1974 Pension Trust (Trust) and the Trustees of the UMWA Plan and Trust (Trustees) in the United States District Court for the District of Columbia, against PEC, PHC, a subsidiary of the Company, and Arch Coal, Inc. (Arch). The plaintiffs sought, pursuant to the Employee Retirement Income Security Act of 1974, as amended (ERISA) and the Multiemployer Pension Plan Amendments Act of 1980 (MPPAA), a declaratory judgment that the defendants were obligated to arbitrate any opposition to the Trustees' determination that the defendants have statutory withdrawal liability as a result of the 2015 Patriot bankruptcy. After a legal and arbitration process and with the approval of the Bankruptcy Court, on January 25, 2017, the UMWA Plan and the Debtors agreed to a settlement of the claim whereby the UMWA Plan will be entitled to $75 million to be paid by the Company in increments through 2021. In connection with the settlement, the Company recorded a liability representing the present value of the installments of $54.3 million and recognized an equivalent charge to "Income (loss) from discontinued operations, net of income taxes" in the consolidated statement of operations for the year ended December 31, 2016. The balance of the liability was $36.7 million and $46.0 million at December 31, 2018 and 2017, respectively.

(7) Inventories

Inventories as of December 31, 2018 and December 31, 2017 consisted of the following:

	December 31, 2018	December 31, 2017
	(Dollars in millions)	
Materials and supplies	$ 118.1	$ 101.5
Raw coal	53.6	78.1
Saleable coal	108.5	111.7
Inventories	$ 280.2	$ 291.3

Materials and supplies inventories presented above have been shown net of reserves of $0.2 million and $0.6 million as of December 31, 2018 and 2017, respectively.

(8) Investments

Equity Method Investments

The Company's equity method investments include its joint venture interest in Middlemount and certain other equity method investments.

The table below summarizes the book value of those investments and related financing receivables, which are reported in "Investments and other assets" in the consolidated balance sheets, and the related "Income from equity affiliates":

			Successor		Predecessor	
	Book Value at		Income from Equity Affiliates			
	December 31, 2018	December 31, 2017	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)					
Equity method investment and financing receivables related to Middlemount	$ 45.0	$ 82.1	$ (69.3)	$ (48.6)	$ (17.4)	$ (22.6)
Other equity method investments	0.9	1.7	1.2	(0.4)	2.4	6.4
Total equity method investments and financing receivables related to Middlemount	$ 45.9	$ 83.8	$ (68.1)	$ (49.0)	$ (15.0)	$ (16.2)

As noted in Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting," the carrying value of the equity method investments and financing receivables related to Middlemount was adjusted to fair value in connection with fresh start reporting based on the net present value of future cash flows associated with the Company's 50% equity interest in Middlemount. As of December 31, 2018, the financing receivables are accounted for as in-substance common stock due to the limited fair value attributed to Middlemount's equity.

The Company received cash payments from Middlemount of $106.7 million, $48.1 million and $32.7 million during the year ended December 31, 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017, respectively.

During the year ended December 31, 2018 the Company determined that a valuation allowance on Middlemount's net deferred tax position was no longer necessary based on recent cumulative earnings and expectation of future earnings. The determination resulted in approximately $9 million of income which was more than offset by a tax reserve of approximately $17 million due to an uncertain tax position relating to an ongoing income tax audit of Middlemount.

During the year ended December 31, 2018, the period April 2 through December 31, 2017, the period January 1 through April 1, 2017, and the year ended December 31, 2016 Middlemount generated revenues of approximately $271 million, $193 million, $60 million and $183 million (on a 50% basis).

Middlemount had current assets, noncurrent assets, current liabilities and noncurrent liabilities of $33.6 million, $181.8 million, $187.9 million and $35.8 million, respectively, as of December 31, 2018 and $61.7 million, $232.2 million, $313.9 million and $41.2 million, respectively, as of December 31, 2017 (on a 50% basis).

(9) Derivatives and Fair Value Measurements

Derivatives

Corporate Risk Management Activities

From time to time, the Company may utilize various types of derivative instruments to manage its exposure to risks in the normal course of business, including (1) foreign currency exchange rate risk and the variability of cash flows associated with forecasted Australian dollar expenditures made in its Australian mining platform, (2) price risk of fluctuating coal prices related to forecasted sales or purchases of coal, or changes in the fair value of a fixed price physical sales contract, (3) price risk and the variability of cash flows related to forecasted diesel fuel purchased for use in its operations, and (4) interest rate risk on long-term debt. These risk management activities are actively monitored for compliance with the Company's risk management policies.

As of December 31, 2018, the Company had currency options outstanding with an aggregate notional amount of $875.0 million Australian dollars to hedge currency risk associated with anticipated Australian dollar expenditures during the first nine months of 2019. The instruments are quarterly average rate options whereby the Company is entitled to receive payment on the notional amount should the quarterly average Australian dollar-to-U.S. dollar exchange rate exceed amounts ranging from $0.77 to $0.78 the over the first nine months of 2019.

As of December 31, 2018, the Company held coal-related financial contracts in relation to a portion of the forecasted sales of its mines' coal production for an aggregate notional volume of 1.7 million tons. Such financial contracts include futures, forwards and options. Of the aggregate notional volume, 0.8 million tons will settle in 2019 and the remainder will settle in 2020.

The Company had no diesel fuel or interest rate derivatives in place as of December 31, 2018.

Coal Trading Activities

On a limited basis, the Company engages in the direct and brokered trading of coal and freight-related contracts (coal trading). Except those contracts for which the Company has elected to apply a normal purchases and normal sales exception, all derivative coal trading contracts are accounted for at fair value. Coal brokering is conducted both as principal and agent in support of various coal production-related activities that may involve coal produced from the Company's mines, coal sourcing arrangements with third-party mining companies or offtake agreements with other coal producers. The Company 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 the Company's coal trading strategy. Revenues from such transactions include realized and unrealized gains and losses on derivative instruments, including those that arise from coal deliveries related to contracts accounted for on an accrual basis under the normal purchases and normal sales exception.

Offsetting and Balance Sheet Presentation

The Company has master netting agreements with certain of its counterparties which allow for the settlement of contracts in an asset position with contracts in a liability position in the event of default or termination. Such netting arrangements reduce the Company's credit exposure related to these counterparties. For classification purposes, the Company records the net fair value of all the positions with a given counterparty as a net asset or liability in the consolidated balance sheets.

The Company's coal trading assets and liabilities include financial instruments cleared through various exchanges, which involve the daily net settlement of open positions. The Company must post cash collateral in the form of initial margin, in addition to variation margin, on exchange-cleared positions that are in a net liability position and receives variation margin when in a net asset position. The Company also transacts in coal trading financial swaps and options through over-the-counter (OTC) markets with financial institutions and other non-financial trading entities under International Swaps and Derivatives Association (ISDA) Master Agreements, which contain symmetrical default provisions. Certain of the Company's coal trading agreements with OTC counterparties also contain credit support provisions that may periodically require the Company to post, or entitle the Company to receive, variation margin. Physical coal and freight-related purchase and sale contracts included in the Company's coal trading assets and liabilities are executed pursuant to master purchase and sale agreements that also contain symmetrical default provisions and allow for the netting and setoff of receivables and payables that arise during the same time period. The Company offsets its coal trading asset and liability derivative positions, and variation margin related to those positions, on a counterparty-by-counterparty basis in the consolidated balance sheets.

The fair value of derivatives reflected in the accompanying balance sheets are set forth in the table below.

	December 31, 2018		December 31, 2017	
	Asset Derivative	Liability Derivative	Asset Derivative	Liability Derivative
	(Dollars in millions)			
Foreign currency option contracts	$ 1.2	$ —	$ 4.2	$ —
Coal contracts related to forecasted sales	6.6	(23.1)	8.4	(46.1)
Coal trading contracts	59.7	(64.4)	119.4	(126.7)
Total derivatives	67.5	(87.5)	132.0	(172.8)
Effect of counterparty netting	(64.5)	64.5	(125.2)	125.2
Variation margin posted	—	21.8	—	35.8
Net derivatives and margin as classified in the balance sheets	$ 3.0	$ (1.2)	$ 6.8	$ (11.8)

The net amounts of asset derivatives are included in “Other current assets” and the net amount of liability derivatives, net of margin, are included in “Accounts payable and accrued expenses” in the accompanying balance sheets.

Effects of Derivatives on Measures of Financial Performance

Currently, the Company does not seek cash flow hedge accounting treatment for its currency- or coal-related derivative financial instruments and thus changes in fair value are reflected in current earnings.

Prior to the Bankruptcy Petitions, as of December 31, 2015, the Company concluded that as a result of deterioration in its credit profile, it could no longer consider its then existing cash flow hedging relationships to be “highly effective” at offsetting the changes in the anticipated exposure of hedged items. Therefore, the Company discontinued the application of cash flow hedge accounting subsequent to December 31, 2015 and changes in the fair value of derivative instruments have been reflected in current earnings after that date. Previous fair value adjustments recorded in “Accumulated other comprehensive income” were frozen until the underlying transactions impacted the Company’s earnings.

The Bankruptcy Petitions constituted an event of default under the Company’s derivative financial instrument contracts and the counterparties terminated the agreements shortly thereafter in accordance with contractual terms. The Company adjusted the corresponding liabilities to be equivalent to the termination value of each contract. The adjustment was recorded in reorganization items, net, in the accompanying consolidated statements of operations during the year ended December 31, 2016.

The tables below show the amounts of pre-tax gains and losses related to the Company’s derivatives.

	Successor		
	Year Ended December 31, 2018		
Financial Instrument	Total (loss) gain recognized in income	(Loss) gain realized in income on derivatives	Unrealized (loss) gain recognized in income on derivatives
	(Dollars in millions)		
Foreign currency option contracts	$ (9.1)	$ (8.4)	$ (0.7)
Coal contracts related to forecasted sales	115.7	97.4	18.3
Coal trading contracts	(2.9)	(5.3)	2.4
Total	$ 103.7	$ 83.7	$ 20.0

Financial Instrument	Successor April 2 through December 31, 2017 Total gain (loss) recognized in income	Gain (loss) realized in income on derivatives	Unrealized (loss) gain recognized in income on derivatives
	(Dollars in millions)		
Foreign currency option contracts	$ 1.8	$ 3.3	$ (1.5)
Coal contracts related to forecasted sales	12.1	35.1	(23.0)
Coal trading contracts	(1.6)	(8.3)	6.7
Total	$ 12.3	$ 30.1	$ (17.8)

Financial Instrument	Predecessor January 1 through April 1, 2017 Total (loss) gain recognized in income	Gain (loss) realized in income on derivatives	Unrealized gain recognized in income on derivatives	Loss reclassified from other comprehensive loss into income
	(Dollars in millions)			
Commodity swap contracts	$ (11.0)	$ —	$ —	$ (11.0)
Foreign currency forward contracts	(16.6)	—	—	(16.6)
Financial coal contracts - Company production	29.2	12.7	16.5	—
Coal trading contracts	2.2	(11.3)	13.5	—
Total	$ 3.8	$ 1.4	$ 30.0	$ (27.6)

Financial Instrument	Predecessor Year Ended December 31, 2016 Total realized (loss) gain recognized in income	Gain realized in income on derivatives	Unrealized loss recognized in income on derivatives	Loss reclassified from other comprehensive income into income (effective portion)	Loss reclassified from other comprehensive income into income (ineffective portion)
	(Dollars in millions)				
Commodity swap contracts	$ (136.8)	$ —	$ —	$ (86.1)	$ (50.7)
Foreign currency forward contracts	(179.3)	—	—	(145.6)	(33.7)
Coal contracts related to forecasted sales	5.6	45.4	(39.8)	—	—
Coal trading contracts	(16.5)	22.1	(38.6)	—	—
Total	$ (327.0)	$ 67.5	$ (78.4)	$ (231.7)	$ (84.4)

During the year ended December 31, 2018, the period April 2 through December 31, 2017, and the period January 1 through April 1, 2017, gains and losses on foreign currency option contracts and commodity swap contracts were included in "Operating costs and expenses," and gains and losses on coal contracts related to forecasted sales and those related to coal trading contracts were included in "Revenues" in the accompanying consolidated statements of operations. During the year ended December 31, 2016, all classifications in the accompanying consolidated statements of operations were similar, except for realized losses of $75.2 million related to commodity swap contracts and foreign currency forward contracts which are included in "Reorganization items, net." Such losses were incurred as a result of the Company's filing of the Bankruptcy Petitions, an event of default which led the derivative contract counterparties to terminate the agreements in accordance with their contractual terms and demand payment at the termination values of each contract.

The Company classifies the cash effects of its derivatives within the "Cash Flows From Operating Activities" section of the consolidated statements of cash flows.

Fair Value Measurements

The Company uses a three-level fair value hierarchy that categorizes assets and liabilities measured at fair value based on the observability of the inputs utilized in the valuation. These levels include: Level 1 - inputs are quoted prices in active markets for the identical assets or liabilities; Level 2 - inputs are other than quoted prices included in Level 1 that are directly or indirectly observable through market-corroborated inputs; and Level 3 - inputs are unobservable, or observable but cannot be market-corroborated, requiring the Company to make assumptions about pricing by market participants.

The following tables set forth the hierarchy of the Company's net financial asset (liability) positions for which fair value is measured on a recurring basis:

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Foreign currency option contracts	$ —	$ 1.2	$ —	$ 1.2
Coal contracts related to forecasted sales	—	(21.2)	—	(21.2)
Coal trading contracts	—	21.8	—	21.8
Equity securities	—	—	10.0	10.0
Total net financial assets	$ —	$ 1.8	$ 10.0	$ 11.8

	December 31, 2017			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Foreign currency option contracts	$ —	$ 4.2	$ —	$ 4.2
Coal contracts related to forecasted sales	—	(40.2)	—	(40.2)
Coal trading contracts	(3.0)	34.0	—	31.0
Total net financial liabilities	$ (3.0)	$ (2.0)	$ —	$ (5.0)

For Level 1 and 2 financial assets and liabilities, the Company utilizes both direct and indirect observable price quotes, including interest rate yield curves, exchange indices, broker/dealer quotes, published indices, issuer spreads, benchmark securities and other market quotes. In the case of certain debt securities, fair value is provided by a third-party pricing service. Below is a summary of the Company's valuation techniques for Level 1 and 2 financial assets and liabilities:

- Foreign currency option contracts: valued utilizing inputs obtained in quoted public markets (Level 2) except when credit and non-performance risk is considered to be a significant input, then the Company classifies such contracts as Level 3.
- Coal contracts related to forecasted sales and coal trading contracts: generally valued based on unadjusted quoted prices in active markets (Level 1) or a valuation that is corroborated by the use of market-based pricing (Level 2) except when credit and non-performance risk is considered to be a significant input (greater than 10% of fair value), then the Company classifies as Level 3.
- Investments in equity securities are based on observed prices in an inactive market (Level 3).

Other Financial Instruments. The following methods and assumptions were used by the Company in estimating fair values for other financial instruments as of December 31, 2018 and 2017:

- Cash and cash equivalents, restricted cash, accounts receivable, including those within the Company's accounts receivable securitization program, notes receivable and accounts payable have carrying values which approximate fair value due to the short maturity or the liquid nature of these instruments.
- Long-term debt fair value estimates are based on observed prices for securities with an active trading market when available (Level 2), and otherwise on estimated borrowing rates to discount the cash flows to their present value (Level 3).

The carrying amount and estimated fair values of the Company's current and long-term debt as of December 31, 2018 and 2017 are summarized as follows:

	December 31, 2018		December 31, 2017	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(Dollars in millions)			
Current and Long-term debt	$ 1,367.0	$ 1,366.2	$ 1,460.8	$ 1,547.4

The Company's risk management function, which is independent of the Company's coal trading function, is responsible for valuation policies and procedures, with oversight from executive management. Generally, the Company's Level 3 instruments or contracts are valued using bid/ask price quotations and other market assessments obtained from multiple, independent third-party brokers or other transactional data incorporated into internally-generated discounted cash flow models. Decreases in the number of third-party brokers or market liquidity could erode the quality of market information and therefore the valuation of the Company's market positions. The Company's valuation techniques include basis adjustments to the foregoing price inputs for quality, such as sulfur and ash content, location differentials, expressed as port and freight costs, and credit risk. The Company's risk management function independently validates the Company's valuation inputs, including unobservable inputs, with third-party information and settlement prices from other sources where available. A daily process is performed to analyze market price changes and changes to the portfolio. Further periodic validation occurs at the time contracts are settled with the counterparty. These valuation techniques have been consistently applied in all periods presented, and the Company believes it has obtained the most accurate information available for the types of derivative contracts held.

Significant increases or decreases in the inputs in isolation could result in a significantly higher or lower fair value measurement. The unobservable inputs do not have a direct interrelationship; therefore, a change in one unobservable input would not necessarily correspond with a change in another unobservable input.

The following table summarizes the changes in the Company's recurring Level 3 net financial assets (liabilities):

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Beginning of period	$ —	$ (0.7)	$ (1.1)	$ (15.6)
Transfers into Level 3	—	—	—	5.3
Transfers out of Level 3	—	0.7	0.2	(0.4)
Total gains realized/unrealized:				
Included in earnings	(1.7)	—	0.2	(2.4)
Purchases	10.0	—	—	—
Sales	—	—	—	—
Settlements	1.7	—	—	12.0
End of period	$ 10.0	$ —	$ (0.7)	$ (1.1)

The Company had no transfers between Levels 1 and 2 during any of the periods presented in the table above. Transfers of liabilities into/out of Level 3 from/to Level 2 during the periods presented were due to the relative value of unobservable inputs to the total fair value measurement of certain derivative contracts falling below, or in the case of transfers in, rising above, the 10% threshold. The Company's policy is to value all transfers between levels using the beginning of period valuation.

The following table summarizes the changes in net unrealized gains relating to Level 3 net financial liabilities held both as of the beginning and the end of the period:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Changes in unrealized gains [1]	$ —	$ —	$ 0.3	$ —

[1] Within the consolidated statements of operations and consolidated statements of comprehensive income for the periods presented, unrealized gains from Level 3 items are combined with unrealized gains and losses on positions classified in Level 1 or 2, as well as other positions that have been realized during the applicable periods.

Credit and Nonperformance Risk. The fair value of the Company's coal derivative assets and liabilities reflects adjustments for credit risk. The Company's exposure is substantially with electric utilities, energy marketers, steel producers and nonfinancial trading houses. The Company's policy is to independently evaluate each customer's creditworthiness prior to entering into transactions and to regularly monitor the credit extended. If the Company engages in a transaction with a counterparty that does not meet its credit standards, the Company seeks to protect its position by requiring the counterparty to provide an appropriate credit enhancement. Also, when appropriate (as determined by its credit management function), the Company has taken steps to reduce its exposure to customers or counterparties whose credit has deteriorated and who may pose a higher risk of failure to perform under their contractual obligations. These steps include obtaining letters of credit or cash collateral (margin), requiring prepayments for shipments or the creation of customer trust accounts held for the Company's benefit to serve as collateral in the event of a failure to pay or perform. To reduce its credit exposure related to trading and brokerage activities, the Company seeks to enter into netting agreements with counterparties that permit the Company to offset asset and liability positions with such counterparties and, to the extent required, the Company will post or receive margin amounts associated with exchange-cleared and certain OTC positions. The Company also continually monitors counterparty and contract non-performance risk, if present, on a case-by-case basis.

As of December 31, 2018, 27% of the Company's credit exposure related to coal trading activities was with investment grade counterparties and 73% was with counterparties that are not rated.

Performance Assurances and Collateral

The Company is required to post variation margin on positions that are in a net liability position and is entitled to receive and hold variation margin on positions that are in a net asset position with an exchange and certain of its OTC derivative contract counterparties. The Company had posted $21.8 million and $35.8 million of net variation margin at December 31, 2018 and 2017, respectively.

In addition to the requirements surrounding variation margin, the Company is required by the exchanges upon which it transacts to post certain additional collateral, known as initial margin, which represents an estimate of potential future adverse price movements across the Company's portfolio under normal market conditions. The Company posted initial margin of $16.7 million and $18.8 million as of December 31, 2018 and 2017, respectively, which is reflected in "Other current assets" in the consolidated balance sheets. As of December 31, 2018 and 2017, respectively, the Company was in receipt of $2.2 million and $1.8 million, respectively, of the required variation and initial margin.

Certain of the Company's derivative trading instruments require the parties to provide additional performance assurances whenever a material adverse event jeopardizes one party's ability to perform under the instrument. If the Company was to sustain a material adverse event (using commercially reasonable standards), its counterparties could request collateralization on derivative trading instruments in net liability positions which, based on an aggregate fair value at December 31, 2018 and 2017, would have amounted to collateral postings to counterparties of approximately $1.3 million and $7.0 million, respectively. As of December 31, 2018, the Company was not required to post collateral to counterparties for such positions. Approximately $0.4 million in collateral was required to be posted to counterparties as of December 31, 2017.

(10) Intangible Contract Assets and Liabilities

As described in Note 2. “Emergence from the Chapter 11 Cases and Fresh Start Reporting,” and Note 3. “Acquisition of Shoal Creek Mine,” the Company has recorded intangible assets and liabilities to reflect the fair value of certain U.S. coal supply agreements as a result of differences between contract terms and estimated market terms for the same coal products, and also recorded intangible liabilities related to unutilized capacity under its port and rail take-or-pay contracts. The balances, net of accumulated amortization, and respective balance sheet classifications at December 31, 2018 and 2017, are set forth in the following tables:

	December 31, 2018		
	(Dollars in millions)		
	Assets	Liabilities	Net Total
Coal supply agreements	$ 70.9	$ (32.9)	$ 38.0
Take-or-pay contracts	—	(57.1)	(57.1)
Total	$ 70.9	$ (90.0)	$ (19.1)
Balance sheet classification:			
Investments and other assets	$ 70.9	$ —	$ 70.9
Accounts payable and accrued expenses	—	(20.3)	(20.3)
Other noncurrent liabilities	—	(69.7)	(69.7)
Total	$ 70.9	$ (90.0)	$ (19.1)

	December 31, 2017		
	(Dollars in millions)		
	Assets	Liabilities	Net Total
Coal supply agreements	$ 177.2	$ (42.7)	$ 134.5
Take-or-pay contracts	—	(90.7)	(90.7)
Total	$ 177.2	$ (133.4)	$ 43.8
Balance sheet classification:			
Investments and other assets	$ 177.2	$ —	$ 177.2
Accounts payable and accrued expenses	—	(27.6)	(27.6)
Other noncurrent liabilities	—	(105.8)	(105.8)
Total	$ 177.2	$ (133.4)	$ 43.8

Amortization of the intangible assets and liabilities related to coal supply agreements occurs ratably based upon coal volumes shipped per contract and is recorded as a component of “Depreciation, depletion and amortization” in the accompanying consolidated statements of operations. Such amortization amounted to net expense of $93.0 million and $121.3 million during the year ended December 31, 2018 and the period April 2 through December 31, 2017, respectively. The Company anticipates net amortization of sales contracts, based upon expected shipments in the next five years, to be an expense of approximately $27 million, $8 million, $3 million, $1 million and $1 million for the years 2019 through 2023, respectively.

Future unutilized capacity and the amortization periods related to the take-or-pay contract intangible liabilities are based upon estimates of forecasted usage. Such amortization, which is classified as a reduction to “Operating costs and expenses” in the accompanying consolidated statements of operations, amounted to $26.6 million and $22.5 million during the year ended December 31, 2018 and the period April 2 through December 31, 2017, respectively. The Company anticipates net amortization of take-or-pay contract intangible liabilities to be approximately $17 million, $9 million, $4 million, $3 million and $3 million for the years 2019 through 2023, respectively, and $21 million thereafter.

(11) Property, Plant, Equipment and Mine Development

Property, plant, equipment and mine development, net, as of December 31, 2018 and December 31, 2017 consisted of the following:

	December 31, 2018	December 31, 2017
	(Dollars in millions)	
Land and coal interests	$ 4,148.8	$ 3,890.5
Buildings and improvements	559.3	470.6
Machinery and equipment	1,456.3	1,149.3
Less: Accumulated depreciation, depletion and amortization	(957.4)	(398.5)
Property, plant, equipment and mine development, net	$ 5,207.0	$ 5,111.9

As more fully described in Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting," all of the Company's property, plant, equipment and mine development assets were adjusted to fair value upon emergence from the Chapter 11 Cases in connection with fresh start reporting.

Land and coal interests included coal reserves with a net book value of $3.0 billion as of December 31, 2018 and 2017. Such coal reserves were comprised of mineral rights for leased coal interests and advance royalties that had a net book value of $2.1 billion and $2.0 billion as of December 31, 2018 and 2017, respectively, and coal reserves held by fee ownership of $0.9 billion and $1.0 billion at December 31, 2018 and 2017, respectively. The amount of coal reserves not subject to current depletion at properties where the Company was not currently engaged in mining operations or leasing to third parties was $0.2 billion as of December 31, 2018 and 2017.

Land and coal interests also include acquired interests in mineral rights at certain Australian exploration properties that had a net book value of $0.1 billion as of December 31, 2018 and 2017.

(12) Income Taxes

Income (loss) from continuing operations before income taxes for the periods presented below consisted of the following:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
U.S.	$ (43.4)	$ 10.4	$ 2,408.7	$ (49.7)
Non-U.S.	707.5	541.7	(2,868.0)	(708.6)
Total	$ 664.1	$ 552.1	$ (459.3)	$ (758.3)

Total income tax provision (benefit) for the periods presented below consisted of the following:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Current:				
U.S. federal	$ (46.8)	$ (101.4)	$ (3.1)	$ (12.4)
Non-U.S.	29.8	40.4	8.3	14.4
State	(0.1)	(0.4)	(6.7)	0.5
Total current	(17.1)	(61.4)	(1.5)	2.5
Deferred:				
U.S. federal	30.4	(85.1)	(101.0)	(82.1)
Non-U.S.	5.7	(14.5)	(160.4)	(12.8)
State	(0.6)	—	(0.9)	(2.1)
Total deferred	35.5	(99.6)	(262.3)	(97.0)
Total income tax provision (benefit)	$ 18.4	$ (161.0)	$ (263.8)	$ (94.5)

The following is a reconciliation of the expected statutory federal income tax expense (benefit) to the Company's income tax provision (benefit) for the periods presented below:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Expected income tax expense (benefit) at U.S. federal statutory rate	$ 139.5	$ 193.2	$ (160.8)	$ (265.4)
Changes in valuation allowance, income tax	(284.6)	(744.9)	(777.2)	2,453.9
Remeasurement due to the Tax Cuts and Jobs Act	9.5	473.5	—	—
Reorganization costs	—	—	2,130.0	29.6
Bad debt deduction	—	—	(1,639.6)	—
Worthless partnership	—	—	—	(2,204.4)
Changes in tax reserves	2.1	7.2	(9.2)	2.3
Excess depletion	(28.5)	(40.4)	(11.2)	(37.2)
Foreign earnings provision differential	97.1	(26.3)	158.2	27.5
Global intangible low-taxed income	68.2	—	—	—
Remeasurement of foreign income tax accounts	(0.2)	(0.3)	9.4	(2.0)
State income taxes, net of federal tax benefit	3.2	(3.1)	40.6	(90.2)
Other, net	12.1	(19.9)	(4.0)	(8.6)
Total income tax provision (benefit)	$ 18.4	$ (161.0)	$ (263.8)	$ (94.5)

Certain reconciliation items included in the above table exclude the remeasurement of foreign income tax accounts as these foreign currency effects are separately presented.

As described in Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting," the Plan provided that the Company's pre-petition equity and certain obligations were canceled and extinguished and a significant portion of its long-term debt was discharged in exchange for new Common Stock and other consideration. Generally, absent an exception, for U.S. tax purposes a debtor recognizes cancellation of debt income (CODI) upon discharge of its outstanding indebtedness for an amount of consideration less than the adjusted issue price of such indebtedness. The Company excluded CODI with respect to the Plan from its taxable income in accordance with U.S. Internal Revenue Code (IRC) Section 108, which allows a taxpayer that is a debtor in a reorganization case to exclude CODI from taxable income if the discharge is granted by a bankruptcy court or pursuant to a plan of reorganization approved by a bankruptcy court. However, in such event, Section 108 requires a reduction in certain income tax attributes otherwise available to the taxpayer, in most cases by the amount of such CODI. Generally, the amount of CODI realized by a taxpayer is the adjusted issue price of any indebtedness discharged less the sum of (i) the amount of cash paid, (ii) the issue price of any new indebtedness issued and (iii) the fair market value of any consideration, including equity, issued to the creditors.

CODI from the discharge of indebtedness was $8.5 billion, of which, $3.9 billion related to third-party indebtedness. The additional $4.6 billion of CODI resulted from the restructuring of a foreign intercompany receivable as part of the Plan. A previous impairment of the same receivable resulted in a tax deduction which increased the Company's federal NOLs by $4.6 billion in 2017. As of January 1, 2018, the Company retained approximately $3.7 billion of gross U.S. federal NOLs, $112.8 million of general business credits (GBCs), $91.1 million of alternative minimum tax (AMT) credits and $262.0 million of foreign tax credits (FTCs) after giving effect to such required reductions. Additionally, the Company's tax basis in certain assets was reduced by $543.1 million and its capital loss carryovers were reduced by $205.7 million.

In connection with the Company's emergence from bankruptcy, the Company experienced an "ownership change" as defined in U.S. IRC Section 382. As a result, the Company's ability to use pre-ownership change NOLs, GBCs, AMT credits, FTCs and other tax attributes to offset future taxable income or taxes owed is limited. Under U.S. IRC Section 382 and Section 383, an entity that experiences an ownership change in bankruptcy generally is subject to an annual limitation (the Annual Limitation) on its use of its pre-ownership change NOLs and other tax attributes after the ownership change equal to the equity value of the entity immediately after implementation of the plan of reorganization (reflecting the increase, if any, in value resulting from the surrender or cancellation of any claims against the Company thereunder), multiplied by the long-term tax exempt rate posted by the Internal Revenue Service (IRS), subject to certain adjustments. A significant portion of the Company's retained NOLs (stated above) are not subject to the Annual Limitation because they are deemed attributable to the period after the ownership change. The Company also had a net unrealized built-in gain at the time of the ownership change; therefore, certain built-in gains recognized within five years after the ownership change will increase the Annual Limitation for the five year recognition period beginning April 3, 2017 through April 2, 2022. The estimated Annual Limitation of $62.0 million, plus the estimated built-in gains recognized, will not prevent the usage of NOLs, GBCs and $1.6 million of FTCs, provided there is sufficient income in the carryforward period. The Company has written off $260.4 million of FTCs based on the Annual Limitation and their short remaining carryover period. The Company maintains a full valuation allowance against its U.S. net deferred tax assets.

On December 22, 2017, the Tax Cuts and Jobs Act (the Act) was signed into law making significant changes to the IRC. Key provisions of the Act that impacted the Company include: (i) repeal of the corporate AMT system, (ii) reduction of the U.S. federal corporate tax rate from 35% to 21% and (iii) further limitation on the deductibility of certain executive compensation. The Company elected to recognize the tax on the new global intangible low-taxed income (GILTI) as a period expense in the period the tax is incurred and recorded a provision of $68.2 million for the year ended December 31, 2018, which was fully offset by the release of valuation allowance associated with the NOLs that absorbed the GILTI inclusion. Other provisions of the Act that have not impacted the Company but may in the future include: (i) replacement of the worldwide taxation system with a territorial tax system which exempts certain foreign operations from U.S. taxation and includes a one-time deemed repatriation tax on deferred foreign earnings, (ii) creation of a new base erosion anti-abuse tax, (iii) repeal of the domestic production deductions, (iv) limitation on the deduction for net interest expense incurred by a U.S. corporation, (v) allowance for immediate capital expensing of certain qualified property and (vi) modification and/or repeal of a number of other international provisions.

The Company has completed its assessment for the income tax effects of the Act for the following items below:

- Repeal of the corporate AMT system: Existing AMT credits as of December 31, 2017 will be refunded over the next four years. The Company has determined that it will receive a refund of existing AMT credits of approximately $91.1 million. A valuation allowance of $85.6 million previously recorded against these credits was released during the period April 2 through December 31, 2017. During 2018, the IRS determined that the sequestration reduction would not apply to the AMT credit refunds and an additional tax benefit of $5.5 million valuation allowance release was recorded as a component of income tax expense from continuing operations. The Company's accounting policy regarding the balance sheet presentation of the credits is to continue to reflect the balance as a deferred tax asset until the completion of the taxable year determining the credit, at which time the amount will be presented as a tax receivable.

- Remeasurement of deferred tax assets and liabilities: Deferred tax assets and liabilities attributable to the U.S. were remeasured from 35% to the reduced tax rate of 21%. The Company recorded a provision of $473.5 million and an offsetting valuation allowance adjustment for the remeasurement for the period April 2 through December 31, 2017. The Company recorded an additional provision of $9.5 million during the year ended December 31, 2018 upon completion of the filing of both U.S. and foreign tax returns for the 2017 tax year and an offsetting valuation allowance.

- Elimination of executive compensation exemptions: The Act made major changes to the $1 million limit on deductible compensation paid to certain "covered" employees. The Act eliminated exemptions for qualified performance based compensation and compensation paid after termination and expanded the number of employees to which the limit applies. The Company recorded a provision of $0.5 million and an offsetting valuation allowance adjustment for the impact of these changes for the period April 2 through December 31, 2017. This amount is equal to the elimination of deferred tax assets associated with deferred compensation amounts that will likely exceed the $1 million limit when paid and did not change as the assessment was finalized during the year ended December 31, 2018.

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities as of December 31, 2018 and 2017 consisted of the following:

	December 31, 2018	December 31, 2017
	(Dollars in millions)	
Deferred tax assets:		
Tax loss carryforwards and credits	$ 1,729.3	$ 2,068.0
Property, plant, equipment and mine development, principally due to differences in depreciation, depletion and asset impairments	304.5	463.8
Accrued postretirement benefit obligations	139.5	194.2
Asset retirement obligations	47.2	30.6
Employee benefits	24.8	25.3
Take or pay obligations	17.1	27.2
Investments and other assets	82.7	137.2
Workers' compensation obligations	6.2	6.4
Other	38.2	28.6
Total gross deferred tax assets	2,389.5	2,981.3
Valuation allowance, income tax	(2,094.3)	(2,432.5)
Total deferred tax assets	295.2	548.8
Deferred tax liabilities:		
Property, plant, equipment and mine development, principally due to differences in depreciation, depletion and asset impairments	203.4	353.3
Coal supply agreements	9.3	29.6
Investments and other assets	43.7	85.7
Total deferred tax liabilities	256.4	468.6
Net deferred tax asset	$ 38.8	$ 80.2
Deferred taxes are classified as follows:		
Noncurrent deferred income tax asset	$ 48.5	$ 85.6
Noncurrent deferred income tax liability	(9.7)	(5.4)
Net deferred tax asset	$ 38.8	$ 80.2

During 2018, the Company reduced valuation allowance $296.5 million due to utilization of NOLs in the U.S. and Australia. The Company's Australian taxable income was driven by continued strength of seaborne coal prices. The Company's U.S. federal taxable income was primarily the result of the inclusion of Australian operation earnings due to GILTI. The Company's GILTI, as calculated under the Act, is not the result of intangible low-taxed income but instead is due to Australian mining operations already taxed in Australia at 30%.

As of December 31, 2018, the Company had gross Australia NOLs of $3.3 billion in Australian dollars and gross U.S. federal NOLs of $3.2 billion. The Company's tax loss carryforwards and credits of $1.7 billion as of December 31, 2018 were comprised primarily of net Australia NOLs and capital tax loss carryforwards of $795.4 million, net federal NOLs of $672.6 million, state NOLs of $84.4 million, AMT credits of $45.5 million, tax GBCs of $112.8 million and other foreign NOLs of $14.2 million. The AMT credits will be fully refunded by 2022. The foreign tax loss carryforwards have no expiration date. The federal NOLs begin to expire in 2036. The state NOLs begin to expire in 2028. The FTCs and GBCs begin to expire in 2023 and 2027, respectively.

In assessing the near-term use of NOLs and tax credits and corresponding valuation allowance adjustments, the Company evaluated the expected level of future taxable income, available tax planning strategies, reversals of existing taxable temporary differences and taxable income in carryback years. For the year ended December 31, 2018, the Company continued to record valuation allowance of $2.1 billion against net deferred tax asset positions, comprised primarily of $0.9 billion in the U.S. and $1.2 billion in Australia. Recognition of those valuation allowances was 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”), which limited the Company’s ability to look to future taxable income in assessing the realizability of the related assets.

Unrecognized Tax Benefits

Net unrecognized tax benefits (excluding interest and penalties) were recorded as follows in the consolidated balance sheets as of December 31, 2018 and 2017:

	December 31, 2018	December 31, 2017
	(Dollars in millions)	
Deferred income taxes	$ 13.0	$ 10.9
Other noncurrent liabilities	1.0	1.8
Net unrecognized tax benefits	$ 14.0	$ 12.7
Gross unrecognized tax benefits	$ 14.0	$ 12.7

The amount of the Company’s gross unrecognized tax benefits increased by $1.3 million since December 31, 2017 due to adjustments to existing positions as part of finalization settlement of state audits and additions for current positions. The amount of the net unrecognized tax benefits that, if recognized, would directly affect the effective tax rate was $14.0 million and $12.7 million at December 31, 2018 and 2017, respectively. A reconciliation of the beginning and ending amount of gross unrecognized tax benefits for the periods presented below is as follows:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Balance at beginning of period	$ 12.7	$ 12.5	$ 20.1	$ 22.9
Additions for current year tax positions	1.8	0.8	—	1.5
Reductions for prior year tax positions	—	(0.5)	(7.6)	(2.8)
Reductions for settlements with tax authorities	(0.5)	(0.1)	—	(1.5)
Balance at end of period	$ 14.0	$ 12.7	$ 12.5	$ 20.1

The Company recognizes interest and penalties related to unrecognized tax benefits in its income tax provision. The Company recorded $0.4 million and $4.8 million of gross interest and penalties for the year ended December 31, 2018 and the period April 2 through December 31, 2017, respectively, and reversed gross interest and penalties of $2.1 million and $0.4 million for the period January 1 through April 1, 2017 and the year ended December 31, 2016, respectively. The Company had $5.4 million and $5.0 million of accrued gross interest and penalties related to unrecognized tax benefits at December 31, 2018 and 2017, respectively.

The Company does not expect a decrease in its net unrecognized tax benefits during the next twelve months.

Tax Returns Subject to Examination

The Company’s federal income tax returns for the 2016 and 2017 tax years are subject to potential examinations by the IRS. The Company’s state income tax returns for the tax years 1999 and thereafter remain potentially subject to examination by various state taxing authorities due to NOL carryforwards. Australian income tax returns for tax years 2013 through 2017 continue to be subject to potential examinations by the Australian Taxation Office.

Foreign Earnings

As of December 31, 2018, the Company has a consolidated earnings deficit outside the U.S. but with some immaterial unremitted earnings in certain jurisdictions. The Company continues to be permanently reinvested with respect to its current and historical earnings. However, when appropriate, the Company has the ability to access foreign cash without incurring residual cash taxes due to the existence of NOLs.

Tax Payments and Refunds

The following table summarizes the Company's income tax (refunds) payments, net for the periods presented below:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
U.S. — federal	$ (103.1)	$ (11.2)	$ —	$ (56.5)
U.S. — state and local	(1.6)	—	—	1.4
Non-U.S.	40.7	10.4	5.5	15.0
Total income tax (refunds) payments, net	$ (64.0)	$ (0.8)	$ 5.5	$ (40.1)

(13) Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consisted of the following:

	December 31, 2018	December 31, 2017
	(Dollars in millions)	
Trade accounts payable	$ 281.7	$ 388.0
Accrued payroll and related benefits	209.3	239.7
Other accrued expenses	184.9	197.7
Accrued taxes other than income	111.4	111.7
Accrued royalties	52.7	67.4
Asset retirement obligations	63.8	34.1
Income taxes payable	10.0	20.6
Accrued interest	15.7	15.5
Accrued health care insurance	10.0	10.6
Workers' compensation obligations	7.0	7.6
Intangible take-or-pay contracts	20.3	27.6
Liabilities from coal trading activities	1.2	11.7
Liabilities associated with discontinued operations	54.0	70.6
Accounts payable and accrued expenses	$ 1,022.0	$ 1,202.8

(14) Long-term Debt

In accordance with the Plan, the Company was recapitalized with new debt and equity instruments, including the 6.000% Senior Secured Notes due March 2022, the 6.375% Senior Secured Notes due March 2025 and the Senior Secured Term Loan due 2025 in the table below. The Company's total indebtedness as of December 31, 2018 and December 31, 2017 consisted of the following:

	December 31, 2018	December 31, 2017
	(Dollars in millions)	
6.000% Senior Secured Notes due March 2022	$ 500.0	$ 500.0
6.375% Senior Secured Notes due March 2025	500.0	500.0
Senior Secured Term Loan due 2025, net of original issue discount	395.9	444.2
Capital lease and other obligations	40.0	76.0
Less: Debt issuance costs	(68.9)	(59.4)
	1,367.0	1,460.8
Less: Current portion of long-term debt	36.5	42.1
Long-term debt	$ 1,330.5	$ 1,418.7

In connection with the Chapter 11 Cases, the Company was required to pay adequate protection payments of $29.8 million to certain first lien creditors of the Predecessor company during the period January 1 through April 1, 2017. The adequate protection payments were recorded as "Interest expense" in the consolidated statements of operations and ceased upon the Effective Date. The Company did not record interest expense subsequent to the filing of the Bankruptcy Petitions for the majority of non-first lien Predecessor indebtedness, which was automatically stayed in accordance with Section 502(b)(2) of the Bankruptcy Code. The amount of contractual interest stayed was $92.9 million for the period January 1, 2017 through the Effective Date.

6.000% and 6.375% Senior Secured Notes

On February 15, 2017, one of PEC's subsidiaries entered into an indenture (the Indenture) with Wilmington Trust, National Association, as trustee, relating to the issuance by PEC's subsidiary of $500.0 million aggregate principal amount of 6.000% senior secured notes due 2022 (the 2022 Notes) and $500.0 million aggregate principal amount of 6.375% senior secured notes due 2025 (the 2025 Notes and, together with the 2022 Notes, the Senior Notes). The Senior Notes were sold on February 15, 2017 in a private transaction exempt from the registration requirements of the Securities Act of 1933. The proceeds from the Senior Notes were used to repay the Predecessor company first lien obligations.

The Senior Notes were issued at par value. The Company paid aggregate debt issuance costs of $49.5 million related to the offering, which will be amortized over the respective terms of the Senior Notes. Interest payments on the Senior Notes are scheduled to occur each year on March 31st and September 30th until maturity. During the year ended December 31, 2018 and the period April 2 through December 31, 2017 the Company recorded interest expense of $71.9 million and $51.7 million related to the Senior Notes.

The Company may redeem the 2022 Notes, in whole or in part, beginning in 2019 at 103.0% of par, in 2020 at 101.5% of par and in 2021 and thereafter at par. The 2025 Notes may be redeemed, in whole or in part, beginning in 2020 at 104.8% of par, in 2021 at 103.2% of par, in 2022 at 101.6% of par and in 2023 and thereafter at par. In addition, prior to the first date on which the Senior Notes are redeemable at the redemption prices noted above, the Company may also redeem some or all of the Senior Notes at a calculated make-whole premium, plus accrued and unpaid interest.

On August 9, 2018, the Company executed an amendment to the Indenture (in the form of a supplemental indenture) following the solicitation of consents from the requisite majorities of holders of each series of Senior Notes. The amendment permits a category of restricted payments at any time not to exceed the sum of $650.0 million, plus an additional $150.0 million per calendar year, commencing with calendar year 2019, with unused amounts in any calendar year carrying forward to and available for restricted payments in any subsequent calendar year. The Company paid consenting Senior Note holders $10.00 in cash per $1,000 principal amount of 2022 Notes and $30.00 in cash per $1,000 principal amount of 2025 Notes, which amounted to $19.8 million. Such consent fees were capitalized as additional debt issuance costs to be amortized over the respective terms of the Senior Notes. The Company also expensed $1.5 million of other fees associated with the amendment to "Interest expense" in the accompanying consolidated statements of operations during the year ended December 31, 2018.

The Indenture contains customary conditions of default and imposes certain restrictions on the Company's activities, including its ability to incur debt, incur liens, make investments, engage in fundamental changes such as mergers and dissolutions, dispose of assets, enter into transactions with affiliates and make certain restricted payments, such as cash dividends and share repurchases.

The Senior Notes rank senior in right of payment to any subordinated indebtedness and equally in right of payment with any senior indebtedness to the extent of the collateral securing that indebtedness. The Senior Notes are jointly and severally and fully and unconditionally guaranteed on a senior secured basis by substantially all of the Company's material domestic subsidiaries and secured by first priority liens over (1) substantially all of the assets of the Company and the guarantors, except for certain excluded assets, (2) 100% of the capital stock of each domestic restricted subsidiary of the Company, (3) 100% of the non-voting capital stock of each first tier foreign subsidiary of the Company or a foreign subsidiary holding company and no more than 65% of the voting capital stock of each first tier foreign subsidiary of the Company or a foreign subsidiary holding company, (4) a legal charge of 65% of the voting capital stock and 100% of the non-voting capital stock of Peabody Investments (Gibraltar) Limited and (5) all intercompany debt owed to the Company or any guarantor, in each case, subject to certain exceptions. The obligations under the Senior Notes are secured on a *pari passu* basis by the same collateral securing the Credit Agreement (as defined below), subject to certain exceptions.

Credit Agreement

In connection with an exit facility commitment letter, on the Effective Date, the Company entered into a credit agreement, dated as of April 3, 2017, among the Company, as Borrower, Goldman Sachs Bank USA, as Administrative Agent, and other lenders party thereto (the Credit Agreement). The Credit Agreement originally provided for a $950.0 million senior secured term loan (the Senior Secured Term Loan), which was to mature in 2022 prior to the amendments described below. The proceeds from the Senior Secured Term Loan were used to repay the Predecessor company first lien obligations.

Following the voluntary prepayments and amendments described below, the Credit Agreement provides for a $400.0 million first lien senior secured term loan (the Senior Secured Term Loan), which bore interest at LIBOR plus 2.75% per annum as of December 31, 2018. During the year ended December 31, 2018 and the period April 2 through December 31, 2017, the Company recorded interest expense of $24.0 million and $39.0 million, respectively, related to the Senior Secured Term Loan.

Proceeds from the Senior Secured Term Loan were received net of an original issue discount and deferred financing costs of $37.3 million that will be amortized over its term. The loan principal is payable in quarterly installments plus accrued interest through December 2024 with the remaining balance due in March 2025. The loan principal was voluntarily prepayable at 101% of the principal amount repaid if voluntarily prepaid prior to October 2018 (subject to certain exceptions, including prepayments made with internally generated cash) and is voluntarily prepayable at any time thereafter without premium or penalty. The Senior Secured Term Loan may require mandatory principal prepayments of up to 75% of Excess Cash Flow (as defined in the Credit Agreement) for any fiscal year if the Company's Total Leverage Ratio (as defined in the Credit Agreement and calculated at December 31, net of any unrestricted cash), is greater than 2.00:1.00. The mandatory principal prepayment requirement is (i) 50% of Excess Cash Flow if the Company's Total Leverage Ratio is less than or equal to 2.00:1.00 and greater than 1.50:1.00, (ii) 25% of Excess Cash Flow if the Company's Total Leverage Ratio is less than or equal to 1.50:1.00 and greater than 1.00:1.00, or (iii) zero if the Company's Total Leverage Ratio is less than or equal to 1.00:1.00. If required, mandatory prepayments resulting from Excess Cash Flows are payable within 100 days after the end of each fiscal year.The calculation of mandatory prepayments would be reduced commensurately by the amount of previous voluntary prepayments. In certain circumstances, the Senior Secured Term Loan also requires that Excess Proceeds (as defined in the Credit Agreement) of $10.0 million or greater from sales of Company assets be applied against the loan principal, unless such proceeds are reinvested within one year.

The Credit Agreement contains customary conditions of default and imposes certain restrictions on the Company's activities, including its ability to incur liens, incur debt, make investments, engage in fundamental changes such as mergers and dissolutions, dispose of assets, enter into transactions with affiliates, and make certain restricted payments, such as cash dividends and share repurchases. Obligations under the Credit Agreement are secured on a *pari passu* basis by the same collateral securing the Senior Notes.

Since entering into the Credit Agreement, the Company has repaid $553.0 million of the original $950.0 million loan principal amount on the Senior Secured Term Loan in various installments, including $546.0 million which was voluntarily prepaid. On September 18, 2017, the Company entered into an amendment to the Credit Agreement (the Amendment) which permitted the Company to add an incremental revolving credit facility in addition to the Company's ability to add one or more incremental term loan facilities under the Credit Agreement. The incremental revolving credit facility and/or incremental term loan facilities can be in an aggregate principal amount of up to $350.0 million plus additional amounts so long as the Company is below Total Leverage Ratio requirements as set forth in the Credit Agreement. The Amendment also made available an additional restricted payment basket that permits additional repurchases, dividends or other distributions with respect to the Company's Common and Preferred Stock in an aggregate amount up to $450.0 million so long as the Company's Fixed Charge Coverage Ratio (as defined in the Credit Agreement) is at least 2.00:1.00 on a pro forma basis.

During the fourth quarter of 2017, the Company entered into the incremental revolving credit facility (the Revolver) for an aggregate commitment of $350.0 million for general corporate purposes. The Company paid aggregate debt issuance costs of $4.7 million. The Revolver matures in November 2020 and permits loans which bear interest at LIBOR plus 3.25%. The Revolver is subject to a 2.00:1.00 Total Leverage Ratio requirement (as defined by the Credit Agreement, modified to limit unrestricted cash netting to $800.0 million). Capacity under the Revolver may also be utilized for letters of credit which incur combined fees of 3.375% per annum. Unused capacity under the Revolver bears a commitment fee of 0.5% per annum. As of December 31, 2018, the Revolver had only been drawn upon for letters of credit amounting to $106.4 million. Such letters of credit were primarily in support of the Company's reclamation obligations, as further described in Note 25. "Financial Instruments, Guarantees With Off-Balance-Sheet Risk and Other Guarantees." During the year ended December 31, 2018, the Company recorded interest expense and fees of $7.2 million, related to the Revolver.

On April 11, 2018, the Company entered into another amendment to the Credit Agreement which lowered the interest rate on the Senior Secured Term Loan to its current level of LIBOR plus 2.75% and eliminated an existing 1.0% LIBOR floor. The amendment also extended the maturity of the Senior Secured Term Loan by three years to 2025 and eliminated previous capital expenditure restriction covenants on both the Senior Secured Term Loan and the Revolver. In connection with this amendment, the Company voluntarily repaid $46.0 million of principal on the Senior Secured Term Loan.

The Company's voluntary prepayments of $546.0 million of Senior Secured Term Loan principal and related amendments have been accounted for as a combination of partial debt extinguishments and debt modifications, depending upon the circumstances in each instance. During 2018, the Company charged a pro rata portion of debt issuance costs and original issue discount of $2.0 million to "Loss on early debt extinguishment" and expensed $0.9 million of financing costs and fees to "Interest expense" in the accompanying consolidated statements of operations, and capitalized an additional $1.0 million of deferred financing costs. During the period April 2 through December 31, 2017, the Company charged a pro rata portion of debt issuance costs and original issue discount of $20.9 million to "Loss on early debt extinguishment" and expensed $2.0 million of financing costs and fees to "Interest expense" in the accompanying consolidated statements of operations, and capitalized an additional $6.1 million of deferred financing costs.

During 2016, the Company recorded a loss on early debt extinguishment of $29.5 million related to the repayment of its debtor-in-possession term loan facility prior to emergence from the Chapter 11 Cases.

Restricted Payments Under the Senior Notes and Credit Agreement

In addition to the $450.0 million restricted payment basket provided for under the September 18, 2017 amendment, the Credit Amendment provides a builder basket for additional restricted payments subject to a maximum Total Leverage Ratio of 2.00:1.00 (as defined in the Credit Agreement).

In addition to the $650.0 million restricted payment basket, plus an additional $150.0 million per calendar year, provided under the August 9, 2018 amendment, the Indenture provides a builder basket for restricted payments that is calculated based upon the Company's Consolidated Net Income, and is subject to a Fixed Charge Coverage Ratio of at least 2.25:1.00 (as defined in the Indenture).

Further, under both the Indenture and Credit Agreement, additional restricted payments are permitted through a $50.0 million general basket and an annual aggregate $25.0 million basket which allows dividends and common stock repurchases. The payment of dividends and purchases of common stock under this latter basket are permitted so long as the Company's Total Leverage Ratio would not exceed 1.25:1.00 on a pro forma basis (as defined in the Credit Agreement and Indenture).

Copies of the Indenture documents are incorporated as Exhibits 4.2 and 4.3 to the Current Report on Form 8-K filed by the Company with the Securities and Exchange Commission (SEC) on April 3, 2017. A copy of the Credit Agreement is included as Exhibit 10.3 to the Current Report on Form 8-K filed by the Company with the SEC on April 3, 2017, and copies of the subsequent amendments referenced above are included as Exhibits 10.1 to the Current Reports on Form 8-K filed by the Company with the SEC on September 18, 2017, November 20, 2017, December 19, 2017 and April 11, 2018, and as Exhibits 10.1 to the Quarterly Reports on Form 10-Q filed by the Company with the SEC on August 3, 2018 and November 1, 2018.

Capital Lease Obligations

Refer to Note 15. “Leases” for additional information associated with the Company’s capital leases, which pertain to the financing of mining equipment used in operations.

(15) Leases

The Company leases equipment and facilities under various non-cancellable lease agreements and historically, the majority of the Company’s leases have been accounted for as operating leases. Certain lease agreements are subject to the restrictive covenants of the Company’s credit facilities and include cross-acceleration provisions, under which the lessor could require certain remedies including, but not limited to, immediate recovery of the present value of any remaining lease payments. During the Chapter 11 Cases, the Company amended and assumed certain leases and made lump sum payments to terminate certain other leases. In relation to the Company’s non-Debtor subsidiaries, the Company successfully negotiated standstill agreements during the Chapter 11 Cases and successfully amended the leases, with those amendments becoming effective upon emergence from the Chapter 11 Cases. Certain of these amendments resulted in new lease agreements which are being accounted for as capital leases with an initial aggregate obligation of approximately $79.9 million.

Rental expense under operating leases, including expense related to short-term operating leases, was $155.1 million, $144.2 million, $57.0 million and $261.8 million for the year ended December 31, 2018, the period April 2 through December 31, 2017, the period January 1 through April 1, 2017 and the year ended December 31, 2016, respectively. The gross book value of property, plant and equipment under capital leases was $125.0 million and $125.3 million as of December 31, 2018 and 2017, respectively, related primarily to the leasing of mining equipment. The accumulated depreciation for these items was $47.9 million and $20.6 million at December 31, 2018 and 2017, respectively, and changes thereto have been included in “Depreciation, depletion and amortization” in the consolidated statements of operations.

The Company also leases coal reserves under agreements that require royalties to be paid as the coal is mined. Certain agreements also require minimum annual royalties to be paid regardless of the amount of coal mined during the year. Total royalty expense was $474.3 million, $364.6 million, $115.2 million and $389.7 million for the year ended December 31, 2018, the period April 2 through December 31, 2017, the period January 1 through April 1, 2017 and the year ended December 31, 2016, respectively.

A substantial amount of the coal mined by the Company is produced from mineral reserves leased from the owner. One of the major lessors is the U.S. government, from which the Company leases substantially all of the coal it mines in Wyoming under terms set by Congress and administered by the U.S. Bureau of Land Management. These leases are generally for an initial term of ten years but may be extended by diligent development and mining of the reserves until all economically recoverable reserves are depleted. The Company has met the diligent development requirements for substantially all of these federal leases either directly through production, by including the lease as a part of a logical mining unit with other leases upon which development has occurred, or by paying an advance royalty in lieu of continued operations. Annual production on these federal leases must total at least 1.0% of the leased reserve or the original amount of coal in the entire logical mining unit in which the leased reserve resides. During 2016, the Company completed substantially all of its required lease payments under U.S. federal coal reserve leases with the U.S. Bureau of Land Management. In addition, royalties are payable monthly at a rate of 12.5% of the gross realization from the sale of the coal mined using surface mining methods and at a rate of 8.0% of the gross realization for coal produced using underground mining methods.

The Company also leases coal reserves in Arizona from The Navajo Nation and the Hopi Tribe under leases that are administered by the U.S. Department of the Interior. These leases expire upon exhaustion of the leased reserves or upon the permanent ceasing of all mining activities on the related reserves as a whole. The royalty rates are also generally based upon a percentage of the gross realization from the sale of coal. These rates are subject to redetermination every ten years under the terms of the leases. The owners of the plant, which is the sole customer of the mine to which these reserves relate, have stated that they do not currently intend to operate of the plant beyond December 2019. The remainder of the leased coal is generally leased from state governments, land holding companies and various individuals. The duration of these leases varies greatly. Typically, the lease terms are automatically extended as long as active mining continues. Royalty payments are generally based upon a specified rate per ton or a percentage of the gross realization from the sale of the coal.

Mining and exploration in Australia is generally conducted under leases, licenses or permits granted by the relevant state government. Mining and exploration licenses and their associated environmental protection approvals (granted by the state government, and in some cases also the federal government) contain conditions relating to such matters as minimum annual expenditures, environmental compliance, protection of flora and fauna, restoration and rehabilitation. Royalties are paid to the state government as a percentage of the sales price (less certain allowable deductions in some cases). Generally, landowners do not own the mineral rights or have the ability to grant rights to mine those minerals. These rights are retained by the state government. Compensation is often payable to landowners, occupiers and Aboriginal traditional owners with residual native title rights and interests for the loss of access to the land from the proposed mining activities. The amount and type of compensation and the ability to proceed to grant of a mining tenement may be determined by agreement or court determination, as provided by law.

Future minimum lease and royalty payments as of December 31, 2018 are as follows:

Year Ending December 31,	Capital Leases	Operating Leases	Coal Lease and Royalty Obligations
		(Dollars in millions)	
2019	$ 28.2	$ 47.6	$ 5.4
2020	8.0	27.6	5.5
2021	0.4	15.9	5.6
2022	0.4	11.8	5.4
2023	0.5	12.1	5.5
2024 and thereafter	8.8	12.1	36.2
Total minimum lease payments	46.3	$ 127.1	$ 63.6
Less interest	6.3		
Present value of minimum capital lease payments	$ 40.0		

As of December 31, 2018, certain of the Company's coal lease obligations were secured by outstanding surety bonds totaling $95.4 million.

(16) Asset Retirement Obligations

Reconciliations of the Company's asset retirement obligations are as follows:

	Successor		Predecessor
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
		(Dollars in millions)	
Balance at beginning of period	$ 691.1	$ 664.2	$ 758.8
Liabilities incurred or acquired	16.3	—	—
Liabilities settled or disposed	(57.8)	(65.2)	(2.7)
Accretion expense	48.5	32.6	12.5
Revisions to estimates	52.1	59.5	(104.4)
Balance at end of period	$ 750.2	$ 691.1	$ 664.2
Less: Current portion (included in "Accounts payable and accrued expenses")	63.8	34.1	31.1
Noncurrent obligation (included in "Asset retirement obligations")	$ 686.4	$ 657.0	$ 633.1
Balance at end of period — active locations	$ 671.8	$ 612.9	$ 540.1
Balance at end of period — closed or inactive locations	$ 78.4	$ 78.2	$ 124.1

During the year ended December 31, 2018, the Company acquired the Shoal Creek Mine and the related asset retirement obligations, as further discussed in Note 3. "Acquisition of Shoal Creek Mine."

During the period April 2 through December 31, 2017, the Company sold its Burton Mine and the related asset retirement obligations, as further discussed in Note 22. "Other Events." The changes in mine operations impacted reclamation estimates and are reflected in the asset retirement obligation asset and liability as of December 31, 2018 and 2017, respectively.

The credit-adjusted, risk-free interest rates utilized to estimate the Company's asset retirement obligations ranged from 7.61% for life of mines 3 years or less to 11.54% for life of mines greater than 20 years for both U.S. and Australia reclamation obligations at December 31, 2018. The same rate was used for U.S. and Australia in 2018 as all cash collateral was converted to surety bonds, bank guarantees or letters of credit to secure reclamation obligations.

As of December 31, 2018 and 2017, the Company had $1,317.0 million and $1,136.8 million, respectively, in surety bonds and bank guarantees outstanding to secure reclamation obligations. Additionally, the Company had $142.3 million and $188.5 million, respectively, of letters of credit in support of reclamation obligations as of December 31, 2018 and 2017. The Company also had restricted cash and cash collateral of $205.2 million as of December 31, 2017 in support of reclamation obligations.

(17) Postretirement Health Care and Life Insurance Benefits

The Company currently provides health care and life insurance benefits to qualifying salaried and hourly retirees of its current and certain former subsidiaries and their dependents from benefit plans established by the Company. Plan coverage for health benefits is provided to future hourly and salaried retirees in accordance with the applicable plan document. Life insurance benefits are provided to future hourly retirees in accordance with the applicable labor agreement.

Net periodic postretirement benefit cost included the following components:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Service cost for benefits earned	$ 8.2	$ 6.9	$ 2.3	$ 10.4
Interest cost on accumulated postretirement benefit obligation	28.3	24.2	8.4	34.5
Amortization of prior service credit	—	—	(2.3)	(9.2)
Amortization of actuarial loss	—	—	5.5	20.4
Net actuarial gain	(128.4)	(22.0)	—	—
Net periodic postretirement benefit cost	$ (91.9)	$ 9.1	$ 13.9	$ 56.1

In connection with fresh start reporting, the Company made a policy election to prospectively record amounts attributable to actuarial valuation changes currently in earnings rather than recording such amounts within accumulated other comprehensive income and amortizing to expense over applicable time periods.

The following includes pre-tax amounts recorded in "Accumulated other comprehensive income":

	Successor	Predecessor	
	Year Ended December 31, 2018	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)		
Net actuarial loss arising during year	$ —	$ —	$ 32.3
Prior service credit arising during year	(51.7)	—	—
Amortization:			
Actuarial loss	—	(5.5)	(20.4)
Prior service credit	—	2.3	9.2
Settlement related to the Patriot bankruptcy:			
Prior service credit	—	—	7.2
Total recorded in "Accumulated other comprehensive income"	$ (51.7)	$ (3.2)	$ 28.3

The Company amortizes prior service credit over an amortization period of the average remaining service period to full eligibility for participating employees (5.9 years at January 1, 2019). Prior to April 2, 2017, the Company amortized actuarial gain and loss using a 0% corridor with an amortization period that covered the average remaining service period to full eligibility for participating employees (10.3 years at January 1, 2017). The estimated prior service credit that will be amortized from accumulated other comprehensive income into net periodic postretirement benefit cost during the year ending December 31, 2019 is $8.8 million.

The following table sets forth the plans' funded status reconciled with the amounts shown in the consolidated balance sheets:

	Successor		Predecessor
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)		
Change in benefit obligation:			
Accumulated postretirement benefit obligation at beginning of period	$ 783.3	$ 803.1	$ 812.1
Service cost	8.2	6.9	2.3
Interest cost	28.3	24.2	8.4
Participant contributions	0.5	0.4	0.2
Plan amendments	(51.7)	—	—
Benefits paid	(44.8)	(29.3)	(12.8)
Actuarial gain	(128.4)	(22.0)	—
Fresh start reporting adjustments	—	—	(7.1)
Accumulated postretirement benefit obligation at end of period	595.4	783.3	803.1
Change in plan assets:			
Fair value of plan assets at beginning of period	—	—	—
Employer contributions	59.3	28.9	12.6
Participant contributions	0.5	0.4	0.2
Benefits paid and administrative fees (net of Medicare Part D reimbursements)	(44.8)	(29.3)	(12.8)
Fair value of plan assets at end of period	15.0	—	—
Funded status at end of period	(580.4)	(783.3)	(803.1)
Less: Current portion (included in "Accounts payable and accrued expenses")	32.7	53.3	56.1
Noncurrent obligation (included in "Accrued postretirement benefit costs")	$ (547.7)	$ (730.0)	$ (747.0)

In October 2018, the Company announced an amendment to its postretirement health care benefit plan that, after December 31, 2018, (a) limits eligibility for retiree medical allowances based upon attainment of certain age and service criteria at December 31, 2018, (b) reduces the annual retiree medical allowance benefits earned by eligible employees, and (c) establishes maximum limits on the amount eligible employees may earn and annual benefit payments. Employees with existing retiree medical allowance balances that lost continuing eligibility due to the amendment were awarded one-time discretionary contributions to their respective employee retirement accounts based upon years of service.

The impact of the amendment on future benefits reduced the Company's accumulated postretirement benefit obligation by $51.7 million. Of that amount, $50.2 million was attributable to the annual benefits and the maximum balance limits, and $1.5 million was attributable to the limitation of eligibility based on age and service criteria. The reduction in liability was recorded with an offsetting balance in accumulated other comprehensive income, net of a deferred tax provision, of $44.6 million, which will be amortized to earnings over an average remaining service period to full eligibility for participating employees of 5.9 years.

The weighted-average assumptions used to determine the benefit obligations as of the end of each year were as follows:

	December 31,	
	2018	2017
Discount rate	4.35%	3.70%
Measurement date	December 31, 2018	December 31, 2017

The weighted-average assumptions used to determine net periodic benefit cost during each period were as follows:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
Discount rate	3.70%	4.10%	4.15%	4.50%
Measurement date	December 31, 2017	April 1, 2017	December 31, 2016	December 31, 2015

The following presents information about the assumed health care cost trend rate:

	Year Ended December 31,	
	2018	2017
Pre-Medicare:		
Health care cost trend rate assumed for next year	6.55%	7.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.75%	4.75%
Year that the rate reaches the ultimate trend rate	2023	2023
Post-Medicare:		
Health care cost trend rate assumed for next year	6.15%	6.50%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.75%	4.75%
Year that the rate reaches the ultimate trend rate	2023	2023

Assumed health care cost trend rates have a significant effect on the expense and liability amounts reported for health care plans. A one-percentage-point change in the assumed health care cost trend would have the following effects for the year ended December 31, 2018:

	One Percentage-Point Increase	One Percentage-Point Decrease
	(Dollars in millions)	
Effect on total service and interest cost components	$ 2.9	$ (2.6)
Effect on total postretirement benefit obligation	$ 50.2	$ (45.7)

Plan Assets

In December 2018, the Company established a Voluntary Employees Beneficiary Association (VEBA) trust to pre-fund a portion of benefits for non-represented retirees. Assets of the Peabody Investments Corp. Non-Represented Retiree VEBA Trust (the Non-Represented Trust) will be invested in accordance with the investment policy established by the Peabody VEBA Retirement Committee after consultation with outside investment advisors and actuaries. As of December 31, 2018, the funds were invested in cash.

Cash funds. The Non-Represented Trust invests in cash funds to manage liquidity resulting from payment of participant benefits and certain administrative fees. The investment consists of a U.S. Government money market fund which is classified within the Level 1 valuation hierarchy.

The following table presents the fair value of assets in the Non-Represented Trust by asset category and by fair value hierarchy:

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Cash funds	$ 15.0	$ —	$ —	$ 15.0
Total assets at fair value	$ 15.0	$ —	$ —	$ 15.0

Contributions

Annual contributions to the Non-Represented Trust are discretionary.

Estimated Future Benefit Payments

The following benefit payments (net of retiree contributions), which reflect expected future service, as appropriate, are expected to be paid by the Company:

	Postretirement Benefits
	(Dollars in millions)
2019	$ 43.4
2020	45.3
2021	46.6
2022	45.8
2023	44.5
Years 2024-2028	205.9

(18) Pension and Savings Plans

One of the Company's subsidiaries, Peabody Investments Corp. (PIC), sponsors a defined benefit pension plan covering certain U.S. salaried employees and eligible hourly employees at certain PIC subsidiaries (the Peabody Plan). A subsidiary of PIC also has a defined benefit pension plan covering eligible employees who are represented by the UMWA under the Western Surface Agreement (the Western Plan). Prior to April 2, 2017, PIC also sponsored an unfunded supplemental retirement plan to provide senior management with benefits in excess of limits under the federal tax law (collectively, the Pension Plans).

Effective May 31, 2008, the Peabody Plan was frozen in its entirety for both participation and benefit accrual purposes. The Company adopted an enhanced savings plan contribution structure in lieu of benefits formerly accrued under the Peabody Plan. In November 2017, the Company purchased a group annuity contract from an insurance company to pay future pension benefits to approximately 1,950 retirees and beneficiaries of the Peabody Plan. As a result of this transaction, the Company settled $71.4 million of its pension obligation, paid from plan assets, and recorded a settlement charge of $2.1 million during the period April 2 through December 31, 2017.

Net periodic pension (benefit) cost included the following components:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Service cost for benefits earned	$ 2.3	$ 1.6	$ 0.6	$ 2.5
Interest cost on projected benefit obligation	31.4	28.0	9.7	41.5
Expected return on plan assets	(42.8)	(33.5)	(11.0)	(45.3)
Amortization of prior service cost	—	—	0.1	0.3
Amortization of net actuarial losses	—	—	6.3	24.7
Settlement charge	—	2.1	—	—
Net actuarial loss (gain)	4.2	(23.5)	—	—
Net periodic pension (benefit) cost	$ (4.9)	$ (25.3)	$ 5.7	$ 23.7

In connection with fresh start reporting, the Company made a policy election to prospectively record amounts attributable to actuarial valuation changes currently in earnings rather than recording such amounts within accumulated other comprehensive income and amortizing to expense over applicable time periods.

The following includes pre-tax amounts recorded in “Accumulated other comprehensive income”:

	Predecessor	
	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)	
Net actuarial loss arising during period	$ —	$ 6.6
Amortization:		
Net actuarial loss	(6.3)	(24.7)
Prior service cost	(0.1)	(0.3)
Total recorded in “Accumulated other comprehensive income”	$ (6.4)	$ (18.4)

Prior to April 2, 2017, the Company amortized actuarial gain and loss using a 5% corridor with a five-year amortization period.

The following summarizes the change in benefit obligation, change in plan assets and funded status of the Pension Plans:

	Successor		Predecessor
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)		
Change in benefit obligation:			
Projected benefit obligation at beginning of period	$ 874.6	$ 936.4	$ 959.3
Service cost	2.3	1.6	0.6
Interest cost	31.4	28.0	9.7
Benefits paid	(55.1)	(45.3)	(15.0)
Actuarial (gain) loss	(57.3)	25.3	—
Settlement	—	(71.4)	—
Fresh start reporting adjustments	—	—	(18.2)
Projected benefit obligation at end of period	795.9	874.6	936.4
Change in plan assets:			
Fair value of plan assets at beginning of period	776.6	783.1	773.0
Actual return on plan assets	(18.7)	80.1	25.1
Employer contributions	62.0	30.1	—
Benefits paid	(55.1)	(45.3)	(15.0)
Settlement	—	(71.4)	—
Fair value of plan assets at end of period	764.8	776.6	783.1
Funded status at end of period	$ (31.1)	$ (98.0)	$ (153.3)
Amounts recognized in the consolidated balance sheets:			
Noncurrent obligation (included in “Other noncurrent liabilities”)	$ (31.1)	$ (98.0)	$ (153.3)
Net amount recognized	$ (31.1)	$ (98.0)	$ (153.3)

The weighted-average assumptions used to determine the benefit obligations as of the end of each year were as follows:

	December 31,	
	2018	2017
Discount rate	4.35%	3.70%
Measurement date	December 31, 2018	December 31, 2017

The weighted-average assumptions used to determine net periodic pension (benefit) cost during each period were as follows:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
Discount rate	3.70%	4.10%	4.15%	4.55%
Expected long-term return on plan assets	5.65%	5.90%	5.90%	6.00%
Measurement date	December 31, 2017	April 1, 2017	December 31, 2016	December 31, 2015

The expected rate of return on plan assets is determined by taking into consideration expected long-term returns associated with each major asset class based on long-term historical ranges, inflation assumptions and the expected net value from active management of the assets based on actual results. Effective January 1, 2019, the Company lowered its expected rate of return on plan assets from 5.65% to 4.20% reflecting the impact of the Company's asset allocation and capital market expectations.

The projected benefit obligation and the accumulated benefit obligation exceeded plan assets for all plans as of December 31, 2018 and 2017. The accumulated benefit obligation for all plans was $795.9 million and $874.6 million as of December 31, 2018 and 2017, respectively.

Assets of the Pension Plans

Assets of the PIC Master Trust (the Master Trust) are invested in accordance with investment guidelines established by the Peabody Plan Retirement Committee and the Peabody Western Plan Retirement Committee (collectively, the Retirement Committees) after consultation with outside investment advisors and actuaries.

The asset allocation targets have been set with the expectation that the assets of the Master Trust will be managed with an appropriate level of risk to fund each Pension Plan's expected liabilities. To determine the appropriate target asset allocations, the Retirement Committees consider the demographics of each Pension Plan's participants, the funded status of each Pension Plan, the business and financial profile of the Company and other associated risk preferences. These allocation targets are reviewed by the Retirement Committees on a regular basis and revised as necessary. The Retirement Committees have developed and implemented a dynamic asset-liability management investment strategy (the Dynamic Investment Strategy) designed to reduce each Pension Plan's funded status volatility risk as funded status increases resulting from changes in liabilities due to discount rates and other factors, investment returns and funding contributions. The Dynamic Investment Strategy adjusts allocations between return-seeking (i.e., equities and other similar investments) and liability hedging (i.e., fixed income duration and spread exposure) portfolios in a pre-established manner, with changes triggered when the Pension Plans reach certain funded status thresholds. As a result of discretionary contributions made in recent years, the Pension Plans have become nearly fully funded and therefore, as of December 31, 2018, the Master Trust investment portfolio reflected the Company's target asset mix of 100% fixed income investments. As of December 31, 2017, the Master Trust investment portfolio reflected the Company's target asset mix of 27% equity securities and 73% fixed income investments. Master Trust assets also include funds invested in various real estate properties representing approximately 1% and 2% of total Master Trust assets as of December 31, 2018 and 2017, respectively. The Retirement Committees' intention is to liquidate these real estate holdings when allowable per the terms of the limited partnership agreements. Generally, dissolution and liquidation of the limited partnerships is required before the Master Trust's real estate holdings can be liquidated and is estimated to occur at various times through 2021.

Assets of the Master Trust are either under active management by third-party investment advisors or in index funds, all of which are selected and monitored by the Retirement Committees. Specific investment guidelines have been established by the Retirement Committees for each major asset class including performance benchmarks, allowable and prohibited investment types and concentration limits. In general, investment guidelines do not permit leveraging the assets held in the Master Trust. However, investment managers may employ various strategies and derivative instruments in establishing overall portfolio characteristics consistent with the guidelines and investment objectives established by the Retirement Committees for their portfolios. Equity investment guidelines do not permit entering into put or call options (except as deemed appropriate to manage interest rate risk), and futures contracts are permitted only to the extent necessary to facilitate liquidity management. Fixed income investment guidelines only allow for exchange-traded derivatives if the investment manager deems the derivative vehicle to be more attractive than a similar direct investment in an underlying cash market or to manage the duration of the fixed income portfolio.

A financial instrument's level within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Following is a description of the valuation techniques and inputs used for investments measured at fair value, including the general classification of such investments pursuant to the valuation hierarchy.

Mutual funds. The Master Trust invests in mutual funds for growth and diversification. Investment vehicles include a fund (benchmarked against the performance of the S&P 500 Index) that invests in large-cap publicly traded common stocks (Large-Cap Fund), an institutional fund that holds a diversified portfolio of long-duration corporate fixed income investments (Corporate Bond Fund), an institutional fund that holds a diversified portfolio of asset backed debt securities (Asset-Backed Fund) and an institutional fund that consists of a diversified portfolio of liquid, short-term instruments of varying maturities (Short-Term Fund). The Large-Cap Fund, which is traded on a national securities exchange in an active market, is valued using daily publicly quoted net asset value (NAV) prices and accordingly classified within Level 1 of the valuation hierarchy. The Corporate Bond Fund, the Asset-Backed Fund and the Short-Term Fund are not traded on a national securities exchange and are valued at NAV, the practical expedient to estimate fair value. As of December 31, 2018, the Large-Cap Fund, the Asset-Backed Fund and the Short-Term Fund have been liquidated in accordance with the Dynamic Investment Strategy.

Corporate bonds. The Master Trust invests in corporate bonds for diversification, volatility reduction of equity securities and to provide a hedge to interest rate movements affecting liabilities. Investment types are predominantly investment-grade corporate bonds. Fair value for these securities is provided by a third-party pricing service that utilizes various inputs such as benchmark yields, reported trades, broker/dealer quotes, issuer spreads and benchmark securities as well as other relevant economic measures. Corporate bonds are classified within the Level 2 valuation hierarchy since fair value inputs are derived prices in active markets and the bonds are not traded on a national securities exchange.

U.S. government securities. The Master Trust invests in U.S. government securities for diversification, volatility reduction of equity securities and to provide a hedge to interest rate movements affecting liabilities. Investment types are predominantly U.S. government bonds, agency securities and municipal bonds. Fair value for these securities is provided by a third-party pricing service that utilizes various inputs such as benchmark yields, reported trades, broker/dealer quotes, issuer spreads and benchmark securities as well as other relevant economic measures. If fair value is based on quoted prices in active markets and traded on a national securities exchange, U.S. government securities are classified within the Level 1 valuation hierarchy; otherwise, U.S. government securities are classified within the Level 2 valuation hierarchy.

International government securities. The Master Trust invests in international government securities for diversification, volatility reduction of equity securities and to provide a hedge to interest rate movements affecting liabilities. Investment types are predominantly non-U.S. government bonds. Fair value for these securities is provided by a third-party pricing service that utilizes various inputs such as benchmark yields, reported trades, broker/dealer quotes, issuer spreads and benchmark securities as well as other relevant economic measures. International government securities are classified within the Level 2 valuation hierarchy since fair value inputs are derived prices in active markets and the bonds are not traded on a national securities exchange.

Common/collective trusts. The Master Trust invests in common/collective trusts (CCT) for growth and diversification. Investment vehicles include a CCT (benchmarked against the performance of the Russell 2000 Index) that invests in small-cap publicly traded common stocks (the Small-Cap CCT), a CCT that invests in publicly traded non-U.S. equity securities (the Equity CCT) and a CCT (benchmarked against the performance of the MSCI Emerging Markets Index) that primarily invests in equity index securities of companies in global emerging markets (the Equity Index CCT). The Equity CCT and the Equity Index CCT are valued using the closing price reported by their primary stock exchange and translated at each valuation date from local currency into U.S. dollars based on independently published currency exchange rates. The NAV is determined in U.S. dollars and calculated as of the last business day of each month for the Equity CCT and daily for the Equity Index CCT. All CCTs are not traded on a national securities exchange and are valued at NAV, the practical expedient to estimate fair value. As of December 31, 2018 all CCTs have been liquidated in accordance with the Dynamic Investment Strategy.

Commercial paper. The Master Trust invests in commercial paper of U.S. corporations to manage liquidity resulting from payment of participant benefits and certain administrative fees. Commercial paper is classified within the Level 2 valuation hierarchy since fair value inputs are derived prices in active markets and the investments are not traded on a national securities exchange.

Cash funds. The Master Trust invests in cash funds to manage liquidity resulting from payment of participant benefits and certain administrative fees. Investment vehicles primarily include a non-interest bearing cash fund with an earnings credit allowance feature, various exchange-traded derivative instruments consisting of futures and interest rate swap agreements used to manage the duration of certain liability-hedging investments. The non-interest bearing cash fund is classified within the Level 1 valuation hierarchy. Exchange traded derivatives, such as options and futures, for which market quotations are readily available, are valued at the last reported sale price or official closing price on the primary market or exchange on which they are traded and are classified within the Level 1 valuation hierarchy.

Real estate interests. The Master Trust invests in real estate interests for diversification. Investments in real estate represent interests in several limited partnerships, which invest in various real estate properties. Interests in real estate are valued using various methodologies, including independent third party appraisals; fair value measurements are not developed by the Company. For some investments, little market activity may exist and determination of fair value is then based on the best information available in the circumstances. This involves a significant degree of judgment by taking into consideration a combination of internal and external factors. Accordingly, interests in real estate are classified within the Level 3 valuation hierarchy. Some limited partnerships issue dividends to their investors in the form of cash distributions that the Pension Plans invest elsewhere within the Master Trust.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date. The inputs or methodologies used for valuing investments are not necessarily an indication of the risk associated with investing in those investments.

The following tables present the fair value of assets in the Master Trust by asset category and by fair value hierarchy:

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Corporate bonds	$ —	$ 466.1	$ —	$ 466.1
U.S. government securities	181.5	17.4	—	198.9
International government securities	—	12.4	—	12.4
Commercial paper	—	2.1	—	2.1
Cash funds	38.4	—	—	38.4
Real estate interests	—	—	6.2	6.2
Total assets at fair value	$ 219.9	$ 498.0	$ 6.2	724.1
Assets measured at net asset value practical expedient (1)				
Private mutual funds				40.7
Total plan assets				$ 764.8

	December 31, 2017			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Mutual funds	$ 108.0	$ —	$ —	$ 108.0
Corporate bonds	—	291.1	—	291.1
U.S. government securities	7.5	21.8	—	29.3
International government securities	—	17.7	—	17.7
Cash funds	30.8	—	—	30.8
Real estate interests	—	—	11.8	11.8
Total assets at fair value	$ 146.3	$ 330.6	$ 11.8	488.7
Assets measured at net asset value practical expedient (1)				
Private mutual funds				180.4
Common collective trusts				107.5
				287.9
Total plan assets				$ 776.6

(1) In accordance with Accounting Standards Update 2015-07, investments that are measured at fair value using the net asset value per share practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the total value of assets of the plans.

The table below sets forth a summary of changes in the fair value of the Master Trust's Level 3 investments:

	Successor		Predecessor
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)		
Balance, beginning of period	$ 11.8	$ 13.8	$ 14.1
Realized gains	2.6	—	0.6
Unrealized (losses) gains relating to investments still held at the reporting date	(2.6)	2.2	(0.6)
Purchases, sales and settlements, net	(5.6)	(4.2)	(0.3)
Balance, end of period	$ 6.2	$ 11.8	$ 13.8

Contributions

Annual contributions to qualified plans are made in accordance with minimum funding standards and the Company's agreement with the Pension Benefit Guaranty Corporation (PBGC). Funding decisions also consider certain funded status thresholds defined by the Pension Protection Act of 2006 (generally 80%). As of December 31, 2018, the Company's qualified plans are expected to be at or above the Pension Protection Act thresholds. Minimum funding standards are legislated by ERISA and are modified by pension funding stabilization provisions included in the Moving Ahead for Progress in the 21st Century Act of 2012, the Highway and Transportation Funding Act of 2014 and the Bipartisan Budget Act of 2015. Based upon minimum funding requirements, the Company is not required to make any payments to its qualified pension plans; however, during the year ended December 31, 2018, the Company made discretionary contributions of $62.0 million to its qualified pension plans.

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid in connection with the Company's benefit obligation:

	Pension Benefits
	(Dollars in millions)
2019	$ 56.8
2020	58.4
2021	59.4
2022	58.9
2023	58.2
Years 2024-2028	274.5

Defined Contribution Plans

The Company sponsors employee retirement accounts under two 401(k) plans for eligible U.S. employees. The Company matches voluntary contributions to each plan up to specified levels. The expense for these plans was $30.3 million, $25.5 million, $5.5 million and $19.2 million for the year ended December 31, 2018, the period April 2 through December 31, 2017, the period January 1 through April 1, 2017 and the year ended December 31, 2016, respectively. A performance contribution feature in one of the plans allows for additional discretionary contributions from the Company. The performance contribution expected to be paid in 2019, relating to the 2018 plan year is $8.9 million. The performance contribution paid during the year ended December 31, 2018 was $8.5 million. There were no performance contributions paid during the period April 2 through December 31, 2017, the period January 1 through April 1, 2017 or the year ended December 31, 2016.

Superannuation

The Company makes superannuation contributions for eligible Australia employees in accordance with the employer contribution rate set by the Government of Australia. The expense related to these contributions was $31.6 million, $19.9 million, $6.1 million and $23.9 million for the year ended December 31, 2018, the period April 2 through December 31, 2017, the period January 1 through April 1, 2017 and the year ended December 31, 2016, respectively. A performance contribution feature allows for additional discretionary contributions from the Company. The discretionary performance contribution expected to be paid in 2019, relating to the 2018 plan year is $2.3 million. The discretionary performance contribution paid during the year ended December 31, 2018 was approximately $3 million. There were no discretionary performance contributions paid during the period April 2 through December 31, 2017, the period January 1 through April 1, 2017 or the year ended December 31, 2016.

(19) Stockholders' Equity

Successor Company

Common Stock

In accordance with the Company's Fourth Amended and Restated Certificate of Incorporation, the Company has 450.0 million authorized shares of Common Stock, par value $0.01 per share. Holders of Common Stock are entitled to one vote per share on all matters to be voted upon by the stockholders. The holders of Common Stock do not have cumulative voting rights in the election of directors. Holders of Common Stock are entitled to receive ratably dividends if, as and when dividends are declared from time to time by the Board out of funds legally available for that purpose, after payment of dividends required to be paid on any outstanding preferred stock or series common stock. Upon dissolution, liquidation or winding up of the Company, the holders of Common Stock are entitled to receive ratably the assets available for distribution to the stockholders after payment of liabilities and subject to the right of holders of any outstanding preferred stock or series common stock. The Common Stock has no preemptive or conversion rights and is not subject to further calls or assessment by the Company. There are no redemption or sinking fund provisions applicable to the Common Stock.

The following table summarizes Common Stock activity during the periods presented below:

	Year Ended December 31, 2018	April 2 through December 31, 2017
	(In millions)	
Shares outstanding at the beginning of the period	105.2	70.9
Shares issued for preferred share conversions	25.5	33.8
Shares issued for warrant conversions	—	6.2
Shares issued for vested restricted stock units	0.7	0.1
Shares issued for disputed claims	0.1	—
Shares repurchased	(21.1)	(5.8)
Shares outstanding at the end of the period	110.4	105.2

See Note 2. “Emergence from the Chapter 11 Cases and Fresh Start Reporting” for additional information.

Preferred Stock

The Board is authorized to issue up to 100.0 million shares of preferred stock, par value $0.01 per share. On the Effective Date, 50.0 million shares of the preferred stock were designated as Series A Convertible Preferred Stock. On January 31, 2018, the remaining outstanding shares of Series A Convertible Preferred Stock were converted into shares of Common Stock. See Note 2. “Emergence from the Chapter 11 Cases and Fresh Start Reporting” for additional information regarding the Series A Convertible Preferred Stock.

The following table summarizes the Series A Convertible Preferred Stock activity during the periods presented below:

	Year Ended December 31, 2018	April 2 through December 31, 2017
	(In millions)	
Shares outstanding at the beginning of the period	13.5	30.0
Shares converted to Common Stock	(13.5)	(17.2)
Shares issued for payable in-kind preferred stock dividends	—	0.7
Shares outstanding at the end of the period	—	13.5

The shares of Series A Convertible Preferred Stock retained the status of authorized but unissued shares of preferred stock following the Mandatory Conversion and accordingly, the Company has 100.0 million authorized shares of preferred stock. The Board can determine the terms and rights of each series, including including whether dividends (if any) will be cumulative or non-cumulative and the dividend rate of the series, redemption or sinking fund provisions, conversion terms, prices and rates and amounts payable on shares of the series in the event of any voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Company and whether the shares of the series will be convertible into shares of any other class or series, or any other security, of the Company or any other corporation. The Board may also determine restrictions on the issuance of shares of the same series or of any other class or series, and the voting rights (if any) of the holders of the series. There were no outstanding shares of preferred stock as of December 31, 2018.

Series Common Stock

The Board is authorized to issue up to 50.0 million shares of series common stock, par value $0.01 per share. The Board can determine the terms and rights of each series, whether dividends (if any) will be cumulative or non-cumulative and the dividend rate of the series, redemption or sinking fund provisions, conversion terms, prices and rates and amounts payable on shares of the series in the event of any voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Company and whether the shares of the series will be convertible into shares of any other class or series, or any other security, of the Company or any other corporation. The Board may also determine restrictions on the issuance of shares of the same series or of any other class or series, and the voting rights (if any) of the holders of the series. There were no outstanding shares of series common stock as of December 31, 2018.

Treasury Stock

Share repurchases. On August 1, 2017, the Board authorized a $500.0 million share repurchase program. Repurchases may be made from time to time at the Company's discretion. On April 25, 2018, the Company announced that the Board authorized the expansion of the Repurchase Program to $1.0 billion. On October 30, 2018, the Company announced that the Board authorized an additional expansion of the Repurchase Program to $1.5 billion. Repurchases may be made from time to time at the Company's discretion. The specific timing, price and size of purchases will depend on the share price, general market and economic conditions and other considerations, including compliance with various debt agreements as they may be amended from time to time. The Repurchase Program does not have an expiration date and may be discontinued at any time. Through December 31, 2018, the Company repurchased 26.9 million shares of its Common Stock for $1,010.4 million (21.1 million shares at a cost of $834.7 million during the year ended December 31, 2018 and 5.8 million shares at a cost of $175.7 million during the period April 2 through December 31, 2017), which included commissions paid of $0.5 million. As of December 31, 2018, there was $490.1 million available for repurchase under the Repurchase Program. Subsequent to December 31, 2018 and through February 20, 2019, the Company purchased 2.3 million additional shares of Common Stock for approximately $75.0 million.

On August 14, 2018, Peabody Energy Corporation entered into a share repurchase agreement (the Share Repurchase Agreement) by and among the Company and its related parties, Elliott Associates, LP, Liverpool Limited Partnership and Sprayberry Investments Inc. to repurchase 7.2 million shares of the Company's common stock for an aggregate purchase price of approximately $300 million, which is included in the total amount of repurchases through December 31, 2018 noted above. Pursuant to the Share Repurchase Agreement, the purchase price per share of $41.82 represented a 1.7% discount from the closing sale price of the common stock on the New York Stock Exchange on August 13, 2018. The repurchase transaction was made in conjunction with the Company's existing share repurchase program and closed on August 21, 2018.

Shares relinquished. The Company routinely allows employees to relinquish Common Stock to pay estimated taxes upon the vesting of restricted stock units and the payout of performance units that are settled in Common Stock under its equity incentive plans. The number of shares of Common Stock relinquished was 0.4 million for the period ended December 31, 2018. The value of the Common Stock tendered by employees was based upon the closing price on the dates of the respective transactions.

Predecessor Company

As described in Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting," in accordance with the Plan and as previously disclosed, each share of the Company's common stock outstanding prior to the Effective Date, including all options and warrants to purchase such stock, was extinguished, canceled and discharged, and each such share, option or warrant had no further force or effect as of the Effective Date. Furthermore, all of the Company's equity award agreements under prior incentive plans, and the awards granted pursuant thereto, were extinguished, canceled and discharged and had no further force or effect as of the Effective Date.

(20) Share-Based Compensation

Successor Company

The Company has established the 2017 Incentive Plan for employees, non-employee directors and consultants that allows for the issuance of share-based compensation in various forms including options (including non-qualified stock options and incentive stock options), stock appreciation rights, restricted stock, restricted stock units, deferred stock, performance units, dividend equivalents and cash incentive awards. Refer to Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting" for additional information regarding the 2017 Incentive Plan and the grant of the Emergence Awards. Under the 2017 Incentive Plan, approximately 14 million shares of the Company's Common Stock were reserved for issuance. As of December 31, 2018, there are approximately 9.9 million shares of the Company's Common Stock available for grant.

Share-Based Compensation Expense and Cash Flows

The Company's share-based compensation expense is recorded in "Operating costs and expenses" and "Selling and administrative expenses" in the consolidated statements of operations. Cash received by the Company upon the exercise of stock options is reflected as a financing activity in the consolidated statements of cash flows. Share-based compensation expense and cash flow amounts were as follows:

	Successor	
	Year Ended December 31, 2018	April 2 through December 31, 2017
	(Dollars in millions)	
Share-based compensation expense	$ 34.9	$ 21.8
Tax benefit	—	—
Share-based compensation expense, net of tax benefit	$ 34.9	$ 21.8
Cash received upon the exercise of stock options and from employee stock purchases	—	—
Write-off tax benefits related to share-based compensation	—	—

As of December 31, 2018, the total unrecognized compensation cost related to nonvested awards was $47.8 million, net of taxes, which is expected to be recognized over 2.5 years with a weighted-average period of 0.7 years.

Deferred Stock Units

During the year ended December 31, 2018 and the period April 2 through December 31, 2017, the Company granted deferred stock units to each of the non-employee members of the Board. The fair value of these units is equal to the market price of the Company's Common Stock at the date of grant. These deferred stock units generally vest on a monthly basis over 12 months and are settled in Common Stock three years after the date of grant.

Restricted Stock Units

On the Effective Date, the Company granted the Emergence Awards. The Emergence Awards granted to the Company's executive officers generally will vest ratably on each of the first three anniversaries of the Effective Date, subject to, among other things, each such executive officer's continued employment with the Company. The Emergence Awards will become fully vested upon each such executive officer's termination of employment by the Company and its subsidiaries without Cause or by the executive for Good Reason (each, as defined in the 2017 Incentive Plan or award agreement) or due to a termination of employment with the Company and its subsidiaries by reason of death or Disability (as defined in the 2017 Incentive Plan or award agreement). In order to receive the Emergence Awards, the executive officers were required to execute restrictive covenant agreements protecting the Company's interests.

The Company grants restricted stock units to certain senior management and non-senior management employees. For units granted to both senior and non-senior management employees containing only service conditions, the fair value of the award is equal to the market price of the Company's Common Stock at the date of grant. Units granted to senior and non-senior management employees vest at various times (none of which exceed three years) in accordance with the underlying award agreement. Compensation cost for both senior and non-senior management employees is recognized on a straight-line basis over the requisite service period. The payouts for active grants awarded during the year ended December 31, 2018 and the period April 2 through December 31, 2017 will be settled in the Company's Common Stock.

A summary of restricted stock unit activity is as follows:

	Year Ended December 31, 2018	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2017	3,513,953	$ 22.04
Granted	476,815	38.19
Vested	(1,218,644)	22.20
Forfeited	(131,037)	23.82
Nonvested at December 31, 2018	2,641,087	$ 24.87

The total fair value at grant date of restricted stock units granted during the year ended December 31, 2018 and the period April 2 through December 31, 2017 was $18.2 million and $79.8 million, respectively.

The restricted stock units receive dividend equivalent units (DEUs) upon payment of cash dividends to holders of Common Stock. DEUs vest subject to the same vesting requirements as the underlying restricted stock unit award. As of December 31, 2018, there were approximately 30,000 nonvested DEUs. The total fair value of restricted stock units and DEUs vested was $46.2 million and $0.9 million during the year ended December 31, 2018 and the period April 2 through December 31, 2017, respectively.

Performance Units

Performance units are typically granted annually in January and vest over a three-year measurement period and are primarily limited to senior management personnel. The performance units are usually subject to the achievement of goals based on the following conditions: three-year return on invested capital and environmental reclamation (performance condition). In addition, the payout of the performance units can be increased or decreased by up to 25% of the award based on three-year stock price performance compared to a custom peer group (market condition). There were no performance units granted during the period April 2 through December 31, 2017. Awards granted in 2018 will be settled in the Company's Common Stock.

A summary of performance unit activity is as follows:

	Year Ended December 31, 2018	Weighted Average Remaining Contractual Life
Nonvested at December 31, 2017	—	—
Granted	206,630	
Forfeited	—	
Vested	—	
Nonvested at December 31, 2018	206,630	2.0

As of December 31, 2018, no performance units had vested.

The performance condition awards were valued utilizing the grant date fair values of the Company's Common Stock adjusted for dividends foregone during the vesting period. The market condition awards were valued utilizing a Monte Carlo simulation model which incorporates the total stockholder return hurdles set for each grant. The assumptions used in the valuations for grants were as follows:

	Year Ended December 31, 2018
Risk-free interest rate	2.24%
Expected volatility	57.75%
Dividend yield	—%

Predecessor Company

In accordance with the Plan and as previously disclosed, each share of the Company's common stock outstanding prior to the Effective Date, including all options and warrants to purchase such stock, were extinguished, canceled and discharged, and each such share, option or warrant had no further force or effect as of the Effective Date. Furthermore, all of the Company's equity award agreements under prior incentive plans, and the awards granted pursuant thereto, were extinguished, canceled and discharged and had no further force or effect as of the Effective Date.

Share-Based Compensation Expense and Cash Flows

The Predecessor Company's share-based compensation expense was recorded in "Selling and administrative expenses" in the consolidated statements of operations. Cash received by the Predecessor Company upon the exercise of stock options and when employees purchased stock under the employee stock purchase plans was reflected as a financing activity in the consolidated statements of cash flows. Share-based compensation expense and cash flow amounts were as follows:

	Predecessor	
	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)	
Share-based compensation expense - equity classified awards	$ 1.9	$ 11.3
Share-based compensation expense - liability classified awards	—	1.5
Total share-based compensation expense	1.9	12.8
Tax benefit	—	—
Share-based compensation expense, net of tax benefit	$ 1.9	$ 12.8
Cash received upon the exercise of stock options and from employee stock purchases	—	—
Write-off tax benefits related to share-based compensation	—	—

(21) Accumulated Other Comprehensive Income (Loss)

The following table sets forth the after-tax components of accumulated other comprehensive income (loss) and changes thereto:

	Foreign Currency Translation Adjustment	Net Actuarial Loss Associated with Postretirement Plans and Workers' Compensation Obligations	Prior Service Credit (Cost) Associated with Postretirement Plans	Cash Flow Hedges	Total Accumulated Other Comprehensive Income (Loss)
	(Dollars in millions)				
Predecessor Company					
December 31, 2015	$ (146.4)	$ (263.8)	$ 31.8	$ (240.5)	$ (618.9)
Reclassification from other comprehensive income to earnings	—	21.0	(5.6)	146.3	161.7
Current period change	(1.8)	(13.5)	(4.5)	—	(19.8)
December 31, 2016	(148.2)	(256.3)	21.7	(94.2)	(477.0)
Reclassification from other comprehensive income to earnings	—	5.8	(1.4)	18.6	23.0
Current period change	5.5	—	—	—	5.5
Fresh start reporting adjustment	142.7	250.5	(20.3)	75.6	448.5
April 1, 2017	$ —	$ —	$ —	$ —	$ —
Successor Company					
Current period change	1.4	—	—	—	1.4
December 31, 2017	1.4	—	—	—	1.4
Current period change	(5.9)	—	44.6	—	38.7
December 31, 2018	$ (4.5)	$ —	$ 44.6	$ —	$ 40.1

The components of accumulated other comprehensive income related to postretirement plans and workers' compensation obligations and cash flow hedges related to Predecessor periods were eliminated in accordance with fresh start reporting as described in Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting." The following table provides additional information regarding items reclassified out of "Accumulated other comprehensive income" into earnings during the periods presented below:

Details about accumulated other comprehensive loss components	Amount reclassified from accumulated other comprehensive income [1] Predecessor January 1 through April 1, 2017	Year Ended December 31, 2016	Affected line item in the consolidated statement of operations
	(Dollars in millions)		
Net actuarial loss associated with postretirement plans and workers' compensation obligations:			
Postretirement health care and life insurance benefits	$ (5.5)	$ (20.4)	Net periodic benefit costs, excluding service cost
Defined benefit pension plans	(6.3)	(24.7)	Net periodic benefit costs, excluding service cost
Workers' compensation amortization	2.7	11.7	Net periodic benefit costs, excluding service cost
	(9.1)	(33.4)	Total before income taxes
	3.3	12.4	Income tax benefit
	$ (5.8)	$ (21.0)	Total after income taxes
Prior service credit (cost) associated with postretirement plans:			
Postretirement health care and life insurance benefits	$ 2.3	$ 9.2	Net periodic benefit costs, excluding service cost
Defined benefit pension plans	(0.1)	(0.3)	Net periodic benefit costs, excluding service cost
	2.2	8.9	Total before income taxes
	(0.8)	(3.3)	Income tax provision
	$ 1.4	$ 5.6	Total after income taxes
Cash flow hedges:			
Foreign currency cash flow hedge contracts	$ (16.6)	$ (145.6)	Operating costs and expenses
Fuel and explosives commodity swaps	(11.0)	(86.1)	Operating costs and expenses
Insignificant items	(0.1)	(0.5)	
	(27.7)	(232.2)	Total before income taxes
	9.1	85.9	Income tax benefit
	$ (18.6)	$ (146.3)	Total after income taxes

(1) Presented as gains (losses) in the consolidated statements of operations.

Comprehensive loss for the Predecessor periods differed from net loss by the amount of unrealized gain or loss resulting from valuation changes of the Company's cash flow hedges (see Note 9. "Derivatives and Fair Value Measurements" for information related to the Company's cash flow hedges), the change in actuarial loss and prior service cost of postretirement plans and workers' compensation obligations (see Note 17. "Postretirement Health Care and Life Insurance Benefits," Note 18. "Pension and Savings Plans" and Note 6. "Discontinued Operations" for information related to the Company's postretirement and pension plans) and foreign currency translation adjustment related to the Company's investments in Middlemount, whose functional currency is the Australian dollar. The values of the Company's cash flow hedging instruments were primarily affected by the U.S. dollar/Australian dollar exchange rate and changes in the prices of certain coal and diesel fuel products.

(22) Other Events

North Goonyella

The Company's North Goonyella Mine in Queensland, Australia experienced a fire in a portion of the mine during September 2018. The underground mine and portions of the surface area remain restricted to access through exclusion zones as mine management continues to evaluate the impact of the fire on the mine and determine potential next phases, including establishing protocols and implementing procedures for re-ventilating and re-entering portions of the mine. Mining operations have been suspended since September 2018. No mine personnel were physically harmed by the September 2018 events. On November 13, 2018 the Queensland Mine Inspectorate (QMI) initiated an investigation into the events that occurred at the mine to determine the cause of the event, assess the response to it and make recommendations to reduce the possibility of future incidents and improve response. The QMI has issued an initial series of document and records requests to the Company, and formal witness interviews are anticipated to follow. Since the investigation is in its early phases, the outcome is presently unknown and subject to numerous uncertainties.

During the year ended December 31, 2018, the Company recorded $58.0 million in containment and idling costs related to the events at North Goonyella and a provision of $66.4 million for expected equipment losses. This provision includes $50.4 million for the estimated cost to replace leased equipment and $16.0 million related to the cost of Company-owned equipment. This provision represents the best estimate of potential loss based on the assessments made to date. In the event that no future mining occurs at the North Goonyella Mine, the Company may record additional charges for the remaining carrying value of the North Goonyella Mine and additional leased equipment of approximately $285 million and $16 million, respectively. Incremental exposures include take-or-pay obligations and other costs associated with idling or closing the mine. The Company filed an insurance claim against applicable insurance policies with combined property damage and business interruption loss limits of $125 million above a $50 million deductible.

Divestitures and Other Transactions

In June 2018, Peabody entered into an agreement to sell approximately 23 million tonnes of metallurgical coal resources adjacent to its Millennium Mine to Stanmore Coal Limited (Stanmore) for approximately $22 million. The sale was completed in July 2018 and the Company recorded a gain of $20.5 million which is included within “Net gain on disposals” in the accompanying consolidated statements of operations for the year ended December 31, 2018. As of December 31, 2018, Stanmore has paid Peabody approximately $7 million, and the remaining balance, which will be paid over the subsequent seven months, is included in “Accounts receivable, net” in the accompanying consolidated balance sheet.

On February 6, 2018, the Company sold its 50% interest in the Red Mountain Joint Venture (RMJV) with BHP Billiton Mitsui Coal Pty Ltd (BMC) for $20.0 million and recorded a gain of $7.1 million, which is included within “Net gain on disposals” in the accompanying consolidated statements of operations for the year ended December 31, 2018. RMJV operated the coal handling and preparation plant utilized by the Company's Millennium Mine. BMC assumed the reclamation obligations and other commitments associated with the assets of RMJV. The Millennium Mine will have continued usage of the coal handling and preparation plant and the associated rail loading facility until the end of 2019 via a coal washing take-or-pay agreement with BMC.

In January 2018, Peabody entered into an agreement to sell its share in certain surplus land assets in Queensland's Bowen Basin to Pembroke Resources South Pty Ltd for approximately $37 million Australian dollars, net of transaction costs. The necessary approval of the Australian Foreign Investment Review Board to complete the transaction was received on March 29, 2018, satisfying all the conditions precedent to the sale, and the Company recorded a gain of $20.6 million, which is included within “Net gain on disposals” in the accompanying consolidated statements of operations for the year ended December 31, 2018.

On November 28, 2017, the Company paid $3.0 million for a third-party's assumption of all rights and obligations related to a guarantee liability recorded pursuant to a 2007 transaction wherein the Company purchased approximately 345 million tons of coal reserves and surface lands in the Illinois Basin. In conjunction with the 2007 purchase, the Company agreed to guarantee certain reclamation and bonding commitments of an affiliate of the seller. The Company extinguished its associated $34.2 million liability upon completion of the 2017 transaction and recorded a gain of $31.2 million which is included within “Net gain on disposals” in the accompanying consolidated statements of operations for the period April 2 through December 31, 2017.

On November 27, 2017, the Company completed the sale of the majority of its Burton Mine and related infrastructure to the Lenton Joint Venture for $11.7 million. The Lenton Joint Venture assumed the reclamation obligations associated with the assets acquired in the sale. The transaction reduced the Company's asset retirement obligation by $40.5 million and reduced the amount of restricted cash held in support of such obligations by approximately $30 million. The Burton Mine, located in Queensland's Bowen Basin, entered a care, maintenance and rehabilitation phase in December 2016 and had no carrying value at the time of sale. In connection with the transaction, the Company recorded a gain of $52.2 million which is included within "Net gain on disposals" in the accompanying consolidated statements of operations for the period April 2 through December 31, 2017.

The Company had a 37.5% interest in Dominion Terminal Associates, a partnership that operates a coal export terminal in Newport News, Virginia that exports both metallurgical and thermal coal primarily to Europe and Brazil. On March 31, 2017, the Company completed a sale of its interest in Dominion Terminal Associates to Contura Terminal, LLC and Ashland Terminal, Inc., both of which are partners of the Dominion Terminal Associates. The Company collected $20.5 million in proceeds and recorded $19.7 million of gain on the sale, which was classified in "Net gain on disposals" in the consolidated statement of operations during the period January 1 through April 1, 2017.

In November 2016, the Company entered into a definitive share sale and purchase agreement (SPA) for the sale of all of its equity interest in Metropolitan Collieries Pty Ltd, the entity that owns the Metropolitan Mine in New South Wales, Australia and the associated interest in the Port Kembla Coal Terminal, to South32 Limited (South32). The SPA provided for a cash purchase price of $200.0 million and certain contingent consideration, subject to a customary working capital adjustment. South32 terminated the agreement in April 2017 after it was unable to obtain necessary approvals from the Australian Competition and Consumer Commission within the timeframe required under the SPA. As a result of the termination, the Company retained an earnest deposit posted by South32 which was recorded in "Revenues" in the accompanying consolidated statements of operations during the period April 2 through December 31, 2017.

In May 2016, the Company completed the sale of its 5.06% participation interest in the Prairie State Energy Campus to the Wabash Valley Power Association for $57.1 million. The Company recognized a gain on sale of $6.2 million related to the transaction, which was classified in "Net gain on disposals" in the consolidated statement of operations for the year ended December 31, 2016.

In May 2016, the Company entered into sale and purchase agreements with Australia-based Pembroke Resources to sell its interest in undeveloped metallurgical reserve tenements in Queensland's Bowen Basin. The transaction included Olive Downs South, Olive Downs South Extended and Willunga tenements, which were sold for $64.1 million in cash plus a royalty stream. The Company recognized a gain on sale of $2.8 million related to those tenements, which was classified in "Net gain on disposals" in the consolidated statement of operations for the year ended December 31, 2016. The sale and purchase agreement for the remaining tenements, namely the Olive Downs North tenements, terminated in October 2017 as certain closing conditions were not satisfied within the prescribed time period.

In November 2015, the Company entered into a definitive agreement to sell its New Mexico and Colorado assets to Bowie Resource Partners, LLC (Bowie) in exchange for cash proceeds of $358 million and the assumption of certain liabilities. Bowie agreed to pay the Company a termination fee of $20 million (Termination Fee) in the event the Company terminated the agreement because Bowie failed to obtain financing and close the transaction. On April 12, 2016, Peabody terminated the agreement and demanded payment of the Termination Fee. Following a favorable judgment by the Bankruptcy Court, the Company collected the Termination Fee from Bowie. The Termination Fee is included in "Revenues" in the accompanying consolidated statements of operations during the period April 2 through December 31, 2017.

Joint Venture

In 2014, the Company agreed to establish an unincorporated joint venture project with Glencore plc (Glencore), in which the Company holds a 50% interest, to combine the existing operations of the Company's Wambo Open-Cut Mine in Australia with the adjacent coal reserves of Glencore's United Mine. The Company expects the project to result in several operational synergies, including improved mining productivity, lower per-unit operating costs and an extended mine life. The joint venture is expected to be formed during the first half of 2019, subject to substantive contingencies, including the requisite regulatory and permitting approvals. At such time as control over the existing open-cut operations is exchanged, the Company will account for its interest in the combined operations at fair value.

(23) Earnings per Share (EPS)

Basic and diluted EPS are computed using the two-class method, which is an earnings allocation that determines EPS for each class of common stock and participating securities according to dividends declared and participation rights in undistributed earnings. The Company's Convertible Preferred Stock was considered a participating security because holders were entitled to receive dividends on an if-converted basis. The Predecessor Company's restricted stock awards were considered participating securities because holders were entitled to receive non-forfeitable dividends during the vesting term. Diluted EPS includes securities that could potentially dilute basic EPS during a reporting period and assumes that participating securities are not executed or converted. As such, the Company includes the share-based compensation awards in its potentially dilutive securities. The calculation of diluted EPS for the Predecessor Company also considered the impact of its Convertible Junior Subordinated Debentures due December 2066 (the Debentures). Dilutive securities are not included in the computation of loss per share when a company reports a net loss from continuing operations as the impact would be anti-dilutive.

For all but the performance units, the potentially dilutive impact of the Company's share-based compensation awards is determined using the treasury stock method. Under the treasury stock method, awards are treated as if they had been exercised with any proceeds used to repurchase common stock at the average market price during the period. Any incremental difference between the assumed number of shares issued and purchased is included in the diluted share computation. For the performance units, their contingent features result in an assessment for any potentially dilutive common stock by using the end of the reporting period as if it were the end of the contingency period for all units granted. For further discussion of the Company's share-based compensation awards, see Note 20. "Share-Based Compensation."

Up to the time of cancellation, a conversion of the Debentures could have resulted in payment for any conversion value in excess of the principal amount of the Debentures in the Predecessor Company's common stock. For diluted EPS purposes, potential common stock was calculated based on whether the market price of the Predecessor Company's common stock at the end of each reporting period was in excess of the conversion price of the Debentures. The effect of the Debentures was excluded from the calculation of diluted EPS for all Predecessor periods presented herein because to do so would have been anti-dilutive for those periods.

The computation of diluted EPS excluded aggregate share-based compensation awards of less than 0.1 million for the year ended December 31, 2018 and the period April 2 through December 31, 2017, respectively, and approximately 0.2 million and 0.4 million for the period January 1 through April 1, 2017 and the year ended December 31, 2016, respectively, because to do so would have been anti-dilutive for those periods. Because the potential dilutive impact of such share-based compensation awards is calculated under the treasury stock method, anti-dilution generally occurs when the exercise prices or unrecognized compensation cost per share of such awards are higher than the Company's average stock price during the applicable period.

The following illustrates the earnings allocation method utilized in the calculation of basic and diluted EPS:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(In millions, except per share amounts)			
EPS numerator:				
Income (loss) from continuing operations, net of income taxes	$ 645.7	$ 713.1	$ (195.5)	$ (663.8)
Less: Series A Convertible Preferred Stock dividends	102.5	179.5	—	—
Less: Net income attributable to noncontrolling interests	16.9	15.2	4.8	7.9
Income (loss) from continuing operations attributable to common stockholders, before allocation of earnings to participating securities	526.3	518.4	(200.3)	(671.7)
Less: Earnings allocated to participating securities	7.9	129.0	—	—
Income (loss) from continuing operations attributable to common stockholders, after allocation of earnings to participating securities [(1)]	518.4	389.4	(200.3)	(671.7)
Income (loss) from discontinued operations, net of income taxes	18.1	(19.8)	(16.2)	(57.6)
Less: Income (loss) from discontinued operations allocated to participating securities	0.3	(4.9)	—	—
Income (loss) from discontinued operations attributable to common stockholders, after allocation of earnings to participating securities	17.8	(14.9)	(16.2)	(57.6)
Net income (loss) attributable to common stockholders, after allocation of earnings to participating securities [(1)]	$ 536.2	$ 374.5	$ (216.5)	$ (729.3)
EPS denominator:				
Weighted average shares outstanding — basic	119.3	101.1	18.3	18.3
Impact of dilutive securities	1.7	1.4	—	—
Weighted average shares outstanding — diluted [(2)]	121.0	102.5	18.3	18.3
Basic EPS attributable to common stockholders:				
Income (loss) from continuing operations	$ 4.35	$ 3.85	$ (10.93)	$ (36.72)
Income (loss) from discontinued operations	0.15	(0.15)	(0.88)	(3.15)
Net income (loss) attributable to common stockholders	$ 4.50	$ 3.70	$ (11.81)	$ (39.87)
Diluted EPS attributable to common stockholders:				
Income (loss) from continuing operations	$ 4.28	$ 3.81	$ (10.93)	$ (36.72)
Income (loss) from discontinued operations	0.15	(0.14)	(0.88)	(3.15)
Net income (loss) attributable to common stockholders	$ 4.43	$ 3.67	$ (11.81)	$ (39.87)

(1) The reallocation adjustment for participating securities to arrive at the numerator to calculate diluted EPS was $0.1 million and $1.2 million for the year ended December 31, 2018 and the period April 2 through December 31, 2017, respectively.

(2) The two-class method assumes that participating securities are not exercised or converted. As such, weighted average diluted shares outstanding excluded 2.1 million shares and 33.5 million shares related to the participating securities for the year ended December 31, 2018 and the period April 2 through December 31, 2017, respectively.

In accordance with the Plan, each share of the Predecessor Company's common stock outstanding prior to the Effective Date, including all options and warrants to purchase such stock, was extinguished, canceled and discharged, and each such share, option or warrant has no further force or effect after the Effective Date. Furthermore, all of the Predecessor Company's equity award agreements under prior incentive plans, and the equity awards granted pursuant thereto, were extinguished, canceled and discharged and have no further force or effect after the Effective Date.

As of January 31, 2018, all 30.0 million shares of Convertible Preferred Stock issued upon the Effective Date had been converted into 59.3 million shares of Common Stock, which is inclusive of the shares that had been issued for the payable in-kind preferred stock dividends.

(24) Management — Labor Relations

On December 31, 2018, the Company had approximately 7,400 employees worldwide, including approximately 5,600 hourly employees; the employee amounts exclude employees that were employed at operations classified as discontinued operations. Approximately 42% of those hourly employees were represented by organized labor unions and were employed by mines that generated 20% of the Company's 2018 coal production from continuing operations. In the U.S., two mines are represented by an organized labor union. In Australia, the coal mining industry is unionized and the majority of hourly workers employed at the Company's Australian mining operations are members of trade unions. The Construction Forestry Maritime Mining and Energy Union generally represents the Company's Australian subsidiaries' hourly production and engineering employees, including those employed through contract mining relationships. The Company believes labor relations with its employees are good. Should that condition change, the Company could experience labor disputes, work stoppages or other disruptions in production that could negatively impact the Company's results of operations and cash flows.

The following table presents the Company's active mining operations as of December 31, 2018 in which the employees are represented by organized labor unions:

Mine	Current Agreement Expiration Date
U.S.	
Kayenta (1)	September 2019
Shoal Creek (2)	April 2021
Australia	
Owner-operated mines:	
Wambo Open-Cut (3)	December 2018
Wambo Underground (3)	March 2021
North Goonyella (4)	December 2018
Metropolitan (5)	January 2021
Millennium (6)	March 2019
Wilpinjong (7)	May 2020
Coppabella (8)	June 2021
Moorvale (9)	June 2020

(1) Hourly workers at the Company's Kayenta Mine in Arizona are represented by the UMWA under the Western Surface Agreement, which is effective through September 16, 2019. This agreement covers approximately 7% of the Company's U.S. subsidiaries' hourly employees, who generated approximately 4% of the Company's U.S. production during the year ended December 31, 2018.

(2) Hourly workers at the Company's Shoal Creek Mine in Alabama are represented by the UMWA under the Shoal Creek Wage Agreement, which is effective through April 1, 2021. This agreement covers approximately 9% of the Company's U.S. subsidiaries' hourly employees. The Company acquired the Shoal Creek Mine on December 3, 2018, as further described in Note 3. "Acquisition of Shoal Creek Mine".

(3) Employees of the Wambo Open-Cut Mine operate under a separate enterprise agreement which expired in December 2018. Negotiations for a new agreement are progressing as planned with only a few outstanding matters to be negotiated. Negotiations are expected to conclude in the first quarter of 2019. There were no wage increases over the three-year term of the current labor agreement. Employees of the Company's Wambo Underground Mine operate under a separate labor agreement. That new agreement will expire in March 2021. There have been no disruptions in the mine's operations during the negotiations. The Wambo coal handling and preparation plant hourly employees are under a separate labor agreement that expired in December 2018. The Company negotiated a new three-year agreement with employees in December 2018, which is currently going through an approval process with the Fair Work Commission. Hourly employees of these mines comprise approximately 23% of the Company's Australian subsidiaries' hourly employees, who generated approximately 18% of the Company's Australian production during the year ended December 31, 2018.

(4) Employees of the North Goonyella Mine operate under a separate labor agreement which expired in December 2018. Negotiations for an extension of the existing agreement until December 2019 are progressing and are expected to conclude in the first quarter of 2019. Hourly employees of this mine comprise approximately 8% of the Company's Australian subsidiaries' hourly employees, who generated approximately 5% of the Company's Australian production during the year ended December 31, 2018.

(5) Employees of the Company's Metropolitan Mine operate under a separate labor agreement, which expires in January 2021. There is also a deputy labor agreement which expired in September 2015. The parties have concluded negotiations in December 2018 for a new three-year agreement and is awaiting approval from the Fair Work Commission. There have been no disruptions to the mine's operations as a result of the negotiations. Hourly employees of this mine comprise approximately 12% of the Company's Australian subsidiaries' hourly employees, who generated approximately 6% of the Company's Australian production during the year ended December 31, 2018.

(6) The existing two-year labor agreement for Millennium Mine expires in March 2019. The negotiations for an extension of the current agreement through the end of 2019 will commence in the first quarter of 2019. Hourly employees of this mine comprise approximately 1% of the Company's Australian subsidiaries' hourly employees, who generated approximately 6% of the Company's Australian production during the year ended December 31, 2018.

(7) In May 2017, the Company entered into a new three-year labor agreement for Wilpinjong Mine which expires in May 2020. The new agreement has minimal wage increases. Hourly employees of this mine comprise approximately 23% of the Company's Australian subsidiaries' hourly employees, who generated approximately 48% of the Company's Australian production during the year ended December 31, 2018.

(8) Employees of the Company's Coppabella Mine operate under a separate enterprise agreement. The Company successfully negotiated a new three-year term agreement that will expire in June 2021. There were no disruptions to the mine's operations as a result of the negotiations. Hourly employees of this mine comprise approximately 20% of the Company's Australian subsidiaries' hourly employees, who generated approximately 9% of the Company's Australian production during the year ended December 31, 2018.

(9) Employees of the Company's Moorvale Mine operate on individual contracts underpinned by a non-union enterprise agreement. Employees are managed according to their individual contracts rather than the enterprise agreement. In July 2017, all employees signed a memorandum of understanding agreeing to a rollover of the existing enterprise agreement until June 2020. The Moorvale coal handling and preparation plant hourly employees operate under a separate labor agreement which expires in October 2019. Negotiations for a new agreement will commence in the third quarter of 2019. Hourly employees of this mine comprise approximately 14% of the Company's Australian subsidiaries' hourly employees, who generated approximately 7% of the Company's Australian production during the year ended December 31, 2018.

(25) Financial Instruments, Guarantees With Off-Balance-Sheet Risk and Other Guarantees

In the normal course of business, the Company is a party to various guarantees and financial instruments that carry off-balance-sheet risk and are not reflected in the accompanying consolidated balance sheets. At December 31, 2018, such instruments included $1,589.8 million of surety bonds and bank guarantees and $245.0 million of letters of credit. Such financial instruments provide support for the Company's reclamation bonding requirements, lease obligations, insurance policies and various other performance guarantees. The Company periodically evaluates the instruments for on-balance-sheet treatment based on the amount of exposure under the instrument and the likelihood of required performance. The Company does not expect any material losses to result from these guarantees or off-balance-sheet instruments in excess of liabilities provided for in the accompanying consolidated balance sheets.

Reclamation Bonding

The Company is required to provide various forms of financial assurance in support of its mining reclamation obligations in the jurisdictions in which it operates. Such requirements are typically established by statute or under mining permits. Historically, such assurances have taken the form of third-party instruments such as surety bonds, bank guarantees, letters of credit, cash collateral held in restricted accounts, and self-bonding arrangements in the U.S. In connection with its emergence from the Chapter 11 Cases, the Company elected to utilize primarily a portfolio of surety bonds to support its U.S. obligations.

At December 31, 2018, the Company's asset retirement obligations of $750.2 million were supported by surety bonds of $1,317.0 million as well as letters of credit issued under the Company's receivables securitization program and Revolver amounting to $147.3 million.

Accounts Receivable Securitization

As described in Note 2. "Emergence from the Chapter 11 Cases and Fresh Start Reporting," the Company entered into the Receivables Purchase Agreement to extend the receivables securitization facility previously in place and expand that facility to include certain receivables from the Company's Australian operations. The term of the receivables securitization program (Securitization Program) ends on April 3, 2020, subject to certain liquidity requirements and other customary events of default set forth in the Receivables Purchase Agreement. The Securitization Program provides for up to $250.0 million in funding accounted for as a secured borrowing, limited to the availability of eligible receivables, and may be secured by a combination of cash collateral and the trade receivables underlying the program. Funding capacity under the Securitization Program may also be drawn upon for letters of credit in support of other obligations. During 2017, the Company entered into amendments to the Securitization Program to include the receivables of additional Australian operations, reduce the restrictions on the availability of certain eligible receivables, add an additional servicer and reduce program fees.

Under the terms of the Securitization Program, the Company contributes the trade receivables of its participating subsidiaries on a revolving basis to P&L Receivables, its wholly-owned, bankruptcy-remote subsidiary, which then sells the receivables to unaffiliated banks. P&L Receivables retains the ability to repurchase the receivables in certain circumstances. The assets and liabilities of P&L Receivables are consolidated with Peabody, and the Securitization Program is treated as a secured borrowing for accounting purposes, but the assets of P&L Receivables will be used first to satisfy the creditors of P&L Receivables, not Peabody's creditors. The borrowings under the Securitization Program remain outstanding throughout the term of the agreement, subject to the Company maintaining sufficient eligible receivables, by continuing to contribute trade receivables to P&L Receivables, unless an event of default occurs.

At December 31, 2018, the Company had no outstanding borrowings and $137.1 million of letters of credit drawn under the Securitization Program. The letters of credit were primarily in support of portions of the Company's obligations for reclamation, workers' compensation and postretirement benefits. The Company had no cash collateral requirement under the Securitization Program at December 31, 2018 and December 31, 2017. The Company incurred fees associated with the Securitization Program of $5.2 million and $5.3 million during the year ended December 31, 2018 and the period April 2 through December 31, 2017, respectively, which have been recorded as "Interest expense" in the accompanying statements of operations. As it relates to the former receivables securitization facility in place prior to the Effective Date, the Company incurred interest expense of $2.0 million during the period January 1 through April 1, 2017 and $8.2 million for the year ended December 31, 2016.

Collateral Arrangements and Restricted Cash

The Company remits cash to certain regulatory authorities and other third parties as collateral for financial assurances associated with a variety of long-term obligations and commitments surrounding the mining, reclamation and shipping of its production. The Company had $323.1 million held by third parties related to such obligations at December 31, 2017. All such collateral was returned to the Company during the year ended December 31, 2018, largely as the result of replacing collateral balances with third-party surety bonding in Australia.

The Company also had $40.1 million of restricted cash at December 31, 2017 related to a class of pending unsecured creditors' claims in connection with the Chapter 11 Cases. The restriction was released on March 22, 2018 after the Debtors satisfied all such claims.

Other

The Company is the lessee under numerous equipment and property leases. It is common in such commercial lease transactions for the Company, as the lessee, to agree to indemnify the lessor for the value of the property or equipment leased, should the property be damaged or lost during the course of the Company's operations. The Company expects that losses with respect to leased property, if any, may be covered by insurance (subject to deductibles). The Company and certain of its subsidiaries have guaranteed other subsidiaries' performance under various lease obligations. Aside from indemnification of the lessor for the value of the property leased, the Company's maximum potential obligations under its leases are equal to the respective future minimum lease payments, and the Company assumes that no amounts could be recovered from third parties. In this regard, the Company made a $50.4 million provision during the year ended December 31, 2018 for loss of leased equipment at the North Goonyella Mine as described in Note 22. "Other Events."

The Company has provided financial guarantees under certain long-term debt agreements entered into by its subsidiaries and substantially all of the Company's U.S. subsidiaries provide financial guarantees under long-term debt agreements entered into by the Company. The maximum amounts payable under the Company's debt agreements are equal to the respective principal and interest payments.

(26) Commitments and Contingencies

Commitments

Unconditional Purchase Obligations

As of December 31, 2018, purchase commitments for capital expenditures were $110.3 million, all of which is obligated within the next three years, with $94.2 million obligated in the next year.

In Australia, the Company has generally secured the ability to transport coal through rail contracts and ownership interests in five east coast coal export terminals that are primarily funded through take-or-pay arrangements with terms ranging up to 24 years. In the U.S., the Company has entered into certain long-term coal export terminal agreements to secure export capacity through the Gulf Coast. As of December 31, 2018, these Australian and U.S. commitments under take-or-pay arrangements totaled $1.3 billion, of which approximately $148 million is obligated within the next year.

Contingencies

From time to time, the Company or its subsidiaries are involved in legal proceedings arising in the ordinary course of business or related to indemnities or historical operations. The Company believes it has recorded adequate reserves for these liabilities. The Company discusses its significant legal proceedings below, including ongoing proceedings and those that impacted the Company's results of operations for the periods presented.

Litigation Relating to the Chapter 11 Cases

Ad Hoc Committee. 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.

Litigation Relating to Continuing Operations

Peabody Monto Coal Pty Ltd, Monto Coal 2 Pty Ltd and Peabody Energy Australia PCI Pty Ltd (PEA-PCI). In October 2007, a claim was made against Peabody Monto Coal Pty Ltd, a wholly-owned subsidiary, and Monto Coal 2 Pty Ltd, an equity accounted investee of Macarthur Coal Limited (Macarthur), now known as PEA-PCI. The claim alleged that the Macarthur companies breached certain agreements by failing to develop a mine project. The claim was amended to assert that Macarthur induced the alleged breach of the Monto Coal Joint Venture Agreement. The Company acquired Macarthur and its subsidiaries in 2011. These claims, which are pending before the Supreme Court of Queensland, Australia, seek damages of up to $1.1 billion Australian dollars, plus interest and costs.

The Company asserts that the Macarthur companies were never under an obligation to develop the mine project because the project was not economically viable. The Company disputes all of the claims brought by the plaintiffs and is vigorously defending its position. Trial is currently set to commence on April 8, 2019.

Berenergy Corporation. The Company has been in a legal dispute with Berenergy Corporation (Berenergy) regarding Berenergy's access to certain of its underground oil deposits beneath the Company's North Antelope Rochelle Mine and contiguous undisturbed areas. Berenergy contends the Company should not be able to mine the area where Berenergy and Peabody hold conflicting leases. Berenergy also contends that if the Company does mine the area, then the Company should be liable to Berenergy for the cost of certain special procedures and equipment required to access the secondary deposits remotely from outside the Company's mine area, which has been estimated at $13.1 million by Berenergy. The Company believes that it should be allowed to mine the area conflicting with Berenergy's leases so long as it pays for the reasonable value of the oil reserves under Berenergy's wells that sit on its four leases, which the Company estimates to be approximately $1.0 million. The parties entered into an interim agreement that allows Peabody to plug certain of Berenergy's wells to allow Peabody to mine certain areas where the two parties hold conflicting leases. This dispute currently has proceedings before the Wyoming Supreme Court and a federal court in Wyoming. The Company will vigorously defend its position in both proceedings, as it believes Berenergy's claims are without merit and that the likelihood of a material loss resulting from the matter is remote.

County of San Mateo, County of Marin, City of Imperial Beach. The Company was named as a defendant, along with numerous other companies, in three nearly identical lawsuits. The lawsuits seek to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the greenhouse gas emissions attributable to those fuels. The lawsuits primarily assert that the companies' products have caused a sea level rise that is damaging the plaintiffs. The complaints specifically alleged that the defendants' activities from 1965 to 2015 caused such damage. The Company filed a motion to enforce the Confirmation Order in the Bankruptcy Court because the Confirmation Order enjoins claims that arose before the effective date of the Plan. The motion to enforce was granted on October 24, 2017, and the Bankruptcy Court ordered the plaintiffs to dismiss their lawsuits against the Company. On November 26, 2017, the plaintiffs appealed the Bankruptcy Court's October 24, 2017 order to the District Court. On November 28, 2017, plaintiffs sought a stay pending appeal from the Bankruptcy Court, which was denied December 8, 2017. On December 19, 2017, the plaintiffs moved the District Court for a stay pending appeal. The District Court denied the stay request on September 20, 2018, and the plaintiffs appealed that decision to the U.S. Court of Appeals from the Eighth Circuit. The parties are waiting for a decision on the merits of the appeal and on the appeal of the stay. In the underlying cases pending in California, the U.S. District Court for the Northern District of California granted plaintiffs' motion for remand and decided the cases should be heard in state court. The defendants appealed the order granting remand to the Ninth Circuit and sought a stay of the U.S. District Court for the Northern District of California decision pending completion of the Ninth Circuit appeal. The U.S. District Court for the Northern District of California granted defendants' request for a stay pending completion of the Ninth Circuit appeal. The plaintiffs filed a motion to dismiss part of the appeal. The parties are now litigating at the Ninth Circuit whether a state or federal court should hear these lawsuits. Regardless of whether state court or federal court is the venue, the Company believes the lawsuits against it should be dismissed under enforcement of the Confirmation Order. The Company does not believe the lawsuits are meritorious and, if the lawsuits are not dismissed, the Company intends to vigorously defend them.

10th Circuit U.S. Bureau of Land Management (BLM) Appeal. On September 15, 2017, the Tenth Circuit Court of Appeals reversed the District Court of Wyoming's decision upholding BLM's approval of four coal leases in the Powder River Basin. Two of the four leases relate to the Company's North Antelope Rochelle Mine in Wyoming. There is no immediate impact on the Company's leases as the Court of Appeals did not vacate the leases as part of its ruling. Rather, the Court of Appeals remanded the case back to the District Court of Wyoming with directions to order BLM to revise its environmental analysis. On November 27, 2017, the District Court of Wyoming ordered BLM to revise its environmental analysis. BLM published its draft environmental analysis on July 30, 2018. The Company, along with the National Mining Association, the Wyoming Mining Association and Arch Coal, Inc., submitted comments on the draft environmental analysis by the comment deadline of October 4, 2018. BLM's recent status report filed with the District Court of Wyoming indicated it would not issue a final environmental analysis until the spring of 2019 and will refine that estimate in a future report. The Company's operations will continue in the normal course during this period since the decision has no impact on mining at this time. The Company currently believes that its operations are unlikely to be materially impacted by this case, but the timing and magnitude of any impact on the Company's future operations is not certain.

Central Arizona Water Conservation District (CAWCD). On May 1, 2018, the Company, along with the Hopi Tribe and the UMWA, filed a lawsuit against the CAWCD. CAWCD operates, on behalf of the Bureau of Reclamation, the Central Arizona Project (CAP), an aqueduct system that brings water from the Colorado River to three counties in Arizona. CAWCD historically obtained most of CAP's power requirements from the Navajo Generating Station (NGS), which is served by a single Peabody mine. NGS is owned by several private companies and one governmental entity. The owners of NGS issued a statement that they do not currently intend to be the operators of the plant beyond December 2019. Recently, CAWCD made the decision to obtain a portion of CAP's power requirements from sources other than NGS for 2020 and thereafter. The lawsuit seeks a determination that federal law requires CAWCD to obtain CAP's power requirements from NGS. A motion to dismiss filed by CAWCD is currently pending.

Other

At times the Company becomes a party to other disputes, including those related to contract miner performance, claims, lawsuits, arbitration proceedings, regulatory investigations and administrative procedures in the ordinary course of business in the U.S., Australia and other countries where the Company does business. Based on current information, the Company believes that such other pending or threatened proceedings are likely to be resolved without a material adverse effect on its financial condition, results of operations or cash flows.

(27) Summary of Quarterly Financial Information (Unaudited)

A summary of the unaudited quarterly results of operations for the years ended December 31, 2018 and 2017 is presented below.

	Year Ended December 31, 2018			
	Successor			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share data)			
Revenues	$ 1,462.7	$ 1,309.4	$ 1,412.6	$ 1,397.1
Operating profit	239.2	165.3	130.3	126.8
Income from continuing operations, net of income taxes	208.3	120.0	83.9	233.5
Net income	207.0	116.4	79.8	260.6
Net income attributable to common stockholders	106.6	113.7	71.5	252.6
Basic EPS — continuing operations [(1)]	$ 0.84	$ 0.94	$ 0.64	$ 1.99
Diluted EPS — continuing operations [(1)]	$ 0.83	$ 0.93	$ 0.63	$ 1.97
Weighted average shares used in calculating basic EPS	120.9	124.5	118.6	113.1
Weighted average shares used in calculating diluted EPS	123.2	126.0	120.3	114.7

(1) EPS for the quarters may not sum to the amounts for the year as each period is computed on a discrete basis.

Operating profit for the first and third quarter of 2018 reflected $30.6 million and $20.7 million of gains on disposal of assets, respectively, primarily driven by net gains on the sale of certain surplus land assets in Queensland's Bowen Basin and the sale of surplus coal resources associated with the Company's Millennium Mine of $20.6 million and $20.5 million, respectively. Operating profit for the third and fourth quarter of 2018 reflected $49.3 million and $17.1 million related to the provision for North Goonyella equipment loss, respectively. Operating profit for the first, second and third quarter of 2018 included steady income from equity affiliates of $22.0 million, $25.2 million and $17.2 million, respectively, due to favorable coal pricing at Middlemount. Operating profit for the fourth quarter of 2018 included acquisition costs related to the Shoal Creek Mine of $4.9 million. Income from continuing operations, net of income taxes for the first, second, third and fourth quarters of 2018 included steady interest expense of $36.3 million, $38.3 million, $38.2 million and $36.5 million respectively, partially offset by interest income of $7.2 million, $7.0 million, $10.1 million and $9.3 million in the first, second, third and fourth quarters of 2018, respectively. Income from continuing operations, net of income taxes for the first quarter of 2018 included a credit of $12.8 million for reorganization items, net due to a bankruptcy claims accrual adjustment in relation to the Company's emergence from the Chapter 11 Cases. Income from continuing operations, net of income taxes for the fourth quarter of 2018 reflected $125.5 million of net mark-to-market gains on actuarially determined liabilities.

	Year Ended December 31, 2017				
	Predecessor		Successor		
	First Quarter	April 1	April 2 through June 30	Third Quarter	Fourth Quarter
	(In millions, except per share data)				
Revenues	$ 1,326.2	$ —	$ 1,258.3	$ 1,477.2	$ 1,517.1
Operating profit	212.5	—	152.6	209.5	301.7
Income (loss) from continuing operations, net of income taxes	124.3	(319.8)	101.4	233.7	378.0
Net income (loss)	120.2	(331.9)	98.7	230.0	364.6
Net income (loss) attributable to common stockholders	115.4	(331.9)	(20.2)	201.4	317.4
Basic EPS — continuing operations (1)	$ 6.46	$ (17.44)	$ (0.18)	$ 1.51	$ 2.50
Diluted EPS — continuing operations (1)	$ 6.44	$ (17.44)	$ (0.18)	$ 1.49	$ 2.47
Weighted average shares used in calculating basic EPS	18.3	18.3	96.8	101.6	104.8
Weighted average shares used in calculating diluted EPS	18.4	18.3	96.8	103.1	106.5

(1) EPS for the quarters may not sum to the amounts for the year as each period is computed on a discrete basis.

Operating profit for the first quarter of 2017 included $30.5 million of asset impairment costs, related to terminated coal lease contracts in the Midwestern U.S. Operating profit for the fourth quarter of 2017 included net gain on disposals of $83.1 million, primarily driven by the sale of the Burton Mine assets and the extinguishment of a guarantee liability for reclamation and bonding commitments of $52.2 million and $31.2 million, respectively, partially offset by $6.6 million of restructuring charges. Operating profit for the first, third and fourth quarters of 2017, as well as the period April 2 through June 30, 2017 included steady income from equity affiliates of $15.0 million, $10.5 million, $22.8 million, and $15.7 million, respectively, due to favorable coal pricing at Middlemount. Income from continuing operations, net of income taxes for the first quarter and April 1, 2017 reflected $41.4 million and $585.8 million, respectively, of reorganization items, net due to the Company's emergence from the Chapter 11 Cases. Income from continuing operations, net of income taxes for the period April 2 through June 30, 2017 and the third quarter of 2017 reflected $41.4 million and $42.5 million, respectively, of interest expense, while the fourth quarter experienced a decrease in interest expense due to prepayments on the Senior Secured Term Loan, reducing interest payments. Income from continuing operations, net of income taxes for the third and fourth quarters of 2017 included a loss on debt extinguishment of $12.9 million and $8.0 million, respectively, resulting from the prepayments of the Senior Secured Term Loan. Income from continuing operations, net of income taxes for the fourth quarter of 2017 also reflected $45.2 million of net mark-to-market gains on actuarially determined liabilities.

(28) Segment and Geographic Information

During the fourth quarter of 2018, the Company purchased the Shoal Creek Mine, as further discussed in Note 3. "Acquisition of Shoal Creek Mine." Due to the acquisition, the Company updated its reportable segments to reflect the manner in which its chief operating decision maker (CODM) views the Company's businesses for purposes of reviewing performance, allocating resources and assessing future prospects and strategic execution. The Company now reports its results of operations primarily through the following reportable segments: Powder River Basin Mining, Midwestern U.S. Mining, Western U.S. Mining, Seaborne Metallurgical Mining, Seaborne Thermal Mining and Corporate and Other. Periods presented in this note have been recast for comparability.

The principal business of the Company's thermal 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 relatively small portion sold as international exports as conditions warrant. The Company's Powder River Basin Mining operations consist of its 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). The Company's Midwestern U.S. Mining operations include its 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). The Company's Western U.S. Mining operations reflect the aggregation of its New Mexico, Arizona and Colorado mining operations. The mines in that segment are characterized by a mix of surface and underground mining extraction processes and coal with a mid-range sulfur content and Btu. Geologically, the Company's Powder River Basin Mining operations mine sub-bituminous coal deposits, its Midwestern U.S. Mining operations mine bituminous coal deposits and its Western U.S. Mining operations mine both bituminous and sub-bituminous coal deposits.

The business of the Company's seaborne operating platform is primarily export focused with customers spread across several countries, with a portion of its metallurgical and thermal coal sold within Australia. Generally, revenues from individual countries vary year by year based on steel and electricity demand, the strength of the global economy, governmental policies and several other factors, including those specific to each country. The Company classifies its seaborne mines within the Seaborne Metallurgical Mining or Seaborne 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 Seaborne Metallurgical Mining segment is of a thermal grade. Similarly, a small portion of the coal mined by the Seaborne Thermal Mining segment is of a metallurgical grade. Additionally, the Company may market some of its metallurgical coal products as a thermal coal product from time to time depending on market conditions.

The Company's Seaborne Metallurgical Mining operations consist of mines in Queensland, Australia, one in New South Wales, Australia and one in Alabama. 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 pulverized coal injection coal.

The Company's Seaborne 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.

The Company's Corporate and Other segment includes selling and administrative expenses, results from equity affiliates, corporate hedging activities, trading and brokerage activities, certain mining and export/transportation joint ventures, restructuring charges and activities associated with the optimization of its coal reserve and real estate holdings, minimum charges on certain transportation-related contracts, the closure of inactive mining sites and certain commercial matters.

The Company's CODM uses Adjusted EBITDA as the primary metric to measure the segments' operating performance. Adjusted EBITDA is a non-GAAP financial measure defined as income (loss) from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expenses, depreciation, depletion and amortization and reorganization items, net. Adjusted EBITDA is also adjusted for the discrete items that management excluded in analyzing the segments' operating performance, as displayed in the reconciliation below. Management believes non-GAAP performance measures are used by investors to measure the Company's operating performance and lenders to measure the Company's ability to incur and service debt. Adjusted EBITDA is not intended to serve as an alternative to U.S. GAAP measures of performance and may not be comparable to similarly-titled measures presented by other companies.

Segment results for the year ended December 31, 2018 were as follows:

	Successor						
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining	Corporate and Other	Consolidated
	(Dollars in millions)						
Revenues	$ 1,424.8	$ 801.0	$ 592.0	$ 1,553.0	$ 1,099.2	$ 111.8	$ 5,581.8
Adjusted EBITDA	284.5	145.2	145.4	441.4	452.0	(89.2)	1,379.3
Additions to property, plant, equipment and mine development	81.0	46.6	13.9	88.7	66.6	4.2	301.0
Federal coal lease expenditures	—	—	0.5	—	—	—	0.5
Income from equity affiliates	—	—	—	—	—	(68.1)	(68.1)

Segment results for the period April 2 through December 31, 2017 were as follows:

	Successor						
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining	Corporate and Other	Consolidated
	(Dollars in millions)						
Revenues	$ 1,178.7	$ 592.3	$ 440.7	$ 1,221.0	$ 772.5	$ 47.4	$ 4,252.6
Adjusted EBITDA	278.8	124.4	131.8	414.9	306.6	(111.2)	1,145.3
Additions to property, plant, equipment and mine development	32.6	21.7	13.8	56.0	39.2	3.3	166.6
Income from equity affiliates	—	—	—	—	—	(49.0)	(49.0)

Segment results for the period January 1 through April 1, 2017 were as follows:

	Predecessor						
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining	Corporate and Other	Consolidated
	(Dollars in millions)						
Revenues	$ 394.3	$ 193.2	$ 149.7	$ 328.9	$ 224.8	$ 35.3	$ 1,326.2
Adjusted EBITDA	91.7	50.0	50.0	109.6	75.6	(35.6)	341.3
Additions to property, plant, equipment and mine development	19.3	2.8	3.1	5.2	2.3	0.1	32.8
Federal coal lease expenditures	—	—	0.5	—	—	—	0.5
Income from equity affiliates	—	—	—	—	—	(15.0)	(15.0)

Segment results for the year ended December 31, 2016 were as follows:

	Predecessor						
	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Seaborne Metallurgical Mining	Seaborne Thermal Mining	Corporate and Other	Consolidated
	(Dollars in millions)						
Revenues	$ 1,473.3	$ 792.5	$ 526.0	$ 1,090.4	$ 824.9	$ 8.2	$ 4,715.3
Adjusted EBITDA	379.9	217.3	101.6	(16.3)	217.6	(368.1)	532.0
Additions to property, plant, equipment and mine development	33.0	18.7	20.8	29.9	22.1	2.1	126.6
Federal coal lease expenditures	248.4	—	0.6	—	—	—	249.0
Income from equity affiliates	—	—	—	—	—	(16.2)	(16.2)

Asset details are reflected at the division level only for the Company's mining segments and are not allocated between each individual segment as such information is not regularly reviewed by the Company's CODM. Further, some assets service more than one segment within the division and an allocation of such assets would not be meaningful or representative on a segment by segment basis.

Assets as of December 31, 2018 were as follows:

	Successor			
	U.S. Thermal Mining	Seaborne Mining	Corporate and Other	Consolidated
	(Dollars in millions)			
Total assets	$ 3,481.7	$ 2,044.6	$ 1,897.4	$ 7,423.7
Property, plant, equipment and mine development, net.	3,180.4	1,661.3	365.3	5,207.0

Assets as of December 31, 2017 were as follows:

	Successor			
	U.S. Thermal Mining	Seaborne Mining	Corporate and Other	Consolidated
	(Dollars in millions)			
Total assets	$ 3,846.5	$ 2,339.6	$ 1,995.1	$ 8,181.2
Property, plant, equipment and mine development, net.	3,361.0	1,501.7	249.2	5,111.9

Assets as of December 31, 2016 were as follows:

	Predecessor			
	U.S. Thermal Mining	Seaborne Mining	Corporate and Other	Consolidated
	(Dollars in millions)			
Total assets	$ 4,255.9	$ 5,402.2	$ 2,119.6	$ 11,777.7
Property, plant, equipment and mine development, net.	3,970.6	3,905.8	900.3	8,776.7

A reconciliation of consolidated income (loss) from continuing operations, net of income taxes to Adjusted EBITDA follows:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
	(Dollars in millions)			
Income (loss) from continuing operations, net of income taxes	$ 645.7	$ 713.1	$ (195.5)	$ (663.8)
Depreciation, depletion and amortization	679.0	521.6	119.9	465.4
Asset retirement obligation expenses	53.0	41.2	14.6	41.8
Selling and administrative expenses related to debt restructuring	—	—	—	21.5
Asset impairment	—	—	30.5	247.9
Provision for North Goonyella equipment loss	66.4	—	—	—
Changes in deferred tax asset valuation allowance and reserves and amortization of basis difference related to equity affiliates	(18.3)	(17.3)	(5.2)	(7.5)
Interest expense	149.3	119.7	32.9	298.6
Loss on early debt extinguishment	2.0	20.9	—	29.5
Interest income	(33.6)	(5.6)	(2.7)	(5.7)
Net mark-to-market adjustment on actuarially determined liabilities	(125.5)	(45.2)	—	—
Reorganization items, net	(12.8)	—	627.2	159.0
Gain on disposal of reclamation liability	—	(31.2)	—	—
Gain on disposal of Burton Mine assets	—	(52.2)	—	—
Break fees related to terminated asset sales	—	(28.0)	—	—
Unrealized (gains) losses on economic hedges	(18.3)	23.0	(16.6)	39.8
Unrealized losses on non-coal trading derivative contracts	0.7	1.5	—	—
Fresh start coal inventory revaluation	—	67.3	—	—
Fresh start take-or-pay contract-based intangible recognition	(26.7)	(22.5)	—	—
Income tax provision (benefit)	18.4	(161.0)	(263.8)	(94.5)
Total Adjusted EBITDA	$ 1,379.3	$ 1,145.3	$ 341.3	$ 532.0

The following table presents revenues as a percent of total revenue from external customers by geographic region:

	Successor		Predecessor	
	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017	Year Ended December 31, 2016
U.S.	47.8%	48.9%	55.2%	54.7%
Japan	10.1%	11.7%	11.4%	6.9%
Taiwan	8.1%	8.7%	5.7%	4.6%
Australia	6.6%	5.3%	4.2%	4.2%
India	6.2%	6.7%	2.7%	3.0%
China	5.9%	7.5%	5.6%	5.4%
South Korea	3.1%	1.1%	0.5%	1.5%
Other	12.2%	10.1%	14.7%	19.7%
Total	100.0%	100.0%	100.0%	100.0%

The Company attributes revenue to individual countries based on the location of the physical delivery of the coal.

(29) Subsequent Events

On February 27, 2019, the Company's Board declared a supplemental dividend of $1.85 per share of Common Stock, payable on March 20, 2019, to shareholders of record on March 12, 2019, which will be funded through existing cash balances. Upon payment of the supplemental dividend, outstanding restricted stock units will receive dividend equivalent units with a value of approximately $6 million, which would equate to approximately 0.2 million units using the quoted share price of the the Company's Common Stock on February 26, 2019 of $30.53 per share.

PEABODY ENERGY CORPORATION
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions[1]	Other	Balance at End of Period
	(Dollars in millions)					
Successor						
Year Ended December 31, 2018						
Reserves deducted from asset accounts:						
Advance royalty recoupment reserve	$ —	$ 0.3	$ —	$ —	$ —	$ 0.3
Reserve for materials and supplies	0.6	0.5	—	(0.9)	—	0.2
Allowance for doubtful accounts	4.6	(0.2)	—	—	—	4.4
Tax valuation allowances	2,432.5	(275.0)	—	—	(63.2) [6]	2,094.3
April 2 through December 31, 2017						
Reserves deducted from asset accounts:						
Advance royalty recoupment reserve	$ —	$ —	$ —	$ —	$ —	$ —
Reserve for materials and supplies	—	1.0	—	(0.4)	—	0.6
Allowance for doubtful accounts	—	4.6	—	—	—	4.6
Tax valuation allowances	3,288.4	(744.9)	—	—	(111.0) [5]	2,432.5
Predecessor						
January 1 through April 1, 2017						
Reserves deducted from asset accounts:						
Advance royalty recoupment reserve	$ 7.8	$ —	$ (7.4) [4]	$ (0.4)	$ —	$ —
Reserve for materials and supplies	5.6	0.5	(6.1) [4]	—	—	—
Allowance for doubtful accounts	13.1	—	(12.8) [4]	(0.3)	—	—
Tax valuation allowances	4,037.5	(777.2)	28.1 [4]	—	—	3,288.4
Year Ended December 31, 2016						
Reserves deducted from asset accounts:						
Advance royalty recoupment reserve	$ 8.3	$ 0.5	$ —	$ (1.0) [2]	$ —	$ 7.8
Reserve for materials and supplies	4.7	4.3	—	(3.4)	—	5.6
Allowance for doubtful accounts	6.6	7.9	—	(1.4)	—	13.1
Tax valuation allowances	1,614.1	2,453.9	—	—	(30.5) [3]	4,037.5

(1) Reserves utilized, unless otherwise indicated.

(2) Deductions to advance royalty recoupment reserve represents the termination of federal and state leases.

(3) Includes the impact of the decrease in Australian dollar exchange rates.

(4) Fresh start reporting adjustments.

(5) Release of valuation allowance primarily related to carrybacks of U.S. net operating losses.

(6) Includes the impact of the decrease in Australian dollar exchange rates, partially offset by the impact of final attribute reduction adjustments in the U.S.

EXHIBIT INDEX

The exhibits below are numbered in accordance with the Exhibit Table of Item 601 of Regulation S-K.

Exhibit No.	Description of Exhibit
2.1	Debtors' Second Amended Joint Plan of Reorganization under Chapter 11 of the Bankruptcy Code as revised March 15, 2017 (Incorporated by reference to Exhibit 2.2 of the Registrant's Current Report on Form 8-K, filed March 20, 2017).
2.2	Order Confirming Debtors' Second Amended Joint Plan of Reorganization under Chapter 11 of the Bankruptcy Code on March 17, 2017 (Incorporated by reference to Exhibit 2.1 of the Registrant's Current Report on Form 8-K, filed March 20, 2017).
2.3	Asset Purchase Agreement, dated as of September 20, 2018, by and between Drummond Company, Inc. and Peabody Southeast Mining, LLC, and, for certain limited purposes, Peabody Energy Corporation (Incorporated by reference to Exhibit 2.1 of the Registrant's Current Report on Form 8-K, filed September 24, 2018).
3.1	Fourth Amended and Restated Certificate of Incorporation of the Registrant (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed April 3, 2017).
3.2	Amended and Restated By-Laws of the Registrant (Incorporated by reference to Exhibit 3.3 of the Registrant's Current Report on Form 8-K filed April 3, 2017).
4.1	Specimen of stock certificate representing the Registrant's common stock, $.01 par value (Incorporated by reference to Exhibit 4.13 to Amendment No. 4 to the Registrant's Form S-1 Registration Statement No. 333-55412, filed May 1, 2001).
4.2	Indenture, dated as of February 15, 2017, between Peabody Securities Finance Corporation and Wilmington Trust, National Association, as Trustee, governing 6.000% Senior Secured Notes due 2022 and 6.375% Senior Secured Notes due 2025 (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K, filed February 15, 2017).
4.3	First Supplemental Indenture, dated as of April 3, 2017, among the Registrant, Peabody Securities Finance Corporation, the subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee (Incorporated by reference to Exhibit 4.3 of the Registrant's Current Report on Form 8-K, filed April 3, 2017).
4.4†	Second Supplemental Indenture, dated as of May 7, 2018, among the Registrant, NGS Acquisition Corp., LLC, and Wilmington Trust, National Association, as trustee.
4.5	Third Supplemental Indenture, dated as of August 9, 2018, between the Registrant and Wilmington Trust, National Association, as trustee (Incorporated by reference to Exhibit 10.1 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2018).
4.6†	Fourth Supplemental Indenture, dated as of December 7, 2018, among the Registrant, Peabody Southeast Mining, LLC, and Wilmington Trust, National Association, as trustee.
10.1	Federal Coal Lease WYW0321779: North Antelope/Rochelle Mine (Incorporated by reference to Exhibit 10.3 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10.2	Federal Coal Lease WYW119554: North Antelope/Rochelle Mine (Incorporated by reference to Exhibit 10.4 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10.3	Federal Coal Lease WYW5036: Rawhide Mine (Incorporated by reference to Exhibit 10.5 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10.4	Federal Coal Lease WYW3397: Caballo Mine (Incorporated by reference to Exhibit 10.6 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10.5	Federal Coal Lease WYW83394: Caballo Mine (Incorporated by reference to Exhibit 10.7 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10.6	Federal Coal Lease WYW136142 (Incorporated by reference to Exhibit 10.8 of Amendment No. 1 to the Registrant's Form S-4 Registration Statement No. 333-59073, filed September 8, 1998).
10.7	Royalty Prepayment Agreement by and among Peabody Natural Resources Company, Gallo Finance Company and Chaco Energy Company, dated September 30, 1998 (incorporated by reference to Exhibit 10.9 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1998).
10.8	Federal Coal Lease WYW154001: North Antelope Rochelle South (Incorporated by reference to Exhibit 10.68 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004).
10.9	Federal Coal Lease WYW150210: North Antelope Rochelle Mine (Incorporated by reference to Exhibit 10.8 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
10.10	Federal Coal Lease WYW151134 effective May 1, 2005: West Roundup (Incorporated by reference to Exhibit 10.1 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005).
10.11	Federal Coal Lease Readjustment WYW78663: Caballo (Incorporated by reference to Exhibit 10.24 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012).

Exhibit No.	Description of Exhibit
10.12	Transfer by Assignment and Assumption of Federal Coal Lease WYW172657: Caballo West (Incorporated by reference to Exhibit 10.25 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012).
10.13	Federal Coal Lease WYW176095: Porcupine South (Incorporated by reference to Exhibit 10.26 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012).
10.14	Federal Coal Lease WYW173408: North Porcupine (Incorporated by reference to Exhibit 10.27 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012).
10.15	Federal Coal Lease WYW172413: School Creek (Incorporated by reference to Exhibit 10.28 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012).
10.16	Separation Agreement, Plan of Reorganization and Distribution, dated October 22, 2007, between the Registrant and Patriot Coal Corporation (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.17	Tax Separation Agreement, dated October 22, 2007, between the Registrant and Patriot Coal Corporation (Incorporated by reference to Exhibit 10.2 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.18	Coal Act Liabilities Assumption Agreement, dated October 22, 2007, among Patriot Coal Corporation, Peabody Holding Company, LLC and the Registrant (Incorporated by reference to Exhibit 10.3 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.19	Salaried Employee Liabilities Assumption Agreement, dated October 22, 2007, among Patriot Coal Corporation, Peabody Holding Company, LLC, Peabody Coal Company, LLC and the Registrant (Incorporated by reference to Exhibit 10.5 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.20	Coal Supply Agreement, dated October 22, 2007, between Patriot Coal Sales LLC and COALSALES II, LLC (Incorporated by reference to Exhibit 10.6 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.21	Settlement Agreement entered into as of October 24, 2013, by and among Patriot Coal Corporation, on behalf of itself and its affiliates, the Registrant, on behalf of itself and its affiliates, and the United Mine Workers of America, on behalf of itself and the UMWA Employees and UMWA Retirees (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed October 30, 2013).
10.22	Purchase and Sale Agreement, dated as of November 20, 2015, by and between Four Star Holdings, LLC and Western Megawatt Resources, LLC (Incorporated by reference to Exhibit 10.28 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2015).
10.23*	Employment Agreement entered into as of August 21, 2013, by and between Peabody Energy Corporation and Glenn L. Kellow (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on August 27, 2013).
10.24*	Restrictive Covenant Agreement entered into as of August 21, 2013, by and between Peabody Energy Corporation and Glenn L. Kellow (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on August 27, 2013).
10.25*	Letter dated January 27, 2015 to Glenn L. Kellow from the Chairman of the Compensation Committee of the Peabody Energy Corporation Board of Directors (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on January 28, 2015).
10.26*	Letter Agreement entered into as of January 27, 2015, by and between Peabody Energy Corporation and Glenn L. Kellow (incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on January 28, 2015).
10.27*	Letter Agreement entered into as of April 20, 2015, by and between Peabody Energy Corporation and Glenn L. Kellow (incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on April 21, 2015).
10.28*	Restated Employment Agreement entered into as of January 7, 2013 by and between the Registrant and Charles F. Meintjes (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed January 10, 2013).
10.29*	Restated Employment Agreement entered into as of December 20, 2012 by and between the Registrant and Kemal Williamson (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on December 26, 2012).
10.30*	Peabody Energy Corporation Executive Severance Plan. (Incorporated by reference to Exhibit 10.92 to the Registrant's Annual Report on Form 10-K filed on February 25, 2015).
10.31*	Peabody Energy Corporation 2015 Amended and Restated Executive Severance Plan. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on November 23, 2015).
10.32*†	Peabody Energy Corporation 2019 Executive Severance Plan.

Exhibit No.	Description of Exhibit
10.33*	Form of Director and Executive Officer Indemnification Agreement between the Registrant and each of its directors and executive officers. (Incorporated by reference to Exhibit 10.93 to the Registrant's Annual Report on Form 10-K filed on February 25, 2015).
10.34*	Peabody Investments Corp. Supplemental Employee Retirement Account (Incorporated by reference to Exhibit 10.1 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
10.35	Limited Waiver to Purchase and Sale Agreement by and between Four Star Holdings, LLC and Western Megawatt Resources, LLC dated March 30, 2016 (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K filed March 31, 2016).
10.36	Fifth Amended and Restated Receivables Purchase Agreement, dated as of March 25, 2016, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K filed March 31, 2016).
10.37	First Amendment to the Fifth Amended and Restated Receivables Purchase Agreement, dated as of April 12, 2016, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as the Sole Purchaser, Committed Purchaser, LC Bank and LC Participant (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed April 13, 2016).
10.38	Second Amendment to the Fifth Amended and Restated Receivables Purchase Agreement, dated as of April 18, 2016, by and among Peabody Energy Corporation, P&L Receivables Company, LLC, the various Sub-Servicers listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as the Sole Purchaser, Committed Purchaser, LC Bank and LC Participant (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed April 22, 2016).
10.39	Superpriority Secured Debtor-In-Possession Credit Agreement, dated as of April 18, 2016, by and among Peabody Energy Corporation, the guarantors party thereto, the lenders party thereto and Citibank, N.A. as Administrative Agent and L/C Issuer (Incorporated by reference to Exhibit 10.2 of the Registrant's Current Report on Form 8-K, filed April 22, 2016).
10.40	Amendment No. 1 to Superpriority Secured Debtor-in-Possession Credit Agreement, dated as of May 9, 2016, by and among Peabody Energy Corporation, the guarantors party thereto, the lenders party thereto and Citibank, N.A. as Administrative Agent (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed May 24, 2016).
10.41	Amendment No. 2 to Superpriority Secured Debtor-in-Possession Credit Agreement, dated as of May 18, 2016, by and among Peabody Energy Corporation, the guarantors party thereto, the lenders party thereto, the issuing bank party thereto, and Citibank, N.A. as Administrative Agent (Incorporated by reference to Exhibit 10.2 of the Registrant's Current Report on Form 8-K, filed May 24, 2016).
10.42	Amendment No. 4 to the Superpriority Secured Debtor-In-Possession Credit Agreement, dated as of October 11, 2016, by and among Peabody Energy Corporation, Peabody Global Funding, LLC (f/k/a Global Center for Energy and Human Development, LLC) and certain Debtors parties thereto as guarantors, the lenders party thereto and Citibank, N.A., as administrative agent (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K filed on October 14, 2016).
10.43	Amendment No. 5 to Superpriority Secured Debtor-In-Possession Credit Agreement, by and among Peabody Energy Corporation, Peabody Global Funding, LLC (f/k/a Global Center for Energy and Human Development, LLC) and certain Debtors parties thereto as guarantors, the lenders party thereto and Citibank, N.A., as administrative agent (Incorporated by reference to the Registrant's Current Report on Form 8-K filed November 23, 2016).
10.44	Amendment No. 6 to Superpriority Secured Debtor-In-Possession Credit Agreement, by and among Peabody Energy Corporation, Peabody Global Funding, LLC and certain Debtors parties thereto as guarantors, the lenders party thereto and Citibank, N.A., as administrative agent (Incorporated by reference to the Registrant's Current Report on Form 8-K filed December 14, 2016).
10.45	Plan Support Agreement entered into as of December 22, 2016 by and among the Registrant and certain other parties thereto (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed December 23, 2016).
10.46	Private Placement Agreement entered into as of December 22, 2016 by and among the Registrant and certain of its creditors party thereto (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed December 23, 2016).
10.47	Amendment to Private Placement Agreement entered into as of December 28, 2016 by and among the Registrant and certain of its creditors party thereto (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed December 30, 2016).
10.48	Second Amendment to Private Placement Agreement entered into as of February 8, 2017 by and among the Registrant and certain of its creditors party thereto (Incorporated by reference to Exhibit 10.127 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2016).

Exhibit No.	Description of Exhibit
10.49	Backstop Commitment Agreement entered into as of December 23, 2016 by and among the Registrant and certain of its creditors party thereto (Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed December 23, 2016).
10.50	Amendment to Backstop Commitment Agreement entered into as of December 28, 2016 by and among the Registrant and certain of its creditors party thereto (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed December 30, 2016).
10.51	Share Sale and Purchase Agreement entered into as of November 3, 2016 by and among Peabody Australia Mining Pty Ltd, Peabody Energy Australia Pty Ltd, South32 Aluminium (Holdings) Pty Ltd, and South32 Treasury Limited (Incorporated by reference to Exhibit 10.124 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2016).
10.52	Exit Facility Commitment Letter entered into as of January 11, 2017, by and among the Registrant, Goldman Sachs Bank USA, JPMorgan Chase Bank, N.A., Credit Suisse AG, Credit Suisse Securities (USA) LLC, Macquarie Capital Funding LLC and Macquarie Capital (USA) Inc. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on January 12, 2017).
10.53	Receivables Purchase Facility Commitment Letter entered into as of January 27, 2017, by and among the Registrant, P&L Receivables Company, LLC and PNC Bank, National Association (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on January 27, 2017).
10.54	Notice Letter and Term Sheet dated as of February 15, 2017, for Amendments to the Receivables Purchase Facility Commitment Letter entered into as of January 27, 2017, by and among the Registrant, P&L Receivables Company, LLC and PNC Bank, National Association (Incorporated by reference to Exhibit 10.128 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2016).
10.55	Settlement Agreement dated as of March 13, 2017 by and among the Registrant, certain subsidiaries of the Registrant, and the United Mine Workers of America 1974 Pension Plan and Trust (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on March 17, 2017).
10.56	Sixth Amended and Restated Receivables Purchase Agreement, dated as of April 3, 2017, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.4 of the Registrant's Current Report on Form 8-K filed April 3, 2017).
10.57	First Amendment to the Sixth Amended and Restated Receivables Purchase Agreement, dated as of June 30, 2017, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various parties identified on the signature pages thereto as Sub-Servicers, Metropolitan Collieries Pty Ltd, and PNC Bank, National Association, as Administrator and as the sole Purchaser Agent, Committed Purchaser, LC Bank and LC Participant on the date thereof (Incorporated by reference to Exhibit 10.9 of the Registrant's Quarterly Report on Form 10-Q, filed August 14, 2017).
10.58	Second Amendment to the Sixth Amended and Restated Receivables Purchase Agreement, dated as of December 13, 2017, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, Regions Bank, and PNC Bank, National Association, as Administrator and as the sole Purchaser Agent, Committed Purchaser, LC Bank and LC Participant on the date thereof (Incorporated by reference to Exhibit 10.57 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2017).
10.59	Credit Agreement dated as of April 3, 2017, among the Registrant, as Borrower, Goldman Sachs Bank USA, as Administrative Agent, and the other lenders party thereto (Incorporated by reference to Exhibit 10.3 of the Registrant's Current Report on Form 8-K, filed April 3, 2017).
10.60	Amendment No. 1 to Credit Agreement, by and among Peabody Energy Corporation, the subsidiaries of the Peabody Energy Corporation party thereto as reaffirming parties, the lenders party thereto and Goldman Sachs Bank USA, as administrative agent, dated as of September 18, 2017 (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K filed September 18, 2017).
10.61	Amendment No. 2 to Credit Agreement, by and among Peabody Energy Corporation, the subsidiaries of Peabody Energy Corporation party thereto as reaffirming parties, the lenders party thereto and Goldman Sachs Bank USA, as administrative agent, dated as of November 17, 2017 (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed November 20, 2017).
10.62	Amendment No. 3 to Credit Agreement, by and among Peabody Energy Corporation, the subsidiaries of Peabody Energy Corporation party thereto as reaffirming parties, the lenders party thereto and Goldman Sachs Bank USA, as administrative agent, dated as of December 18, 2017 (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed December 19, 2017).
10.63	Amendment No. 4 to Credit Agreement, by and among Peabody Energy Corporation, the subsidiaries of Peabody Energy Corporation party thereto as reaffirming parties, the lenders party thereto and Goldman Sachs Bank USA, as administrative agent, dated as of April 11, 2018 (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed April 11, 2018).

Exhibit No.	Description of Exhibit
10.64	Amendment No. 5 to Credit Agreement, by and among Peabody Energy Corporation, the subsidiaries of Peabody Energy Corporation party thereto as reaffirming parties, the lenders party thereto and Goldman Sachs Bank USA, as administrative agent, dated as of June 27, 2018 (Incorporated by reference to Exhibit 10.1 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018).
10.65*	Peabody Energy Corporation 2017 Incentive Plan (Incorporated by reference to Exhibit 4.6 of the Registrant's Registration Statement on Form S-8, filed April 3, 2017).
10.66	Registration Rights Agreement, dated as of April 3. 2017, among the Registrant and the stockholders party thereto (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K filed, April 3, 2017).
10.67	Form of Indemnification Agreement (Incorporated by reference to Exhibit 10.9 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.68*	Form of Restricted Stock Unit Agreement (Incorporated by reference to Exhibit 10.7 of the Registrant's Current Report on Form 8-K, filed April 3, 2017).
10.69*	Form of Restrictive Covenant Agreement under the Peabody Energy Corporation 2017 Incentive Plan (Incorporated by reference to Exhibit 10.8 of the Registrant's Current Report on Form 8-K, filed April 3, 2017).
10.70*	Form of Deferred Stock Unit Agreement under the Peabody Energy Corporation 2017 Incentive Plan (Incorporated by reference to Exhibit 10.12 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.71*	Form of Performance Share Unit Agreement under the Peabody Energy Corporation 2017 Incentive Plan. (Incorporated by reference to Exhibit 10.68 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2017).
10.72	Share Repurchase Agreement, by and among Peabody Energy Corporation and Elliott Associates, LP, Liverpool Limited Partnership, and Spraberry Investments Inc., dated August 14, 2018 (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed August 15, 2018).
10.73†	Form of Indemnification Agreement.
10.74†	Form of Deferred Stock Unit Agreement under the Peabody Energy Corporation 2017 Incentive Plan.
21†	List of Subsidiaries.
23.1†	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm.
23.2†	Consent of Weir International, Inc.
23.3†	Consent of Palaris Australia Pty Ltd.
31.1†	Certification of periodic financial report by the Registrant's Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2†	Certification of periodic financial report by the Registrant's Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1†	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant's Chief Executive Officer.
32.2†	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant's Chief Financial Officer.
95†	Mine Safety Disclosure required by Item 104 of Regulation S-K.
101†	Interactive Data File (Form 10-K for the year ended December 31, 2018 filed in XBRL). The financial information contained in the XBRL-related documents is "unaudited" and "unreviewed."

* These exhibits constitute all management contracts, compensatory plans and arrangements required to be filed as an exhibit to this form pursuant to Item 15(a)(3) and 15(b) of this report.

† Filed herewith.

Stock Price and Performance Information

Market Information

Our common stock is listed on the New York Stock Exchange under the symbol "BTU." As of March 1, 2019, Peabody had approximately 108.3 million shares of common stock outstanding.

Dividends

We have declared and paid quarterly dividends since Feb. 7, 2018. Most recently, our board of directors declared a dividend of $0.13 per share of Common Stock on Feb. 6, 2019, payable on March 6, 2019, to shareholders of record on Feb. 20, 2019. In addition, on Feb. 27, 2019, our board of directors declared a supplemental dividend of $1.85 per share of Common Stock, payable on March 20, 2019, to shareholders of record on March 12, 2019. The declaration and payment of dividends in the future and the amount of those dividends will depend on our results of operations, financial condition, cash requirements, future prospects, any limitations imposed by our debt covenants and other factors that our board of directors may deem relevant to such evaluations.

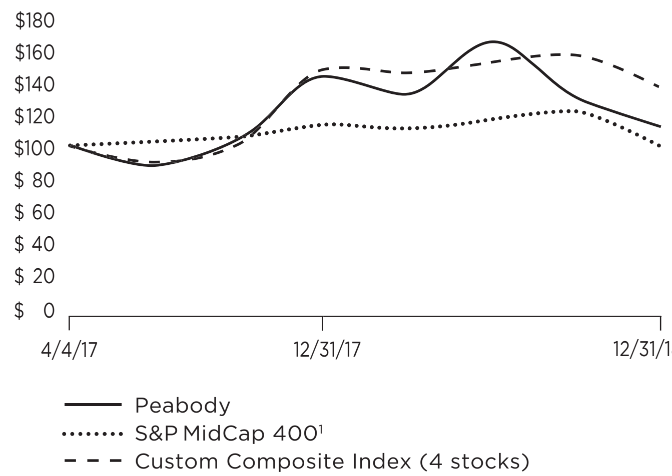
Stock Performance Graph

The following performance graph compares the cumulative total return on our common stock from April 4, 2017, the date our common stock began trading following the effective date of our plan of reorganization, through Dec. 31, 2018, with the cumulative total return of the following indices: (i) the S&P MidCap 400 Stock Index and (ii) a peer group comprised of Arch Coal, Inc., Cloud Peak Energy Inc., Hallador Energy Co., and Warrior Met Coal, Inc. (Custom Composite Index). The Custom Composite Index reflects publicly listed U.S. companies within the coal industry of similar size or product type. Master Limited Partnerships were excluded.

The graph assumes that the value of the investment was $100 at April 4, 2017 for BTU and the Custom Composite Index (Warrior Met Coal, Inc. began trading on the New York Stock Exchange on April 13, 2017) and at March 31, 2017, for the S&P Midcap 400 Index. The graph also assumes that all dividends were reinvested and that the investments were held through Dec. 31, 2018.

These indices are included for comparative purposes only and do not necessarily reflect management's opinion that such indices are an appropriate measure of the relative performance of the stock involved and are not intended to forecast or be indicative of possible future performance of the common stock.

Cumulative Total Return



$100 invested on 4/4/17 in stock or 3/31/17 in index, including reinvestment of dividends. Fiscal year ending December 31.

	4/4/17	12/31/17	12/31/18
Peabody	$100.00	$144.48	$113.22
S&P MidCap 400[1]	$100.00	$111.84	$99.44
Custom Composite Index (4 stocks)	$100.00	$148.71	$140.58

The Custom Composite Index (4 stocks) consist of Arch Coal, Inc., Cloud Peak Energy Inc., Hallador Energy Co., and Warrior Met Coal, Inc.

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Board of Directors and Executives

Directors

Bob Malone (*3)
Executive Chairman, President and Chief Executive Officer of First Sonora Bancshares, Inc.

Former Executive Vice President BP plc and Former Chairman of the Board and President, BP America Inc.

Andrea Bertone (**1, 4)
Former President of Duke Energy International, LLC (Retired)

Nicholas Chirekos (1, 5)
Former Managing Director, North America Head of Mining, J.P. Morgan Securities Inc. (Retired)

Stephen Gorman (2, 3, 4)
Chief Executive Officer of Air Methods Corporation

Former Chief Operating Officer of Delta Air Lines, Inc.

Glenn Kellow (3)
President and Chief Executive Officer, Peabody

Joe Laymon (2, 3, 4)
Former Vice President of Human Resources and Corporate Services for Chevron Corporation (Retired)

Former Group Vice President of Corporate Human Resources and Labor Affairs for Ford Motor Company

Teresa Madden (1, 3, 4)
Former Executive Vice President and Chief Financial Officer of Xcel Energy, Inc. (Retired)

Kenneth Moore (1, 5)
Former Managing Director of First Reserve Corporation

Michael Sutherlin (2, 3, 5)
Former President, Chief Executive Officer and Director of Joy Global Inc. (Retired)

Shaun Usmar (4, 5)
Chief Executive Officer of Triple Flag Mining Finance Ltd.

Former Senior Executive Vice President and Chief Financial Officer of Barrick Gold Corporation

All directors except Mr. Kellow are independent under New York Stock Exchange listing standards.

* Board Chair
** Appointed February 2019
1 Audit Committee
2 Compensation Committee
3 Executive Committee
4 Health, Safety, Security and Environmental Committee
5 Nominating and Corporate Governance Committee

Executive Leadership Team

Glenn Kellow
President and Chief Executive Officer

A. Verona Dorch
Executive Vice President, Chief Legal Officer, Government Affairs and Corporate Secretary

Charles Meintjes
Executive Vice President – Corporate Services and Chief Commercial Officer

Paul Richard
Senior Vice President and Chief Human Resources Officer

George J. Schuller Jr.
President – Australia

Amy Schwetz
Executive Vice President and Chief Financial Officer

Kemal Williamson
President – Americas