CLOUD PEAK ENERGY INC.
Form 10-K
March 15, 2019
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2018

or

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

For the transition period from to

Commission File Number: 001-34547

Cloud Peak Energy Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**26-3088162** (I.R.S. Employer Identification No.)
748 T-7 Road, Gillette, Wyoming (Address of principal executive offices)	**82718** (Zip Code)

(307) 687-6000
(Registrant s telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No x

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

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 x No o

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 x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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

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

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

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

As of June 29, 2018, the last business day of Cloud Peak Energy Inc. s most recently completed second fiscal quarter, the aggregate market value of the voting and non-voting common stock held by non-affiliates of Cloud Peak Energy Inc. was approximately $256 million based on the closing price of Cloud Peak Energy Inc. s common stock as reported that day on the New York Stock Exchange of $3.49 per share. In determining this figure, Cloud Peak Energy Inc. has assumed that all of its directors and executive officers are affiliates. Such assumptions should not be deemed conclusive for any other purpose.

Number of shares outstanding of Cloud Peak Energy Inc. s common stock, as of the latest practicable date: Common stock, $0.01 par value per share, 76,507,272 shares outstanding as of March 8, 2019.

DOCUMENTS INCORPORATED BY REFERENCE

Documents incorporated by reference in this report are listed in the Exhibit Index of this Form 10-K.

CLOUD PEAK ENERGY INC.

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Unless the context indicates otherwise, the terms Cloud Peak Energy, the Company, we, us, and our refer to Cloud Peak Energy Inc. and its subsidiaries.

CAUTIONARY NOTICE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that involve substantial risks and uncertainties. You can identify these statements by forward-looking words such as anticipate, believe, could, estimate, expect, intend, may, plan, potential, should, similar words. You should read statements that contain these words carefully because they discuss our current plans, strategies, prospects, and expectations concerning our business, operating results, financial condition, and other similar matters. While we believe that these forward-looking statements are reasonable as and when made, there may be events in the future that we are not able to predict accurately or control, and there can be no assurance that future developments affecting our business will be those that we anticipate. Additionally, all statements concerning our expectations regarding future operating results are based on current forecasts for our existing operations and do not include the potential impact of any future acquisitions, divestitures, or other transactions. The factors listed under Risk Factors, as well as any cautionary language in this report, describe the known material risks, uncertainties, and events that may cause our actual results to differ materially and adversely from the expectations we describe in our forward-looking statements. Additional factors or events that may emerge from time to time, or those that we currently deem to be immaterial, could cause our actual results to differ, and it is not possible for us to predict all of them. You are cautioned not to place undue reliance on the forward-looking statements contained herein. We undertake no obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events, or otherwise, except as required by law. The following factors are among those that may cause actual results to differ materially and adversely from our forward-looking statements:

- substantial doubt about our ability to continue as a going concern;

- our need to restructure our balance sheet, which may require us to sell assets, restructure our debt, or seek protection under Chapter 11 of the U.S. Bankruptcy Code (Chapter 11);

- our ability to maintain, obtain and comply with the terms of required surety bonds;

- the terms and restrictions of our indebtedness;

- our level of indebtedness;

- liquidity constraints, access to capital and credit markets and availability and costs of credit, surety bonds, letters of credit, and insurance, including risks resulting from the cost or unavailability of financing due to debt and equity capital and credit market conditions for the coal sector or in general, changes in our credit rating, our compliance with the covenants in our debt agreements, the credit pressures on our industry due to depressed conditions, and demands for increased collateral by our surety bond providers;

- our liquidity, results of operations, and financial condition generally, including amounts of working capital that are available;
- current and future expenses incurred in connection with our evaluation of the restructuring of our balance sheet and any resulting transactions;
- our ability to attract and retain key personnel;
- our ability to comply with the restrictions imposed by our A/R Securitization Program and other financing arrangements;
- the timing and extent of any sustained recovery of the currently depressed PRB thermal coal industry and the impact of ongoing or further depressed PRB thermal coal industry conditions on our financial performance, liquidity, and any financial covenant compliance;
- the prices we receive for our coal and logistics services, our ability to effectively execute our forward sales strategy, and changes in utility purchasing patterns resulting in decreased long-term purchases of coal;
- the timing of reductions or increases in customer coal inventories;

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- our ability to obtain new coal sales agreements on favorable terms, to resolve customer requests for reductions or deferrals of coal deliveries, and to respond to any cancellations of their committed volumes on terms that preserve the amount and timing of our forecasted economic value;

- the impact of increasingly variable and less predictable demand for thermal coal based on natural gas prices, summer cooling demand, winter heating demand, economic growth rates, and other factors that impact overall demand for electricity;

- our ability to comply with minimum production requirements under our coal leases and avoid advanced royalty obligations;

- our ability to efficiently and safely conduct our mining operations and to adjust our planned production levels to respond to market conditions and effectively manage the costs of our operations;

- competition with other producers of coal and with traders and re-sellers of coal, including the current oversupply of thermal coal, the impacts of currency exchange rate fluctuations and the strong U.S. dollar, and government environmental, energy and tax policies and regulations that make foreign coal producers more competitive for international transactions;

- the impact of coal industry bankruptcies on our competitive position relative to other companies who have emerged from bankruptcy with reduced leverage and potentially reduced operating costs;

- competition with natural gas, wind, solar, and other non-coal energy resources, which may continue to increase as a result of low domestic natural gas prices, the declining cost of renewables and due to environmental, energy and tax policies, regulations, subsidies, and other government actions that encourage or mandate use of alternative energy sources;

- coal-fired power plant capacity and utilization, including the impact of climate change and other environmental regulations and initiatives, energy policies, political pressures, NGO activities, international treaties or agreements and other factors that may cause domestic and international electric utilities to continue to phase out or close existing coal-fired power plants, reduce or eliminate construction of any new coal-fired power plants, or reduce consumption of coal from the PRB;

- the failure of economic, commercially available carbon capture technology to be developed and adopted by utilities in a timely manner;

- the impact of keep coal in the ground campaigns and other well-funded, anti-coal initiatives by environmental activist groups and others targeting substantially all aspects of our industry;

- our ability to offset declining U.S. demand for coal and achieve longer term growth in our business through our logistics revenue and export sales, including the significant impact of Chinese and Indian thermal coal import demand and production levels from other countries and basins on overall seaborne coal prices;

- the impact of any trade wars on our export business;

- railroad, export terminal and other transportation performance, costs and availability, including the availability of sufficient and reliable rail capacity to transport PRB coal, any development of future export terminal capacity and our ability to access capacity on commercially reasonable terms;

- the impact of our rail and terminal take-or-pay commitments if we do not meet our required export shipment obligations;

- weather conditions and weather-related damage that impact our mining operations, our customers, or transportation infrastructure, including the adverse impact on our costs and production volumes of the heavy rain experienced during the second quarter of 2018, particularly at our Antelope Mine;

- operational, geological, equipment, permit, labor, and other risks inherent in surface coal mining;

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- future development or operating costs for our development projects exceeding our expectations or other factors adversely impacting our development projects;

- our ability to successfully acquire coal and appropriate land access rights at economic prices and in a timely manner and our ability to effectively resolve issues with conflicting mineral development that may impact our mine plans;

- the impact of additional asset impairment charges if required as a result of challenging industry conditions or other factors;

- our plans and objectives for future operations and the development of additional coal reserves, including risks associated with acquisitions;

- the impact of current and future environmental, health, safety, endangered species and other laws, regulations, treaties, executive orders, court decisions or governmental policies, or changes in interpretations thereof and third-party regulatory challenges, including additional requirements, uncertainties, costs, liabilities or restrictions adversely affecting the use, demand or price for coal, our mining operations or the logistics, transportation, or terminal industries;

- the impact of required regulatory processes and approvals to lease coal and obtain, maintain, and renew permits for coal mining operations or to transport coal to domestic and foreign customers, including third-party legal challenges to regulatory approvals that are required for some or all of our current or planned mining activities;

- any increases in rates or changes in regulatory interpretations or assessment methodologies with respect to royalties or severance and production taxes and the potential impact of associated interest and penalties;

- inaccurately estimating the costs or timing of our reclamation and mine closure obligations and our assumptions underlying reclamation and mine closure obligations;

- the availability of, disruptions in delivery or increases in pricing from third-party vendors of raw materials, capital equipment and consumables which are necessary for our operations, such as explosives, petroleum-based fuel, tires, steel, and rubber;

- our assumptions concerning coal reserve estimates;

- our relationships with, and other conditions affecting, our customers (including our largest customers who account for a significant portion of our total revenue) and other counterparties, including economic conditions and the credit performance and credit risks associated with our customers and other counterparties, such as traders, brokers, and lenders under any credit agreement and financial institutions with whom we maintain accounts or enter hedging arrangements;

- the results of our hedging programs and changes in the fair value of derivative financial instruments that are not accounted for as hedges;

- volatility and recent declines in the price of our common stock, including the impact of any delisting of our stock from the NYSE if we fail to cure our noncompliance with the minimum average closing price listing standard;

- litigation and other contingencies;

- the authority of federal and state regulatory authorities to order any of our mines to be temporarily or permanently closed under certain circumstances; and

- other risk factors or cautionary language described from time to time in the reports and registration statements we file with the SEC, including those in Item 1A of this Form 10-K.

GLOSSARY FOR SELECTED TERMS

Amended Credit Agreement. Our revolving credit agreement with PNC Bank, National Association, as administrative agent, and a syndicate of lenders, as amended and restated on May 24, 2018, which was terminated effective November 15, 2018.

Anthracite. Anthracite is the highest rank coal. It is hard, shiny (or lustrous), has a high heat content, and little moisture. Anthracite is used in residential and commercial heating as well as a mix of industrial applications. Some waste products from anthracite piles are used in energy generation.

A/R Securitization Program. Our accounts receivable securitization program.

Ash. Inorganic material consisting of iron, alumina, sodium, and other incombustible matter that remain after the combustion of coal. The composition of the ash can affect the burning characteristics of coal.

Assigned reserves. Reserves that are committed to our surface mine operations with operating mining equipment and plant facilities. All our reported reserves are considered to be assigned reserves.

Bituminous coal. The most common type of coal that is between subbituminous and anthracite in rank. Bituminous coal produced from the central and eastern U.S. coalfields typically have moisture content less than 20% by weight and heating value of 10,500 to 14,000 Btus.

BLM. Department of the Interior, Bureau of Land Management.

BNSF. Burlington Northern Santa Fe Railroad.

Btu. British thermal unit. A measure of the thermal energy required to raise the temperature of one pound of pure liquid water one degree Fahrenheit at the temperature at which water has its greatest density (39 degrees Fahrenheit).

CAA. Clean Air Act.

CAIR. Clean Air Interstate Rule.

CEQ. Council on Environmental Quality.

CO_2. Carbon dioxide. A gaseous chemical compound that is generated, among other ways, as a by-product of the combustion of fossil fuels, including coal, or the burning of vegetable matter.

CPE Inc. Cloud Peak Energy Inc., a Delaware corporation.

CPE Resources. Cloud Peak Energy Resources LLC, a Delaware limited liability company, formerly known as Rio Tinto Sage LLC, which is the sole direct subsidiary of CPE Inc.

Coal seam. Coal deposits occur in layers typically separated by layers of rock. Each layer is called a seam. A coal seam can vary in thickness from inches to a hundred feet or more.

Coalbed methane. Also referred to as CBM or coalbed natural gas (CBNG). Coalbed methane is methane gas formed during the coalification process and stored within the coal seam.

Coke. A hard, dry carbon substance produced by heating coal to a very high temperature in the absence of air. Coke is used in the manufacture of iron and steel.

Compliance coal. Coal that when combusted emits no greater than 1.2 pounds of sulfur dioxide per million Btus and requires no blending or sulfur-reduction technology to comply with current sulfur dioxide emissions under the Clean Air Act.

CSAPR. Cross-State Air Pollution Rule.

Dragline. A large excavating machine used in the surface mining process to remove overburden. A dragline has a large bucket suspended from the end of a boom, which may be 275 feet long or larger. The bucket is suspended by cables and capable of scooping up significant amounts of overburden as it is pulled across the excavation area. The dragline, which can walk on large pontoon-like feet, is one of the largest land-based machines in the world.

EIA. Energy Information Administration.

EIS. Environmental Impact Statement.

EPA. United States Environmental Protection Agency.

Force majeure. An event not anticipated as of the date of the applicable contract, which is not within the reasonable control of the party affected by such event, which partially or entirely prevents such party s ability to perform its contractual obligations. During the duration of such force majeure but for no longer period, the obligations of the party affected by the event may be excused to the extent required.

Fossil fuel. A hydrocarbon such as coal, petroleum, or natural gas that may be used as a fuel.

GHG. Greenhouse gas.

Highwalls. The unexcavated face of exposed overburden and coal in a surface mine.

IR. Incident rate. The rate of injury occurrence, as determined by MSHA, based on 200,000 hours of employee exposure and calculated as follows:

IR = (number of cases x 200,000) / hours of employee exposure.

LBA. Lease by Application. Before a mining company can obtain new coal leases on federal land, the company must nominate lands for lease. The BLM then reviews the proposed tract to ensure maximum coal recovery. The BLM also requires completion of a detailed environmental assessment or an EIS, and then schedules a competitive lease sale. Lease sales must meet fair market value as determined by the BLM. The process is known as Lease by Application. After a lease is awarded, the BLM also has the responsibility to assure development of the resource is conducted in a fashion that achieves maximum economic recovery.

LBM. Lease by Modification. A process of acquiring federal coal through a non-competitive leasing process. An LBM is used in circumstances where a lessee is seeking to modify an existing federal coal lease by adding less than 960 acres in a configuration that is deemed non-competitive to other coal operators.

Lbs SO_2/mmBtu. Pounds of sulfur dioxide emitted per million Btu of heat generated.

Lignite. The lowest rank of coal. It is brownish-black with a high moisture content commonly above 35% by weight and heating value commonly less than 8,000 Btu.

LMU. Logical Mining Unit. A combination of contiguous federal coal leases that allows the production of coal from any of the individual leases within the LMU to be used to meet the continuous operation requirements for the entire LMU.

MATS. Mercury and Air Toxics Standards (formerly Utility Maximum Achievable Control Technology, or Utility MACTS).

Metallurgical coal. The various grades of coal suitable for carbonization to make coke for steel manufacture. Also known as met coal, it possesses four important qualities: volatility, which affects coke yield; the level of impurities, which affects coke quality; composition, which affects coke strength; and basic characteristics, which affect coke oven safety. Metallurgical coal has a particularly high Btu, but low ash content.

MSHA. Mine Safety and Health Administration.

NAAQS. National Ambient Air Quality Standards.

NEPA. National Environmental Policy Act.

NGO. Non-governmental organization.

NO_x. Nitrogen oxides. NO_x represents both nitrogen dioxide (NO_2) and nitrogen trioxide (NO_3), which are gases formed in high temperature environments, such as coal combustion. It is a harmful pollutant that contributes to acid rain and is a precursor of ozone.

Non-reserve coal deposits. Non-reserve coal deposits are coal-bearing bodies that have been sufficiently sampled and analyzed in trenches, outcrops, drilling, and underground workings to assume continuity between sample points, and therefore warrant further exploration work. However, this coal does not qualify as commercially viable coal reserves as prescribed by SEC standards until a final comprehensive evaluation based on unit cost per ton, recoverability, and other material factors concludes legal and economic feasibility. Non-reserve coal deposits may be classified as such by either limited property control or geologic limitation, or both.

Northern PRB. The area within the PRB that lies within Montana and the northern part of Sheridan County, Wyoming.

NYSE. New York Stock Exchange.

ONRR. Department of the Interior, Office of Natural Resources Revenue.

QSO. Qualified Surface Owner. A status attributed by the BLM to a certain class of surface owners of split estate lands, which allow the QSO to prohibit leasing of federal coal without their explicit consent.

Overburden. Layers of earth and rock covering a coal seam. In surface mining operations, overburden is removed prior to coal extraction.

PRB. Powder River Basin. Coal producing area in northeastern Wyoming and southeastern Montana.

Preparation plant. Usually located on a mine site, although one plant may serve several mines. A preparation plant is a facility for crushing, sizing, and washing coal to prepare it for use by a particular customer. The washing process separates higher ash coal and may remove some of the coal s sulfur content.

Probable reserves. Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven 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 reserves, is high enough to assume continuity between points of observation.

Proven 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.

Reclamation. The process of restoring land to its prior condition, productive use, or other permitted condition following mining activities. The process commonly includes recontouring or reshaping the land to its approximate original appearance, restoring topsoil, and planting native grass and shrubs. Reclamation operations are typically conducted concurrently with coal mining operations. Both state and federal laws closely regulate reclamation.

Reserve. That part of a mineral deposit that could be economically and legally extracted or produced at the time of the reserve determination.

Rio Tinto. Rio Tinto plc and Rio Tinto Limited and their direct and indirect subsidiaries, including Rio Tinto Energy America Inc. (RTEA), our predecessor for accounting purposes; Kennecott Management Services Company (KMS); and Rio Tinto America Inc. (RTA), which is the owner of RTEA and KMS.

Riparian habitat. Areas adjacent to rivers and streams with a differing density, diversity, and productivity of plant and animal species relative to nearby uplands.

Riverine habitat. A habitat occurring along a river.

Scrubber. Any of several forms of chemical physical devices that operate to control sulfur compounds formed during coal combustion. An example of a scrubber is a flue gas desulfurization unit.

SEC. Securities and Exchange Commission.

SMCRA. Surface Mining Control and Reclamation Act of 1977.

Spoil-piles. Pile used for any dumping of waste material or overburden material, particularly used during the dragline method of mining.

Subbituminous coal. Black coal that ranks between lignite and bituminous coal. Subbituminous coal produced from the PRB has moisture content between 20% to over 30% by weight, and its heat content ranges from 8,000 to 9,500 Btus.

Sulfur. One of the elements present in varying quantities in coal. Sulfur dioxide (SO_2) is produced as a gaseous by-product of coal combustion.

Sulfur dioxide emission allowance. A tradable authorization to emit sulfur dioxide. Under Title IV of the Clean Air Act, one allowance permits the emission of one ton of sulfur dioxide.

Surface mine. A mine in which the coal lies near the surface and can be extracted by removing the covering layer of soil overburden. Surface mines are also known as open-pit mines.

Thermal coal. Coal used by power plants and industrial steam boilers to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal.

Tonnes. A metric ton, equal to 2,205 pounds.

Tons. A short or net ton, equal to 2,000 pounds.

TRA. Tax Receivable Agreement. We and RTEA entered into a Tax Receivable Agreement in connection with the IPO and the acquisition of our membership units of CPE Resources. The Tax Receivable Agreement required us to pay to RTEA 85% of the amount of cash tax savings, if any, that we realized as a result of the increases in tax basis that we obtained in connection with the initial acquisition of our interest in CPE Resources and our subsequent acquisition of RTEA s remaining units in CPE Resources. In August 2014, we entered into an acceleration and release agreement with Rio Tinto whereby we agreed to pay $45 million to Rio Tinto to terminate the Tax Receivable Agreement.

Truck-and-shovel mining. Similar forms of mining where large shovels or front-end loaders are used to remove overburden, which is used to backfill pits after the coal is removed. Smaller shovels load coal in haul trucks for transportation to the preparation plant or rail loading facilities.

UP. Union Pacific Railroad.

U.S. GAAP. Accounting principles generally accepted in the United States of America.

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PART I

Item 1. *Business.*

Overview

We produce coal in the PRB. We operate some of the safest mines in the coal industry. According to the most current MSHA data, we have one of the lowest employee all injury incident rates among the largest U.S. coal producing companies. We currently operate solely in the PRB, the lowest cost region of the major coal producing regions in the U.S., where we own and operate three surface coal mines: the Antelope Mine, the Cordero Rojo Mine, and the Spring Creek Mine.

Our Antelope Mine and Cordero Rojo Mine are located in Wyoming and our Spring Creek Mine is located in Montana. Our mines produce subbituminous thermal coal with low sulfur content, and we sell our coal primarily to domestic and foreign electric utilities. Thermal coal is primarily consumed by electric utilities and industrial consumers as fuel for electricity generation. In 2018, the coal we produced generated approximately 2% of the electricity produced in the U.S. As of December 31, 2018, we controlled approximately 977.3 million tons of proven and probable reserves. We do not produce any metallurgical coal. See Item 1 Business Mining Operations.

In addition, we have two development projects, both located in the Northern PRB. The Youngs Creek project is an undeveloped surface mine project located in Wyoming, seven miles south of our Spring Creek Mine and contiguous with the Wyoming-Montana state line. The Big Metal project is located near the Youngs Creek project on the Crow Indian Reservation in southeast Montana. On June 7, 2018, Big Metal Coal Co. LLC (Big Metal), our wholly-owned subsidiary, delivered notice to the Crow Tribe of Indians (Crow Tribe) to exercise the Upper Youngs Creek coal lease option and extend the coal lease options for the Squirrel Creek and Tanner Creek project areas. These two projects, in addition to the exercise of the aforementioned options, are described in more detail under Item 1 Business Development Projects. Any future development and coal production from these projects remains subject to significant risks and uncertainty. These development projects have been impaired. For additional information, see Note 7 of Notes to Consolidated Financial Statements in Item 8.

Our logistics business provides a variety of services designed to facilitate the sale and delivery of coal, primarily to Asian utility customers. These services include the purchase of coal from third parties or from our owned and operated mines, coordination of the transportation and delivery of purchased coal, negotiation of take-or-pay rail agreements and take-or-pay port agreements and demurrage settlement with vessel operators. See Item 1. Business Transportation and Logistics Services for further discussion.

Recent Developments

During the fourth quarter of 2018 and through the filing date of this Form 10-K, we made a number of announcements regarding Cloud Peak Energy s engagement of various advisors to assist in reviewing alternatives including the potential sale of the Company and to assist in reviewing our capital structure and strategic restructuring alternatives. During that time, we experienced a number of adverse events that have negatively impacted our financial results, liquidity and future prospects. Our business and liquidity outlook has been adversely impacted since the third quarter of 2018 by a number of factors, which are highlighted in this Recent Developments section:

- operational issues in the fourth quarter of 2018 at our Antelope mine;
- depressed PRB thermal coal industry conditions;
- logistics export pricing declined in the fourth quarter of 2018 to an uneconomic level;
- reduced cash flow projections for 2019 and future years;
- termination of our Credit Agreement due to significantly reduced availability and the impact of the financial covenants;
- significantly reduced liquidity, primarily comprised of our cash and cash equivalents;
- reduced A/R Securitization Program availability, requiring greater cash collateralization;

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- noncompliance with the NYSE s continued listing requirements and potential delisting of our common stock;

- demands for additional reclamation surety bond collateral;

- our election not to make an interest payment under the 2024 Notes (as defined below) on the March 15, 2019 due date, utilizing the grace period provided by the indenture; and

- our continued review of our capital structure and restructuring alternatives.

As a result of the developments noted above, asset impairments were recorded as of December 31, 2018, and there was a determination of substantial doubt in our ability to continue as a going concern, based on current projections. This Recent Developments section highlights these events and should be read together with the rest of this Form 10-K, including without limitation, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations, Item 1A Risk Factors and Item 8 Financial Statements and Supplementary Data.

Fourth Quarter Operational Issues at Antelope Mine

In the fourth quarter of 2018, we experienced continued production issues at our Antelope Mine resulting from weather-related spoil failures due to heavy 2018 rains and related events**.** The rehandle of material by our truck and shovel fleets increased the per ton costs during the fourth quarter of 2018. This activity deferred the planned pre-stripping work into 2019, thereby increasing the projected costs for 2019 to regain a proper mine sequence. For additional discussion and analysis about the adverse effects from these production issues at our Antelope Mine in the fourth quarter of 2018, see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations.

Fourth Quarter Logistics Pricing Decline

In the fourth quarter of 2018, export prices for our logistics business declined significantly. From September 30, 2018 to December 31, 2018, the Kalimantan index declined by 14 percent from $53.25 per tonne to $46.00 per tonne. At this reduced price, our logistics business did not generate positive economic returns as reflected by the loss in our Logistics and Related Activities segment during the fourth quarter of 2018 and lowered our forecasted 2019 expectations. This was a significant difference from the September 30, 2018 pricing and economics.

Reduced Cash Flow Projections for 2019

During 2018, our cash balance decreased by $16.7 million because our cash flows from operations were insufficient to fund our cash interest and capital expenditures during the year. This large decrease in cash occurred during the fourth quarter of 2018 as our cash balance decreased from $109.5 million as of September 30, 2018 to $91.2 million as of December 31, 2018.

Further, as our business plans and financial forecasts were updated and reviewed during the fourth quarter of 2018 and finalized in the first quarter of 2019, our updated financial forecasts reflected significantly lower levels of expected cash flow from operating activities for 2019. The forecasting updates reflected the ongoing production issues at our Antelope Mine, resulting from the spoil failure re-handling described above, which requires significant deferred pre-stripping costs to be incurred in 2019 and lower export pricing assumptions.

Additionally, we experienced lower customer demand overall, particularly for the 8400 Btu coal from our Cordero Rojo Mine, as evidenced by lower contracted volumes and prices. As a result of the decline of the weighted average realized price at the Cordero Rojo Mine from 2018 to 2019, and rising costs caused by higher strip ratios, the cash margins and cash flow projections for 2019 sales at Cordero Rojo are uneconomic. This lower demand also resulted in reduced planned production rates at the Cordero Rojo Mine as part of our 2019 budgeting process that was completed in 2019.

For additional discussion and analysis, see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations.

Termination of Credit Facility

As disclosed in our Current Report on Form 8-K on November 13, 2018, Cloud Peak Energy Resources LLC (CPE Resources), a wholly owned subsidiary of CPE, provided PNC Bank, National Association with notice to terminate the Credit Agreement. The termination of the Credit Agreement was effective as of November 15, 2018. As of September 30, 2018, the $150 million Credit Agreement had a reduced availability of only $16.2 million of borrowing capacity based upon the quarterly financial covenant calculations. Any failure to meet those financial covenants could have resulted in an event of default under the Credit Agreement and cross-default under the indentures governing our senior notes.   The Credit Agreement would have required CPE Resources to pay over $3.0 million in additional commitment and administrative fees during the remaining term of the Credit Agreement through May 2021, which will now be avoided. For additional information, see Note 18 of Notes to Consolidated Financial Statements in Item 8.

Significantly Reduced Liquidity

Subsequent to the termination of the Credit Agreement, our liquidity was comprised of cash and cash equivalents, because the A/R Securitization Program was fully utilized to issue letters of credit as collateral for the reclamation surety bond providers. As of December 31, 2018, our total available liquidity was $91.2 million. As of March 8, 2019, our total available liquidity was $65.5 million, and we expect to continue using additional cash that will further reduce this liquidity.

Reduced Accounts Receivable Securitization Program Availability

Our A/R Securitization Program allows for the issuance of letters of credit. As of December 31, 2018, the A/R Securitization Program would have allowed for $21.3 million of borrowing capacity, which was less than the undrawn face amount of letters of credit outstanding under the A/R Securitization Program of $25.7 million as of December 31, 2018. The $4.4 million difference between the borrowing capacity and the undrawn face amount of the letters of credit outstanding was cash-collateralized into a restricted cash account in early January 2019, thus bringing the borrowing capacity to zero. As of March 8, 2019, the A/R Securitization Program would have allowed for $13.5 million of borrowing capacity, which is less than the $25.7 million in outstanding indebtedness under the A/R Securitization Program. The difference has been cash collateralized. For additional information, see Note 18 of Notes to Consolidated Financial Statements in Item 8.

Noncompliance with the NYSE s Continued Listing Requirements

As disclosed in our Current Report on Form 8-K on December 27, 2018, we were notified by the NYSE that the average closing price of shares of our common stock had fallen below $1.00 per share over a period of 30 consecutive trading days, which is the minimum average share price for continued listing on the NYSE under Section 802.01C of the NYSE Listed Company Manual. Under the NYSE s rules, we have six months following receipt of the notification to regain compliance with the minimum share price requirement. Since that time, our share price has continued to trade well under $1.00.

Demands for Additional Reclamation Surety Bond Collateral

U.S. federal and state laws require we secure certain of our obligations to reclaim lands used for mining and to secure coal lease obligations. The primary method we have used to meet these reclamation obligations and to secure coal lease obligations is to provide a third-party surety bond. As of December 31, 2018, we had $407.6 million of reclamation and lease bonds backed by collateral of $25.7 million in the form of letters of credit under our A/R Securitization Program as well as restricted cash, securing coal lease obligations, and for other operating requirements.

Subsequent to December 31, 2018, we received letters from certain of our third-party surety bond underwriters demanding increased collateral or replacement of their bonds. Any further issuances of letters of credit to satisfy the increased collateral demands or any replacement bonds would immediately reduce the cash and cash equivalents available to support the operations of the business, as the current level of letters of credit exceeds the borrowing credit limit of our A/R Securitization Program. We are currently in discussions with our surety bond underwriters, however we cannot assure you these negotiations will be successful in avoiding increased collateral requirements. These surety bonds are required by the permits governing our mining operations.

Fourth Quarter Asset Impairments

As a result of the aforementioned changes experienced in the fourth quarter of 2018 and the outlook for the business going forward, we recorded asset impairments as of December 31, 2018 with respect to (1) our Cordero Rojo mine and (2) our Youngs Creek and Big Metal development projects.

Our Cordero Rojo Mine produces 8400 Btu coal, and it is experiencing a strip ratio increase at a time of sustained low customer demand. As 2019 and future business plans and financial forecasts were updated and reviewed during the fourth quarter of 2018 and finalized in the first quarter of 2019, a triggering event was identified which required impairment assessment for which the conclusion was that an impairment was determined to exist as of December 31, 2018. The carrying net book value amount related primarily to land access and mineral rights, and was impaired by $372.4 million. The asset impairment charge does not alter the underlying land access and mineral rights. For additional information, see Note 7 of Notes to Consolidated Financial Statements in Item 8.

In addition, we have two development projects, both located in the Northern PRB, the Youngs Creek and Big Metal projects. As 2019 and future business plans and financial forecasts were updated and reviewed during the fourth quarter of 2018 and finalized in the first quarter of 2019, it became evident that, along with the lack of access to the capital markets, the business would not be able to generate the capital required to develop these projects. It was concluded that a triggering event existed, and the fair value was determined to be less than the carrying value, requiring the recognition of an impairment as of December 31, 2018. The carrying net book value amount, which related primarily to land access and mineral rights, was reduced by $309.2 million. The asset impairment charge does not alter the underlying land access and mineral rights. An improved future outlook could provide the opportunity to reassess the potential development of these projects. For additional information, see Note 7 of Notes to Consolidated Financial Statements in Item 8.

Election Not to Make an Interest Payment under the 2024 Notes

As of December 31, 2018 and March 11, 2019, CPE Resources had $290.4 million in outstanding indebtedness under the 12.00% second lien senior notes due 2021 (the 2021 Notes) and $56.4 million in outstanding indebtedness under the 6.375% senior notes due 2024 (the 2024 Notes , and collectively with the 2021 Notes, the senior notes).

CPE Resources has an interest payment obligation under the 2024 Notes of approximately $1.8 million, which is due on March 15, 2019. The indenture governing the 2024 Notes provides a 30-day grace period that extends the latest date for making this interest payment to April 14, 2019, before an Event of Default occurs under the indenture. Although we have sufficient liquidity to make the interest payment, we elected not to make this interest payment on the due date and plan to utilize the 30-day grace period provided by the indenture, to allow additional time to assess our restructuring alternatives. If we do not make this interest payment by April 14, 2019, an Event of Default would occur under the indenture governing the 2024 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2024 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2024 Notes. An Event of Default under the 2024 Notes for failure to pay interest would not result in a default under the 2021 Notes unless the 2024 Notes are accelerated. An Event of Default under the 2024 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance. We continue to evaluate alternatives associated with this interest payment.

CPE Resources has an interest payment obligation under the 2021 Notes of approximately $17.4 million, which is due on May 1, 2019. The indenture governing the 2021 Notes provides a 30-day grace period that extends the latest date for making this interest payment to May 31, 2019, before an Event of Default occurs under the indenture. If we do not make this interest payment by May 31, 2019, an Event of Default would occur under the indenture governing the 2021 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2021 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2021 Notes. An Event of Default under the 2021 Notes for failure to pay interest would not result in a default under the 2024 Notes unless the 2021 Notes are accelerated. An Event of Default under the 2021 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance.

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Ability to Continue as a Going Concern

Our reduced liquidity, most notably with the termination of our Credit Agreement in November 2018 due to the limited availability thereunder based on the financial covenants, along with our forecasts projecting lower levels of operating cash flow have limited our access to the capital markets. Our liquidity is now limited to cash and cash equivalents. Our forecasted cash from operations alone is insufficient to fund cash interest and capital expenditures. This has resulted in our conclusion that there is substantial doubt about our ability to continue as a going concern. As a result, we will continue to pursue options to alleviate this condition, including but not limited to evaluating our restructuring options, but there can be no guarantees that this will alleviate the substantial doubt that exists. Our consolidated financial statements have been prepared assuming we will continue as a going concern, which contemplates continuity of operations, realization of assets and the satisfaction of liabilities in the normal course of business. As a result, the accompanying consolidated financial statements do not include any adjustments relating to the recoverability and classification of assets and their carrying amounts, or the amount and classification of liabilities that may result should we be unable to continue as a going concern.

On March 14, 2019, we entered into a Forbearance Agreement (the Forbearance Agreement) by and among Cloud Peak Energy Receivables LLC, CPE Resources and PNC Bank, National Association, as administrator, relating to our A/R Securitization Program, which provides that PNC Bank, National Association will not exercise any of its remedies upon a default under the A/R Securitization Program based on the existence of substantial doubt regarding our ability to continue as a going concern. Pursuant to the Forbearance Agreement, the forbearance period terminates on the earlier of (i) April 14, 2019 and (ii) the date on which any additional events of default may occur, as specified therein.

Review of Capital Structure and Restructuring Alternatives

As disclosed in our Current Report on Form 8-K on November 13, 2018, we announced a Strategic Alternatives Review. Our Board of Directors, working together with its management team and legal and financial advisors, has commenced a review of strategic alternatives, including a potential sale of the Company. We engaged J.P. Morgan Securities LLC as our financial advisor and Allen & Overy LLP as our legal counsel in connection with our review of strategic alternatives. This fourth quarter 2018 process did not result in a transaction.

As disclosed on our Current Report on Form 8-K on January 29, 2019, we issued a press release providing an update to the previously-announced review of strategic alternatives, announcing the retention of Centerview Partners LLC as our investment banker, Vinson & Elkins LLP as our legal advisor, and FTI Consulting, Inc. as our financial advisor to assist us in our review of capital structure and restructuring alternatives.

Our restructuring evaluation process is continuing. We are actively engaged in discussions with certain of our creditor groups financial and legal advisors regarding potential alternatives, including asset sales, a private debt restructuring, or a court-supervised reorganization under Chapter 11 of the U.S. Bankruptcy Code, and related financing needs. Although this process remains uncertain and fluid, we will need to restructure our balance sheet in order to improve our capital structure, adjust our business to ongoing depressed PRB thermal coal industry conditions, address our significantly reduced liquidity and continue as a going concern. As noted above, an interest payment on our 2024 Notes will need to be made by April 14, 2019, to avoid a default under the indenture governing the 2024 Notes. An Event of Default under the 2024 Notes for failure to pay interest would not result in a default under the 2021 Notes unless the 2024 Notes are accelerated. An Event of Default under the 2024 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance. We continue to evaluate alternatives associated with this interest payment. If we determine not to make this interest payment by April 14, 2019, we may seek protection under Chapter 11.

In connection with our review of capital structure and restructuring alternatives, we expect our mining operations and reclamation activities to continue in the ordinary course of business.

As a result of our ongoing restructuring evaluation, we currently expect to delay our 2019 annual stockholders meeting.

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Segment Information

Our reportable segments include Owned and Operated Mines and Logistics and Related Activities. For a discussion on these segments, please see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations as well as Note 5 of Notes to Consolidated Financial Statements in Item 8.

History

CPE Inc., a Delaware corporation organized on July 31, 2008, is a holding company that manages its 100% owned consolidated subsidiary CPE Resources, but has no business operations or material assets other than its ownership interest in CPE Resources. CPE Inc. s only source of cash flow from operations is distributions from CPE Resources pursuant to the CPE Resources limited liability company agreement. CPE Inc. also receives management fees pursuant to a management services agreement between CPE Inc. and CPE Resources as reimbursement of certain administrative expenses. Our business operations are conducted by CPE Resources, a Delaware limited liability company formed on August 19, 2008. Between 1993 and 1998, our predecessor acquired the Antelope Mine, Spring Creek Mine, the Cordero Rojo Mine, and a 50% non-operating interest in the Decker Mine. On September 12, 2014, we sold our 50% interest in the Decker Mine to an affiliate of Ambre Energy North America, Inc. (Ambre Energy), now known as Lighthouse Resources Inc.

CPE Inc. acquired approximately 51% and the managing member interest in CPE Resources in exchange for a promissory note, which was repaid with proceeds from the initial public offering of its common stock (IPO) on November 19, 2009. Rio Tinto retained ownership of the remaining 49% interest in CPE Resources until December 15, 2010, when CPE Inc. priced a secondary offering of its common stock on behalf of Rio Tinto (the Secondary Offering). In connection with the Secondary Offering, CPE Inc. exchanged shares of its common stock for common membership units of CPE Resources held by Rio Tinto, resulting in our acquisition of 100% of Rio Tinto s holdings in CPE Resources.

Coal Characteristics

In general, coal of all geological compositions is characterized by end use either as thermal or metallurgical. Heat value and sulfur content are the most important variables in the economic marketing and transportation of thermal coal. We mine, process, and market low sulfur content, subbituminous thermal coal, the characteristics of which are described below. Because we currently operate only in the PRB, which does not have metallurgical coal, we produce only thermal coal.

Heat Value

The heat value of coal is commonly measured in Btus. Subbituminous coal from the PRB has a typical heat value that ranges from 8,000 to 9,500 Btus. Subbituminous coal from the PRB is used primarily by electric utilities and by some industrial customers for steam generation. Coal found in other regions in the U.S., including the eastern and Midwestern regions, tends to have a higher heat value than coal found in the PRB, other than lignite coal which has lower heat value than subbituminous coal but is typically only used to supply coal to utilities that are directly adjacent to the mine.

Sulfur Content

Federal and state environmental regulations, including regulations that limit the amount of sulfur dioxide that may be emitted as a result of combustion, have affected and may continue to affect the demand for certain types of coal. See Environmental and Other Regulatory Matters Clean Air Act. The sulfur content of coal can vary from seam to seam and within a single seam. The concentration of sulfur in coal affects the amount of sulfur dioxide produced in combustion. Coal-fired power plants can comply with sulfur dioxide emissions regulations by burning coal with low sulfur content, blending coals with various sulfur contents, purchasing emission allowances on the open market and/or using sulfur-reduction technology, such as scrubbers, which can reduce sulfur dioxide emissions by up to 95% or more.

PRB coal typically has a lower sulfur content than eastern U.S. coal and generally emits no greater than 1.2 pounds of sulfur dioxide per million Btus.

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Other

Ash is the inorganic residue remaining after the combustion of coal. As with sulfur content, ash content varies from seam to seam. Ash content is an important characteristic of coal because it impacts boiler performance and electric generating plants must handle and dispose of ash following combustion. The ash content of PRB coal is generally low, representing approximately 5% to 10% by weight. The composition of the ash, including the proportion of sodium oxide, as well as the ash fusion temperatures are important characteristics of coal and help determine the suitability of the coal to specific end users. In limited cases, domestic customers at the Spring Creek Mine have required, and may continue to require, the addition of earthen materials to dilute the sodium oxide content of the post-combustion ash of the coal.

Moisture content of coal varies by the type of coal and the region where it is mined. In general, high moisture content is associated with lower heat values and generally makes the coal more expensive to transport. Moisture content in coal, on an as-sold basis, can range from approximately 2% to over 35% of the coal s weight. PRB coals have typical moisture content of 20% to 30%.

Mercury and chlorine are trace elements within coal that are of primary consideration relative to utility plant emissions and performance. Trace amounts of mercury and chlorine in PRB coal are relatively low compared to coal from other regions.

Coal Mining Methods

Surface Mining

All of our mines are surface mining operations utilizing both dragline and truck-and-shovel mining methods. Surface mining is used when coal is found relatively close to the surface. Surface mining typically involves the removal of topsoil and drilling and blasting the overburden with explosives. The overburden is then removed with draglines, trucks, shovels, and dozers. Trucks and shovels then remove the coal. The final step involves replacing the overburden and topsoil after the coal has been excavated, reestablishing vegetation into the natural habitat and making other changes designed to provide local community benefits. We typically recover 90% or more of the economic coal seam for the mines we operate.

Coal Preparation and Blending

In almost all cases, the coal from our mines is crushed and shipped directly from our mines to the customer. Typically, no other preparation is needed for a saleable product. However, coals of various sulfur and ash contents can be mixed or   blended   to meet the specific combustion and environmental needs of customers. All of our coal can be blended with coal from other coal producers. Spring Creek Mine s location and the high Btu content of its coal make its coal better suited than our other coal for export and transportation to U.S. coal customers on the Great Lakes for blending by the customer with coal sourced from other locations to achieve a suitable overall product.

Mining Operations

We currently operate solely in the PRB. Two of the mines we operate are located in Wyoming, and one is located in Montana. We currently own the majority of the equipment utilized in our mining operations. We employ preventative maintenance and rebuild programs and upgrade our equipment as part of our efforts to ensure that it is productive, well maintained, and cost competitive. Our maintenance programs also utilize procedures designed to enhance the efficiencies of our operations. The following table provides summary information regarding our mines as of December 31, 2018.

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Mine	2018 As Delivered Average				Tons Sold		
	Btu per lb	Ash Content (%)	Sulfur Content (%)	Sulfur Content (lbs SO2/mmBtu)	2018	2017 (million tons)	2016
Antelope	8,851	5.64	0.23	0.52	23.2	28.4	29.8
Cordero Rojo	8,436	5.29	0.29	0.69	12.6	16.4	18.3
Spring Creek	9,252	5.37	0.33	0.72	13.9	12.6	10.4
Other (1)	N/A	N/A	N/A	N/A		0.3	0.3
Total					49.7	57.8	58.8

(1) The tonnage shown for Other represents our purchases from third-party sources that we have resold. See Mining Operations Broker Sales and Third-Party Sources.

Our Owned and Operated Mines segment includes our Antelope Mine, Cordero Rojo Mine, and Spring Creek Mine. Our Antelope and Cordero Rojo mines are served by the BNSF and UP railroads. Our Spring Creek Mine is served solely by the BNSF railroad.

The following map shows the locations of our mining operations:

Antelope Mine

The Antelope Mine is located in the southern end of the PRB approximately 60 miles south of Gillette, Wyoming. The mine extracts thermal coal from the Anderson and Canyon Seams, with up to 44 and 36 feet, respectively, in thickness. Significant areas of unleased coal north and west of the mine are available for nomination by us or other mining operations or persons. See Item 2 Properties Reserve Acquisition Process. Based on the average sulfur content of 0.50 lbs SO_2/mmBtu, the reserves at our Antelope Mine are considered compliance coal under the Clean Air Act, and this coal is some of the lowest sulfur coal produced in the PRB.

Cordero Rojo Mine

The Cordero Rojo Mine is located approximately 25 miles south of Gillette, Wyoming. The mine extracts thermal coal from the Wyodak Seam, which ranges from approximately 55 to 70 feet in thickness. Significant additional areas of unleased coal are potentially available for nomination by us or other mining operations or persons adjacent to our current operations. See Item 2 Properties Reserve Acquisition Process. Based on the average sulfur content of 0.66 lbs SO_2/mmBtu, the reserves at our Cordero Rojo Mine are considered compliance coal under the Clean Air Act.

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Spring Creek Mine

The Spring Creek Mine is located in Montana approximately 20 miles north of Sheridan, Wyoming. The mine extracts thermal coal from the Anderson-Dietz Seam, which averages approximately 80 feet in thickness. The location of the mine relative to the Great Lakes is attractive to our customers in the northeast because of lower transportation costs. The location of the Spring Creek Mine also provides access to export terminals in the Pacific Northwest, providing a geographic advantage relative to other PRB mines. During the years ended December 31, 2018, 2017, and 2016, we shipped approximately 4.6, 4.2, and 0.6 million tons, respectively, of Spring Creek coal through the Westshore terminal located in British Columbia, Canada. Based on the average sulfur content of 0.73 lbs SO_2/mmBtu, the reserves at our Spring Creek Mine are considered compliance coal under the Clean Air Act.

Development Projects

Youngs Creek Project

The Youngs Creek project, an undeveloped surface mine project in the Northern PRB region, is located in Wyoming, approximately 13 miles north of Sheridan, Wyoming, seven miles south of our Spring Creek Mine and seven miles from the mainline railroad, contiguous with the Wyoming-Montana state line. It is near the Big Metal project (described below). We acquired the Youngs Creek project in June 2012. The coal located at the Youngs Creek project is similar quality to that of our Spring Creek Mine and offers lower sodium levels. We have not been able to classify the Youngs Creek project mineral rights as proven and probable reserves as they remain subject to further exploration and evaluation based on market conditions. The Youngs Creek project mining permit covers 283.6 million tons of non-reserve coal deposits, of which approximately 267 million tons benefit from a royalty rate of 8.0% of the coal sales price free on board (FOB) at the mine site, payable to the sellers, which is below the normal 12.5% royalty rate payable on federal coal. We control additional leased and private coal related to the Youngs Creek project that has not yet been evaluated and is not yet in any mine plan. We also acquired approximately 38,800 acres of surface rights, which includes land extending north to our Spring Creek Mine, and onto the Crow Indian Reservation to the west.

Big Metal Project

In January 2013, Big Metal entered into an option agreement and a corresponding exploration agreement with the Crow Tribe. These agreements were approved by the U.S. Department of the Interior in June 2013. This coal project is located on the Crow Indian Reservation in southeast Montana, near our Spring Creek Mine and Youngs Creek project in the Northern PRB region. The option and exploration agreements provided for exploration rights and exclusive options to lease three separate coal deposits on the Crow Indian Reservation over an initial five-year term, which would have expired June 14, 2018, with two extension periods through 2035 if certain conditions were met. On June 7, 2018, Big Metal delivered notice to the Crow Tribe to exercise the Upper Youngs Creek coal lease option and extend the coal lease options for the Squirrel Creek and Tanner Creek project areas. In connection with the option exercise and option extensions, Big Metal paid approximately $1.8 million to the Crow Tribe in June 2018. Since inception of the option agreement, Big Metal has made option and lease bonus payments totaling approximately $12 million to the Crow Tribe, including the option exercise payments in June 2018. The coal lease will still require approval from the U.S. Department of the Interior and related regulatory actions before it is effective. Exercise of the Upper Youngs Creek option and payment of the initial option payments for the Squirrel Creek and Tanner Creek project areas triggered the commencement of the first option extension periods for Squirrel Creek and Tanner Creek through December 31, 2025.

Upon the exercise of an option or options to lease, we pay the Crow Tribe an amount equal to $0.08 per ton to $0.15 per ton, depending on the lease area and coal deposit and subject to adjustment for inflation. The agreements also set forth adjustable royalty rates, ranging from 7.5% to 15% of the coal sales price FOB at the mine site and contain standard coal production taxes to be paid to the Crow Tribe. The coal located at the Big Metal project is similar quality to that of our Spring Creek Mine and offers lower sodium levels. We have completed the exploration program for the Big Metal project and are evaluating the development options for this project. We believe that the proximity of the Big Metal project to the Spring Creek Mine and the Youngs Creek project represents an opportunity to optimize our mine developments in the Northern PRB.

Any future development and coal production from these projects remains subject to significant risk and uncertainty.

The map below shows where the Youngs Creek project and Big Metal project (Squirrel Creek, Tanner Creek, and Upper Youngs Creek coal deposits) are located relative to our Spring Creek Mine.

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(1) Non-reserve coal deposits are not reserves under SEC Industry Guide 7. Estimates of non-reserve coal deposits are subject to further exploration and development, are more speculative, and may or may not be converted to future reserves of the company.

Customers, Contracts and Logistics Services

We focus on building long-term relationships with customers through our reliable performance and commitment to customer service. We supply coal to 46 domestic and foreign electric utilities and over 85% of our sales were to customers with an investment grade credit rating as of December 31, 2018. Furthermore, 84% of our 2018 sales were to customers with whom we have had relationships for more than 10 years. During 2018, approximately 53% of our consolidated revenue was derived from our top ten customers. No customer accounted for 10% or more of our total revenue in 2018, 2017, or 2016.

Coal produced approximately 27% of electricity generation in the U.S. through October 2018. The following map shows the percentage of our tons sold by state of destination during 2018 from coal produced at the three mines we own and operate. Our coal supplies fueled approximately 2% of the electricity generated in the U.S. in 2018. Approximately 9% of the tons produced at our mines were sold to customers outside of the U.S. in 2018.

We categorize our customers by how we sell coal to them. Our mine customers purchase coal directly from our mine sites, where the sale occurs at the mine site and where title and risk of loss typically pass to the customer at that point. Mine customers arrange for and bear the costs of transporting their coal from our mines to their plants or other specified discharge points. Our mine customers are typically domestic utility companies primarily located in the mid-west and south central U.S., although we also sell to other domestic utility companies, as well as to third-party brokers.

Our logistics customers purchase coal from us, along with our logistics services to deliver the coal to the customer at a terminal or the customer s plant or other delivery point remote from our mine site. Title and risk of loss pass to the customer at the remote delivery point. Our logistics services include the purchase of coal from third parties or from our owned and operated mines, at market prices, as well as the contracting and coordination of the transportation and other handling services from third-party operators, which are typically rail and terminal companies. Logistics customers are primarily foreign and domestic utility companies as well as third-party brokers. With respect to our international sales, at present, we are primarily focused on end-user customers. However, a small portion of our sales are made to international traders who sell on to end-user customers.

Mine Customers

Coal Sales Agreements

As is customary in the coal industry, we generally enter into fixed price, fixed volume supply contracts with our mine customers. Contracts with our mine customers historically featured terms of one to five years, although recent trends have been toward sales with shorter terms, including monthly and quarterly contracts. This has led to greater variability and less long-term predictability of our sales. For the year ended December 31, 2018, approximately 81% of our revenue was derived from supply contracts with terms of one year or greater.

Our coal is primarily sold on a mine-specific basis to utility customers through a request-for-proposal process. The terms of our coal sales agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these contracts vary by customer, including base price adjustment features, price re-opener terms, coal quality requirements, quantity parameters, permitted sources of supply, impact of future regulatory changes, extension options, force majeure, termination, assignment and other provisions.

Our coal sales agreements typically contain hardship provisions to adjust the base price due to new statutes, ordinances or regulations that affect our costs related to performance of the agreement. Additionally, some of our contracts contain provisions that allow for the recovery of costs incurred as a result of modifications or changes in the interpretations or application of any applicable statute by local, state or federal government authorities. These provisions only apply to the base price of coal contained in these supply contracts. In some circumstances, a significant adjustment in base price can lead to termination of the contract. In addition, a small number of our contracts contain clauses that may allow customers to terminate the contract in the event of significant changes in environmental laws and regulations, which result in the customer being unable to perform under the terms of the contract.

Most of our coal sales agreements to mine customers include a fixed price for the term of the agreement or a pre-determined escalation in price for each year. Some of our customer contracts may include variable pricing. These price re-opener and index provisions may allow either party to commence a renegotiation of the contract price at a pre-determined time. Price re-opener provisions may automatically set a new price based on prevailing market price or, in some instances, require us to negotiate a new price, sometimes within specified ranges of prices. In some agreements, if the parties do not agree on a new price, either party has an option to terminate the contract. Under some of our contracts, we have the right to match lower prices offered to our customers by other suppliers.

Quality and volumes for the coal are stipulated in coal sales agreements. Some customers are allowed to vary the amount of coal taken under the contract. Most of our coal sales agreements contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics, such as heat content, sulfur, ash and ash fusion temperature. Failure to meet these specifications can result in economic penalties, suspension or cancellation of shipments or termination of the contracts. Our contracts also typically attempt to account for the low sulfur content of our coal by reflecting a market adjustment for the low sulfur in the contract price or through an adjustment calculated based on the as-delivered average sulfur content of our coal, or both.

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Contracts with our mine customers also typically contain force majeure provisions allowing temporary suspension of performance by us or our customers for the duration of specified events beyond the control of the affected party, including events such as strikes, adverse mining conditions, mine closures or serious transportation problems that affect us or unanticipated plant outages that may affect the buyer. These contracts generally provide that, in the event a force majeure circumstance exceeds a certain period (e.g., 60-90 days), the unaffected party may have the option to terminate the transaction or transactions under the agreement. Some of those contracts stipulate that this tonnage can be made up by mutual agreement or at the discretion of the buyer. Generally, contracts with our mine customers allow our customers to suspend performance in the event that the railroad fails to provide its services due to circumstances that would constitute a force majeure under the terms of the contract between the mine customer and the railroad.

Many of our contracts contain clauses that require us and our customers to maintain a certain level of creditworthiness or provide appropriate credit enhancement upon request. The failure to do so can result in a suspension of shipments under the contract. In some of our contracts, we have a right of substitution, allowing us to provide coal from different mines, including third-party mines, as long as the replacement coal meets quality specifications and will be sold at the same delivered cost.

Generally, under the terms of our coal sales agreements, we agree to indemnify or reimburse our customers for damage to their or their rail carrier s equipment resulting from our negligence, and for damage to their equipment due to non-coal materials being included with our coal before leaving our property.

Transportation

Transportation is typically one of the largest components of a purchaser s total cost. Coal used for domestic consumption by our mine customers is typically sold FOB at the mine or nearest loading facility, and the purchaser of the coal bears the transportation costs and risk of loss. Most electric generators arrange long-term shipping contracts with rail or barge companies to assure stable delivery costs. Our Antelope and Cordero Rojo mines are served by the BNSF and UP railroads. Our Spring Creek Mine is served solely by the BNSF railroad.

Although the purchaser pays the freight, transportation costs still are important to coal mining companies because the purchaser will consider the delivered cost of coal, including transportation costs, in determining from which mines it will purchase. Transportation costs borne by the customer vary greatly based on each customer s proximity to the mine.

Logistics Customers

Coal Sales Agreements

We generally enter into binding contracts that are fixed-price, fixed-volume supply contracts with our domestic logistics customers. Contracts with these logistics customers generally have terms of one to three years. The terms of our sales agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these contracts vary by customer, including base price adjustment features, price re-opener terms, logistics and coal quality requirements, quantity parameters, permitted sources of supply, impact of future regulatory changes, extension options, force majeure, termination, assignment and other provisions.

With our international logistics customers, we often enter into contracts that contain multi-year terms with future year pricing to be agreed upon, meaning that there is an expectation of sales, provided that mutual agreement on pricing can be reached. This is consistent with conventional industry standards for sales into the Asian Pacific region. Our Asian delivered shipments are typically priced broadly in line with a number of relevant international coal indices adjusted for energy content and other quality and delivery criteria. These indices include the Newcastle benchmark price, as published by Global Coal and others, and the Platts Kalimantan 5000. The Newcastle benchmark price is an established index for high Btu Australian bituminous thermal coal available to be loaded on a vessel at a coal terminal near Newcastle, north of Sydney. The Kalimantan 5000 is an established index for subbituminous Indonesian thermal coal. Our delivered sales have historically priced at a range between 60% to 75% of the forward Newcastle price and at a smaller discount to the forward Kalimantan 5000 price due to quality and freight cost differentials. In late 2018, the collapse of the Indonesian rupiah lowered producers U.S. Dollar cost and the Indonesian Government removed export restrictions to increase U.S. Dollar exports. The result has been an increase in Indonesian exports and a drop in the Kalimantan 5000 index. The

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current wide gap between Newcastle and Kalimantan 5000 index pricing is not common compared to historical spreads.

Contracts with our logistics customers include terms similar to those described for our mine customers and may include terms relating to:

- demurrage fees for international contracts, charged to us when a vessel is not dispatched in the agreed-upon time;
- fixed pricing for the current year of sales, and a provision providing for future years pricing to be negotiated by a specific point in time for some of our foreign contracts; and
- additional coal quality requirements, such as grindability, which deals with the hardness of the coal, and ash fusion temperature, which measures the softening and melting behavior of the ash contained in the coal.

Transportation and Logistics Services

For our logistics customers, we provide a variety of services designed to facilitate the sale and delivery of coal. These services include the purchase of coal from third parties or from our owned and operated mines, coordination of the transportation and delivery of purchased coal, negotiation of take-or-pay rail agreements and take-or-pay port agreements and demurrage settlements with vessel operators. We also bear the costs of transporting the coal to the delivery point. For our international customers, this generally means that we cover the costs associated with an export terminal located in the Pacific Northwest. Our logistics customers located overseas are generally responsible for paying the cost of ocean freight, although occasionally we may arrange or be responsible for the cost of that transportation as well.

We have an agreement with an unaffiliated Korean representative company, WoonBong Energy, which helps us facilitate our sales in South Korea. WoonBong Energy provides market research on Korean coal customers and demand, acts as an intermediary for communications with our Korean customers and assists with logistics issues in sales to Korean customers. WoonBong Energy provides these services exclusively for us in South Korea. We have similar arrangements in certain other Asian countries.

To help support and ensure export terminal capacity for export sales, we enter into multi-year throughput agreements with export terminal companies and railroads. These types of take-or-pay agreements require us to pay for a minimum quantity of coal to be transported on the railway or through the terminal regardless of whether we sell any coal. If we fail to make sufficient export sales to meet our minimum obligations under the take-or-pay agreements, we are still obligated to make payments to the export terminal company or railroad. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Obligations for more detail. Also included in the costs within our Logistics and Related Activities segment are fees to cover rail and export terminal charges, as well as fees to cover capital costs and investments that we incur to enable us to provide logistics services to our logistics customers, such as the purchase or lease of rail cars.

Historical Westshore and BNSF Logistics Agreements

In 2011, we entered into a multi-year throughput contract with Westshore Terminals Limited Partnership (Westshore) for a portion of our anticipated export sales through their export terminal in Vancouver, British Columbia. In August 2014, we increased our long-term committed capacity at Westshore from 2.8 million tons to 6.3 million tons initially, increasing to 7.2 million tons in 2019. In addition, the revised agreement extended the term of our throughput agreement by two years through the end of 2024.

In October 2015, we announced an amended agreement with Westshore whereby the previously committed volumes for 2016 through 2018 were reduced to zero in exchange for an upfront payment made in October 2015, plus quarterly payments during 2016 through 2018, as specified in the amended agreement. In December 2015, we announced a similar amendment to our transportation agreement with BNSF.

In November 2016, due to the improvement in export coal prices, we entered into agreements with Westshore and BNSF to ship coal during the fourth quarter of 2016. These agreements were effective for the fourth quarter of 2016 only, and did not change the aforementioned amended agreements discussed above, or the terms of the previous throughput or transportation agreements. Under the fourth quarter agreements, we received a partial credit against current charges for the quarterly payments made under the previous agreements.

At December 31, 2016, we terminated our previous agreement with Westshore and entered into a new agreement. In February 2017, we terminated our previous agreement with BNSF and entered into a new agreement effective in April 2017. The new agreements provided for shipments in 2017 and 2018 and required minimum payments for those two years. We had the right to terminate our commitments at any time in exchange for buyout payments.

Current Westshore and BNSF Logistics Agreements

On December 28, 2017, we extended our agreement with Westshore through the end of 2020. We further amended this agreement in July 2018 to extend through the end of 2022 and allow for greater capacity in 2021 and 2022 to 10.5 million total annual throughput tons. We retain the right to terminate our commitments at any time in exchange for a buyout payment. The buyout payment amount varies throughout the period based upon an agreed schedule. Additionally, after the new Westshore agreement terminates and through 2024, if we choose to ship to export customers, we are required to offer to ship through Westshore up to a specified annual tonnage on terms similar to the new agreement before shipping through any other export terminal. Westshore has the right to accept or reject our offer in its sole discretion. See Note 6 of Notes to Consolidated Financial Statements in Item 8 for further discussion regarding the accounting treatment of these transactions.

We signed an agreement with BNSF on January 9, 2018, extending the existing agreement through the end of 2020. We have the right to terminate our commitments for the remaining years at any time in exchange for buyout payments. We are currently in discussions with BNSF regarding an extension through December 2022 to support our increased port capacity for our Asian export business.

Other Logistics Agreements

In addition to our current port agreement with Westshore, we hold an option contract to increase our future export capacity through the proposed Millennium Bulk Terminals (MBT) coal export facility in Washington State. The timing and outcome of the permit process related to MBT, and therefore the construction of the terminal, is uncertain.

We also previously had a minority ownership interest in the joint venture that was seeking to develop Gateway Pacific Terminal (GPT) in Washington State. SSA Marine, the majority interest holder and project developer, notified us of its intention to no longer pursue a coal terminal. As a result, in January 2017, we abandoned our ownership interest in the joint venture, and we no longer have any ownership interest or associated funding obligations for the joint venture. We continue to have residual contractual rights as a potential customer of the terminal if the project is resumed in a designated period of time in the future. The abandonment of our interest in GPT had no effect on our financial statements since we fully impaired our investment in 2015.

Broker Sales and Third-Party Sources

From time to time, we purchase coal through brokers. We also sell any excess produced coal to brokers and third-party sources, including brokers who sell to end users in foreign countries. For delivery during the years ended December 31, 2018, 2017, and 2016, we purchased and resold 0.0, 0.3, and 0.3 million tons, respectively, through brokers and third-party sources.

Sales and Marketing

We have a team of experienced sales, marketing, and customer service personnel. To help develop and maintain the relationships we have with our mine and logistics customers, we have divided the department into teams consisting of:

- Sales and Marketing, which focuses on traditional requests for proposals by our mine customers and after sales service;

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- Logistics, which provides logistical and additional contract support to our domestic customers, and also focuses on logistics, transportation and related services on behalf of our Logistics and Related Activities segment;

- Trading and Revenue Management, which provides industry insight, recommends pricing strategies and participates in the spot and forward markets; and

- Export Sales, which focuses on sales to our international logistics customers.

As of March 8, 2019, we had 9 employees in our sales and marketing department.

Suppliers

Principal supplies used in our business include heavy mobile equipment, petroleum-based fuels, explosives, tires, steel and other raw materials, as well as spare parts and other consumables used in the mining process. We use third-party suppliers for a portion of our equipment rebuilds and repairs, drilling services and construction. We use sole source suppliers for certain parts of our business such as dragline shovel parts and services and tires. We believe adequate substitute suppliers are available. For further discussion of our suppliers, see Item 1A Risk Factors Risks Related to Our Business and Industry *Increases in the cost of raw materials and other industrial supplies, or the inability to obtain a sufficient quantity of those supplies, could increase our operating expenses, disrupt or delay our production and materially adversely affect our profitability*.

Competition

The coal industry is highly competitive. See Item 1A Risk Factors Risks Related to Our Business and Industry *Competition with domestic and foreign coal producers, with traders and re-sellers of coal and with producers of natural gas and other competing energy sources may continue to negatively affect our sales volumes and our ability to sell coal at a favorable price.* We compete with other coal producers, with traders and re-sellers of coal and with other energy producers throughout the U.S. and, for our export sales, internationally. The most important factors on which we compete with other coal producers and with traders and re-sellers of coal are coal price, coal quality and characteristics, costs to transport the coal, customer service, and the reliability of supply. Demand for coal and the prices that we will be able to obtain for our coal are closely linked to coal consumption patterns of the domestic and foreign electric generation industries. These coal consumption patterns are influenced by factors beyond our control, including weather and economic conditions, the supply and demand for domestic and foreign electricity, domestic and foreign governmental regulations and taxes, environmental and other regulatory changes, global climate change initiatives, technological developments, the price and availability of other fuels, such as natural gas and crude oil, the availability of subsidies, and renewable mandates designed to encourage greater use of alternative energy sources, including hydroelectric, nuclear, wind and solar power, and currency exchange rate fluctuations, all of which can decrease demand for thermal coal or may decrease demand for PRB coal compared to other global coal basins.

Because the U.S. federal government owns most of the coal in the vicinity of our mines, we compete with other coal producers operating in the PRB for additional coal through the competitive LBA process.

Employees

As of March 8, 2019, we had approximately 1,300 full-time employees. None of our employees are currently parties to collective bargaining agreements. We believe that we have good relations with our employees. As of March 8, 2019, we had approximately 150 external contractors on a full-time, equivalent basis.

Executive Officers

The information required by Item 401 of Regulation S-K is included in Part III, Item 10 of this report.

Environmental and Other Regulatory Matters

Federal, state and local authorities regulate the U.S. coal mining industry with respect to various matters, including air quality standards, water pollution, plant and wildlife protection, the discharge of materials into the environment and the effects of mining on surface and groundwater quality and availability. These laws and

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regulations, which are extensive, change frequently, and have tended to become stricter over time, have had, and will continue to have, a significant adverse effect on our production costs and our competitive position relative to certain other sources of electricity generation. Future laws, regulations, orders, or treaties, including those relating to global climate change, may continue to cause coal to become a less attractive fuel source, thereby further reducing coal s share of the market for fuels and other energy sources used to generate electricity. See Environmental and Other Regulatory Matters Global Climate Change.

We are committed to conducting our mining operations in compliance with all applicable federal, state and local laws and regulations. We have procedures in place that are designed to enable us to comply with these laws and regulations. As an example, all of the mines we operate are certified to the international standard for environmental management systems (ISO 14001). We believe we are substantially in compliance with applicable laws and regulations. However, due to the complexity and interpretation of these laws and regulations, we cannot guarantee that we have been or will be at all times in complete compliance.

Mining Permits and Approvals

Numerous governmental permits or approvals are required for mining operations. When we apply for these permits and approvals, we may be required to prepare and present data to federal, state or local authorities pertaining to the effect or impact that any proposed production or processing of coal may have upon the environment. For example, in order to obtain a federal coal lease, an EIS must be prepared to assist the BLM in determining the potential environmental impact of lease issuance, including any direct and indirect effects from the mining, transportation and burning of coal. In recent years, particular attention has been focused on the impact of the production and usage of coal on global climate change. This has resulted in extensive comments and regulatory litigation from environmental groups. See also Note 21 of Notes to Consolidated Financial Statements in Item 8 for a discussion regarding certain challenges by environmental activist groups against various regulatory processes impacting our mines. Accordingly, our nominations or lease applications may be subject to delays or challenges. In order to obtain mining permits and approvals from federal and state regulatory authorities, mine operators must also submit a reclamation plan for restoring, upon the completion of mining operations, the mined property to its prior condition, productive use or other permitted condition. As discussed in more detail in Surety Bonds below, mine operators must also provide financial assurance to ensure performance of the reclamation plan and to guarantee long-term obligations. Typically, we submit the necessary permit applications several months or even years before we plan to begin mining a new area. In the states where we operate, the applicable laws and regulations also provide that a mining permit or modification can be delayed, refused or revoked if officers, directors, stockholders with specified interests or certain other affiliated entities with specified interests in the applicant or permittee have, or are affiliated with another entity that has, outstanding permit violations. Thus, past or ongoing violations of applicable laws and regulations by these interested persons and entities could provide a basis to revoke our existing permits and to deny the issuance of additional permits. As a result of these requirements, the authorization, permitting and implementation requirements imposed by federal, state and local authorities may be costly and time consuming and may limit or delay commencement or continuation of mining operations. Under some circumstances, substantial fines and penalties, including revocation or suspension of mining permits, may be imposed under governing laws, rules and regulations. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws.

Permitting requirements also require, under certain circumstances, that we obtain surface owner consent if the surface estate has been split from the mineral estate. This requires us to negotiate with third parties for surface access that overlies coal we acquired or intend to acquire. These negotiations can be costly and time-consuming, lasting years in some instances, which can create additional delays in the permitting process. If we cannot successfully negotiate for land access, we could be denied a permit to mine coal we already own.

Surface Mining Control and Reclamation Act

SMCRA establishes mining, environmental protection, reclamation and closure standards for all aspects of surface coal mining. Mining operators must obtain SMCRA permits and permit renewals from the federal Office of Surface Mining (OSM) or from the applicable state agency if the state agency has obtained regulatory primacy by developing a mining regulatory program no less stringent than that established under SMCRA. Both Wyoming and Montana, where our owned and operated mines are located, have achieved primacy to administer the SMCRA program.

SMCRA permit provisions include a complex set of requirements, which include, among other things, coal prospecting, mine plan development, topsoil or growth medium removal and replacement, selective handling of overburden materials, mine pit backfilling and grading, disposal of excess spoil, protection of the hydrologic balance, surface runoff and drainage control, establishment of suitable post mining land uses and re-vegetation. We begin the process of preparing a mining permit application by collecting baseline data to adequately characterize the pre-mining environmental conditions of the permit area. This work is typically conducted by third-party consultants with specialized expertise and typically includes surveys and/or assessments of: cultural and historical resources; geology; soils; vegetation; aquatic organisms; wildlife; potential for threatened, endangered or other special status species; surface and ground water hydrology; climatology; riverine and riparian habitat and wetlands. The geologic data and information derived from the surveys and/or assessments are used to develop the mining and reclamation plans presented in the permit application, which address the provisions and performance standards of the state s equivalent SMCRA regulatory program. SMCRA permit applications also include information used for documenting surface and mineral ownership, variance requests, access roads, mining methods, mining phases, other agreements that may relate to coal, other minerals, oil and gas rights, water rights, permitted areas and ownership and control information required to determine compliance with OSM s regulations, including information regarding mining and compliance history. A mine operator must also submit a bond or otherwise secure the performance of all reclamation obligations associated with the proposed activities.

Upon submission to the regulatory agency, a permit application goes through an administrative completeness review and a thorough technical review. Public notice of the proposed permit is required, beginning a notice and comment period that is required before a permit can be issued. It is not uncommon for a SMCRA mine permit application to take over two years to prepare and review, depending on the size and complexity of the mine, and another two or more years for the permit to be issued, depending primarily on the regulatory authority s approach to handling comments and objections received from the general public and other agencies. Also, it is not uncommon for a permit to be delayed as a result of litigation related to the specific permit or another related company s permit.

From time to time, OSM will also update its mining regulations under SMCRA. For example, in December 2016, the OSM published a final rule to revise its regulations related to protecting streams and related wildlife from adverse impacts of surface coal mining operations. The rule would have imposed stricter guidelines on conducting coal mining operations within buffer zones; required mine operators to collect additional baseline data about the site of the proposed mining operation and adjacent areas; imposed additional surface and groundwater monitoring requirements; enacted specific requirements for the protection or restoration of perennial and intermittent streams; and imposed additional bonding and financial assurance requirements. In February 2017, the rule was revoked pursuant to the Congressional Review Act. Accordingly, the rule has no force or effect and cannot be replaced by a similar rule absent future legislation. This type of rule or other new SMCRA regulations could result in additional material costs, obligations, and restrictions associated with our operations.

In addition to the bond requirement described above, the Abandoned Mine Land Fund, which was created by SMCRA, imposes a fee on all coal produced. The proceeds of the fee are used to restore mines closed or abandoned prior to SMCRA s adoption in 1977. The current fee is $0.28 per ton of coal produced from surface mines. In 2018, 2017, and 2016 we recorded $13.8 million, $16.1 million, and $16.3 million, respectively, of expense related to these reclamation fees.

Surety Bonds

Federal and state laws require a mine operator to secure the performance of its reclamation and lease obligations required under SMCRA through the use of surety bonds or other approved forms of security to cover the costs the state would incur if the mine operator were unable to fulfill its obligations. At some point, federal and state laws may be amended to require certain forms of financial assurance that are more costly to obtain. Recently, there has been heightened regulatory pressure on reclamation bonding and self-bonding in particular. We exited self-bonding in the first quarter of 2017. The primary method we have used to meet these reclamation obligations and to secure coal lease obligations is to provide a third-party surety bond. As of December 31, 2018, we had $407.6 million of reclamation and lease bonds backed by collateral of $25.7 million in the form of letters of credit under our A/R Securitization Program used for mining, securing coal lease obligations, and for other operating requirements. For additional discussion and recent developments regarding our surety bonds, please see Recent Developments .

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Mine Safety and Health

Stringent health and safety standards have been in effect since Congress enacted the Coal Mine Health and Safety Act of 1969. The Federal Mine Safety and Health Act of 1977 (the Mine Act), significantly expanded the enforcement of safety and health standards and imposed safety and health standards on all aspects of mining operations. In addition to federal regulatory programs, all of the states in which we operate also have state programs for mine safety and health regulation and enforcement. Collectively, federal and state safety and health regulation in the coal mining industry is among the most comprehensive and pervasive systems for protection of employee health and safety affecting any segment of U.S. industry. The Mine Act is a strict liability statute that requires mandatory inspections of surface and underground coal mines and requires the issuance of enforcement action when it is believed that a standard has been violated. A penalty is required to be imposed for each cited violation. Negligence and gravity assessments result in a cumulative enforcement arrangement that may result in the issuance of withdrawal orders. The Mine Act also contains criminal liability provisions. For example, it imposes criminal liability for corporate operators who knowingly or willfully authorize, order or carry out violations and for any person who knowingly falsifies records required under the Mine Act. The Mine Act also provides that civil and criminal penalties may be assessed against individual agents, officers and directors who knowingly authorize, order or carry out violations.

In 2006, in response to underground mine accidents, Congress enacted the Mine Improvement and New Emergency Response Act (the MINER Act). The MINER Act significantly amended the Mine Act, requiring improvements in mine safety practices, increasing criminal penalties and establishing a maximum civil penalty for non-compliance, and expanding the scope of federal oversight, inspection and enforcement activities. Since passage of the MINER Act, and particularly since the April 2010 explosion at Massey Energy Company s (previously acquired by Alpha Natural Resources) Upper Big Branch Mine, enforcement scrutiny has increased, including more inspection hours at mine sites, increased numbers of inspections and increased issuance of the number and the severity of enforcement actions and related penalties. Various states also have enacted their own new laws and regulations addressing many of these same subjects. MSHA continues to interpret and implement various provisions of the MINER Act, along with introducing new proposed regulations and standards. For example, the second phase of the MSHA s respirable coal mine dust rule went into effect in February 2016, and requires increased sampling frequency and the use of continuous personal dust monitors. In August 2016, the third and final phase of the rule became effective, reducing the overall respirable dust standard in coal mines from 2.0 to 1.5 milligrams per cubic meter of air. Our compliance with these or any other new mine health and safety regulations could increase our mining costs.

We have implemented various internal standards to promote employee health and safety. In addition, we are also Occupational Health and Safety Assessment Series 18001 certified. Nevertheless, if we were to be found in violation of mine safety and health regulations, we could face penalties or restrictions that may materially and adversely impact our operations, financial results and liquidity.

Black Lung

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator must pay federal black lung benefits to claimants who are current and former employees and 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 January 1, 1970. The trust fund is funded by an excise tax on 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 excise tax does not apply to coal shipped outside the U.S. In 2018, 2017, and 2016 we recorded $22.6 million, $26.4 million, and $28.6 million, respectively, of expense related to this excise tax.

The Patient Protection and Affordable Care Act includes significant changes to the federal black lung program including an automatic survivor benefit paid upon the death of a miner with an awarded black lung claim and establishes a rebuttable presumption with regard to pneumoconiosis among miners with 15 or more years of coal mine employment that are totally disabled by a respiratory condition. These changes could have a material impact on our costs expended in association with the federal black lung program. For miners last employed as miners after 1969 and who are determined to have contracted black lung, we maintain coverage to help cover the cost of present and future claims through the use of trusts or insurance policies. We may also be liable under state laws for black lung claims that are covered through insurance policies.

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Clean Air Act

The CAA and comparable state laws that regulate air emissions affect coal mining operations both directly and indirectly. Direct impacts on coal mining and processing operations include CAA permitting requirements and emission control requirements relating to air pollutants, including particulate matter, which may include controlling fugitive dust. The CAA indirectly affects coal mining operations by extensively regulating the emissions of particulate matter, sulfur dioxide, nitrogen oxides, mercury and other compounds emitted by coal-fired power plants. In recent years, Congress has considered legislation that would require increased reductions in emissions of sulfur dioxide, nitrogen oxide and mercury. In addition to the GHG issues discussed below, the air emissions programs that may materially and adversely affect our operations, financial results, liquidity, and demand for our coal, directly or indirectly, include, but are not limited to, the following:

- *Acid Rain.* Title IV of the CAA requires reductions of sulfur dioxide emissions by electric utilities. Affected power plants have sought to reduce sulfur dioxide emissions by switching to lower sulfur fuels, installing pollution control devices, reducing electricity generating levels or purchasing or trading sulfur dioxide emission allowances. We cannot accurately predict the future effect of these Clean Air Act provisions on our operations.

- *NAAQS for Criterion Pollutants.* The CAA requires the EPA to set standards, referred to as NAAQS, for six common air pollutants, including nitrogen oxide, sulfur dioxide, particulate matter, and ozone. Areas that are not in compliance (referred to as non-attainment areas) with these standards must take steps to reduce emissions levels. Although our operations are not currently located in non-attainment areas, we could be required to incur significant costs to install additional emissions control equipment, or otherwise change our operations and future development if that were to change. Over the past several years, the EPA has revised its NAAQS for nitrogen oxide, sulfur dioxide, and particulate matter, and, in November 2014, proposed a revised standard for ozone, in each case making the standards more stringent. The EPA has determined that the areas in which we operate are classified under the new nitrogen oxide standard as unclassifiable/attainment . Based on the EPA s third round of area designations, no areas in which we operate have been designated as nonattainment under the 2010 revised sulfur dioxide NAAQS. In November 2015, the EPA also revised the NAAQS for ground level ozone to a stricter, lower standard of 70 parts per billion. The EPA completed area designations for the 2015 ozone standards in July 2018.

- *Clean Air Interstate Rule and Cross-State Air Pollution Rule.* CAIR calls for power plants in 28 states and the District of Columbia to reduce emission levels of sulfur dioxide and nitrogen oxide pursuant to a cap-and-trade program similar to the system now in effect for acid rain. In June 2011, the EPA finalized CSAPR, a replacement rule to CAIR, which requires 28 states in the Midwest and eastern seaboard of the U.S.to reduce power plant emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. Nitrogen oxide and sulfur dioxide emissions reductions were scheduled to commence in 2012, with further reductions effective in 2014. However, in August 2012, the U.S. Court of Appeals for the District of Columbia Circuit (the D.C. Circuit) vacated CSAPR and ordered the EPA to continue enforcing CAIR. In April 2014, the U.S. Supreme Court reversed the D.C. Circuit s decision vacating CSAPR. The EPA subsequently moved the Appeals Court for an order lifting the stay of CSAPR and extending the CSAPR compliance deadlines. In October 2014, the Court granted the EPA s request to lift the stay, and in November 2014, the EPA issued an interim final rule reconciling the CSAPR rule with the Court s order, which calls for Phase 1 implementation in 2015 and Phase 2 implementation in 2017. In September 2016, the EPA finalized an update to the CSAPR ozone season program by issuing the Final CSAPR Update. For states to meet their requirements under CSAPR, a number of coal-fired electric generating units will likely need to be retired, rather than retrofitted with the necessary emission control technologies, reducing demand for thermal coal.

- *NO_x State Implementation Plan Call.* The NO_x SIP Call program was established by the EPA in October 1998 to reduce the transport of nitrogen oxide and ozone on prevailing winds from the Midwest and South to states in the Northeast, which alleged that they could not meet federal air quality standards because of migrating pollution. The program is designed to reduce nitrogen oxide emissions by one million tons per year in 22 eastern states and the District of Columbia. As a result of the program, many power plants have been or will be required to install additional emission control measures, such as selective catalytic reduction devices. Installation of additional emission control measures will make it more costly to operate coal-fired power plants, potentially making coal a less attractive fuel.

- *Mercury and Hazardous Air Pollutants.* In February 2012, the EPA formally adopted a rule to regulate emissions of mercury and other metals, fine particulates, and acid gases such as hydrogen chloride from coal- and oil-fired power plants, referred to as MATS . In March 2013, the EPA finalized reconsideration of the MATS rule as it pertains to new power plants, principally adjusting emissions limits for new coal-fired units to levels considered attainable by existing control technologies. In subsequent litigation, the U.S. Court of Appeals for the D.C. Circuit upheld various portions of the rulemaking in two separate decisions issued in March and April 2014, respectively. In June 2015, the U.S. Supreme Court struck down the MATS rule based on the EPA s failure to take costs into consideration and remanded the case back to the D.C. Circuit. The D.C. Circuit has remanded the rule to the EPA, but allowed the current rule to stay in place until the EPA issues a new finding. In April 2016, the EPA issued a final finding that it is appropriate and necessary to set standards for emissions of air toxics from coal- and oil-fired power plants. In December 2018, the EPA issued a proposed revised Supplemental Cost Finding for the MATS rule proposing to determine that it is not appropriate and necessary to regulate Hazardous Air Pollutant (HAP) emissions from power plants under Section 112 of the Clean Air act. The EPA is not proposing, however, to rescind or repeal the HAP emission standards and other requirements of the MATS rule. Apart from MATS, several states have enacted or proposed regulations requiring reductions in mercury emissions from coal-fired power plants, and federal legislation to reduce mercury emissions from power plants has been proposed. Regulation of mercury emissions by the EPA, states, Congress, or pursuant to an international treaty may further decrease the demand for coal. Like CSAPR, MATS and other similar future regulations could accelerate the retirement of a significant number of coal-fired power plants, in addition to the significant number of plants and units that have already been retired as a result of environmental and regulatory requirements and uncertainties adversely impacting coal-fired generation. Such retirements would adversely impact our business.

- *Regional Haze, New Source Review and Methane.* The EPA has initiated a regional haze program to protect and improve visibility at and around national parks, national wilderness areas and international parks. In December 2011, the EPA issued a final rule under which the emission caps imposed under CSAPR for a given state would supplant the obligations of that state with regard to visibility protection. In May 2012, the EPA finalized a rule that allows the trading programs in CSAPR to serve as an alternative to determining source-by-source Best Available Retrofit Technology (BART). This rule provides that states in the CSAPR region can substitute participation in CSAPR for source-specific BART for sulfur dioxide and/or nitrogen oxides emissions from power plants. In January 2014, the EPC promulgated a final rule partially disapproving the Wyoming Regional Haze State Implementation Plan (SIP). The state of Wyoming and others challenged the final rule. After mediated discussions through the U.S. Court of Appeals for the Tenth Circuit s Mediation Office, Basin Electric, Wyoming and the EPA reached a settlement in 2017. In April 2018, the state of Wyoming submitted a SIP revision in accordance with the terms of the settlement. The EPA proposed to approve the revision in October 2018 and also proposed revisions to the state of Wyoming s Federal Implementation Plan (FIP) in accordance with the terms of the 2017 settlement.

- In addition, the EPA s new source review program under certain circumstances requires existing coal-fired power plants, when modifications to those plants significantly change emissions, to install the more stringent air emissions control equipment required of new plants. Litigation seeking to force the EPA to list coal mines as a category of air pollution sources that endanger public health or welfare under

Section 111 of the CAA and establish standards to reduce emissions from sources of methane and other emissions related to coal mines was dismissed by the D.C. Circuit in May 2014. In that case, the Court denied a rulemaking petition citing agency discretion and budgetary restrictions, and ruled the EPA has reasonable discretion to carry out its delegated responsibilities, which includes determining the timing and relative priority of its regulatory agenda. In July 2014, the D.C. Circuit denied a petition seeking a rehearing of the case *en banc*. Litigation around these issues may continue, and could result in the need for additional air pollution controls for coal-fired units and our operations.

Global Climate Change

Global climate change initiatives and public perceptions regarding fossil fuels have resulted, and are expected to continue to result, in decreased coal-fired power plant capacity and utilization, phasing out and closing many existing coal-fired power plants, reducing or eliminating construction of new coal-fired power plants in the United States and certain other countries, increased costs to mine coal and decreased demand and prices for thermal coal, including PRB coal.

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There are three important sources of GHGs associated with the coal industry. The end use of our coal in electricity generation is the largest of the three sources of GHGs. Combustion of fuel for mining equipment used in coal production is another source of GHGs. In addition, coal mining can release methane, a GHG, directly into the atmosphere. These emissions from coal consumption and production are subject to pending and proposed regulation as part of initiatives to address global climate change.

The Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change (the Kyoto Protocol) became effective in 2005, and bound those developed countries that ratified it (which the U.S. did not do) to reduce their global GHG emissions. Discussions to develop a treaty to replace the Kyoto Protocol after its expiration in 2012 are still ongoing. Most recently, the United Nations Framework Convention on Climate Change met in Paris, France in December 2015 and agreed to an international climate agreement. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions. The Paris climate agreement entered into force in November 2016. However, in August 2017, the U.S. State Department officially informed the United Nations of the intent of the U.S. to withdraw from the agreement, with the earliest possible effective date of withdrawal being November 4, 2020. Despite the planned withdrawal, certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. These commitments could further reduce demand and prices for our coal.

The EPA has adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including coal-fired electric power plants, and begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. These rules were legally challenged, but in June 2012, the D.C. Circuit denied these challenges. Among the rules promulgated after the EPA s endangerment finding was the Tailoring Rule, which requires that all new or modified stationary sources of GHGs that will emit more than 75,000 tons of carbon dioxide per year and are otherwise subject to CAA regulation, and any other facilities that will emit more than 100,000 tons of carbon dioxide per year, to undergo prevention of significant deterioration (PSD) permitting, which requires that the permitted entity adopt the best available control technology. As a result, the EPA is now requiring new sources, including coal-fired power plants, to undergo control technology reviews for GHGs (predominately carbon dioxide) as a condition of permit issuance. These reviews may impose limits on GHG emissions, or otherwise be used to compel consideration of alternative fuels and generation systems, as well as increase litigation risk for and so discourage development of coal-fired power plants.

Additionally, the U.S. Supreme Court, in a decision issued in June 2014, addressed whether the EPA s regulation of GHG emissions from new motor vehicles properly triggered GHG permitting requirements for stationary sources under the CAA. The decision reversed, in part, and affirmed, in part, a 2012 D.C. Circuit decision that upheld the EPA s GHG-related regulations. Specifically, the Court held that the EPA exceeded its statutory authority when it interpreted the CAA to require PSD and Title V permitting for stationary sources based on their potential GHG emissions. However, the Court also held that the EPA s determination that a source already subject to the PSD program due to its emission of conventional pollutants may be required to limit its GHG emissions by employing the best available control technology was permissible.

In August 2015, the EPA issued its final Clean Power Plan (CPP) rules that establish carbon pollution standards for power plants, called CO_2 emission performance rates. Judicial challenges led the U.S. Supreme Court to grant a stay in February 2016 of the implementation of the CPP before the United States Court of Appeals for the District of Columbia (Circuit Court) even issued a decision. By its terms, this stay will remain in effect throughout the pendency of the appeals process including at the Circuit Court and the Supreme Court through any certiorari petition that may be granted. The Supreme Court s stay applies only to EPA s regulations for CO_2 emissions from existing power plants and will not affect EPA s standards for new power plants. It is not yet clear how either the Circuit Court or the Supreme Court will rule on the legality of the CPP. Additionally, in October 2017 EPA proposed to repeal the CPP, although the final outcome of this action and the pending litigation regarding the CPP is uncertain at this time. In August 2018, EPA issued the proposed

Affordable Clean Energy (ACE) Rule, which would replace the CPP. If the ACE Rule is finalized, it will likely be subject to judicial challenge. If the effort to repeal or replace the CPP is unsuccessful and the rules were upheld at the conclusion of the appellate process and were implemented in their current form, or if the ACE Rule results in state plans to reduce the level of GHG emissions from electric utility generating units, demand for coal would likely be further decreased, potentially significantly, and our business would be adversely impacted.

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Various states and regions have adopted GHG initiatives and certain governmental bodies, including the State of California, have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities. A number of states have enacted legislative mandates requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power.

These and other current or future global climate change laws, regulations, court orders or other legally enforceable mechanisms, or related public perceptions regarding climate change, are expected to require additional controls on coal-fired power plants and industrial boilers and may cause some users of coal to further switch from coal to alternative sources of fuel, thereby depressing demand and pricing for coal.

Clean Water Act

The Clean Water Act (CWA) and corresponding state and local laws and regulations affect coal mining operations by restricting the discharge of pollutants, including dredged or fill materials, into waters of the U.S. The CWA provisions and associated state and federal regulations are complex and subject to amendments, legal challenges and changes in implementation. Congress has also considered legislation that seeks to clarify the scope of CWA jurisdiction. Recent court decisions, regulatory actions and proposed legislation have created uncertainty over CWA jurisdiction and permitting requirements.

CWA requirements that may directly or indirectly affect our operations include the following:

- *Wastewater Discharge.* Section 402 of the CWA creates a process for establishing effluent limitations for discharges to streams that are protective of water quality standards through the National Pollutant Discharge Elimination System (NPDES), and corresponding programs implemented by state regulatory agencies. Regular monitoring, reporting and compliance with performance standards are preconditions for the issuance and renewal of NPDES permits that govern discharges into waters of the U.S. Failure to comply with the CWA or NPDES permits can lead to the imposition of significant penalties, litigation, compliance costs and delays in coal production. Furthermore, the imposition of future restrictions on the discharge of certain pollutants into waters of the U.S. could increase the difficulty of obtaining and complying with NPDES permits, which could impose additional time and cost burdens on our operations. For instance, waters that states have designated as impaired (i.e., as not meeting present water quality standards) are subject to Total Maximum Daily Load regulations, which may lead to the adoption of more stringent discharge standards for our coal mines and could require more costly treatment.

Likewise, when water quality in a receiving stream is better than required, states are required to conduct an anti-degradation review before approving discharge permits. Anti-degradation policies may increase the cost, time and difficulty associated with obtaining and complying with NPDES permits and may require more costly treatment.

- *Dredge and Fill Permits.* Many mining activities, including the development of settling ponds and other impoundments, require a Section 404 permit from the Army Corps of Engineers (the Corps). Generally speaking, these Section 404 permits allow the placement of fill materials into navigable waters of the U.S. including wetlands, streams, and other regulated areas. The Corps has issued general nationwide permits for specific categories of activities that are similar in nature and that are determined to have minimal adverse effects on the environment. Permits issued pursuant to Nationwide Permit 21 (NWP 21) generally authorize the disposal of dredged or fill material from surface coal mining activities into waters of the U.S., subject to certain restrictions. NWP 21s are typically reissued for a five-year period and require appropriate mitigation, and permit holders must receive explicit authorization from the Corps before proceeding with proposed mining activities. The Corps reauthorized use of NWP 21 for surface coal mines in January 2017. The new NWP 21 closely mirrors the 2012 NWP 21, but removes a provision authorizing disposal of dredged or fill material from certain surface coal mining activities that were previously authorized by the 2007 NWP 21 and clarifies that any losses of stream bed are applied to the 1/2-acre limit for loss of jurisdictional wetlands and waters. Expansion of our mining operations into new areas may trigger the need for individual Corps approvals, which could be more costly and take more time to obtain.

- Considerable legal uncertainty exists surrounding the standard for what constitutes jurisdictional waters and wetlands subject to the protections and requirements of the Clean Water Act. A 2015 rulemaking by

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EPA to revise the standard was stayed nationwide by the U.S. Court of Appeals for the Sixth Circuit and stayed for certain primarily western states by a United States District Court in North Dakota. In January 2018, the Supreme Court determined that the circuit courts do not have jurisdiction to hear challenges to the 2015 rule, removing the basis for the Sixth Circuit to continue its nationwide stay. In February 2018, the EPA and the Corps published a final rule extending the applicability date of the 2015 rule such that the rule would not be applicable until February 2020. In August 2018, the U.S. District Court for the District of South Carolina invalidated the two-year nationwide delay of the rule, leaving the 2015 rule in effect in 26 states, while the pre-2015 regulations and guidance continue to apply in 24 states. In December 2018, the EPA and the Corps proposed a new definition of waters of the United States . Judicial challenges to the 2015 rulemaking are likely to continue to work their way through the courts along with challenges to the more recent rulemaking extending the applicability date of the 2015 rule. The agencies efforts to repeal the 2015 rule and to revise the definition of waters of the United States will also likely be subject to lengthy judicial challenges. For now, EPA and the Corps are complying with the South Carolina District Court s order in the 26 states in which it applies. Should the 2015 rule be enforced in the states in which we operate, or should a different rule expanding the definition of what constitutes a water of the United States be finalized as a result of EPA and the Corps s rulemaking process we, could face increased costs and delays due to additional permitting and regulatory requirements and possible challenges to permitting decisions.

- *Cooling Water Intake*. In May 2014, the EPA issued a new final rule pursuant to Section 316(b) of the CWA that affects the cooling water intake structures at power plants in order to reduce fish impingement and entrainment. The rule is expected to affect over 500 power plants. These requirements could increase our customers costs and may adversely affect the demand for coal, which may materially impact our results or operations.

Resource Conservation and Recovery Act

The EPA determined that coal combustion residues (CCR) do not warrant regulation as hazardous wastes under the Resource Conservation and Recovery Act (RCRA) in May 2000. Most state hazardous waste laws do not regulate CCR as hazardous wastes. The EPA also concluded that beneficial uses of CCR, other than for mine filling, pose no significant risk and no additional national regulations of such beneficial uses are needed. However, the EPA determined that national non-hazardous waste regulations under RCRA are warranted for certain wastes generated from coal combustion, such as coal ash, when the wastes are disposed of in surface impoundments or landfills or used as minefill. In December 2014, the EPA finalized regulations that address the management of coal ash as a non-hazardous solid waste under Subtitle D. The rules impose engineering, structural and siting standards on surface impoundments and landfills that hold coal combustion wastes and mandate regular inspections. The rule also requires fugitive dust controls and imposes various monitoring, cleanup, and closure requirements. There have also been several legislative proposals that would require the EPA to further regulate the storage of CCR. For example, in December 2016, Congress passed the Water Infrastructure Improvements for the Nation Act, which allows states to establish permit programs to regulate the disposal of CCR units in lieu of the EPA s CCR regulations. These requirements, as well as any future changes in the management of CCR, could increase our customers operating costs and potentially reduce their ability or need to purchase coal. In addition, contamination caused by the past disposal of CCR, including coal ash, can lead to material liability for our customers under RCRA or other federal or state laws and potentially further reduce the demand for coal.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and similar state laws affect coal mining operations by, among other things, imposing cleanup requirements for threatened or actual releases of hazardous substances into the environment. Under CERCLA and similar state laws, joint and several liability may be imposed on hazardous substance generators, site owners, transporters, lessees and others regardless of fault or the legality of the original disposal activity. Although the EPA currently excludes most wastes generated by coal mining and processing operations from the primary hazardous waste laws, such wastes can, in certain circumstances, constitute hazardous substances for the purposes of CERCLA. In addition, the disposal, release or spilling of some products used by coal companies in operations, such as chemicals, could trigger the liability provisions of CERCLA or similar state laws. Thus, we may be subject to liability under CERCLA and similar state laws for coal mines that we currently own, lease or operate or that we or our predecessors have previously owned, leased or operated, and sites to which we or our predecessors sent hazardous substances. We may be liable under CERCLA or similar state laws for the cleanup of hazardous substance contamination and natural resource damages at sites where we control surface rights. These liabilities could be significant and materially and adversely impact our financial results and liquidity.

Endangered Species Act

The federal Endangered Species Act (the ESA) and counterpart state legislation protect species threatened with possible extinction. The U.S. Fish and Wildlife Service (the USFWS) works closely with the OSM and state regulatory agencies to ensure that species subject to the ESA are protected from mining-related impacts. A number of species indigenous to the areas in which we operate are protected under the ESA. Other species in the vicinity of our operations, such as the mountain plover, which the USFWS determined not to list as threatened in May 2011, may have their listing status reviewed in the future.

Compliance with ESA requirements could have the effect of prohibiting or delaying us from obtaining mining permits. These requirements may also include restrictions on timber harvesting, road building and other mining or agricultural activities in areas containing the affected species or their habitats. For example, our Spring Creek Mine applied for a lease modification under the BLM leasing regulations and a mine permit amendment to add lands to the permit area. Portions of these lands have been designated as core habitat for the greater sage grouse by the Montana Fish, Wildlife and Parks Department. While the USFWS has determined that the greater sage grouse should not be listed as a threatened or endangered species, the BLM has developed Conservation Plans designed to preserve and protect greater sage-grouse habitat. Montana has also developed sage grouse conservation plans through the Montana Governor s executive order. Our approvals to mine or otherwise affect these areas will be subject to review by the BLM and the Montana Department of Environmental Quality and determinations of our ability to adequately mitigate impacts to sage grouse and sage grouse habitat. The plans do however, recognize the right to mine where there are valid existing rights. The BLM has stated that conserving sagebrush habitat will be an important consideration in the BLM review of proposed coal mines or coal mine expansions. The plans also recommended that the Secretary of the Interior withdraw 10 million acres from hardrock mining for up to 20 years; however in 2017 the BLM canceled its Sagebrush Focal Area withdrawal application and the Department of the Interior s proposed withdrawal of 10 million acres of federal lands from location and entry under the mining law in the Greater Sage-grouse habitat. The BLM also terminated the associated environmental analysis process. Our mines are not located within the areas that the BLM had designated for withdrawing from hardrock mining.

Future actions could result in more stringent requirements being issued by the BLM and other agencies involved in the leasing and permitting process. The USFWS must review its 2015 decision to not list the sage grouse again in 2020. Should more stringent protective measures be applied or if the greater sage-grouse is listed as a threatened species by the USFWS, this could significantly impair our ability to conduct our mining operations or result in increased operating costs, heightened difficulty in obtaining future mining permits, or the need to implement additional mitigation measures.

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. In addition, the storage of explosives is subject to regulatory requirements. For example, pursuant to a rule issued by the Department of Homeland Security in 2007, facilities in possession of chemicals of interest (including ammonium nitrate at certain threshold levels) are required to complete a screening review. Our mines are low risk, Tier 4 facilities that are not subject to additional security plans. In 2008, the Department of Homeland Security proposed regulation of ammonium nitrate under the ammonium nitrate security rule. Many of the requirements of the rule would be duplicative of those in place under the Bureau of Alcohol Tobacco and Firearms, including registration and background checks. Additional requirements may include tracking and verifications for each transaction related to ammonium nitrate. A final rule has yet to be issued. In December 2014, the OSM announced its decision to pursue a rulemaking to revise regulations under SMCRA, which will address all blast generated fumes and toxic gases. OSM has not yet issued a proposed rule to address these blasts, and it is unclear if or when a proposed rule will be issued. The outcome of these rulemakings could materially adversely impact our cost or ability to conduct our mining operations.

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National Environmental Policy Act

NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment, such as issuing a permit or other approval. In the course of such evaluations, an agency will typically prepare an environmental assessment to assess the potential direct, indirect and cumulative impacts of a proposed project. Where the activities in question have significant impacts to the environment, the agency must prepare an EIS. Compliance with NEPA can be time-consuming and may result in the imposition of mitigation measures that could affect our mining costs and the amount of coal that we are able to produce from mines on federal lands, and may require public comment. Whether agencies have complied with NEPA is subject to protest, appeal or litigation, which can delay or halt projects. The NEPA review process, including potential disputes regarding the level of evaluation required for climate change impacts, may extend the time and/or increase the costs and difficulty for obtaining necessary governmental approvals, and may lead to litigation regarding the adequacy of the NEPA analysis, which could delay or potentially preclude the issuance of approvals or grant of leases.

Other Environmental Laws

We are required to comply with numerous other federal, state and local environmental laws and regulations in addition to those previously discussed. These additional laws include, for example, the Safe Drinking Water Act, and the Toxic Substances Control Act and transportation laws adopted to ensure the appropriate transportation of our coal both nationally and internationally. Laws, regulations, and treaties of other countries may also adversely impact our export sales by reducing demand for PRB coal, or coal in general, as a source of power generation in those countries.

Federal Power Act Grid Reliability Proposal

Pursuant to a directive from the Secretary of the Department of Energy, in 2017, the Federal Energy Regulatory Commission (FERC) issued a notice of proposed rulemaking under the Federal Power Act regarding the valuation by regional electric grid system operators of the reliability and resilience attributes of electricity generation. The rulemaking would have required the FERC to impose market rules that would allow certain cost recovery by electricity-generating units that maintain a 90-day fuel supply on-site and that are therefore capable of providing electricity during supply disruptions from emergencies, extreme weather or natural or man-made disasters. Many coal-fired electricity generating plants could have qualified under this criteria and the cost recovery could have helped improve the economics of their operations. However, in January 2018, the FERC terminated the proposed rulemaking, finding that it failed to satisfy the legal requirements of section 206 of the Federal Power Act, and initiated a new proceeding to further evaluate whether additional FERC action regarding resilience is appropriate. Should a version of this rule be adopted along the lines originally proposed, it could provide economic incentives for companies that produce electricity from coal, among other fuels, which could either slow or stabilize the trend in retiring coal-fired power plants and could thereby maintain certain levels of domestic demand for coal. We cannot speculate on the timing or nature of any subsequent FERC or grid operator actions resulting from FERC s decision to further study the issue of grid resiliency.

Available Information

We file annual, quarterly and current reports, and amendments to those reports, proxy statements and other information with the SEC. You may access and read our filings without charge through the SEC s website at www.sec.gov.

We also make the documents listed above available without charge through our website, www.cloudpeakenergy.com, as soon as practicable after we file or furnish them with the SEC. You may also request copies of the documents, at no cost, by telephone at (720) 566-2900 or by mail at Cloud Peak Energy Inc., 385 Interlocken Crescent, Suite 400, Broomfield, Colorado, 80021, Attention: Investor Relations. In addition to reports we file or furnish with the SEC, we publicly disclose material information from time to time in our press releases, at annual meetings of stockholders, in publicly accessible conferences and investor presentations, and through our website. The information on our website is not part of this Form 10-K.

Item 1A. ***Risk Factors.***

You should carefully consider the risk factors described below and other information contained in this Form 10-K. If any of the following risk factors, as well as other risks and uncertainties that are not currently known to us or that we currently believe are not material, actually occur, our business, financial condition and results of operations could be materially adversely affected and you may lose all or a significant part of your investment.

Risks Related to Our Indebtedness and Liquidity

We need to restructure our balance sheet in order to improve our capital structure, adjust our business to ongoing depressed PRB thermal coal industry conditions, address our significantly reduced liquidity and continue as a going concern. Our potential restructuring alternatives include asset sales, a private debt restructuring or a court-supervised restructuring proceeding under Chapter 11 of the U.S. Bankruptcy Code. Alternatively, an involuntary petition for bankruptcy may be filed against us. Any of these restructuring alternatives could have a material adverse impact on our business, financial condition, results of operations, and cash flows and could place our stockholders at significant risk of losing all of their investment in our shares.

As disclosed on our Current Report on Form 8-K on January 29, 2019, we issued a press release providing an update to the previously-announced review of strategic alternatives, announcing the retention of Centerview Partners LLC as our investment banker, Vinson & Elkins LLP as our legal advisor, and FTI Consulting, Inc. as our financial advisor to assist us in our review of capital structure and restructuring alternatives.

Our restructuring evaluation process is continuing. We are actively engaged in discussions with certain of our creditor groups financial and legal advisors regarding potential alternatives, including asset sales, a private debt restructuring or a court-supervised reorganization under Chapter 11 of the U.S. Bankruptcy Code and related financing needs. Although this process remains uncertain and fluid, we will need to restructure our balance sheet in order to improve our capital structure, adjust our business to ongoing depressed PRB thermal coal industry conditions, address our significantly reduced liquidity, and continue as a going concern.

An interest payment on our 2024 Notes will need to be made by April 14, 2019, to avoid a default under the indenture governing the 2024 Notes. An Event of Default under the 2024 Notes for failure to pay interest would not result in a default under the 2021 Notes unless the 2024 Notes are accelerated. An Event of Default under the 2024 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance. We continue to evaluate alternatives associated with this interest payment. If we determine not to make this interest payment by April 14, 2019, we may seek protection under Chapter 11.

A bankruptcy proceeding could have a material adverse effect on our business, financial condition, results of operations and liquidity. It is impossible for us to predict with certainty the amount of time needed to complete a Chapter 11 proceeding. For as long as a Chapter 11 proceeding were to continue, our senior management would be required to spend a significant amount of time and effort dealing with the reorganization as well as focusing on our business operations. A lengthy Chapter 11 proceeding would involve significant additional professional fees and expenses, and create significant liquidity needs for our business. A bankruptcy proceeding also could make it more difficult to retain management and other key personnel necessary to the success of our business. In addition, while we are in a bankruptcy proceeding, our customers and suppliers may lose confidence in our ability to reorganize our business successfully and could seek to establish other commercial relationships, particularly if the process is prolonged. Any bankruptcy proceeding or restructuring may cause, among other things:

- third parties to lose confidence in our ability to deliver coal on time and at specification, resulting in a significant decline in our revenues, profitability and cash flow;

- difficulty retaining, attracting or replacing key employees;

- employees to be distracted from performance of their duties or more easily attracted to other career opportunities; and

- our third-party surety bond providers, suppliers, vendors, hedge counterparties and service providers to renegotiate the terms of our agreements, terminate their relationship with us or require financial assurances from us.

Additionally, all of our indebtedness is senior to the existing common stock in our capital structure. As a result, if we seek relief under Chapter 11, we believe that our shares of existing common stock would likely be canceled, with a very limited recovery or no recovery for holders of our common stock. And, if we execute a

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restructuring outside of Chapter 11, we believe that such transaction could result in substantial dilution of our shares of existing common stock.

Our substantial indebtedness could adversely affect our results of operations and financial condition and prevent us from fulfilling our financial obligations.

As of December 31, 2018, we had consolidated indebtedness of $349.3 million. We also have lease and royalty obligations related to our federal coal leases. Our outstanding indebtedness could have important consequences such as:

- limiting our ability to obtain additional financing to fund growth, such as mergers and acquisitions; working capital; capital expenditures; debt service requirements; future LBAs; or other cash requirements;

- requiring much of our cash flow to be dedicated to interest obligations and making it unavailable for other purposes;

- with respect to any indebtedness under any future credit agreement or other variable rate debt, exposing us to the risk of increased interest costs if the underlying interest rates rise on our variable rate debt;

- limiting our ability to invest operating cash flow in our business (including to obtain new LBAs or make capital expenditures) due to debt service requirements;

- causing us to need to sell assets and properties at an inopportune time;

- limiting our ability to compete effectively with companies that are not as leveraged and that may be better positioned to withstand economic downturns, including competitors who have become less leveraged when they emerged from bankruptcy;

- limiting our ability to acquire new coal reserves and/or LBAs and plant and equipment needed to conduct operations;

- limiting our flexibility in planning for, or reacting to, and increasing our vulnerability to, changes in our business, the industry in which we operate and general economic and market conditions; and

- resulting in a further downgrade in the credit rating of our indebtedness, which could increase the cost of future borrowings and negatively impact our available liquidity.

We may incur substantially more debt in the future. If our indebtedness is further increased, the related risks that we now face, including those described above, could increase. In addition to the principal repayments on outstanding debt, we have other demands on our cash resources, including significant maintenance and other capital expenditures, including LBAs, and operating expenses. Our ability to pay our debt depends upon our operating performance. In particular, economic conditions could cause revenue to decline, and hamper our ability to repay indebtedness. If we do not have enough cash to satisfy our debt service obligations, we may be required to refinance all or part of our debt, restructure our debt, seek protection under Chapter 11, sell assets, limit certain capital expenditures, including future LBAs, or reduce spending or we may be required to issue equity. We may not be able to, at any given time, refinance our debt or sell assets and we may not be able to, at any given time, issue equity, in either case on acceptable terms or at all.

If we are unable to comply with the covenants or restrictions contained in our debt instruments, the lenders could declare all amounts outstanding under those instruments to be due and payable and foreclose on their collateral, which could materially adversely affect our financial condition and operations.

Our debt instruments include covenants that, among other things, restrict our ability to dispose of assets, incur additional indebtedness, pay dividends or make other restricted payments, create liens on assets, make investments, loans or advances, make acquisitions, engage in mergers or consolidations and engage in certain transactions with affiliates. These restrictions could limit our ability to plan for or react to market conditions or meet extraordinary capital needs or otherwise restrict corporate activities.

A failure to comply with any of these restrictions or covenants could have serious consequences to our financial condition or result in a default under those debt instruments and under other agreements containing cross-default provisions. A default would permit lenders to accelerate the maturity of the debt under these debt instruments and to foreclose upon collateral securing the debt. Furthermore, an event of default or an acceleration under one of our debt instruments could also cause a cross-default or cross-acceleration of another debt instrument or contractual obligation, which would adversely impact our liquidity. Under these circumstances, we might not have sufficient funds or other resources to satisfy all of our obligations. We may not be granted waivers or amendments to these debt instruments if for any reason we are unable to comply with these debt instruments, and we may not be able to refinance our debt on terms acceptable to us, or at all.

Additionally, CPE Resources has an interest payment obligation under the 2024 Notes of approximately $1.8 million, which is due on March 15, 2019. The indenture governing the 2024 Notes provides a 30-day grace period that extends the latest date for making this interest payment to April 14, 2019, before an Event of Default occurs under the indenture. We elected not to make this interest payment on the due date and plan to utilize the 30-day grace period provided by the indenture, to allow additional time to assess our restructuring alternatives. If we do not make this interest payment by April 14, 2019, an Event of Default would occur under the indenture governing the 2024 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2024 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2024 Notes. An Event of Default under the 2024 Notes for failure to pay interest would not result in a default under the 2021 Notes unless the 2024 Notes are accelerated. An Event of Default under the 2024 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance. We continue to evaluate alternatives associated with this interest payment.

CPE Resources has an interest payment obligation under the 2021 Notes of approximately $17.4 million, which is due on May 1, 2019. The indenture governing the 2021 Notes provides a 30-day grace period that extends the latest date for making this interest payment to May 31, 2019, before an Event of Default occurs under the indenture. If we do not make this interest payment by May 31, 2019, an Event of Default would occur under the indenture governing the 2021 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2021 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2021 Notes. An Event of Default under the 2021 Notes for failure to pay interest would not result in a default under the 2024 Notes unless the 2021 Notes are accelerated. An Event of Default under the 2021 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance.

Provisions in our debt instruments could discourage an acquisition of us by a third party.

Upon the occurrence of certain transactions constituting a change of control as defined in the indentures, holders of the senior notes have the right to require us to repurchase all outstanding notes at 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase. This provision could make it more difficult or more expensive for a third party to acquire us.

As a result of ongoing depressed PRB thermal coal industry conditions and previous coal producer bankruptcy filings, the coal industry has experienced increased credit pressures that could result in additional demands for credit support by third parties or decisions by banks, surety bond providers, investors or other companies to reduce or eliminate their exposure to the coal industry, including our company. These credit pressures could materially and adversely impact our liquidity and ability to meet our regulatory requirements.

Ongoing depressed PRB thermal coal industry conditions and previous coal producer bankruptcy filings have resulted in, and could result further in, increased credit pressures on the coal industry. These credit pressures, which have had a material impact on our business, include, for example, (a) vendors, suppliers, customers and other commercial counterparties seeking prepayments, security deposits, letters of credit and other credit protections, and (b) banks, surety bond providers, investors and other companies reducing or eliminating their exposure to the coal industry. Although some of these credit pressures may be company-specific, many are directed to the coal industry in general due to the current overall negative investor sentiment toward the industry. Any credit demands by third parties or refusals by banks, surety bond providers, investors or others to extend, renew or refinance credit on commercially reasonable terms may adversely impact our business, financial condition, results of operations, cash flows and liquidity. In some cases, such as any collateral requirements imposed by surety bond providers to issue surety bonds that secure our future performance under various federal and state laws, our ability to meet regulatory requirements may also be adversely impacted if we are not able to satisfy cash or other collateral requirements. As of December 31, 2018, we had $407.6 million of reclamation and lease bonds backed by collateral of $25.7 million in the form of letters of credit under our A/R Securitization Program used for mining, securing coal lease obligations, and for other operating requirements. Subsequent to December 31, 2018, we received letters from certain of our third-party surety bond underwriters demanding increased collateral or replacement of their bonds. Any further issuances of letters of credit to satisfy the increased collateral demands or any replacement bonds would immediately reduce the cash and cash equivalents available to support the operations of the business, as the current level of letters of credit exceeds the borrowing credit limit of our A/R Securitization Program. We are currently in discussions with our surety bond underwriters, however we cannot assure you these negotiations will be successful in avoiding increased collateral requirements. These surety bonds are required by the permits governing our mining operations.

Failure to maintain our surety bonds on acceptable terms could affect our ability to secure reclamation and coal lease obligations and materially adversely affect our ability to mine or lease coal.

Federal and state laws require us to secure the performance of certain long-term obligations, such as mine closure costs, reclamation costs, and federal and state workers compensation costs, including black lung. The primary methods we use to meet those obligations are to provide a third-party surety bond or a letter of credit. Recently, there has been heightened regulatory pressure on reclamation bonding and self-bonding in particular. Our failure to retain, or inability to acquire, surety bonds or letters of credit or to provide a suitable alternative could adversely affect our ability to mine or lease coal, which would materially adversely affect our business and results of operations. That failure could result from a variety of factors, including lack of availability, higher expense or unfavorable market terms, the exercise by third-party surety bond issuers of their right to refuse to renew the surety bonds and restrictions on availability of collateral for current and future third-party surety bond issuers under the terms of any credit arrangements then in place.

Furthermore, while we have maintained a history of timely payments related to our LBAs, if we are unable to maintain our good payer status, we would be required to seek bonding for any remaining payments, which could adversely impact our cash flows, if such bonds could be obtained at all.

In addition, if federal or state laws are amended to require certain forms of financial assurance other than surety bonds, such as letters of credit, obtaining them, if we could obtain them at all, could have a material negative impact on our liquidity and results of operations.

Our existing operations and future development plans require substantial capital expenditures, which we may be unable to provide.

Our existing operations and future plans are dependent upon our acquisitions of additional reserves, which require substantial capital expenditures. We also require capital for, among other purposes:

- acquisition of surface rights;

- equipment and the development of our mining operations;
- capital renovations;
- export terminal development projects;
- maintenance and expansions of plants and equipment; and
- compliance with environmental laws and regulations.

To the extent that cash on hand and cash generated internally are not sufficient to fund capital requirements, we will require additional debt and/or equity financing. However, additional debt or equity financing may not be available to us or, if available, may not be available on satisfactory terms. Additionally, our debt instruments may restrict our ability to obtain such financing. If we are unable to obtain additional capital, we may not be able to maintain or increase our existing production rates and we could be forced to reduce or delay capital expenditures or change our business strategy, sell assets or restructure or refinance our indebtedness, all of which could have a material adverse effect on our business or financial condition.

Risks Related to Our Business and Industry

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

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate issues, are resulting in increased regulation of coal combustion in many jurisdictions, unfavorable lending policies by government-backed lending institutions and development banks toward the financing of new overseas coal-fueled power plants and divestment efforts affecting the investment community, which could significantly affect demand for our products or our securities. Global climate issues continue to attract public and scientific attention. Numerous reports, such as the Fourth and Fifth Assessment Report of the Intergovernmental Panel on Climate Change and the Fourth National Climate Assessment have also engendered concern about the impacts of human activity, especially fossil fuel combustion, on global climate issues. In turn, increasing government attention is being paid to global climate issues and to emissions of GHGs, including emissions of carbon dioxide from coal combustion by power plants. The 2015 Paris climate summit agreement resulted in voluntary commitments by numerous countries to reduce their GHG emissions, and could result in additional firm commitments by various nations with respect to future GHG emissions. These commitments could further disfavor coal-fired generation, particularly in the medium- to long-term.

Enactment of laws or passage of regulations regarding emissions from the combustion of coal by the United States, some of its states or other countries, or other actions to limit such emissions, could also result in electricity generators further switching from coal to other fuel sources or additional coal-fueled power plant closures. Further, policies limiting available financing for the development of new coal-fueled power plants could adversely impact the global demand for coal in the future.

There have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, promoting the divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. In California, for example, legislation was signed into law in October 2015 that required California s state pension funds to divest investments in companies that generate 50% or more of their revenue from coal mining by July 2017. More recently, in December 2017, the Governor of New York announced that the New York Common Fund will immediately cease all new investments in entities with significant fossil fuel activities, and the World Bank announced that it will no longer finance upstream oil and gas after 2019, except in exceptional circumstances. Other activist campaigns have urged banks to cease financing coal-driven businesses. As a result, numerous major banks have enacted such policies. The impact of such efforts may adversely affect the demand for and price of securities issued by us, and impact our access to the capital and financial markets.

Additional regulatory developments have been oriented at increasing the regulatory burden associated with mining coal and coal-fired generation. Regulatory initiatives proposed, adopted, or enacted in the United States by previous administrations include: the MATS rule, the national emission standards for hazardous air pollutants boiler rules, the new source performance standards for fossil-fuel fired power plants, revisions to the nitrogen oxide and sulfur dioxide NAAQS, the CAIR rule, the Clean Power Plan, the regional haze program, regulation of CCR, revisions to the Corps Section 404 permitting regime, and OSM s stream protection rule. See Item 1 Business Environmental and Other Regulatory Matters. Although the current administration is seeking to unwind many of these initiatives including through a series of executive orders and new regulations, any such actions are subject to judicial review in which the current administration may not prevail, and a future administration may adopt a different approach and pursue further rulemakings to undo or revise any such regulations. These and other governmental actions that directly or indirectly affect the coal mining industry and coal-fired power generation have made, and will continue to make, it more difficult and costly to mine and ship coal, and operate coal-fired assets. Meanwhile, substantial government subsidies are available to fund various aspects of renewable power generation and supply, which may hurt our ability to compete against these alternative forms of electric generation.

In addition, several well-funded, non-governmental organizations have explicitly undertaken campaigns to minimize or eliminate the use of coal as a source of electricity generation. For example, the goals of Sierra Club s Beyond Coal campaign include retiring one-third of the nation s coal-fired power plants by 2020, replacing retired coal plants with clean energy solutions, and keeping coal in the ground. It has been reported that the Beyond Coal campaign has been funded by several high-profile, high-net-worth individuals and organizations, including approximately $80 million from Michael Bloomberg and his philanthropic foundation, Bloomberg Philanthropies. In an effort to stop or delay coal mining activities, the Sierra Club and other activist groups have brought, and continue to bring, numerous lawsuits, including against the BLM to challenge not only the issuance of individual coal leases, but also the federal coal leasing program more broadly. Other lawsuits continue to be brought challenging 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 net effect of these and other similar developments is to make it more costly and difficult to maintain our business and to continue to depress demand and pricing for our coal. A substantial or extended decline in the prices we receive for our coal due to these or other factors could further reduce our revenue and profitability, cash flows, liquidity, and value of our coal reserves and result in losses. These conditions, among other factors, could lead us to seek relief under Chapter 11.

Changes in U.S. trade policies and any resulting trade wars could materially and adversely impact our logistics business, including by negatively affecting our logistics supply chain or international demand and pricing for U.S. thermal coal.

The current Administration has made public statements indicating possible significant changes in U.S. trade policy and has taken certain actions that have adversely impacted U.S. trade and relationships with trading partners, including imposing tariffs on certain goods imported into the United States. Any changes in U.S. trade policy could trigger, and certain actions already taken have triggered, additional retaliatory actions by affected countries, resulting in trade wars. Trade wars may lead to reduced economic activity, increased costs, reduced demand and changes in purchasing behaviors for affected goods, limits on trade with the United States or other potentially adverse economic outcomes. These or other consequences from any trade wars could adversely impact our export volumes, prices and financial results if, for example, demand or pricing for seaborne thermal coal from the U.S. decreases or there are retaliatory measures, including tariffs, that negatively affect our logistics supply chain and our ability or cost to transport our coal by rail to the Westshore export terminal in British Columbia, Canada and from there to export customers. Any negative impacts to our logistics revenues, costs or supply chain could have a material adverse impact on our logistics results and on our consolidated results.

Coal prices are subject to change based on a number of factors and thermal coal prices are currently depressed. If thermal coal prices remain depressed, or if there is a substantial or extended decline in prices, it could materially reduce our revenue and profitability, cash flows, liquidity, and value of our coal reserves and result in losses.

Our revenue, results of operations, and the value of our coal reserves depend on the prices we receive for our coal and logistics services. Over the last several years, prices for thermal coal have become more volatile and depressed due to an oversupply of coal and significantly reduced demand in the U.S. and various other countries. During the fourth quarter of 2018, the Kalimantan 5000 price index decreased approximately 14%, which materially and negatively impacted our economic position. The prices we receive for our coal and logistics services depend upon factors beyond our control, including:

- domestic and foreign supply and demand for coal, including Asian and other foreign demand for PRB coal exports, and the impact of domestic and foreign government environmental, energy and tax policies and currency exchange rate fluctuations;

- domestic and foreign demand for electricity and steel;

- domestic and foreign economic conditions;

- the quantity, quality, and price of coal available from domestic and foreign competitors, including coal re-sellers and traders;

- competition for production of electricity from non-coal sources, including the price and availability of alternative fuels, such as natural gas and crude oil, and alternative energy sources, such as nuclear, hydroelectric, wind and solar power, and the effects of technological developments related to these non-coal and alternative energy sources;

- adverse weather, climatic or other natural conditions, including natural disasters;

- legislative, regulatory and judicial developments, environmental regulatory changes, or changes in energy and tax policy and energy conservation measures that would adversely affect the coal or utility industries, such as legislation or regulation that limits carbon dioxide or sulfur dioxide emissions or provides for increased funding, subsidies or other incentives for, or mandates the use of, alternative energy sources to address climate change;

- shareholder activism or activities by non-governmental organizations to restrict the use of coal;

- domestic and foreign governmental regulations and taxes, including with respect to air emission standards for coal-fired power plants, and the ability of coal-fired power plants to economically meet these standards;

- changes in coal-fired power plant capacity and utilization, including the extent to which new coal plants are built in the United States and other countries;

- market price fluctuations for sulfur dioxide emission allowances;

- the capacity of, cost of, and proximity to, rail transportation and terminal facilities and rail and terminal performance; and

- the other risks described in this Item 1A.

If thermal coal prices remain depressed, or if there is a substantial or extended decline in the prices we receive for our coal and logistics services due to these or other factors, it could materially reduce our revenue and profitability, cash flows, liquidity, and value of our coal reserves and result in losses.

Competition with domestic and foreign coal producers, with traders and re-sellers of coal and with producers of natural gas and other competing energy sources may continue to negatively affect our sales volumes and our ability to sell coal at a favorable price.

The coal industry is highly competitive. We compete with other domestic and many foreign coal producers, with traders and re-sellers of coal and with other energy producers throughout the U.S. and, for our export sales, internationally. In addition to the price of coal, coal quality, and transportation costs, demand for coal also has a significant impact on our ability to compete domestically and internationally for coal sales. Demand for coal depends upon a number of factors, including:

- general economic conditions and weather patterns, both of which are significant contributors to the demand for electricity;

- delivered prices for coal, including the relative costs of transportation, such as ocean freight rates, from our mine site and competing mines or supplies of coal;

- availability and cost of alternative fuel sources, such as natural gas;

- technological developments;

- environmental, tax, and other governmental policies and regulations, including EPA regulations; and

- currency exchange rate fluctuations impacting our export sales.

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Demand for U.S. coal has fluctuated over the last decade because of these and other factors and, in recent years, has declined substantially due to global climate change initiatives and other regulatory initiatives that favor natural gas or non-fossil fuel sources of electricity generation, sustained low natural gas prices in the United States, weak global economic conditions and other factors, including those described in this Item 1A. A decline in domestic demand for coal, or a decline in foreign demand for U.S. coal, has caused, and could continue to cause, additional significant competition among coal producers and downward pressure on coal prices. Furthermore, overcapacity and increased production in the future, similar to the activities that occurred during the mid-1970s and early 1980s, could result in additional production capacity throughout the industry, causing increased competition and lower coal prices, materially reducing our revenue, profitability, cash flows, and liquidity.

In addition to competing with other coal producers, we compete generally with producers of other fuels, such as natural gas. A decline in the price of natural gas has made natural gas more competitive against coal and resulted in utilities switching from coal to natural gas. Sustained low natural gas prices may also cause utilities to continue to phase out or close existing coal-fired power plants or reduce or eliminate construction of any new coal-fired power plants, which could have a material adverse effect on demand and prices received for our coal.

Government action requiring the use and dispatch of alternative energy sources and fuels or providing financing or incentives to encourage continuing technological advances and deployment in this area could further enable alternative energy sources to become more competitive with coal. If alternative energy sources, such as hydroelectric, wind or solar, continue to become more cost-competitive, demand for coal could decrease and cause a decrease in the price of coal.

If we do not grow our longer term logistics revenue and export sales at favorable prices, we may incur losses in our logistics business and be subject to significant take-or-pay commitments.

Our ability to grow our export sales revenue and logistics margins depends on a number of factors, including the price we receive for our coal and our logistics services, the existence of sufficient and cost-effective export terminal capacity for the shipment of thermal coal to foreign customers, and demand by customers in Asia and in other potential export destinations for PRB coal.

International customer demand for PRB coal, and the prices those customers may be willing to pay for PRB coal and related transportation services provided by our logistics business, can be affected by a variety of factors, including supplier diversity and security considerations, economic conditions and demand for electricity in the relevant locations, international energy and tax policies and regulatory requirements, and availability and pricing for thermal coal delivered from alternative international coal basins. Further, our export sales are priced relative to various international coal indices adjusted for energy content and other quality and delivery criteria. These indices are volatile and heavily influenced by Chinese and Indian thermal coal import demand. For example, over the last five years, Newcastle prices have varied from a high of $122.57 per tonne to a low of $47.37 per tonne. Similarly, Kalimantan 5000 prices have varied from a high of $77.00 per tonne to a low of $36.80 per tonne. Fluctuations in these indices may be affected by a wide range of international supply and demand factors, including those listed above. Our export sales may also be negatively impacted by currency exchange rate fluctuations that make coal from other countries more economical than PRB coal and provide competitive advantages to non-U.S. producers when the U.S. dollar is strong in comparison to those foreign currencies. For example, the Newcastle and Kalimantan 5000 benchmark price indices are denominated in U.S. dollars. If demand for exports declines or we are unable to secure a favorable price for the export of our coal and logistics services, our cash flows, profitability, liquidity, and results of operations may be materially adversely affected.

At present, there is limited terminal capacity for the export of PRB coal to foreign destinations. Our access to existing and any future terminal capacity, including the proposed MBT in which we have an option for potential future capacity, may be adversely affected by regulatory and permit requirements, environmental and other legal challenges, public perceptions and resulting political pressures, operational issues at terminals and competition among North American coal producers for access to limited terminal capacity, among other factors. If we fail to maintain terminal capacity, or are denied access to existing or any future terminals for the export of our coal on commercially reasonable terms, or at all, our results from our future export transactions will be materially adversely affected.

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In addition, we have significant multi-year take-or-pay contracts for rail and terminal capacity related to our logistics services for export sales. These contracts require us to pay for a minimum quantity of coal to be transported on the railway or through the terminal regardless of whether we sell any coal or the prices we receive for our coal or logistics services. If we fail to make sufficient export sales to meet our minimum obligations under these take-or-pay contracts, we are still obligated to make payments to the railway or terminal, which could have a negative impact on our cash flows, profitability and results of operations. As of December 31, 2018, we had take-or-pay commitments of $80.8 million that could be potentially payable if we fail to meet our minimum shipment obligations. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Obligations.

The regulatory environment may also adversely impact our logistics business and future export sales. For example, the ONRR previously finalized changes to how coal royalties are calculated for sales to affiliated entities, which could have adversely impacted export sales for vertically integrated mining and logistics entities, such as our logistics business, and placed vertically integrated entities at a competitive disadvantage compared to independent coal brokers. Moreover, the ONRR proposal included a so-called default provision , which would have created further uncertainty as to how the ONRR would apply its proposed royalty rules to our export sales. We, along with other energy industry companies and trade associations, filed litigation to challenge this ONRR rule. The current administration delayed the effective date of the rule in February 2017 before ultimately rescinding the rule in August 2017. The states of California and New Mexico have filed a legal challenge to the rescission of the ONRR rule in a federal district court in California and are seeking the reinstatement of the rule formerly adopted by the Obama administration. Should the plaintiffs prevail in this litigation and obtain an order vacating the rescission of the ONRR rule, or should a similar rule be promulgated by this or a future administration, our business and revenues may be adversely affected.

Our long-term growth may be materially adversely impacted if economic, commercially available carbon capture technology for power plants is not developed and adopted in a timely manner.

Federal or state laws or regulations may be adopted that would impose new or additional limits on the emissions of GHGs, including, but not limited to, CO_2 from electric generating units using fossil fuels such as coal or natural gas. In order to comply with such regulations, electric generating units using fossil fuels may be required to implement carbon capture technology. For example, in October 2015, the EPA released a rule that establishes, for the first time, new source performance standards under the federal Clean Air Act for CO_2 emissions from new fossil fuel-fired electric utility generating power plants. Under the final rule, the EPA designated partial carbon capture and sequestration (CCS) as the best system of emission reduction (BSER) for newly constructed fossil fuel-fired steam generating units at power plants to employ to meet the standard. However, in December 2018, EPA proposed amendments to the October 2015 rulemaking that would revise the 2015 standards and vacate the previous determination that the BSER for this source category is CCS due primarily to concerns about the high costs and limited geographic availability of CCS. Instead, EPA proposed to find that the BSER is the most efficient demonstrated steam cycle (*i.e.*, supercritical steam conditions for large EGUs and best available subcritical steam conditions for small EGUs) in combination with the best operating practices. Future implementation of the revised standards and BSER determination are uncertain at this time. If finalized, the revised standards and BSER determination will likely be subject to legal challenge. If the 2015 standards and BSER determination remain in place, there is a risk that CCS technology, which may include storage, conversion, or other commercial use for captured carbon, may not be commercially practical in limiting emissions as otherwise required by the October 2015 rule or similar rules that may be proposed in the future. If such legislative or regulatory programs are adopted, and economic, commercially available carbon capture technology for power plants is not developed or adopted in a timely manner, it would negatively affect our customers and would further reduce the demand for coal as a fuel source, causing coal prices and sales of our coal to decline, perhaps materially.

Our business, financial condition and results of operations may be adversely affected by unfavorable global or U.S. economic and market conditions.

The global economic downturn in 2008, particularly with respect to the U.S. economy and various European and Asian economies, and global financial and credit market disruptions had a negative impact on us and the coal industry generally. For example, the economic downturn negatively impacted electricity demand and led to an oversupply of thermal coal and depressed prices.

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Furthermore, because we typically seek to enter into long-term arrangements for the sale of a substantial portion of our coal, the average sales price we receive for our coal may lag behind any general economic recovery. Future economic downturns or further disruptions in the financial and credit markets could negatively impact our business, financial condition and results of operations.

***Decreases in U.S. and global demand for electricity due to economic, weather or other conditions could negatively affect coal prices*.**

Our coal customers primarily use our coal as fuel for electricity generation. Overall economic activity and the associated demands for power by industrial users can have significant effects on overall electricity demand and can be caused by a number of factors. An economic slowdown can significantly slow the growth of electricity demand and could result in reduced demand for coal. For example, declines in the rate of international economic growth in countries such as China, India or other developing countries could further negatively impact the demand for U.S. coal and result in a continuing oversupply of coal. Weather patterns can also greatly affect electricity demand. Extreme temperatures, both hot and cold, cause increased power usage and, therefore, increase generating requirements from all sources. Mild temperatures, on the other hand, result in lower electrical demand, which allows generators to choose the sources of power generation when deciding which generation sources to dispatch. For example, the unusually warm winter of 2015/2016 led to low natural gas heating demand at a time of high gas production. This in turn led to low natural gas prices and substitution of gas for coal. When gas prices rose, this substitution of PRB coal decreased, but not enough to offset the increased utility coal stockpiles during this period, which lead to a reduction in utility coal contracting and depressed thermal coal prices. Decreases in coal demand for these or other reasons could cause further downward pressure on coal prices and would negatively impact our results of operations.

Our coal mining operations are subject to operating risks, which could result in materially increased operating expenses and decreased production levels

We mine coal at surface mining operations located in Wyoming and Montana. Our coal mining operations are subject to a number of operating risks. These operating risks include, among others:

- poor mining conditions resulting from geological, hydrologic, ground or other conditions, which may cause instability of highwalls or spoil-piles or cause damage to nearby infrastructure such as roads, power lines, railways and gas pipelines;

- critical mining and plant equipment failures, unexpected maintenance problems or damage from fire, flooding or other events;

- adverse weather and natural disasters, such as heavy rains, flooding, droughts, dust and other natural events affecting operations, transportation or customers;

- the unavailability of raw materials, equipment (including heavy mobile equipment) or other critical supplies such as tires and explosives, fuel, lubricants and other consumables of the type, quantity and/or size needed to meet production expectations;

- the capacity of, and proximity to, rail transportation facilities and rail transportation delays or interruptions, including derailments;

- competition and/or conflicts with other natural resource extraction activities and production within our operating areas, such as coalbed methane extraction or oil and gas development; and

- a major incident at a mine site that causes all or part of the operations of a mine to cease for some period of time.

Because we maintain very little produced coal inventory, disruptions in our operations due to these or other risks could negatively impact or even halt production and shipments, significantly increase the cost of mining and impact our ability to meet our contractual obligations to customers and others, which could have a material adverse effect on our results of operations. For example, continued production issues at our Antelope Mine, lower export prices and lower demand overall are expected to result in significantly lower levels of cash flow from operating activities in the future and have limited our ability to access capital markets. We maintain insurance policies that provide limited coverage for some of these risks, although there can be no assurance regarding the extent, if any, to which these risks would be covered by our insurance policies.

The availability and reliability of sufficient transportation capacity and increases in transportation costs could materially adversely affect the demand for our coal or impair our ability to supply coal to our domestic and export customers.

Transportation costs represent a significant portion of the total cost of coal for our domestic and export customers. The cost and availability of transportation is a key factor in a customer s purchasing decision and impacts our coal sales and the price we receive for our coal. Coal could become a less competitive source of energy if the costs of transportation increase or the availability or capacity of rail lines or export terminals is insufficient. Transportation costs and availability could also make our coal less competitive than coal produced from other regions.

Our ability to sell coal to our customers depends primarily upon third-party rail systems and export terminals. If our customers are unable to obtain transportation services, or to do so on a cost-effective basis, our business and growth strategy could be adversely affected. Alternative transportation and delivery systems are generally inadequate and not suitable to handle the quantity of our shipments or to ensure timely delivery to our customers. Existing and proposed export terminals are also subject to permit requirements and challenges from environmental organizations which may make it complicated or expensive to expand existing terminal capacity or open new export terminals in a timely and cost-effective manner. In addition, much of the PRB is served by two rail carriers, and the Northern PRB is only serviced by one rail carrier. The loss of sufficient and reliable access to rail capacity in the PRB, as we have experienced in recent years, could create disruption until this access was restored; significantly impairing our ability to supply coal and resulting in materially decreased revenue. Similarly, being denied access to an export terminal could significantly affect our future export sales, materially decreasing our logistics revenue and growth opportunities. Our ability to open new mines or expand existing mines may also be affected by the access to, and availability and cost of rail, export terminal or other transportation systems available for servicing these mines.

Typically, our mine customers contract and pay directly for transportation of coal from the mine or port to the point of use. However, for contracts with our logistics customers, we are required to enter into transportation agreements pursuant to which we arrange and pay for all rail transport, terminal, and for our international customers, demurrage charges. As the volume of deliveries coordinated to customer contracted destinations increases, so do our costs and risks. Our ability to supply coal to our customers and our customers ability to take our coal may be impacted by the disruption of these transportation services because of weather-related problems; mechanical difficulties; maintenance shut-downs; environmental, political and regulatory issues; train derailment; bridge or structural concerns; infrastructure damage, whether caused by ground instability, accidents or otherwise; strikes; lock-outs; lack of fuel or maintenance items; fuel costs; accidents; terrorism or domestic catastrophe or other events. For example, in the spring and summer of 2011, the Midwest region experienced severe flooding which disrupted rail service to mines in the PRB and affected the ability of those customers who were impacted by the flooding to take coal deliveries. During 2014, we also experienced rail interruptions due to increased competition for rail crews from crude oil and grain shipments, which negatively impacted our shipments and financial results. Any similar disruption in the future could negatively impact our results of operations. In addition, some scientists have opined that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur in areas where we or our clients operate, they could have an adverse effect on our assets and operations.

If we are unable to acquire or develop additional coal reserves that are economically recoverable, our future profitability may be reduced and our future success and growth may be significantly impacted.

Our profitability depends substantially on our ability to mine, in a timely and cost-effective manner, coal reserves that possess the quality characteristics our customers desire. Because our reserves decline as we mine our coal, our future success and growth depend upon our ability to acquire additional coal that is economically recoverable. We primarily acquire additional coal through the federal competitive leasing process, but we also enter into state and private coal leases as well as acquire coal from private third parties. If we fail to acquire or develop additional reserves, our existing reserves will eventually be depleted. Our ability to obtain

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additional coal reserves in the future could also be limited by a number of factors, any of which could impact our business and growth strategy, including:

- the availability of cash we generate from our operations;
- available financing and restrictions under our debt instruments;
- competition from other coal companies for properties;
- lack of suitable acquisition or LBA opportunities;
- delays or changes in the federal leasing process due to third-party legal challenges, regulatory developments or climate change initiatives; or
- the inability to acquire coal properties or federal coal leases on commercially reasonable terms.

Any significant delay in acquiring reserves could negatively impact our production rate. We will need to acquire additional coal reserves that can be mined on an economically recoverable basis to maintain our production capacity and competitive position. We may be unable to mine future reserves at profitability levels achieved at times in the past. The price we receive for our coal also impacts how economically we can recover our existing coal. Our ability to develop economically recoverable reserves will be materially adversely impacted if prices for thermal coal sold remain depressed or decrease significantly.

Because most of the coal in the vicinity of our mines is owned by the U.S. federal government, our future success and growth would be affected if we are unable to acquire or are significantly delayed in the acquisition of additional reserves through the federal competitive leasing process, including due to third party legal challenges or changes in the federal coal leasing program.

The U.S. federal government owns most of the coal in the vicinity of our mines. Accordingly, the federal competitive leasing process is our primary means of acquiring additional reserves. There is no requirement that the federal government must lease its coal or give preference to any LBA applicant, which means our bids for federal coal leases may compete with other coal producers bids. Federal coal leases are expensive to obtain and the review process to submit an LBA for bid continues to lengthen. We expect this trend to continue. The size of potential LBA tracts may also make it easier for new mining operators to enter the market on economic terms and may, therefore, further increase competition for federal coal leases. In order to win a lease in the LBA process and acquire additional coal, our bid for a coal tract must meet or exceed the fair market value of the coal based on the internal estimates of the BLM, which are not published. Any failure or delay in acquiring a coal lease through the LBA process, or the inability to do so on economic terms, could cause our production to decline, materially adversely affecting our business, cash flows and results of operations.

Increased opposition from non-governmental organizations and other third parties may also lengthen, delay or adversely impact the LBA process, which may result in difficulties in obtaining leases or impact our ability to mine the coal subject to those leases and/or delay our access to mine the coal. See Note 21 of Notes to Consolidated Financial Statements in Item 8 for a discussion regarding certain challenges by environmental activist groups against potential lease modifications and other regulatory processes relating to our mines.

The LBA process also requires us to acquire rights to mine from certain surface owners overlying the coal before the federal government will agree to lease the coal. Surface rights in the PRB are becoming increasingly more difficult and costly to acquire. Certain federal regulations provide a specific class of surface owners, also known as QSO, with the ability to prohibit the BLM from leasing its coal. For example, in connection with an LBA that we previously nominated for our Cordero Rojo Mine, the BLM indicated that certain surface owners satisfy the regulatory definition of QSO. If a QSO owns the land overlying a coal tract, federal laws prohibit us from leasing the coal tract without first securing surface rights to the land, or purchasing the surface rights from the QSO. This right of QSOs allows them to exercise significant influence over negotiations to acquire surface rights and can delay the LBA process or ultimately prevent the acquisition of coal underlying their surface. If we are unable to successfully negotiate access rights with QSOs at a price and on terms acceptable to us, we may be unable to acquire federal coal leases on land owned by the QSO. Our profitability could be materially adversely affected if the prices to acquire land owned by QSOs increase.

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If we are unable to acquire surface rights to access our coal, we may be unable to obtain a permit or otherwise be unable to mine coal we own and may be required to employ expensive techniques to mine around those sections of land we cannot access in order to access other sections of coal reserves.

After we acquire coal, we are required to obtain a permit to mine the coal through the applicable state agencies before we are allowed to begin mining. In part, the permitting requirements provide that, under certain circumstances, we must obtain surface owner consent if the surface estate has been split from the mineral estate, which is commonly known as a split estate. We have in the past and may in the future be required to negotiate with multiple parties for the surface access that overlies coal we acquired. If we are unable to successfully negotiate surface access with any of these surface owners, or do so on commercially reasonable terms, we may be denied a permit to mine some of the coal we have acquired or may find that we cannot mine the coal at a profit or at all. If we are denied a permit, this would create significant delays and restrictions in our mining operations and materially adversely impact our business and results of operations. Furthermore, if we determine to alter our plans to mine around the affected areas, we could incur significant additional costs to do so, which could increase our operating expenses considerably and could materially adversely affect our results of operations. Failure to successfully negotiate access for surface rights overlying coal that we control in a timely manner may also result in significant accounting charges, which could have a material adverse impact on our results of operations.

Defects in title or the loss of a leasehold interest in, or superior or conflicting property rights impacting, reserves or surface rights could limit our ability to mine our coal reserves and adversely impact our operations and costs.

A title defect on any lease, whether private or through a governmental entity, or the surface rights related to any of our reserves could adversely affect our ability to mine the associated coal reserves. Consistent with industry practice, we conduct only limited investigations of title to our coal properties prior to leasing. Title to properties leased from private third parties is not usually fully verified until we make a commitment to develop a property, which may not occur until we have obtained the necessary permits and completed exploration of the property. Title or other defects in surface rights held by us or other third parties could impair our ability to mine the associated coal reserves or cause us to incur unanticipated costs.

In addition, these leasehold interests may be subject to superior property rights of other third parties. The federal government leases many different mineral rights in addition to coal, such as coalbed methane, natural gas and crude oil rights. Some of these minerals are located on, or are adjacent to, some of our coal and LBA areas, potentially creating conflicting interests between us and the lessees of those interests and may affect our ability to operate as planned if our title is not superior or cost-effective arrangements cannot be timely negotiated. We are regularly in negotiations with third parties in an effort to address potentially conflicting mineral development. These negotiations may not be effective. In that event, our mine plans, future costs and production rates may be adversely impacted. Anticipated oil and gas development is expected to continue to increase the frequency of these potential conflicts.

Further, the majority of our coal interests are acquired by lease from state or federal governments. If any of our leases are terminated, for lack of diligent development or otherwise, we would be unable to mine the affected coal and our business and results of operations could be materially adversely affected.

We may not recover our investments in our mining, exploration, port access rights, development projects, 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;
- unfavorable regulatory or legal developments impacting our industry;
- lower-than-expected domestic and international demand and coal pricing;
- technical and geological operating difficulties;

- an inability to economically extract our coal reserves;
- unanticipated increases in operating costs;
- disputes or difficulties with counterparties for our development projects; and
- an inability to obtain additional export terminal capacity due to extensive permit requirements and challenges from environmental organizations.

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, which could have a substantial adverse impact on our results of operations. For example, during the year ended December 31, 2018, we recorded a non-cash impairment charge of $682.4 million related to our Cordero Rojo Mine Complex, due to the weak outlook for 8400 Btu coal, and both our Youngs Creek and Big Metal Projects as a result of the projects being acquired in times of significantly higher coal prices. Additionally, we recorded a non-cash impairment of $2.3 million representing the remaining goodwill value at the Antelope and Spring Creek mines during the year ended December 31, 2018. During the year ended December 31, 2016, we recorded impairments of $2.6 million, primarily for engineering costs related to the Overland Conveyor project at our Antelope Mine and $2.0 million related to a shovel that we do not expect to use because of declining productions. Because of the volatile nature of U.S. and international coal demand and pricing, 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 further adjustments to the carrying value of mineral rights and other assets.

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

Acquisitions are a potentially important part of our long-term growth strategy, and we may pursue acquisition opportunities in the future in the U.S. and other jurisdictions. If we fail to accurately estimate the future results and value of an acquired business or are unable to successfully integrate the businesses or properties we acquire, our business, financial condition or results of operations could be negatively affected, and we may be unable to grow our business. Acquisition transactions involve various risks, including:

- uncertainties in assessing the strengths and potential profitability, and the related weaknesses, risks, contingent and other liabilities, of acquisition candidates;
- changes in business, industry, market or general economic conditions that affect the assumptions underlying our rationale for pursuing the acquisition;

- the inability to achieve identified operating and financial synergies anticipated to result from an acquisition;

- the potential loss of key customers, management or employees of an acquired business;

- the nature and composition of the workforce, including the acquisition of a unionized workforce;

- diversion of our management s attention from other business concerns;

- regulatory challenges for completing and operating the acquired business, including opposition from environmental groups or regulatory agencies;

- environmental or geological problems in acquired coal properties, including factors that make the coal unsuitable for intended customers (due to ash, heat value, moisture, or contaminants), that make the coal more expensive to mine, or delay our ability to mine;

- inability to acquire sufficient surface rights to enable extraction of coal resources;

- outstanding permit violations associated with acquired assets;

- difficulties or unexpected issues arising from our evaluation of internal control over financial reporting of the acquired business;

- risks related to operating in new jurisdictions or industries, including increased exposure to foreign government and currency risks with respect to any international acquisitions; and

- unanticipated liabilities associated with the acquired companies.

Any one or more of these factors could cause us not to realize the benefits we might anticipate from an acquisition. Moreover, any acquisition opportunities we pursue could materially increase our liquidity and 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.

We may be unable to obtain, maintain or renew permits or licenses necessary for our operations, including due to third party legal challenges or climate change-related assessments that are increasingly required as part of our regulatory processes, which would materially reduce our production, cash flows and profitability.

As a mining company, we must obtain a number of permits and licenses from various federal, state and local agencies and regulatory bodies that impose strict regulations on environmental and operational matters in connection with our coal operations, including restricting the number of tons we may mine under our air quality permits. We are also subject to strict regulatory requirements and oversight for our Sequatchie Valley reclamation property in Tennessee. These rules, and the interpretations of these rules, are complex, change frequently and are often subject to discretionary interpretations by the regulators, all of which make compliance more difficult or impractical, and may possibly preclude the continuance of ongoing operations, impact the development of future mining operations, restrict the amount of our production, or subject us to significant fines and penalties.

The public, including non-governmental organizations, anti-mining groups and individuals, have certain statutory rights to comment upon and submit objections to requested permits and EISs prepared in connection with applicable regulatory processes. These groups may also participate in the permitting and licensing process, including bringing citizens lawsuits to challenge the issuance of permits, the validity of an EIS or performance of mining activities, which can create delay and uncertainty in acquiring permits and mining the coal underlying our leases. Refer to Note 21 of Notes to Consolidated Financial Statements in Item 8 for a discussion regarding certain challenges by environmental activist groups against regulatory permits and approvals for our mines. These challenges seek to vacate prior regulatory decisions and authorizations that are legally required for some or all of our current or planned mining activities. If we are required to reduce or modify our mining activities as a result of these challenges, the impact could have a material adverse effect on our shipments, financial results and liquidity, and could result in claims from third parties if we are unable to meet our commitments under pre-existing commercial agreements as a result of any such required reductions or modifications to our mining activities.

If our permits or licenses are not issued or renewed in a timely fashion or at all, or if permits issued or renewed are conditioned in a manner that restricts our ability to efficiently and economically conduct our mining activities, or if we are found to have violated any permitting or regulatory requirements, we could suffer a material reduction in our production, an impairment of our mineral rights, significant fines and penalties, and our cash flows or profitability could be materially adversely affected.

Existing and future legislation, treaties, regulatory requirements and public concerns relating to GHG emissions could negatively affect our customers and further reduce the demand for coal as a fuel source, causing coal prices and sales of our coal to materially decline.

Global climate change initiatives and public perceptions regarding fossil fuels have resulted, and are expected to continue to result, in decreased coal-fired power plant capacity and utilization, phasing out and closing many existing coal-fired power plants, reducing or eliminating construction of new coal-fired power plants in the United States and certain other countries, increased costs to mine coal and decreased demand and prices for thermal coal, including PRB coal. See Item 1 Business Environmental and Other Regulatory Matters Global Climate Change.

There are three important sources of GHGs associated with the coal industry. The end use of our coal in electricity generation is the largest of the three sources of GHGs. Combustion of fuel for mining equipment used in coal production is another source of GHGs. In addition, coal mining can release methane, a GHG, directly into the atmosphere. These emissions from coal consumption and production are subject to pending and proposed regulations as part of regulatory initiatives to address global climate change and global warming. Various international, federal, regional and state proposals are being considered to limit emissions of GHGs, including possible future U.S. treaty commitments, new federal or state legislation that may, among other things establish a cap-and-trade regime, and regulation under existing environmental laws by the EPA and other regulatory agencies. For example, the United States recently joined nearly 200 other nations in an agreement to voluntarily limit GHG emissions. Although the United States has since announced its intention to withdraw from the agreement, certain U.S. cities and states have announced their intention to satisfy their proportionate obligations under the agreement. These and other voluntary pledges could further decrease demand and pricing for our coal. Future regulation of GHG emissions may require additional controls on, or the closure of, coal-fired power plants and industrial boilers or may restrict the construction of new coal-fired power plants. For example, the EPA released the CPP, which would have required reductions in emissions from existing power plants, as well as new source performance standards for GHG emissions for new coal and oil-fired power plants, which require partial carbon capture and sequestration. However, the CPP was stayed by the U.S. Supreme Court and never went into effect. More recently, the EPA proposed the ACE Rule, which would establish emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. The ACE Rule would replace the CPP. See Risks Related to Our Business and Industry *Our long-term growth may be materially adversely impacted if economic, commercially available carbon capture technology for power plants is not developed and adopted in a timely manner*. These regulatory initiatives may increase our costs and decrease demand and pricing for our coal and logistics services, and may lead to increased demand for domestic electricity fired by natural gas because gas-fired plants are cheaper to construct, and permits to construct these plants can be easier to obtain.

The permitting of new coal-fired power plants has also recently been contested, at times successfully, by state regulators and environmental organizations due to concerns related to GHG emissions from the new plants. Private litigation has also been brought against industry participants based on GHG-related concerns. The U.S. Supreme Court held that federal common law provides no basis for public nuisance claims against utilities due to their carbon dioxide emissions, but tort-type liabilities and other GHG-related claims against utilities and energy producers may be asserted. For example, in 2011 residents and property owners along the Mississippi Gulf coast filed litigation against approximately 90 companies in energy, fossil fuels and chemical industries, including PRB and other domestic coal companies, alleging that the defendants caused the emission of GHGs that contributed to global warming, which in turn caused a rise in sea levels and added to the ferocity of Hurricane Katrina in 2005, which combined to destroy the plaintiffs property. The lawsuit was dismissed by the Federal District Court in 2012 and the dismissal was affirmed by the Fifth Circuit Court of Appeals in May 2013. However, if other GHG-related litigation, such as the California Climate Change Litigation, is successful, the coal industry and our company may be materially adversely impacted. For a discussion of the California Climate Change Litigation, see Note 21 of Notes to Consolidated Financial Statements in Item 8.

Extensive environmental laws, including existing and potential future legislation, treaties and regulatory requirements relating to air emissions, affect our customers and could further reduce the demand for coal as a fuel source and cause coal prices and sales of our coal to materially decline.

The operations of our customers are subject to extensive environmental regulation particularly with respect to air emissions. For example, CSAPR initially requires 28 states in the Midwest and eastern seaboard of the U.S. to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. In August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR and ordered the EPA to continue enforcing CAIR. The U.S. Supreme Court reversed the D.C. Circuit s vacation of CSAPR, and the D.C. Circuit granted a request by the EPA to lift the stay of the rule. Subsequently, in November 2014, the EPA issued an interim final rule reconciling the CSAPR rule with the Court s order to lift the stay, calling for Phase 1 implementation in 2015 and Phase 2 implementation in 2017. In September 2016, the EPA finalized an update to the CSAPR ozone season program by issuing the Final CSAPR Update. CSAPR is one of a number of significant regulations that the EPA has issued or expects to issue that will impose more stringent requirements relating to air, water and waste controls on electric generating units. These rules include the EPA s requirements for

CCR management, which were finalized in December 2014 and further regulate the handling of wastes from the combustion of coal. In addition, in March 2013, the EPA formally adopted a revised final rule to reduce emissions of toxic air pollutants from power plants. Specifically, MATS for

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power plants will reduce emissions from new and existing coal- and oil-fired electric utility steam generating units. In June 2015, the U.S. Supreme Court struck down the MATS rule based on the EPA s failure to take costs into consideration and remanded the case back to the D.C. Circuit. The D.C. Circuit remanded the rule to the EPA. In April 2016, the EPA issued a final finding that it is appropriate and necessary to set standards for emissions of air toxics from coal- and oil-fired power plants.

Considerable uncertainty is associated with air emissions initiatives. Under the previous administration, new regulations were in the process of being developed, and many existing and potential regulatory initiatives are subject to review by federal or state agencies or the courts or have been targeted for rescission by the current administration. Stringent air emissions limitations are either in place or are likely to be imposed in the short to medium term, and these limitations will likely require significant emissions control expenditures for many coal-fired power plants. As a result, these power plants may switch to other fuels that generate fewer of these emissions or may install more effective pollution control equipment that reduces the need for low-sulfur coal. Any further switching of fuel sources away from coal, closure of existing coal-fired power plants, or reduced construction of new coal-fired power plants could have a material adverse effect on demand for, and prices received for, our coal. Alternatively, less stringent air emissions limitations, particularly related to sulfur, to the extent enacted, could make low-sulfur coal less attractive, which could also have a material adverse effect on the demand for, and prices received for, our coal. See Item 1 Business Environmental and Other Regulatory Matters.

Our mining operations are subject to extensive environmental, health, safety or other laws and regulations that could materially increase our costs or limit our ability to produce and sell coal.

Our mining operations, including our Sequatchie Valley reclamation property in Tennessee, are subject to extensive federal, state and local environmental, health and safety, transportation, labor and other laws and regulations. See Item 1 Business Environmental and Other Regulatory Matters. Examples include those relating to:

- employee health and safety;
- emissions to air and discharges to water;
- plant and wildlife protection, including endangered species protections;
- the reclamation and restoration of properties after mining or other activity has been completed;
- remediation of contaminated soil, surface and groundwater; and

- the effects of operations on surface water and groundwater quality and availability.

Furthermore, we must compensate employees for work-related injuries through our workers compensation insurance funds. The erosion through tort liability of the protections we are currently provided by workers compensation laws could increase our liability for work-related injuries.

MSHA is responsible for monitoring compliance with federal mine health and safety standards at our mines. MSHA has various enforcement tools that it can use, including the issuance of citations resulting in monetary penalties and orders of withdrawal from a mine or part of a mine. Since the April 2010 explosion at Massey Energy Company s (previously acquired by Alpha Natural Resources) Upper Big Branch Mine, increased scrutiny has been placed on the mining industry and has had significant impacts on the regulation of mine safety matters at the federal and state levels. For example, federal authorities have announced additional targeted inspections of coal mines to evaluate several safety concerns, including the accumulation of coal dust and the proper ventilation of gases such as methane. Federal authorities are also frequently proposing changes to mine safety rules and regulations, which could potentially result in additional or enhanced required safety equipment, more frequent mine inspections, stricter and more thorough enforcement practices and enhanced reporting requirements. Any new environmental and/or health and safety requirements may be replicated in the states in which we operate and could increase our operating costs or otherwise prevent, delay or reduce our planned production, any of which could adversely affect our financial condition, results of operations and cash flows.

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The costs, liabilities and requirements associated with complying with these requirements are often significant and time-consuming and may delay commencement or continuation of exploration or production. These factors could have a material adverse effect on our results of operations, cash flows and financial condition. New legislation or administrative regulations or new judicial interpretations or administrative enforcement of existing laws and regulations may also require us to change operations significantly or incur increased costs. For example, in November 2011, several environmental groups sued the EPA in Washington federal court to compel the EPA to include coal mines on the list of stationary sources governed by air pollution performance standards. In that case, the Court denied the groups rulemaking petition, and in July 2014, also denied a petition seeking a rehearing of the case en banc. Any imposition of air emission standards on coal mines or any other such changes could have a material adverse effect on our financial condition and results of operations.

Because of the extensive regulatory environment in which we operate, we cannot assure complete compliance with all laws and regulations. Failure to comply with these laws may result in significant costs to us to correct such violations, as well as civil or criminal penalties and limitations or shutdowns of our operations. These laws and regulations may also significantly impair our ability to conduct our mining operations or result in increased operating costs.

Federal and state regulatory agencies have the authority to order any of our mines to be temporarily or permanently closed under certain circumstances, which could materially adversely affect our ability to meet our customers demands.

Federal and state regulatory agencies have the authority following significant health and safety incidents, such as fatalities, to order a mine to be temporarily or permanently closed. If this were to occur, we may be required to incur capital expenditures to re-open the mine. In the event that these agencies order the closing of our mines, our coal sales agreements and our take-or-pay contracts related to our export terminals may permit us to issue force majeure notices, which suspend our obligations to deliver coal under these contracts. However, our customers may challenge our issuances of force majeure notices. If these challenges are successful, we may have to purchase coal from third-party sources, if it is available, to fulfill these obligations, incur capital expenditures to re-open the mines and/or negotiate settlements with the customers, which may include price reductions, the reduction of commitments or the extension of time for delivery or terminate customers contracts. Any of these actions could have a material adverse effect on our business and results of operations.

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

Our operations use hazardous materials and generate hazardous and non-hazardous wastes. In addition, many of the locations that we own, lease or operate were used for coal mining and/or involved the generation, use, storage and disposal of hazardous substances either before or after we were involved with these locations. We may be subject to claims under federal and state statutes and/or common law doctrines for toxic torts, natural resource damages and other damages, as well as for the investigation and cleanup of soil, surface water, groundwater and other media. These claims may arise, for example, out of current or former conditions at sites that we own, lease or operate currently, as well as at sites that we or predecessor entities owned, leased or operated in the past, and at contaminated third-party sites at which we have disposed of hazardous substances and waste. As a matter of law, and despite any contractual indemnity or allocation arrangements or acquisition agreements to the contrary, our liability for these claims may be joint and several, so that we may be held responsible for more than our share of any contamination, or even for the entire share.

We may incur material costs and liabilities resulting from claims for damage to property or natural resources or injury to persons arising from our operations. If we are pursued for sanctions, costs and liabilities in respect of these matters, our mining operations and, as a result, our profitability could be materially adversely affected.

Significant increases in taxes we pay on the coal we produce at our mine sites or deliver through our logistics business, such as royalties or severance and production taxes, including as a result of

governmental audits, legislative, regulatory, or interpretive changes, could materially and adversely affect our profitability.

We pay federal, state and private royalties and federal, state and county severance and production taxes on the coal we sell. A substantial portion of our royalties, severance, and production taxes are levied as a percentage of gross revenue with the remaining levied on a per ton basis. For example, we pay production royalties of 12.5% of gross proceeds to the federal government on all coal sold at the mine sites. We incurred royalties and severance and production taxes totaling $184.8 million, $209.2 million and $208.7 million for the years ended December 31, 2018, 2017 and 2016, respectively. The calculations used to determine royalty or severance and production tax payments can be complex and subject to interpretation, making it difficult in some cases to estimate such payments. If royalties or severance and production tax rates were to significantly increase, or if the methodology by which the government agencies assess royalties or severance and production tax rates materially changes, our results of operations could be materially adversely affected. See Note 21 of Notes to Consolidated Financial Statements in Item 8. Examples that could materially adversely affect our results include:

- the federal government could again seek to significantly alter the method for valuing royalty payments;
- a state government could increase severance or production taxes or any other tax applicable to our operations in that state; and
- we could be required to make additional payments (including significant related interest and penalties) as a result of pending or future governmental audits, which can date back many years.

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

SMCRA and counterpart state laws and regulations establish operational, reclamation and closure standards for all aspects of surface mining. We accrue for the costs of current mine disturbance and final mine closure. Estimates of our total reclamation and mine-closing liabilities are based upon permit requirements and our experience. The amounts recorded are dependent upon a number of variables, including the estimated future asset retirement costs, estimated proven reserves, assumptions involving profit margins of third-party contractors, inflation rates, discount rates and assumed credit-adjusted, risk-free rates. Furthermore, these obligations are unfunded. If our accruals are insufficient or our liability in a particular year is greater than currently anticipated, our future operating results could be materially adversely affected.

Increases in the cost of raw materials and other industrial supplies, or the inability to obtain a sufficient quantity of those supplies, could increase our operating expenses, disrupt or delay our production and materially adversely affect our profitability.

We use considerable quantities of explosives, petroleum-based fuels, tires, steel and other raw materials, as well as spare parts and other consumables in the mining process. If the prices of steel, explosives, tires, petroleum products or other materials increase significantly or if the value of the U.S. dollar declines relative to foreign currencies with respect to certain imported supplies or other products, our operating expenses will increase, which could materially adversely impact our profitability. Additionally, a limited number of suppliers exist for certain supplies, such as explosives and tires, as well as certain mining equipment, and any of our suppliers may divert their products to buyers in other mines or industries or divert their raw materials to produce other products that have a higher profit margin. Shortages in raw materials used in the manufacturing of supplies and mining equipment, which, in some cases, do not have ready substitutes, or the cancellation of our supply contracts under which we obtain these raw materials and other consumables, could limit our ability to obtain these supplies or equipment. As a result, we may not be able to acquire adequate replacements for these supplies or equipment on a cost-effective basis or at all, which could also materially increase our operating expenses or halt, disrupt or delay our production.

Furthermore, operating expenses at our mining locations are sensitive to changes in certain variable costs, including diesel fuel prices, which is one of our largest variable costs. Our results depend on our ability to adequately control our costs, including diesel fuel. Any increase in the price we pay for diesel fuel will have a negative impact on our results of operations. See Item 7 Management s Discussion and Analysis of Financial

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Condition and Results of Operations Years Ended December 31, 2018, 2017, and 2016   Cost of Product Sold   and Item 7A   Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk.

Our hedging activities for diesel fuel may prevent us from benefiting from cost price decreases.

We have entered into derivative financial instruments to help manage our exposure to market price changes to our diesel fuel costs, which are indexed to the West Texas Intermediate (WTI) crude oil price as quoted on the New York Mercantile Exchange. As such, the nature of the derivative financial instruments does not directly offset market changes to our diesel fuel costs.

While any hedge would provide us protection in the event of crude oil price increases, it would reduce our benefit when crude oil prices decrease below our floor and may require substantial payments by us to settle our financial instruments. See Item 7A   Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk   and Note 13 of Notes to Consolidated Financial Statements in Item 8.

Our hedging activities for coal sales prices may result in a negative impact from sales price changes.

As part of our logistics business, we periodically enter into derivative financial instruments in the form of international coal forward contracts to help manage our exposure to future coal sales prices by fixing a price now for a future contracted coal delivery. This type of hedge is designed to protect us from any price decreases. While our hedging strategy provides us some degree of protection in the event future coal prices decrease it may also prevent us from benefiting if future coal prices increase above our hedged price and may require substantial payments by us to settle our financial instruments.

In addition, we have periodically used domestic coal futures contracts to help manage our exposure to market changes in domestic coal prices. This type of hedge is designed to benefit us when prices change relative to our current open positions. If there are significant and extended unfavorable price movements against our positions, our earnings and liquidity could be negatively impacted. See Item 7A   Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk   and Note 13 of Notes to Consolidated Financial Statements in Item 8.

Changes in the fair value of derivative financial instruments that are not accounted for as a hedge could cause volatility in our earnings.

From time to time, we enter into certain derivative financial instruments to help manage our exposure to future coal prices, both with respect to our export and domestic sales prices and to rises in our diesel costs. Derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. To the extent these derivative financial instruments do not qualify for hedge accounting or we choose not to designate them for hedge accounting, we are required to record changes in the fair value of these derivative financial instruments in our Consolidated Statement of Operations, resulting in increased volatility in our income in future periods.

Inaccuracies or future reductions in our estimates of our coal reserves could result in decreased profitability from lower than expected revenue or higher than expected costs.

We base our estimates of reserves on engineering, economic and geological data assembled and analyzed by our internal geologists and engineers, which are reviewed by an independent consultant every two years. Our estimates of proven and probable coal reserves as to both quantity and quality are updated annually to reflect the production of coal from the reserves, updated geological models and mining recovery data, the tonnage contained in new lease areas acquired and estimated costs of production and sales prices. There are numerous factors and assumptions inherent in estimating the quantities and qualities of, and costs to mine, coal reserves, any one of which may vary considerably from actual results. These factors and assumptions include:

- coal characteristics such as Btu and sulfur content;

- geological and mining conditions, which may not be fully identified by available exploration data and/or may differ from our experiences in areas where we currently mine;

- future coal prices and demand;
- equipment and productivity;
- operating costs, including for critical supplies such as fuel, tires and explosives;
- capital expenditures and development and reclamation costs;
- the percentage of coal ultimately recoverable;
- the effects of regulation, including the issuance of required permits, and taxes, including severance and production taxes and royalties, and other payments to governmental agencies; and
- timing for the development of the reserves.

Any changes to the above factors and assumptions could cause our estimates of the quantities and qualities of economically recoverable coal to vary significantly. Changes to the above factors and assumptions could also materially impact how we classify our reserves based on risk of recovery and our estimates of future net cash flows expected from these properties. Actual production recovered from identified reserve areas and properties, and revenue and expenditures associated with our mining operations, may vary materially from estimates. Any inaccuracy or further reductions in our proven and probable reserves estimates could result in decreased profitability from lower than expected revenue and/or higher than expected costs.

The majority of our coal sales agreements are forward sales contracts at fixed prices, which may not reflect favorable then-existing prices for coal or may affect our profitability if we cannot adequately control the costs of production for coal underlying such contracts.

We have historically sold most of our coal under long-term coal sales agreements, which we generally define as contracts with a term of one to five years. For the year ended December 31, 2018, approximately 81% of our revenue was derived from supply contracts with terms of one year or greater. The prices for coal sold under these agreements are typically fixed for an agreed amount of time. Pricing in some of these contracts is subject to certain adjustments in later years or under certain circumstances, and may be below the current market price for similar type coal at any given time, depending on the time frame of the contract.

As a consequence of the substantial volume of our forward sales, our ability to capitalize on near term rises in coal prices is limited. We have less coal available to sell under short-term contracts or on the spot market and we similarly have fewer tons to commit under long-term contracts at higher prices. Our ability to realize higher prices is also restricted if customers elect to purchase additional volumes of coal, which is allowable under some contracts, at contract prices that are lower than spot prices.

Furthermore, to the extent our costs increase but pricing under our long-term coal sales agreements remains fixed, we may be unable to pass such increasing costs on to our customers. If we are unable to control our costs, our results may be negatively impacted.

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

For the year ended December 31, 2018, we derived approximately 23% of our total revenue from sales to our three largest customers and approximately 53% of our total revenue from sales to our ten largest customers. We may be unsuccessful in obtaining and renewing coal sales agreements with these customers, and some or all of these customers could discontinue purchasing coal from us. If any of these customers, particularly any of our three largest customers, was to significantly reduce the quantities of coal it purchases from us, or if we are unable to sell coal to these customers on terms as favorable to us, the results of our business would be adversely impacted.

Changes in purchasing patterns in the coal industry may make it difficult for us to enter into new contracts with customers, or do so on favorable terms, which could materially adversely affect our business and results of operations.

In recent years, we have experienced customers being less willing to enter into long-term coal sales agreements as they continue to adjust to relatively low U.S. natural gas prices, increased price volatility, increased fungibility of coal products, frequently changing regulations that have often disfavored coal usage and the increasing deregulation of their industry. In addition, the prices for coal in the spot market may be lower than the prices previously set under many of our long-term coal sales agreements. As our contracts with customers expire or are otherwise renegotiated, our customers may be less willing to extend or enter into new long-term coal sales agreements under their existing or similar pricing terms or our customers may decide to purchase fewer tons of coal than in the past.

To the extent our customers continue to shift away from long-term supply contracts, it will be more difficult to predict our future sales. As a result, we may not have a market for our future production at acceptable prices. The prices we receive in the spot market may be less than the contractual price an electric utility is willing to pay for a committed supply. Furthermore, spot market prices tend to be more volatile than contractual prices, which could result in decreased revenue and profitability. As of March 2019, we had approximately 44 million tons of committed sales for 2019 and 32 million tons for 2020, which is below our historical forward sales levels, leaving more coal left to be sold for those periods.

As a result of depressed thermal coal demand and competition from low priced natural gas, we received in the past, and may receive in the future, increased requests from customers to renegotiate, defer or cancel committed purchases under existing agreements. If we are unable to resolve these customer requests on terms that preserve the amount and timing of our forecasted economic value, our anticipated cash flows, results and liquidity may be materially adversely impacted.

From time to time in the ordinary course of our business, customers may seek to renegotiate the terms of our coal sales agreements to reallocate certain committed volumes into future time periods, reduce or cancel committed volumes or make other adjustments to our coal sales agreements. We address these requests on a case-by-case basis and seek to reach mutually agreed resolutions of these requested modifications as part of managing our long-term customer relationships. As a result of depressed thermal coal demand and competition from low priced natural gas, we have received in the past, and may receive in the future, increased requests from customers to renegotiate, defer or cancel committed purchases under existing agreements, as occurred in early 2016. If we are unable to resolve these customer requests on terms that preserve the amount and timing of our forecasted economic value, our anticipated cash flows, results and liquidity may be materially adversely impacted.

Demand for U.S. thermal coal has declined significantly in recent years and is increasingly subject to fluctuations due to summer cooling demand, winter heating demand, economic growth rates and other factors that impact demand for electricity. This has resulted in a reduction in long-term sales, less visibility into future shipment volumes and increased fluctuations in shipments and associated financial results from period to period.

As a result of regulatory, political, and public pressures against using coal to generate electricity, increased competition with low-cost natural gas, increased competition with taxpayer subsidized solar and wind generation, improving energy efficiency, and other factors, demand for U.S. thermal coal has declined significantly in recent years, supporting a lower percentage of baseload electricity demand, and is increasingly subject to fluctuations due to summer cooling demand, winter heating demand, economic growth rates and other factors that impact demand for electricity. This has resulted in a reduction in long-term sales of thermal coal, less visibility into future shipment volumes and increased fluctuations in shipments and associated financial results from period to period. Although we are seeking to adjust our business and cost structure to reflect lower and more variable demand for thermal coal and to address the adverse impact of these changing conditions on our financial performance, our business requires substantial fixed costs and long lead-time investment decisions and we may not be successful in adjusting to these changing conditions.

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We are exposed to counterparty risk with our customers, trading partners, financial institutions and other parties with whom we conduct business.

We face an increased risk that we do not receive payment for coal sold and delivered if the creditworthiness of any of our counterparties deteriorates or if any of our counterparties become subject to bankruptcy proceedings. The creditworthiness of these counterparties depends on any number of factors, including the economic volatility and tightening of credit markets, and deregulation of the U.S. utilities markets, allowing utilities to sell their power plants to their non-regulated affiliates or third parties that may have credit ratings that are below investment grade. Competition with other coal suppliers could cause us to extend credit to customers and on terms that could increase the risk of payment default.

From time to time, we have contracts to supply coal to energy trading and brokering companies, under which they purchase the coal for their own account or resell to domestic and foreign end users. If the creditworthiness of these energy trading and brokering companies declines, this would increase the risk that we may not be able to collect payment for all coal sold and delivered to or on behalf of those companies. Furthermore, if any of these companies seek to renegotiate or cancel sales of coal because of fluctuations in spot prices for coal, issues with their end users accepting the coal or other factors, we may be unable to sell previously anticipated volumes of coal at favorable prices or at all. We also enter into derivative financial instruments with a number of financial institutions. If one or more of these institutions were to default on its future obligation to us, our cash flows and results of operations would be negatively impacted.

In certain circumstances we may be entitled to demand credit enhancements or withhold shipments of coal from these parties if we determine they are not creditworthy. However, these protections may be insufficient to cover our risks or could cause us to resell the coal on the spot market at unfavorable prices or not at all.

We maintain cash balances that we may invest from time to time in marketable securities issued by various counterparties including the U.S. government and U.S. government sponsored entities, municipal entities, financial institutions and other corporations. If any of these counterparties fail, we could lose the principal invested with such counterparties, which would materially adversely impact our business, liquidity, and results of operations.

Certain provisions in our coal sales agreements may provide limited protection during adverse economic conditions or may result in economic penalties or suspension upon a failure to meet contractual requirements.

Price adjustment, price re-opener and other similar provisions in our supply contracts may reduce the protection from short-term coal price volatility traditionally provided by these contracts. Most of our contracts with mine customers and some of our contracts with logistics customers contain provisions that allow for the base price of our coal to be adjusted due to new statutes, ordinances or regulations that affect our costs related to performance. Because these provisions only apply to the base price of coal, these terms may provide only limited protection due to changes in regulations. Some of our contracts with mine customers also contain provisions that allow the purchase prices to be renegotiated at periodic intervals. A price re-opener provision is one in which either party can renegotiate the price of the contract, sometimes at pre-determined times. Index provisions allow for the adjustment of the price based on a fixed formula. These provisions may reduce the protection available under our contracts from short-term coal price volatility. Our international contracts may contain a fixed price for the first year of the contract with future years prices to be negotiated at a specific point in time. If the parties fail to satisfactorily negotiate a price, the contract could be terminated. Any adjustment or renegotiations leading to a significantly lower contract price, or a termination of the contract, could result in decreased revenue.

Our coal sales agreements with our mine customers typically contain force majeure provisions allowing temporary suspension of performance by us or our customers during the duration of specified events beyond the control of the affected party. For example, as a result of the very mild 2015/16 winter and low natural gas prices, a greater than normal number of our customers in 2016 sought to reduce the amount of tons delivered to them under our coal sales agreements through contractual remedies, such as contract buyout provisions. Our contracts with our mine customers also typically allow our customers to suspend performance in the event that the railroad fails to provide its services due to circumstances that would constitute a force majeure. In addition, our contracts with our international logistics customers generally contain a clause that requires us to pay the demurrage fee charged by the vessel for delays in shipping the coal on behalf of our foreign customers.

Most of our coal sales agreements also contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics, such as heat content, sulfur, ash and ash fusion temperature. Failure to meet these specifications can result in economic penalties, including price adjustments, suspension, rejection or cancellation of deliveries or termination of the contracts. A number of our contracts also contain clauses, which, in some cases, may allow customers to terminate the contract in the event of certain changes in environmental laws and regulations.

Our ability to operate our business effectively could be impaired if we fail to attract and retain key personnel.

Our ability to operate our business and implement our strategies depends, in part, on the continued contributions of our executive officers and other key employees. The loss of any of our key senior executives could have a material adverse effect on our business unless and until we find a qualified replacement. A limited number of persons exist with the requisite experience and skills to serve in our senior management positions. We may not be able to locate or employ qualified executives on acceptable terms and our failure to retain or attract qualified executives could have an adverse effect on our ability to operate our business.

Efficient coal mining using modern techniques and equipment also requires skilled laborers in multiple disciplines such as electricians, equipment operators, mechanics, engineers and welders, among others. We have from time to time encountered shortages for these types of skilled labor and typically compete for such positions with other industries, including oil and gas. If we experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially adversely affected. In the future, we may utilize a greater number of external contractors for portions of our operations. The costs of these contractors have historically been higher than that of our employed laborers. If our labor and contractor prices increase, or if we experience materially increased health and benefit costs with respect to our employees, our results of operations could be materially adversely affected.

Our work force could become unionized in the future, which could negatively impact the stability of our production and materially reduce our profitability.

All of our mines are operated by non-union employees. Our employees have the right at any time under the National Labor Relations Act to form or affiliate with a union, and in the past, unions have conducted limited organizing activities in this regard. If our employees choose to form or affiliate with a union and the terms of a union collective bargaining agreement are significantly different from our current compensation and job assignment arrangements with our employees, these arrangements could negatively impact the stability of our production and materially reduce our profitability. In addition, even if our managed operations remain non-union, our business may still be adversely affected by work stoppages at unionized companies or unionized transportation and service providers.

Terrorist attacks and threats, escalation of military activity in response to these attacks or acts of war may materially adversely affect our business and results of operations.

Terrorist attacks and threats, escalation of military activity or acts of war may have significant effects on general economic conditions, fluctuations in consumer confidence and spending, market liquidity, and disruptions to the domestic or international coal supply chains, each of which could negatively impact our business. Furthermore, any such acts, which directly affect our customers and their business may have negative consequences to our own operations. Strategic targets such as energy-related assets and transportation assets may be at greater risk of future terrorist attacks than other targets in the U.S. or in other countries. Disruption or significant increases in energy prices could result in government-imposed price controls. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business and results of operations, including from delays or losses in transportation, decreased sales of our coal or extended collections from customers that are unable to timely pay us in accordance with the terms of their supply agreement.

We face the risk of systems failures as well as cybersecurity risks, including hacking.

The computer systems and network infrastructure we and others use could be vulnerable to unforeseen problems. These problems may arise in both our internally developed systems and the systems of our third-party service providers. Our operations are dependent upon our ability to protect computer equipment against damage from fire, power loss or telecommunication failure. Any damage or failure that causes an interruption in our operations could adversely affect our business. In addition, our computer systems and network infrastructure present security risks, and could be susceptible to hacking.

Our reliance on information technology, including systems managed by third parties, exposes us to risks from system failures and cybersecurity incidents that could materially and adversely affect our operations, financial results and reputation and result in significant costs and liabilities.

Our business depends on the reliable and secure operation of computer systems, network infrastructure, digital communication technologies and other information technology. Problems may arise in both our internally managed systems and those of third parties, including:

- our service providers for technology, communications and data storage;
- our consulting and advisory firms and contractors that have access to our confidential and proprietary data;
- administrators for our employee medical claims;
- rail and export terminal companies that are part of the supply chain for the delivery of our coal;
- coal power generation facilities that purchase our coal; and
- vendors who provide mining equipment, supplies, and services necessary for our operations.

These systems could be vulnerable to problems resulting from accidents such as fire, power loss or telecommunication failure. In addition, these systems could be vulnerable to cybersecurity incidents or other deliberate activities by others. Cybersecurity risks include those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches, cyber or phishing attacks, ransomware, malware, social engineering, physical breaches or other actions. Cybersecurity risks continue to evolve at a rapid pace.

Although we have implemented information technology controls and systems and provide employee training on phishing, malware, and other cyber risks designed to protect information and mitigate the risk of data loss and other cybersecurity risks, such measures cannot entirely eliminate cybersecurity threats, and the controls we have installed may be breached. Additionally, we have limited control and visibility over third-party systems that we rely on for our business. If any of these information technology systems cease to function properly or are breached, we could suffer disruptions to our mining operations and corporate functions and those events may materially and adversely impact our financial results and reputation and result in significant costs and liabilities.

Although we have not suffered any material losses relating to historical cybersecurity attacks on our systems as of the date of this report, there is no assurance that we will not suffer such losses in the future. In addition, as cyber threats continue to change, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate or remediate any cyber vulnerabilities.

Other Risks Related to Our Corporate Structure and Common Stock

If we are unable to regain compliance with the NYSE minimum share price requirement or continue to meet the NYSE s other continued listing requirements, the NYSE may delist our common stock.

Our common stock is currently listed on the NYSE. On December 26, 2018, we were notified by the NYSE that the average closing price of shares of our common stock had fallen below $1.00 per share over a period of 30 consecutive trading days, which is the minimum average share price for continued listing on the NYSE under Section 802.01C of the NYSE Listed Company Manual. Under the NYSE s rules, we have six months following receipt of the notification to regain compliance with the minimum share price requirement. We can regain compliance at any time during the six-month cure period if our common stock has a closing share price of at least $1.00 per share on the last trading day of any calendar month during the period and also has an average closing share price of at least $1.00 per share over the 30-trading day period ending on the last trading day of that month or on the last day of the cure period.

While the notice from the NYSE has no immediate impact on the listing of our common stock, our common stock could be delisted from the NYSE if we are unable to regain compliance with the NYSE s minimum share price requirement by the end of the six-month cure period. In addition, our common stock could be delisted pursuant to Section 802.01 of the NYSE Listed Company Manual if the trading price of our common stock on the NYSE falls below $0.16 per share. In this event, we would not have an opportunity to cure the stock price deficiency, and our common stock would be delisted immediately and suspended from trading on the NYSE. A delisting of our common stock, either as result of a failure to regain compliance with the NYSE s minimum share price requirement or our failure to satisfy other qualitative or quantitative standards for continued listing on the NYSE, could negatively impact us by, among other things, reducing the liquidity and market price of our common stock; reducing the number of investors willing to hold or acquire our common stock; and limiting our ability to issue additional securities or obtain additional financing in the future.

The price of our common stock has declined significantly and could decline further for a variety of reasons, resulting in a substantial loss on investment and negatively impacting our ability to raise equity capital.

Our stock price decreased from $4.80 per share on January 2, 2018 to $0.37 per share on December 31, 2018, and it could decline further. Such decline could result from a variety of factors, including, among other things, substantial doubt about our ability to continue as a going concern, concerns about our future prospects, actual or anticipated fluctuations in our operating results or financial condition, new laws or regulations or new interpretations of existing laws or regulations impacting our business, our customers businesses, or the coal transportation and logistics industry, sales of CPE Inc. s common stock by our stockholders or by us, a downgrade or cessation in coverage from one or more of our analysts, broad market fluctuations and general economic conditions and any other factors described in this Risk Factors section of this Form 10-K.

The current trading price of our common stock, or any further decline thereof, impedes our ability to raise capital through the issuance of additional shares of CPE Inc. s common stock or other equity securities and may cause a loss of part or all of an investment in shares of our common stock. In addition, if we sell additional shares of CPE Inc. common stock, that would result in dilution to existing stockholders and may result in decreases to our stock price and the value of existing investments in our stock. Those decreases may be more significant if we sell additional shares at depressed trading prices.

Our previous separation from Rio Tinto could subject us and our stockholders to any number of risks and uncertainties. For example, Rio Tinto has provided notice that it is seeking indemnification under our master separation agreement of any indemnifiable liabilities arising from the climate change litigation in California against Rio Tinto and numerous other fossil fuel industry defendants.

We entered into various agreements with Rio Tinto and its affiliates in connection with the 2009 IPO and separation from Rio Tinto. CPE Resources agreed to indemnify Rio Tinto for certain liabilities pursuant to these agreements. As discussed in this Form 10-K in Note 21, Commitments and Contingencies of our Consolidated Financial Statements, certain Rio Tinto entities are named defendants in litigation filed in July 2017 by multiple California local governments in California state court, naming numerous fossil fuel companies as defendants (together, the California Climate Change Litigation). The California Climate Change Litigation alleges, among other things, that defendants knowingly contributed to GHG emissions that have adversely impacted the environment, thereby creating financial liabilities for the plaintiffs and that defendants engaged in a coordinated effort to conceal and deny their own knowledge of those climate change threats, discredit scientific evidence and create doubt in the minds of customers, consumers, regulators, the media, journalists, teachers and the public about the consequences of the impacts of their alleged fossil fuel pollution. Although Cloud Peak Energy is not named as a defendant, in August 2017, Rio Tinto provided Cloud Peak Energy with a notice seeking indemnification pursuant to our 2009 master separation agreement with Rio Tinto, which requires us to indemnify Rio Tinto for certain liabilities relating to our business conducted prior to and after the closing of our 2009 separation from Rio Tinto and may potentially include liabilities in connection with the California Climate Change Litigation. Because the master separation agreement and other separation-related agreements were entered into while we were part of Rio Tinto, some of the terms of these agreements are likely less favorable to us than similar agreements negotiated between unaffiliated third parties. Third parties may also seek to hold us responsible for liabilities of Rio Tinto that we did not assume in connection with the 2009 IPO and for which Rio Tinto agreed to indemnify us, including liabilities related to the Jacobs Ranch and Colowyo mines, as well as the uranium mining venture that we do not own. If any of these liabilities are significant and we are ultimately held liable for them, we may not be able to recover the full amount of our losses from Rio Tinto. Refer to the applicable exhibits listed in

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Item 15 of this Form 10-K for the complete terms and conditions of the principal outstanding agreements with Rio Tinto entered into in connection with our 2009 IPO.

CPE Inc. is a holding company with no direct operations of its own and depends on distributions from CPE Resources to meet its ongoing obligations.

CPE Inc. is a holding company with no direct operations of its own and has no independent ability to generate revenue. Consequently, its ability to obtain operating funds depends upon distributions from CPE Resources and payments under the management services agreement. Pursuant to its management services agreement, CPE Resources makes payments to CPE Inc. in the form of a management fee and cost reimbursements to fund CPE Inc. s day-to-day operating expenses, such as payroll for its officers. However, if CPE Resources cannot make the payments pursuant to the management services agreement, CPE Inc. may be unable to cover these expenses.

The distribution of cash flows by CPE Resources to CPE Inc. is subject to statutory restrictions under the Delaware Limited Liability Company Act and contractual restrictions under CPE Resources s debt instruments that may limit the ability of CPE Resources to make distributions. In addition, any distributions and payments of fees or costs are subject to CPE Resources s financial condition.

As the sole member of CPE Resources, CPE Inc. incurs income taxes on any net taxable income of CPE Resources. The debt instruments allow CPE Resources to distribute cash in amounts sufficient for CPE Inc. to pay its tax liabilities payable to any governmental entity. To the extent CPE Inc. needs funds for any other purpose, and CPE Resources is unable to provide such funds for any reason, it could have a material adverse effect on our business, financial condition, results of operations or prospects.

We may issue shares of preferred stock with greater rights than our common stock.

Our certificate of incorporation authorizes our Board of Directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from our stockholders. Any preferred stock that is issued may rank ahead of our common stock in terms of dividends, liquidation rights, or voting rights. If we issue preferred stock, it may adversely affect the market price of our common stock.

We do not expect to pay dividends on our common stock.

We do not expect to pay any dividends on our common stock, in cash or otherwise, in the foreseeable future. We intend to retain any earnings for use in our business. In addition, the indentures governing our senior notes restrict our ability to pay dividends on our common stock. In the future, we may agree to further restrictions on our ability to pay dividends.

Anti-takeover provisions in our charter documents and other aspects of our structure may discourage, delay or prevent a change in control of our company and may adversely affect the trading price of CPE Inc. s common stock.

Certain provisions in CPE Inc. s amended and restated certificate of incorporation and amended and restated bylaws and other aspects of our structure may discourage, delay or prevent a change in our management or a change in control over us that stockholders may consider favorable. Among other things, CPE Inc. s amended and restated certificate of incorporation and amended and restated bylaws:

- provide for a classified Board of Directors, which may delay the ability of our stockholders to change the membership of a majority of our Board of Directors;

- authorize the issuance of   blank check   preferred stock that could be issued by our Board of Directors to thwart a takeover attempt;

- do not provide for cumulative voting;

- provide that vacancies on the Board of Directors, including newly created directorships, may be filled only by a majority vote of directors then in office;

- limit the calling of special meetings of stockholders;

- provide that stockholders may not act by written consent;

- provide that our directors may be removed only for cause;

- require supermajority voting to effect certain amendments to our certificate of incorporation and our bylaws; and

- require stockholders to provide advance notice of new business proposals and director nominations under specific procedures.

In addition, as described further in Note 11 of Notes to Consolidated Financial Statements in Item 8 below, on January 11, 2019, CPE Inc. entered into the Rights Agreement (the Rights Agreement) to diminish the risk that the Company s ability to use its net operating losses and certain other tax assets becomes limited. The Rights Agreement is designed to reduce the likelihood that the Company will experience an ownership change under Section 382 of the Internal Revenue Code by (i) discouraging any person or group from becoming a 4.95% shareholder and (ii) discouraging any existing 4.95% shareholder from acquiring additional shares of CPE Inc. s common stock.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

See Item 1 Business Mining Operations for specific information about our mining operations.

Coal Reserves

As of December 31, 2018, we controlled approximately 977.3 million tons of proven and probable coal reserves. All of our proven and probable reserves are classified as thermal coal.

The following table summarizes the tonnage of our coal reserves that is classified as proven or probable, and assigned, as well as our property interest, as of December 31, 2018:

Mine	Proven Preserves	Probable Reserves	Total Proven & Probable Reserves	Assigned Reserves	Reserves Owned	Reserves Leased
		(nearest million, in tons)		(%)	(nearest million, in tons)	
Antelope	385.6	86.8	472.4	100		472.4
Cordero Rojo	233.4	51.9	285.3	100	38.0	247.3
Spring Creek	202.2	17.4	219.6	100		219.6
Total (1)	821.2	156.1	977.3		38.0	939.3

(1) Totals reflect rounding.

The following table provides the quality (average sulfur content and average Btu per pound) of our coal reserves as of December 31, 2018:

Mine	Total Proven & Probable Reserves	Average Btu per lb (1)	Average Sulfur Content	Average Sulfur Content
	(nearest million, in tons)		(%)	(lbs SO2/ mmBtu)
Antelope	472.4	8,875	0.22	0.50
Cordero Rojo	285.3	8,425	0.28	0.66
Spring Creek	219.6	9,350	0.34	0.73
Total (2)	977.3			

(1) Average Btu per pound includes weight of moisture in the coal on an as-sold basis.

(2) Totals reflect rounding.

We also control certain coal deposits that are contiguous to or near our primary reserve bases. The tons in these deposits are classified as non-reserve coal deposits and are not included in our reported reserves. These non-reserve coal deposits include:

- 7.5 million tons near our Antelope Mine;
- 53.2 million tons near our Cordero Rojo Mine;
- 3.9 million tons near our Spring Creek Mine; and
- 283.6 million tons at the Youngs Creek project.

Non-reserve coal deposits are not reserves under SEC Industry Guide 7. Estimates of non-reserve coal deposits are subject to further exploration and development, are more speculative and may or may not be converted to future reserves of the company.

Our reserve and non-reserve coal deposit estimates as of December 31, 2018 were prepared by our staff of geologists and engineers, who have extensive experience in PRB coal. These individuals are responsible for collecting and analyzing geologic data within and adjacent to leases controlled by us. Our Manager, Geology is the technical person primarily responsible for the preparation of our reserves estimates. He has a Bachelor of Science degree in Geology and over 10 years of industry experience with positions of increasing responsibility in mining geology and reserve determination. He reports to our Director, Geological Services and Special Projects, who has a Bachelor of Science degree in Mining Engineering and over 30 years of industry experience with positions of increasing responsibility in coal quality and mine planning, operations, project evaluations, risk management, and technical management at CPE Inc. The Director, Geological Services and Special Projects reports directly to our Executive Vice President and Chief Operating Officer. An external review of our reserves and non-reserve coal deposit estimates is performed every two years. The most recent review was performed for the year ended December 31, 2018 and was completed in January 2019 by John T. Boyd Company, mining and geological consultants. The results verified our reserve and non-reserve coal deposit estimates as of December 31, 2018.

Our coal reserve estimates are based on data obtained from our drilling activities and other available geologic data. All of our reserves are assigned, associated with our active coal properties, and incorporated in detailed mine plans. Estimates of our reserves are based on more than 7,000 drill holes. Our proven reserves have a typical drill hole spacing of 1,500 feet or less, and our probable reserves have a typical drill hole spacing of 2,500 feet or less.

Along with the geological data we assemble for our coal reserve estimates, our staff of geologists and engineers also analyzes the economic data such as cost of production, projected sales price and other data concerning permitting and advances in mining technology. Various factors and assumptions are utilized in estimating coal reserves, including assumptions concerning future coal prices and operating costs. These estimates are periodically updated to reflect past coal production and other geologic or mining data. Acquisitions or sales of coal properties will also change these estimates. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam.

Reserve Acquisition Process

Since our inception, we have focused on growth through the acquisition of proven and probable coal reserves and non-reserve coal deposits. Historically, this was accomplished through the federal competitive leasing process, known as the LBA process. For example, in 2011 we acquired 383 million tons of proven and probable coal reserves in two federal coal leases for our Antelope Mine.

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We acquire a large portion of our coal through the LBA process, and as a result, most of our coal is held under federal leases. Under this process, before a mining company can obtain a new federal coal lease, the company must nominate a coal tract for lease and then win the lease through a competitive bidding process. The LBA process has lasted anywhere from two to five years or more from the time the coal tract is nominated to the time a final bid is accepted by the BLM. After the LBA is awarded, the company then conducts the necessary testing to determine what amount can be classified as reserves and begins the process to permit the coal for mining, which generally takes another two to five years. Third-party legal challenges, such as legal challenges filed against the BLM and the Secretary of the Interior by environmental groups with respect to the LBA process in the PRB may result in delays and other adverse impacts on the LBA process.

To initiate the LBA process, companies wanting to acquire additional coal must file an application with the BLM s state office indicating interest in a specific coal tract. The BLM reviews the initial application to determine whether the application conforms to existing land-use plans for that particular tract of land and whether the application would provide for maximum coal recovery. The application is further reviewed by a regional coal team at a public meeting. Based on a review of the available information and public comment, the regional coal team will make a recommendation to the BLM whether to continue, modify or reject the application.

If the BLM determines to continue the application, the company that submitted the application will pay for a BLM-directed environmental analysis or an EIS to be completed. This analysis or impact statement is subject to publication and public comment. The BLM may consult with other government agencies during this process, including state and federal agencies, surface management agencies, Native American tribes or bands, the U.S. Department of Justice or others as needed. The public comment period for an analysis or impact statement typically occurs over a 60-day period.

After the environmental analysis or EIS has been issued and a recommendation has been published that supports the lease sale of the LBA tract, the BLM schedules a public competitive lease sale. The BLM prepares an internal estimate of the fair market value of the coal that is based on its economic analysis and comparable sales analysis. Prior to the lease sale, companies interested in acquiring the lease must send sealed bids to the BLM. The bid amounts for the lease are payable in five annual installments, with the first 20% installment due when the mining operator submits its initial bid for an LBA. Before the lease is approved by the BLM, the company must first furnish to the BLM an initial rental payment for the first year of rent along with either a bond for the next 20% annual installment payment for the bid amount, or an application for history of timely payment, in which case the BLM may waive the bond requirement if the company successfully meets all the qualifications of a timely payer. The bids are opened at the lease sale. If the BLM decides to grant a lease, the lease is awarded to the company that submitted the highest total bid meeting or exceeding the BLM s fair market value estimate, which is not published. The BLM, however, is not required to grant a lease even if it determines that a bid meeting or exceeding the fair market value of the coal has been submitted. The winning bidder must also submit a report setting forth the nature and extent of its coal holdings to the U.S. Department of Justice for a 30-day antitrust review of the lease. If the successful bidder was not the initial applicant, the BLM will refund the initial applicant certain fees it paid in connection with the application process, for example the fees associated with the environmental analysis or EIS, and the winning bidder will bear those costs. Coal awarded through the LBA process and subject to federal leases is administered by the U.S. Department of the Interior under the Federal Coal Leasing Amendment Act of 1976. Once the BLM has issued a lease, the company must next complete the permitting process before it can mine the coal. See Item 1 Business Environmental and Other Regulatory Matters Mining Permits and Approvals.

The federal coal leasing process is designed to be a public process, giving stakeholders and other interested parties opportunities to comment on the BLM s proposed and final actions and allow third-party comments. Because of this, third parties, including NGOs, can challenge the BLM s actions, which may delay the leasing process. If these challenges prove successful or are litigated for a prolonged period of time, a coal company s ability to bid on or acquire a new coal lease could be significantly delayed, or could cause the BLM to not offer a lease for bid at all. In addition, these types of challenges create some uncertainty with respect to the timing of future LBA bids and lease acquisitions and may ultimately delay the leasing process or prevent mining operations. Even after a lease has been issued and a successful bidder has paid installment money to the BLM, legal challenges may still seek to delay or prevent mining operations. It is possible that subsequent EISs for other mines in the PRB currently underway but not yet final could be similarly challenged. There also exists the possibility of similar challenges to the permitting and licensing process, which is also a public process designed to allow public comments. The BLM also allows for small tracts of coal to be acquired through the LBM leasing process. An LBM is a non-competitive leasing process and is used in circumstances where a lessee is seeking to modify an existing federal coal lease by adding less than 960 acres in a configuration that is deemed non-competitive to other coal operators. For example, in December 2012, we applied for two separate LBMs with the BLM: one at the Spring Creek Mine and one at the Antelope Mine. A Decision Record to issue the Antelope LBM was made by the BLM and was appealed by certain environmental groups. In early 2018, we received re-approval for the Antelope LBM. In February 2018, the BLM s re-approval was challenged by three environmental groups. See Note 21 of Notes to Consolidated Financial Statements in Item 8 for further information. The Spring Creek application is being processed by the BLM.

Each of our federal coal leases has an initial term of 20 years, renewable for subsequent 10-year periods and for so long thereafter as coal is produced in commercial quantities. The lease requires diligent development within the first 10 years of the lease award with a required coal extraction of 1% of the total coal under the lease by the end of that 10-year period. At the end of the 10-year development period, the lessee is required to maintain continuous operations, as defined in the applicable leasing regulations. In certain cases, a lessee may combine contiguous leases into an LMU. This allows the production of coal from any of the leases within the LMU to be used to meet the continuous operation requirements for the entire LMU. We currently have an LMU for our Antelope Mine. We pay to the federal government an annual rent of $3.00 per acre and production royalties of 12.5% of gross revenue on surface mined coal. The federal government remits approximately 50% of the production royalty payments to the state after deducting administrative expenses. Some of our mines are also subject to coal leases with the states of Montana or Wyoming, as applicable, and have different terms and conditions that we must adhere to in a similar way to our federal leases. Under these federal and state leases, if the leased coal is not diligently developed during the initial 10-year development period or if certain other terms of the leases are not complied with, including the requirement to produce a minimum quantity of coal or pay a minimum production royalty, if applicable, the BLM or the applicable state regulatory agency can terminate the lease prior to the expiration of its term.

Most of the coal we lease from the U.S. comes from split estate lands in which one party, such as the federal government, owns the coal and a private party owns the surface. In order to mine the coal we acquire, we must acquire rights to mine from certain owners of the surface lands overlying the coal. Certain federal regulations provide a specific class of surface owners, QSOs, with the ability to prohibit the BLM from leasing its coal. For example, in connection with an LBA tract that we previously nominated for our Cordero Rojo Mine, the BLM indicated that certain surface owners satisfied the regulatory definition of QSO. If the land overlying a coal tract is owned by a QSO, federal laws prohibit us from leasing the coal tract without first securing surface rights to the land, or purchasing the surface rights from the QSO, which would allow us to conduct our mining operations. Furthermore, the state permitting process requires us to demonstrate surface owner consent for split estate lands before the state will issue a permit to mine coal. This consent is separate from the QSO consent required before leasing federal coal. This right of QSOs and certain other surface owners allows them to exercise significant influence over negotiations and prices to acquire surface rights and can delay the federal coal lease or permitting processes or ultimately prevent the acquisition of the federal coal lease or permit over that land entirely. There are QSOs that own land adjacent to or near our existing mines that may be attractive acquisition candidates for us. Typically, we seek to purchase the land overlying our coal or enter into option agreements granting us an option to purchase the land upon acquiring a federal coal lease. We own substantially all of the land over our reserves. We may not own or control the land over our non-reserve coal deposits, which would be required before these non-reserve coal deposits could be classified as reserves and mined.

Most of the coal we have acquired from private third parties is in the form of coal leases obtained through private negotiations with one or more third parties. These leases generally include, among other terms and conditions, a set term of years with the right to renew the lease for a stated period and royalties to be paid to the lessor as a percentage of the sales price. These leases may require payment of a lease bonus or minimum royalty, payable either at the time of execution of the lease or in periodic installments, and a minimum production of coal from the leased areas in order to hold the leases by active production. We believe that the term of years will allow the recoverable reserve to be fully extracted in accordance with our projected mine plan. Consistent with industry practice, we conduct only limited investigations of title to our coal properties prior to leasing. Title to properties leased from private third parties is not usually fully verified until we make a commitment to develop a property, which may not occur until we have obtained the necessary permits and completed exploration of the property.

We acquired rights to significant coal deposits when we completed the acquisition of the Youngs Creek project, a non-operating mine in Northeast Wyoming in the Northern PRB, whereby we acquired rights to 283.6 million tons of non-reserve coal deposits along with significant related surface assets. We also announced in

2013 that we signed an option agreement and a corresponding exploration agreement with the Crow Tribe for the exploration and potential development of significant coal resources on the Crow Indian Reservation in southeast Montana in the Northern PRB region. In June 2018, we delivered notice to the Crow Tribe to exercise the Upper Youngs Creek coal lease option and extend the coal lease options for the Squirrel Creek and Tanner Creek project areas. See Item 1 Business Development Projects Youngs Creek Project Our inability to obtain third party financial assurances in connection with the permits required for the leased property may have a material adverse effect on our ability to qualify for any federal lease sales.

Office Space

As of December 31, 2018, we completed the move of our corporate headquarters from downtown Gillette, Wyoming to our Cordero Rojo Mine, which is located approximately 25 miles south of Gillette, Wyoming. As of December 31, 2018, we still owned approximately 32,000 square feet of office space related to our former headquarters. The building was sold in February 2019. In addition, we lease approximately 28,000 square feet of office space in Broomfield, Colorado under a lease that expires in February 2021. As of December 31, 2018, all of our long-lived assets were located in the U.S. See Note 5 of Notes to Consolidated Financial Statements in Item 8.

Item 3. ***Legal Proceedings.***

For a discussion of legal proceedings, please see Note 21 of Notes to Consolidated Financial Statements in Item 8.

Item 4. ***Mine Safety Disclosures***

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

PART II

Item 5. *Market for Registrant s Common Equity and Related Stockholder Matters.*

Our common stock, $0.01 par value, is traded on the NYSE under the symbol CLD . As of the close of business on March 8, 2019, there were 79 holders of record of our common stock. On December 26, 2018, we were notified by the NYSE that the average closing price of shares of our common stock had fallen below $1.00 per share over a period of 30 consecutive trading days, which is the minimum average share price for continued listing on the NYSE under Section 802.01C of the NYSE Listed Company Manual. Under the NYSE s rules, we have six months following receipt of the notification to regain compliance with the minimum share price requirement. Our common stock will continue to be listed on the NYSE during this six month period, subject to compliance with other continued listing requirements. Our common stock symbol CLD has been assigned a .BC indicator by the NYSE to signify that we currently are not in compliance with the NYSE s continued listing requirements. In addition, our common stock could be delisted pursuant to Section 802.01 of the NYSE Listed Company Manual if the trading price of our common stock on the NYSE falls below $0.16 per share. In this event, we would not have an opportunity to cure the stock price deficiency, and our common stock would be delisted immediately and suspended from trading on the NYSE.

Stock Performance Graph

The following performance graph compares the cumulative total return on CPE Inc. s common stock with the cumulative total return of the following indices: (i) the Standard & Poor s (S&P) MidCap 400 stock index and (ii) the Custom Composite Index. The Custom Composite Index is comprised of the peer group that is associated with our performance-based share units issued under our Long Term Incentive Plan. As of December 31, 2018, this group was comprised of Alliance Resource Partners LP, Antero Resources Corporation, Arch Coal, Inc., Cabot Oil & Gas Corporation, CONSOL Energy Inc., Eclipse Resources Corporation, EQT Corporation, EXCO Resources Inc., Foresight Energy LP, Hallador Energy Company, Natural Resource Partners L.P., Peabody Energy Corporation, Range Resources Corporation, Rhino Resource Partners LP, Rice Energy Inc., Ultra Petroleum Corp., and Westmoreland Coal Company. Each year the compensation committee of our Board of Directors reviews this group and makes changes if deemed appropriate in the judgment of the compensation committee. In 2018, CNX Coal Resources LP was removed from the Custom Composite Index and replaced by CONSOL Energy Inc., the parent company of CNX Coal Resources LP. In addition, Rice Energy Inc. was also added to the Custom Composite Index, however it was acquired by EQT Corporation, which is already a part of the Custom Composite Index. Finally, Noble Energy, Inc. and Whiting Petroleum Corp. were both removed from the Custom Composite Index because they were significantly larger than the average company in the group. SunCoke Energy, Inc. was removed due to their Global Industry Classification Standard being Steel rather than Coal and Consumable Fuels or Oil and Gas. To replace these companies, Eclipse Resources Corporation, EXCO Resources Inc., Peabody Energy Corporation, and Ultra Petroleum Corp. were added.

The graph assumes that you invested $100 in CPE Inc. s common stock and in each index at the closing price on December 31, 2013, that all dividends, if any, were reinvested and that you continued to hold your investment through December 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 CPE Inc. s common stock.

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Company/ Market/ Peer Group	2013	2014	2015	2016	2017	2018
CPE Inc.	100.00	51.00	11.56	31.17	24.72	2.04
S&P Midcap 400 Index	100.00	109.77	107.38	129.65	150.71	134.01
New Custom Composite(1)	100.00	71.97	38.47	49.81	44.67	30.20
New Custom Composite + CPE Inc.(1)	100.00	71.67	38.09	49.56	44.40	29.85
Old Custom Composite(2)	100.00	70.16	38.81	50.10	41.74	28.91
Old Custom Composite + CPE Inc.(2)	100.00	69.96	38.54	49.90	41.56	28.65

(1) Reflects the Custom Composite Index as of December 31, 2018.

(2) Reflects the Custom Composite Index as of December 31, 2017.

In accordance with SEC rules, the information contained in the Stock Performance Graph above shall not be deemed to be soliciting material, or to be filed with the SEC or subject to the SEC s Regulation 14A or 14C, other than as provided under Item 201(e) of Regulation S-K, or to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended, except to the extent that we specifically request that the information be treated as soliciting material or specifically incorporate it by reference into a document filed under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended.

Issuer Purchases of Equity Securities

The table below represents information pursuant to Item 703 of Regulation S-K regarding all share repurchases for the three-month period ended December 31, 2018:

	(a) Total Number of Shares Purchased (1)	(b) Average Price per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares that may yet be purchased under the Plans or Programs
October 1 through October 31, 2018		$		N/A
November 1 through November 30, 2018		$		N/A
December 1 through December 31, 2018		$		N/A

(1) Represents any shares withheld to cover withholding taxes upon the vesting of restricted stock.

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Item 6. ***Selected Financial Data.***

The following tables set forth our selected consolidated financial and other data on a historical basis. The information below should be read in conjunction with Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8 Financial Statements and Supplementary Data included elsewhere in this report.

We have derived the historical consolidated financial data as of December 31, 2018 and 2017 and for each of the three years in the period ended December 31, 2018 from our audited Consolidated Financial Statements included in Item 8 of this report. We have derived the historical Consolidated Balance Sheets data as of December 31, 2016, 2015, and 2014 and the historical Consolidated Statements of Operations (Loss) data for the years ended December 31, 2015 and 2014 from our audited Consolidated Financial Statements not included in this report.

Selected Consolidated Financial and Other Data

	Year Ended December 31, (in millions, except per share amounts)				
	2018	**2017**	**2016**	**2015**	**2014**
Statement of Operations Data					
Revenue	$ 832.4	$ 887.7	$ 800.4	$ 1,124.1	$ 1,324.0
Operating income (loss)(1)	(705.9)	(1.4)	63.2	(78.2)	134.6
Net income (loss)	(718.0)	(6.6)	21.8	(204.9)	79.0
Income (loss) per common share - basic	$ (9.49)	$ (0.09)	$ 0.36	$ (3.36)	$ 1.30
Income (loss) per common share - diluted	$ (9.49)	$ (0.09)	$ 0.35	$ (3.36)	$ 1.29

	December 31, (in millions)				
	2018	**2017**	**2016**	**2015**	**2014**
Balance Sheet Data					
Cash and cash equivalents	$ 91.2	$ 107.9	$ 83.7	$ 89.3	$ 168.7
Property, plant and equipment, net	654.4	1,365.8	1,432.4	1,488.4	1,589.1
Total assets	$ 928.7	$ 1,698.7	$ 1,714.8	$ 1,802.2	$ 2,151.2
Long-term debt	396.4	405.3	475.0	491.2	489.7
Federal coal leases obligations	1.8				64.0
Capital leases	2.5	4.9	7.6	8.9	9.0
Total liabilities	$ 635.0	$ 690.9	$ 763.1	$ 914.3	$ 1,063.3
Total equity (2)	$ 293.7	$ 1,007.8	$ 951.7	$ 887.9	$ 1,087.8

	Year Ended December 31, (in millions)				
	2018	**2017**	**2016**	**2015**	**2014**
Other Data					
Adjusted EBITDA (3)(4)	$ 67.3	$ 104.9	$ 98.6	$ 123.8	$ 201.9
Asian export tons Logistics and Related Activities	4.6	4.2	0.6	3.6	4.0

Tons sold Owned and Operated Mines (5)	49.7	57.4	58.5	75.1	85.9
Tons purchased and resold		0.3	0.3	0.3	0.1
Total tons sold	49.7	57.8	58.8	75.3	87.1

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(1) *Operating income (loss)* for the years ended December 31, 2014 through December 31, 2017 previously included all components of net benefit costs. Upon our adoption of ASU 2017-17 on January 1, 2018, only service costs remain in *Operating income (loss).* See Note 3 of Notes to Consolidated Financial Statements in Item 8.

(2) No cash dividends were declared or paid on our common stock during the periods presented.

(3) EBITDA and Adjusted EBITDA are intended to provide additional information only and do not have any standard meaning prescribed by U.S. GAAP. A quantitative reconciliation of historical *Net income (loss)* to Adjusted EBITDA is found in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Non-GAAP Financial Measures.

(4) Includes a non-cash gain on the termination of our postretirement medical plan of $21.5 million for the year ended December 31, 2018. Excluding this non-cash gain, Adjusted EBITDA would have been $45.8 million for the year ended December 31, 2018. See Note 19 of Notes to Consolidated Financial Statements in Item 8 for a discussion regarding the termination of our postretirement medical plan effective January 1, 2019.

(5) Inclusive of intersegment sales.

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

Unless the context indicates otherwise, the terms Cloud Peak Energy, the Company, we, us, and our refer to Cloud Peak Energ Inc. and its subsidiaries.

This Item 7 may contain forward-looking statements that involve substantial risks and uncertainties. When considering these forward-looking statements, you should keep in mind the cautionary statements in this report and our other SEC filings. See Cautionary Notice Regarding Forward-Looking Statements and Item 1A Risk Factors elsewhere in this document.

This Item 7 is intended to help the reader understand our results of operations and financial condition. This discussion should be read in conjunction with our Consolidated Financial Statements in Item 8.

Overview

We produce coal in the PRB. We operate some of the safest mines in the coal industry. According to the most current MSHA data, we have one of the lowest employee all injury incident rates among the largest U.S. coal producing companies. We currently operate solely in the PRB, the lowest cost region of the major coal producing regions in the U.S., where we own and operate three surface coal mines: the Antelope Mine, the Cordero Rojo Mine, and the Spring Creek Mine.

Our Antelope Mine and Cordero Rojo Mine are located in Wyoming and our Spring Creek Mine is located in Montana. Our mines produce subbituminous thermal coal with low sulfur content, and we sell our coal primarily to domestic and foreign electric utilities. Thermal coal is primarily consumed by electric utilities and industrial consumers as fuel for electricity generation. In 2018, the coal we produced generated approximately 2% of the electricity produced in the U.S. As of December 31, 2018, we controlled approximately 977.3 million tons of proven and probable reserves. We do not produce any metallurgical coal. See Item 1 Business Mining Operations.

In addition, we have two development projects, both located in the Northern PRB. The Youngs Creek project is an undeveloped surface mine project located in Wyoming, seven miles south of our Spring Creek Mine and contiguous with the Wyoming-Montana state line. The Big Metal project is located near the Youngs Creek project on the Crow Indian Reservation in southeast Montana. On June 7, 2018, Big Metal Coal Co. LLC (Big Metal), our wholly-owned subsidiary, delivered notice to the Crow Tribe of Indians (Crow Tribe) to exercise the Upper Youngs Creek coal lease option and extend the coal lease options for the Squirrel Creek and Tanner Creek project areas. These two projects, in addition to the exercise of the aforementioned options, are described in more detail under Item 1. Business Development Projects. Any future development and coal production from these projects remains subject to significant risks and uncertainty. These development projects have been impaired. For additional information, see Note 7 of Notes to Consolidated Financial Statements in Item 8.

Our logistics business provides a variety of services designed to facilitate the sale and delivery of coal, primarily to Asian utility customers. These services include the purchase of coal from third parties or from our owned and operated mines, coordination of the transportation and delivery of purchased coal, negotiation of take-or-pay rail agreements and take-or-pay port agreements and demurrage settlement with vessel operators. See Item 1 Business Transportation and Logistics Services for further discussion.

Recent Developments

During the fourth quarter of 2018 and through the filing date of this Form 10-K, we made a number of announcements regarding Cloud Peak Energy s engagement of various advisors to assist in reviewing alternatives including the potential sale of the Company and to assist in reviewing our capital structure and strategic restructuring alternatives. During that time, we experienced a number of adverse events that have negatively impacted our financial results, liquidity and future prospects. Our business and liquidity outlook has been adversely impacted since the third quarter of 2018 by a number of factors, which are highlighted in this Recent Developments section:

- operational issues in the fourth quarter of 2018 at our Antelope mine;
- depressed PRB thermal coal industry conditions;

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- logistics export pricing declined in the fourth quarter of 2018 to an uneconomic level;
- reduced cash flow projections for 2019 and future years;
- termination of our Credit Agreement due to significantly reduced availability and the impact of the financial covenants;
- significantly reduced liquidity, primarily comprised of our cash and cash equivalents;
- reduced A/R Securitization Program availability, requiring greater cash collateralization;
- noncompliance with the NYSE s continued listing requirements and potential delisting of our common stock;
- demands for additional reclamation surety bond collateral;
- our election not to make an interest payment under the 2024 Notes (as defined below) on the March 15, 2019 due date, utilizing the grace period provided by the indenture; and
- our continued review of our capital structure and restructuring alternatives.

As a result of the developments noted above, asset impairments were recorded as of December 31, 2018, and there was a determination of substantial doubt in our ability to continue as a going concern, based on current projections. This Recent Developments section highlights these events and should be read together with the rest of this Form 10-K, including without limitation, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations, Item 1A Risk Factors and Item 8 Financial Statements and Supplementary Data.

Fourth Quarter Operational Issues at Antelope Mine

In the fourth quarter of 2018, we experienced continued production issues at our Antelope Mine resulting from weather-related spoil failures due to heavy 2018 rains and related events**.** The rehandle of material by our truck and shovel fleets increased the per ton costs during the fourth quarter of 2018. This activity deferred the planned pre-stripping work into 2019, thereby increasing the projected costs for 2019 to regain a proper mine sequence. For additional discussion and analysis about the adverse effects from these production issues at our Antelope Mine in the fourth quarter of 2018, see Current Considerations .

Fourth Quarter Logistics Pricing Decline

In the fourth quarter of 2018, export prices for our logistics business declined significantly. From September 30, 2018 to December 31, 2018, the Kalimantan index declined by 14 percent from $53.25 per tonne to $46.00 per tonne. At this reduced price, our logistics business did not generate positive economic returns as reflected by the loss in our Logistics and Related Activities segment during the fourth quarter of 2018 and lowered our forecasted 2019 expectations. This was a significant difference from the September 30, 2018 pricing and economics.

Reduced Cash Flow Projections for 2019

During 2018, our cash balance decreased by $16.7 million because our cash flows from operations were insufficient to fund our cash interest and capital expenditures during the year. This large decrease in cash occurred during the fourth quarter of 2018 as our cash balance decreased from $109.5 million as of September 30, 2018 to $91.2 million as of December 31, 2018.

Further, as our business plans and financial forecasts were updated and reviewed during the fourth quarter of 2018 and finalized in the first quarter of 2019, our updated financial forecasts reflected significantly lower levels of expected cash flow from operating activities for 2019. The forecasting updates reflected the ongoing production issues at our Antelope Mine, resulting from the spoil failure re-handling described above, which requires significant deferred pre-stripping costs to be incurred in 2019 and lower export pricing assumptions.

Additionally, we experienced lower customer demand overall, particularly for the 8400 Btu coal from our Cordero Rojo Mine, as evidenced by lower contracted volumes and prices. As a result of the decline of the weighted average realized price at the Cordero Rojo Mine from 2018 to 2019, and rising costs caused by higher strip ratios, the cash margins and cash flow projections for 2019 sales at Cordero Rojo are uneconomic. This lower demand also resulted in reduced planned production rates at the Cordero Rojo Mine as part of our 2019 budgeting process that was completed in 2019.

Termination of Credit Facility

As disclosed in our Current Report on Form 8-K on November 13, 2018, Cloud Peak Energy Resources LLC (CPE Resources), a wholly owned subsidiary of CPE, provided PNC Bank, National Association with notice to terminate the Credit Agreement. The termination of the Credit Agreement was effective as of November 15, 2018. As of September 30, 2018, the $150 million Credit Agreement had a reduced availability of only $16.2 million of borrowing capacity based upon the quarterly financial covenant calculations. Any failure to meet those financial covenants could have resulted in an event of default under the Credit Agreement and cross-default under the indentures governing our senior notes. The Credit Agreement would have required CPE Resources to pay over $3.0 million in additional commitment and administrative fees during the remaining term of the Credit Agreement through May 2021, which will now be avoided. For additional information, see Note 18 of Notes to Consolidated Financial Statements in Item 8.

Significantly Reduced Liquidity

Subsequent to the termination of the Credit Agreement, our liquidity was comprised of cash and cash equivalents, because the A/R Securitization Program was fully utilized to issue letters of credit as collateral for the reclamation surety bond providers. As of December 31, 2018, our total available liquidity was $91.2 million. As of March 8, 2019, our total available liquidity was $65.5 million, and we expect to continue using additional cash that will further reduce this liquidity.

Reduced Accounts Receivable Securitization Program Availability

Our A/R Securitization Program allows for the issuance of letters of credit. As of December 31, 2018, the A/R Securitization Program would have allowed for $21.3 million of borrowing capacity, which was less than the undrawn face amount of letters of credit outstanding under the A/R Securitization Program of $25.7 million as of December 31, 2018. The $4.4 million difference between the borrowing capacity and the undrawn face amount of the letters of credit outstanding was cash-collateralized into a restricted cash account in early January 2019, thus bringing the borrowing capacity to zero. As of March 8, 2019, the A/R Securitization Program would have allowed for $13.5 million of borrowing capacity, which is less than the $25.7 million in outstanding indebtedness under the A/R Securitization Program. The difference has been cash collateralized. For additional information, see Note 18 of Notes to Consolidated Financial Statements in Item 8.

Noncompliance with the NYSE s Continued Listing Requirements

As disclosed in our Current Report on Form 8-K on December 27, 2018, we were notified by the NYSE that the average closing price of shares of our common stock had fallen below $1.00 per share over a period of 30 consecutive trading days, which is the minimum average share price for continued listing on the NYSE under Section 802.01C of the NYSE Listed Company Manual. Under the NYSE s rules, we have six months following receipt of the notification to regain compliance with the minimum share price requirement. Since that time, our share price has continued to trade well under $1.00.

Demands for Additional Reclamation Surety Bond Collateral

U.S. federal and state laws require we secure certain of our obligations to reclaim lands used for mining and to secure coal lease obligations. The primary method we have used to meet these reclamation obligations and to secure coal lease obligations is to provide a third-party surety bond. As of December 31, 2018, we had $407.6 million of reclamation and lease bonds backed by collateral of $25.7 million in the form of letters of credit under our A/R Securitization Program as well as restricted cash, securing coal lease obligations, and for other operating requirements.

Subsequent to December 31, 2018, we received letters from certain of our third-party surety bond underwriters demanding increased collateral or replacement of their bonds. Any further issuances of letters of credit to satisfy the increased collateral demands or any replacement bonds would immediately reduce the cash and cash equivalents available to support the operations of the business, as the current level of letters of credit exceeds the borrowing credit limit of our A/R Securitization Program. We are currently in discussions with our surety bond underwriters, however we cannot assure you these negotiations will be successful in avoiding increased collateral requirements. These surety bonds are required by the permits governing our mining operations.

Fourth Quarter Asset Impairments

As a result of the aforementioned changes experienced in the fourth quarter of 2018 and the outlook for the business going forward, we recorded asset impairments as of December 31, 2018 with respect to (1) our Cordero Rojo mine and (2) our Youngs Creek and Big Metal development projects.

Our Cordero Rojo Mine produces 8400 Btu coal, and it is experiencing a strip ratio increase at a time of sustained low customer demand. As 2019 and future business plans and financial forecasts were updated and reviewed during the fourth quarter of 2018 and finalized during the first quarter of 2019, a triggering event was identified which required impairment assessment for which the conclusion was that an impairment was determined to exist as of December 31, 2018. The carrying net book value amount related primarily to land access and mineral rights, and was impaired by $372.4 million. The asset impairment charge does not alter the underlying land access and mineral rights. For additional information, see Note 7 of Notes to Consolidated Financial Statements in Item 8.

In addition, we have two development projects, both located in the Northern PRB, the Youngs Creek and Big Metal projects. As 2019 and future business plans and financial forecasts were updated and reviewed during the fourth quarter of 2018 and finalized during the first quarter of 2019, it became evident that, along with the lack of access to the capital markets, the business would not be able to generate the capital required to develop these projects. It was concluded that a triggering event existed, and the fair value was determined to be less than the carrying value, requiring the recognition of an impairment as of December 31, 2018. The carrying net book value amount, which related primarily to land access and mineral rights, was reduced by $309.2 million. The asset impairment charge does not alter the underlying land access and mineral rights. An improved future outlook could provide the opportunity to reassess the potential development of these projects. For additional information, see Note 7 of Notes to Consolidated Financial Statements in Item 8.

Election Not to Make an Interest Payment under the 2024 Notes

As of December 31, 2018 and March 11, 2019, CPE Resources had $290.4 million in outstanding indebtedness under the 12.00% second lien senior notes due 2021 (the 2021 Notes) and $56.4 million in outstanding indebtedness under the 6.375% senior notes due 2024 (the 2024 Notes , and collectively with the 2021 Notes, the senior notes).

CPE Resources has an interest payment obligation under the 2024 Notes of approximately $1.8 million, which is due on March 15, 2019. The indenture governing the 2024 Notes provides a 30-day grace period that extends the latest date for making this interest payment to April 14, 2019, before an Event of Default occurs under the indenture. Although we have sufficient liquidity to make the interest payment, we elected not to make this interest payment on the due date and plan to utilize the 30-day grace period provided by the indenture, to allow additional time to assess our restructuring alternatives. If we do not make this interest payment by April 14, 2019, an Event of Default would occur under the indenture governing the 2024 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2024 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2024 Notes. An Event of Default under the 2024 Notes for failure to pay interest would not result in a default under the 2021 Notes unless the 2024 Notes are accelerated. An Event of Default under the 2024 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance. We continue to evaluate alternatives associated with this interest payment.

CPE Resources has an interest payment obligation under the 2021 Notes of approximately $17.4 million, which is due on May 1, 2019. The indenture governing the 2021 Notes provides a 30-day grace period that extends the latest date for making this interest payment to May 31, 2019, before an Event of Default occurs under the indenture. If we do not make this interest payment by May 31, 2019, an Event of Default would occur under the indenture governing the 2021 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2021 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2021 Notes. An Event of Default under the 2021 Notes for failure to pay interest would not result in a default under the 2024 Notes unless the 2021 Notes are accelerated. An Event of Default under the 2021 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R

Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance.

Ability to Continue as a Going Concern

Our reduced liquidity, most notably with the termination of our Credit Agreement in November 2018 due to the limited availability thereunder based on the financial covenants, along with our forecasts projecting lower levels of operating cash flow have limited our access to the capital markets. Our liquidity is now limited to cash and cash equivalents. Our forecasted cash from operations alone is insufficient to fund cash interest and capital expenditures. This has resulted in our conclusion that there is substantial doubt about our ability to continue as a going concern. As a result, we will continue to pursue options to alleviate this condition, including but not limited to evaluating our restructuring options, but there can be no guarantees that this will alleviate the substantial doubt that exists. Our consolidated financial statements have been prepared assuming we will continue as a going concern, which contemplates continuity of operations, realization of assets and the satisfaction of liabilities in the normal course of business. As a result, the accompanying consolidated financial statements do not include any adjustments relating to the recoverability and classification of assets and their carrying amounts, or the amount and classification of liabilities that may result should we be unable to continue as a going concern.

On March 14, 2019, we entered into a Forbearance Agreement (the Forbearance Agreement) by and among Cloud Peak Energy Receivables LLC, CPE Resources and PNC Bank, National Association, as administrator, relating to our A/R Securitization Program, which provides that PNC Bank, National Association will not exercise any of its remedies upon a default under the A/R Securitization Program based on the existence of substantial doubt regarding our ability to continue as a going concern. Pursuant to the Forbearance Agreement, the forbearance period terminates on the earlier of (i) April 14, 2019 and (ii) the date on which any additional events of default may occur, as specified therein.

Review of Capital Structure and Restructuring Alternatives

As disclosed in our Current Report on Form 8-K on November 13, 2018, we announced a Strategic Alternatives Review. Our Board of Directors, working together with its management team and legal and financial advisors, has commenced a review of strategic alternatives, including a potential sale of the Company. We engaged J.P. Morgan Securities LLC as our financial advisor and Allen & Overy LLP as our legal counsel in connection with our review of strategic alternatives. This fourth quarter 2018 process did not result in a transaction.

As disclosed on our Current Report on Form 8-K on January 29, 2019, we issued a press release providing an update to the previously-announced review of strategic alternatives, announcing the retention of Centerview Partners LLC as our investment banker, Vinson & Elkins LLP as our legal advisor, and FTI Consulting, Inc. as our financial advisor to assist us in our review of capital structure and restructuring alternatives.

Our restructuring evaluation process is continuing. We are actively engaged in discussions with certain of our creditor groups financial and legal advisors regarding potential alternatives, including asset sales, a private debt restructuring, or a court-supervised reorganization under Chapter 11 of the U.S. Bankruptcy Code, and related financing needs. Although this process remains uncertain and fluid, we will need to restructure our balance sheet in order to improve our capital structure, adjust our business to ongoing depressed PRB thermal coal industry conditions, address our significantly reduced liquidity and continue as a going concern. As noted above, an interest payment on our 2024 Notes will need to be made by April 14, 2019, to avoid a default under the indenture governing the 2024 Notes. An Event of Default under the 2024 Notes for failure to pay interest would not result in a default under the 2021 Notes unless the 2024 Notes are accelerated. An Event of Default under the 2024 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance. We continue to evaluate alternatives associated with this interest payment.

If we determine not to make this interest payment by April 14, 2019, we may seek protection under Chapter 11.

In connection with our review of capital structure and restructuring alternatives, we expect our mining operations and reclamation activities to continue in the ordinary course of business.

As a result of our ongoing restructuring evaluation, we currently expect to delay our 2019 annual stockholders meeting.

Segment Information

Our reportable segments include Owned and Operated Mines and Logistics and Related Activities. For a discussion of these segments, see Note 5 of Notes to Consolidated Financial Statements in Item 8.

Core Business Operations

Our key business drivers include the following:

- the volume of coal sold by our Owned and Operated Mines segment;
- the price for which we sell our coal;
- the costs of mining, including labor, repairs and maintenance, fuel, explosives, depreciation of capital equipment, and depletion of coal leases;
- the amount of royalties, severance taxes, and other governmental levies that we pay;
- capital expenditures to acquire property, plant and equipment;
- the volume of deliveries coordinated by our Logistics and Related Activities segment to customer contracted destinations;
- the revenue we receive for our logistics services; and
- the costs for logistics services, rail and port charges for coal sales made on a delivered basis, including demurrage and any take-or-pay charges.

The volume of coal that we sell in any given year is driven by global and domestic demand for coal-generated electric power. Demand for coal-generated electric power may be affected by many factors including weather patterns, natural gas prices, railroad performance, the availability of coal-fired and alternative generating capacity and utilization, the closure of coal-fired power plants, environmental and legal challenges, political and regulatory factors, energy policies, international and domestic economic conditions, currency exchange rate fluctuations, and other factors discussed in this Item 7 and in Item 1A Risk Factors.

The price at which we sell our coal is a function of the demand for coal relative to the supply. We typically seek to enter into multi-year contracts with our customers, which helps mitigate the risks associated with any short-term imbalance in supply and demand. In earlier years, we entered each year with expected production effectively fully sold. This strategy helped us run our mines at predictable production rates, which improves control of operating costs. In recent years, our business has become more variable and less predictable because utilities are adjusting their purchasing pattern based on natural gas prices, weather, and other factors and have also been increasingly purchasing coal for shorter terms. Due to operational issues at the Antelope Mine, we shipped 49.7 million tons in 2018, which was below our commitment to sell 52 million tons for 2018. We worked with our customers to move Antelope tons into 2019 where possible.

As is common in the PRB, coal seams at our existing mines naturally deepen, resulting in additional overburden to be removed at additional cost. We have experienced increased operating costs for longer haul distances, maintenance and supplies, and employee wages and salaries. We use derivative financial instruments to help manage our exposure to diesel fuel prices. We entered into West Texas Intermediate (WTI) derivative financial instruments to economically hedge our diesel fuel costs in 2017 and 2016. In July 2018, we entered into WTI derivative financial instruments to economically hedge our diesel fuel costs for the remainder of 2018 and all of 2019.

We incur significant capital expenditures to maintain, update and expand our mining equipment, surface land holdings and coal reserves. As the costs of acquiring federal coal leases and associated surface rights increase, our depletion costs also increase.

The volume of coal sold on a delivered basis is influenced by international and domestic market conditions. Coal sold on a delivered basis to customer-contracted destinations, including sales to Asian customers, involves us arranging and paying for logistics services, which can include rail, rail car hire, vessel chartering, and port charges, including any demurrage incurred and other costs. These logistics costs are affected by volume, various scheduling considerations, and negotiated rates for rail and port services. We have exposure to take-or-pay commitments for our rail and port committed capacities.

Current Considerations

Owned and Operated Mines Segment

Mine shipments to domestic customers were 44.9 million tons in 2018, which is down from the 53.1 million tons of shipments in 2017.

Shipments during 2018 were negatively impacted by ongoing operational issues at the Antelope Mine. Antelope production continued to be impacted by the spoil failures through January 2019, which resulted from the heavy rain experienced during the second quarter of 2018. While the immediate impact of the rain was mitigated by early August, the increased moisture caused significant spoil failures in both dragline pits in mid-August. This occurred as coal was removed from the base of the wet spoil piles. The spoil failures resulted in increased per ton costs, as mining costs included significant re-handle expense, during a period of reduced coal shipments. In the fourth quarter 2018, Antelope experienced further operational issues and associated costs as the mine continued to address the impacts of the earlier spoil failures. Antelope Mine produced 23.2 million tons of coal in 2018, which was 4.8 million tons lower than plan. As resources were diverted from pre-stripping, this activity and related expense will continue to result in a higher per ton cost in 2019. As 26.6 million tons of coal had been contracted for 2018 delivery, we worked with our customers to agree on deferrals of 1.4 million tons into 2019, or other resolutions, including cancellation of the deliveries, for the unshipped portion of previously contracted volumes from the Antelope Mine.

Shipments during 2018 were also negatively impacted by the low demand for the 8400 Btu coal at the Cordero Rojo Mine. Shipments of 12.6 million tons were 3.8 million tons fewer than 2017 shipments of 16.4 million tons. In the fourth quarter 2018, we experienced even greater demand and pricing challenges with 8400 Btu coal.

Natural gas prices during the fourth quarter increased to above $4.00 per MMBtu due to colder weather across much of the U.S. and well below average inventories. Since the start of 2019, natural gas prices have declined to near $3.00 per MMBtu on milder weather forecasted. As of December 28, 2018, U.S. Energy Information Administration data showed that natural gas inventories have declined by 14% compared to year ago levels.

Energy Ventures Analysis estimates there were 51 million tons of PRB coal inventories on utility stockpiles at the end of December 2018, a decline of 20 million tons from December 2017 levels. We believe declining customer inventories will support contracting during 2019. Our capacity to contract for additional quantities in the first quarter of 2019 are limited due to the deferral of tons from 2018 from our Antelope mine, however, our limited open volumes for the remainder of 2019 could benefit from any additional in-year sales depending on pricing.

Logistics and Related Activities Segment

The international thermal Newcastle coal price index during the fourth quarter of 2018 remained around $100 per tonne, currently settling around $97 per tonne due to strong demand. Since September 30, 2018, however, the Kalimantan 5000 GAR index price, which the Spring Creek Mine coal typically prices against, declined by 14% to end the year at $46 per tonne. At this reduced price, our logistics business would not generate positive economic returns. The late 2018 collapse of the Indonesian rupiah has lowered producers U.S. Dollar cost and the Indonesian Government has removed export restrictions to increase U.S. Dollar exports. The result has been an increase in Indonesian exports and a drop in the Kalimantan 5000 index. The current wide gap between Newcastle and Kalimantan 5000 index pricing is not common compared to typical historical spreads between those indices. More recently, the Kalimantan index has increased to $56.55 per tonne, as of March 1, 2019.

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We exported 4.6 million tons during 2018 as compared to 4.2 million tons in 2017. We expect lower prices during the first quarter of 2019 as subbituminous prices were depressed during the fourth quarter of 2018.

Based on estimates through December 2018, year-to-date thermal imports into China have increased 20 million tonnes, or almost 10%, compared to December 2017. China s electricity generation has increased by 7.4% through December after increasing by 6.5% last year, with most of this increase from thermal coal generation.

Thermal coal imports to India have increased by nearly 18% this year as domestic coal production has struggled to keep pace with rising demand. South Korean thermal coal imports continue to grow as recently commissioned plants increase their generation. Since we announced the JERA Trading contract to supply a new integrated gasification combined cycle (IGCC) power plant in Japan beginning in late 2019, we have been discussing test burns with five Japanese utilities. Two test burns were successfully completed in 2018, and during the fourth quarter, another test burn cargo was negotiated and shipped in January 2019. There is no assurance that these test burns will lead to future sales.

2019 Budget

We finalized our 2019 budget in February 2019. We have budgeted production volumes of 50.0 million tons, of which we plan for approximately 4.6 million tons to be exported.

We have budgeted for approximately $16.0 million of maintenance capital needs.

Environmental and Other Regulatory Matters

Federal, state and local authorities regulate the U.S. coal mining industry with respect to various matters, including air quality standards, water pollution, plant and wildlife protection, the discharge of materials into the environment and the effects of mining on surface and groundwater quality and availability. These laws and regulations have had, and will continue to have, a significant adverse effect on our production costs and our competitive position relative to certain other sources of electricity generation. Future laws, regulations or orders, including those relating to global climate change, may cause coal to become a less attractive fuel source, thereby reducing coal s share of the market for fuels and other energy sources used to generate electricitySee Item 1 Business Environmental and Other Regulatory Matters.

In addition, the change in U.S. Presidential Administrations in 2017 resulted in a number of executive branch initiatives, some of which are discussed below, that seek to unwind the prior Administration s fossil fuel actions and to promote development of U.S. natural resources and economic growth. For instance, the current Administration issued Executive Order 13783 on promoting energy independence and economic growth, which, among other things, directed the United States Environmental Protection Agency (EPA) to review the Clean Power Plan (CPP) rules and also calls for the review of existing regulations that potentially burden the development or use of domestically produced energy resources. This executive order further directed the Council on Environmental Quality (CEQ) to rescind its final guidance discussing how federal agencies should consider the effects of GHG emissions and climate change in their National Environmental Policy Act (NEPA) evaluations, which the CEQ did on April 5, 2017. This guidance could have created additional delays and costs in the NEPA review process or in our operations, or even an inability to obtain necessary federal approvals for our operations, including due to the increased risk of legal challenges from environmental groups seeking additional analysis of climate impacts. Nevertheless, because of the uncertainty associated with these initiatives and pending or anticipated legal challenges by certain environmental groups, states or others, we cannot predict the ultimate impact of the current Administration s initiatives on future demand for coal or our financial results.

Clean Power Plan

In August 2015, the EPA issued the CPP rules that established carbon emission standards for power plants, called CO_2 emission performance rates. The EPA expected each state to develop implementation plans for power plants in its state to meet the individual state targets established in the CPP. The EPA gave states the option to develop compliance plans for annual rate-based reductions (pounds per megawatt hour) or mass-based tonnage limits for CO_2. The EPA also proposed a federal compliance plan to implement the CPP in the event that an approvable state plan was not submitted to the EPA.

Judicial challenges were filed against the CPP. On February 9, 2016, the U.S. Supreme Court granted a stay of the implementation of the CPP before the United States Court of Appeals for the District of Columbia (Circuit Court) issued a final decision. By its terms, this stay remains in effect throughout the pendency of the appeals process including at the Circuit Court and the Supreme Court if any certiorari petition is granted. The stay suspends the rule, including the requirement that states submit their initial plans by September 2016. The Supreme Court s stay applies only to EPA s regulations for CO_2 emissions from existing power plants and does not affect EPA s standards for new power plants, which are also subject to judicial challenges. On the same day when Executive Order 13783 was issued, the EPA filed a motion in the Circuit Court requesting that the Circuit Court hold the case in abeyance while the EPA conducted the review of the CPP. The Circuit Court granted the motion and ordered the parties to file a supplemental briefing regarding whether to remand the case to the EPA.

On October 10, 2017, EPA Administrator Pruitt announced that the EPA would seek to repeal the CPP in its entirety. In August 2018, the EPA proposed the ACE Rule, which would establish emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants and replace the CPP. The ACE Rule has several components, including a determination of the best system of emission reduction for GHG emissions from coal-fired power plants and a list of candidate technologies states can use to establish standards of performance when developing their plans. The proposed ACE Rule, if and when finalized, will most likely be subject to further judicial review. It is not clear what changes to the pending appeals, if any, will result from the EPA s decision to seek repeal of the CPP in its entirety including whether the appellate process regarding the CPP will continue. Were the CPP upheld so that the rule would be implemented in the current form, or if the ACE Rule results in state plans to reduce the level of GHG emissions from electric utility generating units, then demand for coal could, depending on the specific requirements of any new regulations, be further decreased, potentially significantly, and adversely impact our business.

Federal Coal Leasing and Royalties

On March 28, 2017, the Secretary of the U.S. Department of the Interior (DOI) lifted a moratorium in effect since January 2016 on the issuance of new leases for coal resources on federally-owned lands. As a result of this action, the BLM is no longer precluded from accepting new applications for thermal coal sales or modifying existing leases subject to certain exceptions. This action could benefit members of the coal industry, including our company.

On July 1, 2016 the DOI published the final Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform Rule (2017 Valuation Rule). This rule was developed by the ONRR to significantly change the manner in which non-arm s length sales of natural resources from federal lands are valued for royalty purposes by mandating a net-back calculation from the first third-party sale and introducing an uncertain default rule. On February 27, 2017, the DOI postponed implementation of the 2017 Valuation Rule pending review of several petitions that had been filed to challenge the rule.

On August 7, 2017, the DOI followed through on its announced intention and issued a final rule to repeal the 2017 Valuation Rule in its entirety. As previously indicated by DOI, the agency will return to the benchmarks, which have been consistently and successfully utilized by the energy industry since the late 1980 s. The states of California and New Mexico have filed a legal challenge to the repeal of the 2017 Valuation Rule in a federal district court in California. Their lawsuit seeks the reinstatement of the 2017 Valuation Rule. If the court were to restore the 2017 Valuation Rule to legal effect and that ruling were not overturned on further appeal, that outcome could adversely impact export sales for vertically integrated mining and logistics entities such as Cloud Peak Energy Inc. and place vertically integrated entities at a competitive disadvantage to independent coal brokers or exporters of non-federal coal.

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Years Ended December 31, 2018, 2017, and 2016

Summary

The following table summarizes key results (in millions):

	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016	Percent Change 2018 vs 2017	Percent Change 2017 vs 2016
Total tons sold	49.7	57.8	58.8	(14.0)%	(1.7)%
Total revenue	$ 832.4	$ 887.7	$ 800.4	(6.2)	10.9
Net income (loss)	$ (718.0)	$ (6.6)	$ 21.8	*	(130.3)
Diluted EPS	$ (9.49)	$ (0.09)	$ 0.35	*	(125.7)
Adjusted EBITDA (1)(2)	$ 67.3	$ 104.9	$ 98.6	(35.8)	6.4

* *Not meaningful*

(1) EBITDA and Adjusted EBITDA are intended to provide additional information only and do not have any standard meaning prescribed by U.S. GAAP. A quantitative reconciliation of historical net income (loss) to Adjusted EBITDA is found in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Non-GAAP Financial Measures.

(2) Includes a non-cash gain on the termination of our postretirement medical plan of $21.5 million for the year ended December 31, 2018. Excluding this non cash gain, Adjusted EBITDA would have been $45.8 million for the year ended December 31, 2018. See Note 19 of Notes to Consolidated Financial Statements in Item 8 for a discussion regarding the termination of our postretirement medical plan effective January 1, 2019.

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Results of Operations

Revenue

The following table presents *Revenue* (in millions, except per ton amounts):

	Year Ended December 31,			Percent Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
Owned and Operated Mines					
Realized price per ton sold	$ 12.11	$ 12.17	$ 12.40	(0.5)%	(1.9)%
Tons sold	49.7	57.4	58.5	(13.4)	(1.9)
Coal revenue	$ 601.7	$ 699.1	$ 725.4	(13.9)	(3.6)
Other revenue	$ 13.5	$ 16.8	$ 13.2	(19.6)	27.3
Logistics and Related Activities					
Total tons sold	4.8	4.4	0.9	9.1	*
Realized price per ton sold - Asian export	$ 58.17	$ 50.20	$ 43.55	15.9	15.3
Tons sold - Asian export	4.6	4.2	0.6	9.5	*
Realized price per ton sold - Domestic	$ 51.31	$ 47.05	$ 50.08	9.0	(6.0)
Tons sold - Domestic	0.2	0.2	0.3		(33.3)
Revenue	$ 279.0	$ 222.5	$ 43.6	25.4	*
Other					
Revenue	$	$ 4.2	$ 30.3	(100.0)	(86.1)
Eliminations of intersegment sales					
Revenue	$ (61.8)	$ (54.9)	$ (12.1)	(12.6)	*
Total Consolidated					
Revenue	$ 832.4	$ 887.7	$ 800.4	(6.2)%	10.9%

* *Not meaningful*

Owned and Operated Mines Segment

The following table shows volume and price related changes to coal revenue at our Owned and Operated Mines (in millions):

Year ended December 31, 2016	$ 725.4
Changes associated with volumes	(13.0)
Changes associated with prices	(13.3)
Year ended December 31, 2017	$ 699.1
Changes associated with volumes	(94.6)

Changes associated with prices		(2.8)
Year ended December 31, 2018	$	601.7

Coal revenue decreased approximately 14% for the year ended December 31, 2018 compared to the year ended December 31, 2017 primarily due to fewer tons sold and lower realized prices. Volumes decreased by approximately 13% for the year ended December 31, 2018 as a result of the operational issues experienced at our Antelope Mine as well as continued depressed demand for 8400 Btu coal. Realized prices decreased in 2018 as higher priced contracts from prior years expired and were replaced with lower-priced contracts consistent with the current pricing environment. Other revenue decreased for the year ended December 31, 2018 compared to the year ended December 31, 2017 primarily due to business interruption insurance proceeds of $3.1 million, received in 2017, from a claim filed in 2016 related to lost tonnage due to a customer force majeure.

Coal revenue decreased approximately 4% for the year ended December 31, 2017 compared to the year ended December 31, 2016 primarily due to fewer tons sold and lower realized prices. Volumes decreased by approximately 2% for the year ended December 31, 2017 as a result of the mild weather experienced at the end of summer and into the beginning of winter, low natural gas prices, and higher customer stockpiles. Realized prices decreased in 2017 as higher priced contracts from prior years expired and were replaced with lower-priced contracts consistent with the current pricing environment. Other revenue increased for the year ended December 31, 2017 compared to the year ended December 31, 2016 primarily due to business interruption insurance proceeds of $3.1 million, received in 2017, from a claim filed in 2016 related to lost tonnage due to a customer force majeure.

Logistics and Related Activities Segment

Our Asian delivered sales are priced broadly in line with a number of relevant international coal indices adjusted for energy content and other quality and delivery criteria including the Newcastle benchmark price and the Kalimantan 5000. Our delivered sales have historically priced at a range between 60% to 75% of the forward Newcastle price and at a smaller discount to the forward Kalimantan 5000 price due to quality and freight cost differentials.

Revenue increased approximately 25% for the year ended December 31, 2018 compared to the year ended December 31, 2017 due to an improved export market. We shipped 36 vessels, or 4.6 million tons, internationally in 2018, at a higher average price per ton, compared to 32 vessels for a total of 4.2 million tons in 2017.

Revenue increased more than fivefold for the year ended December 31, 2017 compared to the year ended December 31, 2016 due to greater international shipments as a result of the recovery in international pricing for seaborne thermal coal, which allowed us to begin export shipments during the fourth quarter of 2016. We shipped 32 vessels internationally for a total of 4.2 million tons in 2017 compared to 0.6 million tons on six vessels in 2016.

Other

Revenue decreased for the year ended December 31, 2018 compared to the year ended December 31, 2017 due to no brokered sales during 2018, compare to $3.9 million in 2017.

Revenue decreased approximately 86% for the year ended December 31, 2017 compared to the year ended December 31, 2016 due to a decrease of $27.3 million related to buyouts of customer coal contracts, as customers took their contracted coal in 2017. This was partially offset by an increase of $1.2 million in broker revenue in 2017.

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Cost of Product Sold

The following table presents *Cost of product sold* (in millions, except per ton amounts):

	Year Ended December 31,			Percent Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
Owned and Operated Mines					
Average cost per ton sold	$ 11.19	$ 9.87	$ 9.81	13.4%	0.6%
Cost of product sold (produced coal)	$ 555.6	$ 566.9	$ 573.9	(2.0)	(1.2)
Other cost of product sold	$ 7.7	$ 8.2	$ 12.1	(6.1)	(32.2)
Logistics and Related Activities					
Average cost per ton sold - Asian export	$ 53.73	$ 48.48	$ 90.92	10.8	(46.7)
Average cost per ton sold - Domestic	$ 46.25	$ 43.28	$ 45.33	6.9	(4.5)
Cost of product sold	$ 263.5	$ 233.9	$ 72.6	12.7	*
Other					
Cost of product sold	$ 0.1	$ 4.1	$ 2.7	(97.6)	51.9
Eliminations of Intersegment Sales					
Cost of product sold	$ (61.4)	$ (55.1)	$ (11.5)	(11.4)	*
Total Consolidated					
Cost of product sold	$ 765.5	$ 758.0	$ 649.8	1.0%	16.7%

* *Not meaningful*

Owned and Operated Mines Segment

Cost of product sold decreased for the year ended December 31, 2018, as compared to the year ended December 31, 2017, as a result of 7.7 million fewer tons of coal sold, which resulted in lower direct operating costs. We saw significant decreases in production taxes and royalties as well as labor in 2018. Production taxes and royalties decreased by $29.3 million directly related to the lower volumes. Labor was lower by $10.9 million due to a decrease in headcount and benefits. These decreases were partially offset by increases in fuel and lubes as well as repairs and maintenance. Fuel and lubes increased $13.2 million primarily as a result of an increase in the price of diesel and higher consumption rates. Repairs and maintenance increased $8.8 million due to bucket and dipper rebuilds, haul truck, dozer and scraper engines, and general maintenance required for running additional haul trucks.

Cost of product sold decreased for the year ended December 31, 2017, as compared to the year ended December 31, 2016, as a result of 1.1 million fewer tons of coal sold, which resulted in lower direct operating costs. We saw significant decreases in labor, repairs and maintenance, and postretirement medical costs in 2017. Labor was lower by nearly $10.0 million due to a decrease in headcount and benefits. Repairs and maintenance decreased $4.0 million due to lower equipment hours, condition monitoring, and in-house repairs completed at our rebuild center. Postretirement medical costs were lower by $3.0 million as a result of the plan change made in April 2016 and a full year of amortizing the negative prior service cost base. These decreases were partially offset by a $9.0 million increase in diesel costs due to higher fuel prices in 2017.

Cost of product sold and average cost per ton sold have been revised for the years ended December 31, 2017 and 2016 from prior period presentation to reflect the adoption of ASU 2017-07. The adoption, which required certain postretirement benefit costs to be relocated out of *Operating income (loss)*, increased *Cost of product sold* and average cost per ton sold by $5.3 million and $0.09, respectively, from what was previously reported for the year ended December 31, 2017. For the year ended December 31, 2016, *Cost of product sold* and average cost per ton sold increased by $3.4 million and $0.06, respectively, from what was previously reported. See Note 3 of Notes to Consolidated Financial Statements in Item 8 for further information regarding the impact of this ASU on our Consolidated Statements of Operations and Comprehensive Income (Loss).

Logistics and Related Activities Segment

Cost of product sold increased for the year ended December 31, 2018, as compared to the year ended December 31, 2017 due to the increase in export sales. We shipped 4.6 million tons internationally on 36 vessels in 2018, compared to 4.2 million tons on 32 vessels in 2017. In addition, rail fuel surcharges, severance taxes, and price variable rail rates on our export sales have increased. This was partially offset by lower demurrage costs. We incurred $182.9 million in costs under our logistics agreements with Westshore and BNSF in 2018, including amortization of $18.2 million.

Cost of product sold increased for the year ended December 31, 2017, as compared to the year ended December 31, 2016 due to our decision to resume export sales. We entered into amended transportation agreements with Westshore and BNSF in the fourth quarter of 2015 to reduce our committed volumes to zero in exchange for upfront payments and quarterly payments. In December 2016 and February 2017, we terminated our previous transportation agreements with Westshore and BNSF, respectively, and entered into new agreements. We incurred $162.4 million and $51.5 million in costs under our logistics agreements with Westshore and BNSF, including amortization of $35.8 million and $32.7 million, during 2017 and 2016, respectively. See Note 6 of our Notes to Consolidated Financial Statements in Item 8 for additional information on our transportation agreements. We shipped 32 vessels during 2017 compared to six vessels in 2016.

Other

Cost of product sold decreased for the year ended December 31, 2018, as compared to the year ended December 31, 2017 due to a decrease in our broker activity.

Cost of product sold increased for the year ended December 31, 2017, as compared to the year ended December 31, 2016 due to increases in the cost of purchased coal for our broker deals.

Operating Income (Loss)

The following table presents *Operating income (loss)* (in millions):

	Year Ended December 31,	**Percent Change**

		2018		2017		2016	2018 vs 2017	2017 vs 2016
Owned and Operated Mines								
Operating income (loss)	$	(689.0)	$	60.2	$	122.1	*%	(50.7)%
Logistics and Related Activities								
Operating income (loss)	$	15.5	$	(11.4)	$	(28.9)	*	60.6
Other								
Operating income (loss)	$	(31.9)	$	(50.2)	$	(29.4)	36.5	(70.7)
Eliminations of Intersegment Sales								
Operating income (loss)	$	(0.5)	$	0.1	$	(0.6)	*	116.7
Total Consolidated								
Operating income (loss)	$	(705.9)	$	(1.4)	$	63.2	*%	(102.2)%

* *Not meaningful*

Owned and Operated Mines Segment

Operating income decreased for the year ended December 31, 2018, as compared to the year ended December 31, 2017 as a result of $684.7 million related to *Impairments* in 2018, attributable to the analyses done on the long lived assets at the Cordero Rojo Mine and certain undeveloped coal properties relating to our Youngs Creek and Big Metal Projects. In addition, *Revenue* decreased as previously discussed. This was partially offset by lower *Depreciation and depletion* of $23.4 million in part due to reductions in our ARO liability. Finally, *Cost of product sold* decreased as previously discussed.

Operating income decreased for the year ended December 31, 2017, as compared to the year ended December 31, 2016, as a result of $41.9 million higher *Depreciation and depletion* primarily due to a $47.4 million decrease to reclamation asset depreciation related to a decrease in the ARO liability at all three mine sites in 2016. Additionally, we recognized mark-to-market losses on our domestic coal futures contracts and WTI derivative financial instruments of $2.7 million in 2017, as compared to gains of $8.1 million in 2016. Finally, as previously discussed above, *Revenue* decreased $22.7 million. This was partially offset by the decrease to *Cost of product sold* of $12.8 million, as discussed above, and a decrease of $2.6 million related to *Impairments* in 2016.

Logistics and Related Activities Segment

There were no factors other than those previously discussed for *Revenue* and *Cost of product sold* that influenced the increase in the operating income during the year ended December 31, 2018, as compared to the year ended December 31, 2017.

There were no factors other than those previously discussed for *Revenue* and *Cost of product sold* that influenced the decrease in the operating loss during the year ended December 31, 2017, as compared to the year ended December 31, 2016.

Other

Operating loss decreased for the year ended December 31, 2018, as compared to the year ended December 31, 2017 as a result of a decrease in *Selling, general and administrative expenses* (SG&A) of $18.7 million, primarily driven by a decrease in labor. Labor decreased due to lower stock based compensation and bonus accrual. Stock based compensation was lower due to the valuation of the cash settled 2016 performance share units, while the bonus accrual was lower due to the operational issues experienced in 2018.

Operating loss increased for the year ended December 31, 2017, as compared to the year ended December 31, 2016 primarily as a result of the *Revenue* and *Cost of product sold* factors previously discussed above. In addition, *Depreciation and depletion* was higher by $3.2 million. This was partially offset by $4.6 million lower *Debt restructuring costs* related to the Exchange Offers (as defined below) on our senior notes in 2016, a decrease in *Selling, general and administrative expenses* (SG&A) of $3.4 million due to lower labor costs, and the absence of *Impairments* of $2.0 million in 2016.

Other Income (Expense)

The following table presents *Other income (expense)* (in millions):

	Year Ended December 31,	**Percent Change**

	2018	2017	2016	2018 vs 2017	2017 vs 2016
Other income (expense)	$ (14.2)	$ (35.4)	$ (44.2)	59.9%	19.9%

Other expense for the year ended December 31, 2018 decreased $21.2 million, as compared to the year ended December 31, 2017, primarily due to the $21.5 million gain on the termination of our postretirement medical plan. See Note 19 of Notes to Consolidated Financial Statements in Item 8 for further information.

Other expense for the year ended December 31, 2017 decreased $8.8 million, as compared to the year ended December 31, 2016, primarily due to a decrease in interest expense related to the early retirement of the 2019 Notes, and the reduction in principal on our 2024 Notes. These decreases were partially offset by an increase in interest expense related to the new 2021 Notes (as defined below), higher amortization of debt issuance costs, and increased interest related to undrawn letters of credit.

Other income (expense) has been revised for the years ended December 31, 2017 and 2016 from prior period presentation to reflect the adoption of ASU 2017-07. The adoption, which required certain postretirement benefit costs to be relocated out of Operating income (loss), decreased Other expense by $6.4 million and $4.1 million from what was previously reported for the years ended December 31, 2017 and 2016, respectively. See

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Note 3 of Notes to Consolidated Financial Statements in Item 8 for further information regarding the impact of this ASU on our Consolidated Statements of Operations and Comprehensive Income (Loss).

Income Tax Provision

The following table presents *Income tax benefit (expense)* (in millions):

	Year Ended December 31,			Percent Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
Income tax benefit (expense)	$ 1.9	$ 29.5	$ 2.2	(93.6)%	*%
Effective tax rate	0.3%	80.0%	(11.7)%	(99.6)%	*%

* *Not meaningful*

Our statutory income tax rate including state income taxes, for the year ended December 31, 2018, was approximately 23%. Our statutory income tax rate including state income taxes, for the years ended December 31, 2017, and 2016 was approximately 37%.

The difference between our statutory income tax rate and our effective income tax rate for the year ended December 31, 2018 is primarily the result of changes in federal tax laws and the change in valuation allowance to maintain the carrying amount of our deferred tax assets at zero. The difference between our statutory income tax rate and our effective income tax rate for the year ended December 31, 2017 is primarily the result of changes in federal tax laws and the change in valuation allowance to maintain the carrying amount of our deferred tax assets at zero. The difference between our statutory rate and the effective rate for the year ended December 31, 2016 was primarily the result of the change in valuation allowance to reduce the carrying amount of our deferred tax assets to zero.

In September 2018, we received a denial of appeal from ONRR related to royalties paid on coal sales to a domestic customer. We appealed the denial to the Interior Board of Land Appeals. We have booked a full reserve on our balance sheet in relation to this claim.

In December 2016, we received an assessment from ONRR related to royalties paid on coal sales to international customers during the period 2008 2011. We have appealed the Order and expect to prevail on the merits should the action move beyond our appeal, although there is inherent uncertainty in the litigation process and we cannot assure you that our appeal will be successful.

Liquidity and Capital Resources

	Year Ended December 31, 2018	2017	2016
		(in millions)	
Cash and cash equivalents	$ 91.2	$ 107.9	$ 83.7

In addition to our cash and cash equivalents, our primary sources of liquidity have been cash from our operations and any borrowing capacity under our A/R Securitization Program (as defined below). We previously had borrowing capacity under our terminated Amended Credit Agreement (as defined below). On November 9, 2018, we delivered notice to PNC Bank, National Association, to terminate the Amended Credit Agreement, which was effective on November 15, 2018. See Terminated Credit Agreement below. We had no availability for borrowing under the A/R Securitization Program as of December 31, 2018. Our total liquidity, which includes cash and cash equivalents and amounts available under our A/R Securitization Program, was $91.2 million as of December 31, 2018. As of March 8, 2019, our total available liquidity was $65.5 million, and we expect to continue using additional cash that will further reduce this liquidity. We also have a capital leasing program, with a balance of $2.5 million as of December 31, 2018, for some of our capital equipment purchases subject to the conditions in the master lease agreement.

Cash balances depend on a number of factors, such as the volume of coal sold by our Owned and Operated Mines segment; the price for which we sell our coal; the costs of mining, including labor, repairs and maintenance, fuel and explosives; the amount of royalties, severance taxes, and other governmental levies that we pay; capital expenditures to acquire property, plant and equipment; the volume of deliveries coordinated by our Logistics and Related Activities segment to customer contracted destinations; the revenue we receive for our logistics services; demurrage and any take-or-pay charges; coal-fired electricity demand, regulatory changes and energy policies impacting our business; and other risks and uncertainties, including those discussed in Item 1A Risk Factors.

Subsequent to December 31, 2018, we received letters from certain of our third-party surety bond underwriters demanding increased collateral or replacement of their bonds. Any further issuances of letters of credit to satisfy the increased collateral demands or any replacement bonds would immediately reduce the cash and cash equivalents available to support the operations of the business, as the current level of letters of credit exceeds the borrowing credit limit of our A/R Securitization Program. We are currently in discussions with our surety bond underwriters, however we cannot assure you these negotiation will be successful in avoiding increased collateral requirements. These surety bonds are required by the permits governing our mining operations.

Capital expenditures are necessary to keep our equipment fleets updated to maintain our mining productivity and competitive position and to add new equipment as necessary. Capital expenditures (excluding capitalized interest) for the years ended December 31, 2018, 2017, and 2016 were $14.2 million, $13.1 million, and $33.6 million, respectively. We have budgeted approximately $16 million of maintenance capital expenditures in 2019.

We are continuing to minimize our capital expenditures, reduce costs and maximize cash flows from operations; however, our business and liquidity outlook has adversely changed since the third quarter of 2018. See Recent Developments.

The TCJA legislation, enacted in December 2017, made significant changes to U.S. tax laws, including (i) the reduction in the federal corporate tax rate, (ii) the elimination of the corporate alternative minimum tax (AMT) and the ability to offset regular tax liability or claim refunds for AMT credits carried forward, and (iii) imposing limitations on the deductibility of interest expense. We have historically been subject to the AMT, under which taxes were imposed at a 20% rate on taxable income, subject to certain adjustments, and we assumed that we would be subject to the AMT in future periods. As such, the elimination of the corporate AMT and reduction in the federal corporate tax rate to 21% does not have a material impact on our estimates for cash taxes payable in the next several years.

The material immediate impact of TCJA to us is the elimination of the AMT and the ability to offset our regular tax liability or claim refunds for taxable years 2018 through 2021 for AMT credits carried forward from prior periods. We currently anticipate we will realize approximately $31.5 million in AMT value over the next four years with approximately half of this value realized in 2019 for taxable year 2018. We will continue to assess the long-term impact of TCJA to us.

On December 26, 2018, we were notified by the NYSE that the average closing price of shares of our common stock had fallen below $1.00 per share over a period of 30 consecutive trading days, which is the minimum average share price for continued listing on the NYSE under Section 802.01C of the NYSE Listed Company Manual. Under the NYSE s rules, we have six months following receipt of the notification to regain compliance with the minimum share price requirement.

As discussed under Recent Developments , we have concluded that there is substantial doubt about our ability to continue as a going concern and will likely be required to significantly reduce, delay or eliminate capital expenditures, implement further cost reductions, seek the sale of some or all of our assets or seek relief under Chapter 11. If we limit, defer or eliminate our capital expenditure plan or are unsuccessful in developing reserves through our capital program or our cost-cutting efforts are too overreaching, the value of our properties and our financial condition and results of operations could be adversely affected.

Overview of Cash Transactions

We started 2018 with cash, cash equivalents and restricted cash of $108.7 million and concluded the year ended December 31, 2018 with $92.1 million. The decrease in cash was primarily due to cash used in investing and financing activities of $15.9 million and $16.7 million respectively, and was partially offset by cash provided by operating activities of $16.1 million.

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Cash Flows

	Year Ended December 31, 2018	2017	2016
		(in millions)	
Beginning balance - cash, cash equivalents, and restricted cash	$ 108.7	$ 84.4	$ 97.8
Net cash provided by operating activities	16.1	52.0	48.7
Net cash used in investing activities	(15.9)	(14.7)	(33.1)
Net cash used in financing activities	(16.7)	(13.1)	(29.0)
Ending balance - cash, cash equivalents, and restricted cash	$ 92.1	$ 108.7	$ 84.4

The decrease in cash provided by operating activities from 2017 to 2018 was primarily due to a decrease in *Net income (loss)* as adjusted for non-cash items including depreciation and depletion of $49.0 million and asset impairments of $684.7 million, partially offset by reduced post retirement benefit costs of $24.8 million.

The increase in cash provided by operating activities from 2016 to 2017 was primarily due to an increase in *Net income (loss)* as adjusted for non-cash items due to lower operating costs partially offset by a decrease in working capital, including $22.9 million in payments to Westshore and BNSF related to our amended logistics agreements.

The increase in cash used in investing activities from 2017 to 2018 was primarily a result of an increase in the purchases of property, plant and equipment of $1.1 million.

The decrease in cash used in investing activities from 2016 to 2017 was primarily a result of a decrease in the purchases of property, plant and equipment of $20.5 million partially offset by the recoveries from equipment loss in 2016 of $2.8 million. We also released $8.5 million of restricted cash held in an escrow account with Westshore in 2016, however, as a result of the adoption of ASU 2016-18 (defined in Note 3 in Notes to Consolidated Financial Statements in Item 8), this release is now reflected in the beginning balance of cash, cash equivalents and restricted cash above. The 2016 restriction of $0.7 million in cash is included in the ending balance of cash, cash equivalents, and restricted cash above. The release and restriction were previously included in cash used in investing activities in 2016.

The increase in cash used in financing activities from 2017 to 2018 was primarily due to principal payments on federal coal leases for $0.6 million and a payment of deferred financing costs of $0.9 million.

The decrease in cash used in financing activities from 2016 to 2017 was primarily due to cash proceeds in 2017 of $64.4 million from the issuance of $13.5 million shares of common stock. In addition, 2016 included the payment of $18.3 million of cash premium, $4.7 million in *Debt restructuring costs*, and $3.6 million in deferred financing costs all related to the Exchange Offers (as defined below) and the issuance of the 2021 Notes. These were partially offset by $62.1 million for the redemption of our outstanding 2019 Notes and the principal payments on the 2021 Notes of $12.4 million related to the deferred gain.

Fourth Quarter 2016 Exchange Offers

On October 17, 2016, our direct and indirect wholly-owned subsidiaries, CPE Resources and Cloud Peak Energy Finance Corp. (collectively, the Issuers), completed offers to exchange (the Exchange Offers) up to $400 million aggregate principal amount of their outstanding $300 million aggregate principal balance of the 2019 Notes and $200 million aggregate principal balance of 6.375% Senior Notes due 2024 (the 2024 Notes , together with the 2019 Notes, the Old Notes) for new 12.00% Second Lien Senior Secured Notes due 2021 to be issued by the Issuers (the 2021 Notes) and, in some cases, cash consideration, subject to the terms and conditions of the Exchange Offers. The primary purposes of the Exchange Offers were to extend the maturity of the 2019 Notes to November 2021, to reduce leverage by capturing the trading discounts on the Old Notes and to further our ongoing efforts to provide sufficient liquidity to manage through depressed PRB thermal coal industry conditions.

Holders of $237.9 million aggregate principal amount of the 2019 Notes and $143.6 million aggregate principal amount of the 2024 Notes tendered such notes pursuant to the Exchange Offers. On October 17, 2016,

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the Issuers accepted for exchange all such Old Notes validly tendered, issued $290.4 million aggregate principal amount of 2021 Notes, and made cash payments of $26.0 million in the aggregate (including $7.7 million in accrued and unpaid interest) to tendering holders of the Old Notes. The transaction resulted in recognition of $4.7 million in expenses for the year ended December 31, 2016. Upon completion of the Exchange Offers, $62.1 million aggregate principal amount of the 2019 Notes remained outstanding, while $56.4 million aggregate principal amount of the 2024 Notes remain outstanding.

The exchanges of the Old Notes for the 2021 Notes were accounted for as a troubled debt restructuring. As the future cash flows of the 2021 Notes were greater than the carrying amount of the Old Notes, no gain was recognized. The amount of extinguished debt will be amortized over the remaining life of the 2021 Notes using the effective interest method and recognized as a reduction of interest expense. The effective interest rate of the 2021 Notes is 6.46% compared to the stated rate of 12.00%. As a result, our reported interest expense will be significantly less than the contractual cash interest payments throughout the term of the 2021 Notes. Our current tax attributes are expected to offset any cash tax impacts from the Exchange Offers.

First Quarter 2017 Equity Offering and 2019 Notes Redemption

On February 28, 2017, we issued 13.5 million shares of common stock through a registered underwritten public offering and received proceeds, net of underwriting discounts and commissions, of $64.7 million. We used the net proceeds from the offering to fund the full redemption of our remaining outstanding 2019 Notes. On March 31, 2017, we redeemed the 2019 Notes at a total cost of $64.5 million, reflecting a redemption price of 101.417% of the principal amount of $62.1 million, or $63.0 million, plus accrued and unpaid interest of $1.5 million. In addition, we wrote off $0.7 million in deferred financing costs and original issue discount as of the redemption date. The primary purpose of the redemption of the 2019 Notes was to reduce outstanding long-term debt and extend our nearest term maturity date to 2021. The 2019 Notes bore interest at fixed annual rates of 8.50%.

Senior Notes

We refer to the 2021 Notes and the 2024 Notes collectively as the senior notes. The 2021 Notes and 2024 Notes bear interest at fixed annual rates of 12.00% and 6.375%, respectively. There are no mandatory redemption or sinking fund payments for the senior notes. Interest payments are due semi-annually on May 1 and November 1 for the 2021 Notes and due semi-annually on March 15 and September 15 for the 2024 Notes.

CPE Resources has an interest payment obligation under the 2024 Notes of approximately $1.8 million, which is due on March 15, 2019. The indenture governing the 2024 Notes provides a 30-day grace period that extends the latest date for making this interest payment to April 14, 2019, before an Event of Default occurs under the indenture. Although we have sufficient liquidity to make the interest payment, we elected not to make this interest payment on the due date and plan to utilize the 30-day grace period provided by the indenture, to allow additional time to assess our restructuring alternatives. If we do not make this interest payment by April 14, 2019, an Event of Default would occur under the indenture governing the 2024 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2024 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2024 Notes. An Event of Default under the 2024 Notes for failure to pay interest would not result in a default under the 2021 Notes unless the 2024 Notes are accelerated. An Event of Default under the 2024 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance. We continue to evaluate alternatives associated with this interest payment.

CPE Resources has an interest payment obligation under the 2021 Notes of approximately $17.4 million, which is due on May 1, 2019. The indenture governing the 2021 Notes provides a 30-day grace period that extends the latest date for making this interest payment to May 31, 2019, before an Event of Default occurs under the indenture. If we do not make this interest payment by May 31, 2019, an Event of Default would occur under the indenture governing the 2021 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2021 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2021 Notes. An Event of Default under the 2021 Notes for failure to pay interest would not result in a default under the 2024 Notes unless the 2021 Notes are accelerated. An Event of Default under the 2021 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance.

We may redeem some or all of the 2021 Notes by paying specified redemption prices in excess of their principal amount, plus accrued and unpaid interest, if any, prior to November 1, 2020, or by paying their principal amount thereafter, plus accrued and unpaid interest, if any. We may also redeem some or all of the 2024 Notes by paying specified redemption prices in excess of their principal amount, plus accrued and unpaid interest, if any, prior to March 15, 2022, or by paying their principal amount thereafter, plus accrued and unpaid interest, if any.

The 2021 Notes were issued with joint and several guarantees by CPE Inc. and by all of our existing and future domestic restricted subsidiaries, and secured by second-priority liens on substantially all of our assets. The termination of the Amended Credit Agreement in November 2018 may have resulted in a release of the guarantees and liens granted by all of our existing and future domestic restricted subsidiaries under the 2021 Notes indenture. The 2024 Notes were issued with joint and several guarantees by CPE Inc. and by all of our existing and future domestic restricted subsidiaries. The termination of the Amended Credit Agreement in November 2018 may have resulted in a release of the guarantees granted by all of our existing and future domestic restricted subsidiaries under the 2024 Notes indenture. However, we believe that holders of the 2021 Notes and 2024 Notes may challenge whether such releases described above occurred, or were permitted to have occurred under applicable law.

The indentures governing the senior notes, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional indebtedness and issue preferred equity; pay dividends or distributions; repurchase equity or repay subordinated indebtedness; make investments or certain other restricted payments; create liens; sell assets; enter into agreements that restrict dividends, distributions, or other payments from restricted subsidiaries; enter into transactions with affiliates; and consolidate, merge, or transfer all or substantially all of their assets and the assets of their restricted subsidiaries on a combined basis.

Upon the occurrence of certain transactions constituting a change in control as defined in the indentures, holders of our senior notes could require us to repurchase all outstanding senior notes at 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase.

Accounts Receivable Securitization Program

In January 2013, we formed Cloud Peak Energy Receivables LLC, a special purpose, bankruptcy-remote wholly-owned subsidiary, to purchase, subject to certain exclusions, in a true sale, trade receivables generated by certain of our subsidiaries without recourse (other than customary indemnification obligations for breaches of specific representations and warranties), and then transfer undivided interests of those accounts receivable to a financial institution for cash borrowings for our ultimate benefit. On February 11, 2013, we executed the Accounts Receivable Securitization Program (A/R Securitization Program) with a committed capacity of up to $75 million. The total borrowings are limited by eligible accounts receivable, as defined under the terms of the A/R Securitization Program. On January 31, 2017, the A/R Securitization Program was amended to extend the term of the A/R Securitization Program to January 23, 2020, allow for the ability to issue letters of credit, and revise the maximum combined borrowing capacity for both cash and letters of credit to $70 million. On May 24, 2018, the A/R Securitization Program was amended to extend the term of the A/R Securitization Program to May 24, 2021 from January 23, 2020. All other terms of the program remained substantially the same. On March 14, 2019, we entered into a Forbearance Agreement by and among Cloud Peak Energy Receivables LLC, CPE Resources and PNC Bank, National Association, as administrator, relating to our A/R Securitization Program, which provides that PNC Bank, National Association will not exercise any of its remedies upon a default under the A/R Securitization Program based on the existence of substantial doubt regarding our ability to continue as a going concern. Pursuant to the Forbearance Agreement, the forbearance period terminates on the earlier of (i) April 14, 2019 and (ii) the date on which any additional events of default may occur, as specified therein. As of December 31, 2018, the A/R Securitization Program would have allowed for $21.3 million of borrowing capacity, which was less than the undrawn face amount of letters of credit outstanding under the A/R Securitization Program of $25.7 million as of December 31, 2018. The $4.4 million difference between the borrowing capacity and the undrawn face amount of the letters of credit outstanding was cash-collateralized into a restricted cash account in early January 2019, thus bringing the borrowing capacity to zero. There were no borrowings outstanding from the A/R Securitization Program as of December 31, 2018 or December 31, 2017. As of March 8, 2019, the A/R Securitization Program would have allowed for $13.5 million of borrowing capacity, which is less than the $25.7 million in outstanding indebtedness under the A/R Securitization Program. The difference has been cash collateralized. For additional information, see Note 18 of Notes to Consolidated Financial Statements in Item 8.

Upon execution of the 2018 amendment, we recorded $0.9 million of new deferred financing costs. The aggregate deferred financing costs are being amortized on a straight-line basis to interest expense over the remaining terms of the A/R Securitization Program.

Terminated Credit Agreement

On February 21, 2014, CPE Resources entered into a five-year Credit Agreement with PNC Bank, National Association, as administrative agent, and a syndicate of lenders, which was amended on September 5, 2014, September 9, 2016 and May 24, 2018 (as amended, the Credit Agreement).

On September 9, 2016, we entered into a Second Amendment to the Credit Agreement (the Second Amendment), which replaced the quarterly EBITDA-based financial covenants that previously required us to (a) maintain defined minimum levels of interest coverage and (b) comply with a maximum net secured debt leverage ratio. These financial covenants were replaced with a new monthly minimum liquidity covenant that required us to maintain liquidity, as defined in the Credit Agreement, of not less than $125 million as of the last day of each month. The Second Amendment reduced the maximum borrowing capacity under the Credit Agreement to $400 million, from the previous maximum capacity of $500 million. It also revised the permitted debt covenant and permitted lien covenant to allow the issuance of second lien debt in an amount up to $350 million. Additionally, it revised various negative covenants and baskets that would apply to, among other things, the incurrence of debt, making investments, asset dispositions and restricted payments. Lastly, it established a requirement for deposit account control agreements with the administrative agent for certain of our deposit accounts.

On May 24, 2018, we entered into an Amended and Restated Credit Agreement (the Amended Credit Agreement) that amended and restated the existing Credit Agreement. The Amended Credit Agreement extended the maturity of the Credit Agreement from February 21, 2019 to May 24, 2021 and reduced the maximum borrowing capacity to $150 million from the previous maximum capacity of $400 million. The borrowing capacity under the Amended Credit Agreement was reduced by the undrawn face amount of letters of credit issued and outstanding under the Amended Credit Agreement, which could have been up to $70 million at any time. The Amended Credit Agreement also required quarterly financial covenants of (a) a ratio of first lien gross debt under the Amended Credit Agreement, capital leases and the A/R Securitization Program (including issued but undrawn letters of credit) to EBITDA (as defined in the Amended Credit Agreement) equal to or less than 1.75 to 1; (b) a ratio of EBITDA less capital expenditures to Fixed Charges (as defined in the Amended Credit Agreement) of not less than 1.15 to 1; and (c) a ratio of funded debt (excluding issued but undrawn letters of credit) less unrestricted cash to EBITDA equal to or less than (i) 4.00 to 1 through June 30, 2019, (ii) 3.50 to 1 from September 30, 2019 to December 31, 2019, (iii) 3.00 to 1 from March 31, 2020 to June 30, 2020 and (iv) 2.50 to 1 from September 30, 2020 to maturity. The Amended Credit Agreement also revised the minimum liquidity covenant to require minimum liquidity of not less than $100 million as of the last day of each fiscal quarter, which was reduced from the prior requirement under the Credit Agreement to maintain monthly liquidity of not less than $125 million. Lastly, it revised various negative covenants and baskets that would apply to, among other things, the incurrence of debt, making investments, asset dispositions, and restricted payments. The borrowing capacity was limited by the financial covenants, calculated on a quarterly basis, and fluctuated from quarter to quarter.

A default under the Amended Credit Agreement would have permitted the lenders to terminate their commitment to make cash advances or issue letters of credit, and require cash collateralization if there were any outstanding letters of credit obligations. A default and acceleration of obligations under the Amended Credit Agreement would have also triggered cross-defaults for our Senior Notes due 2021 and 2024, which would have permitted the Senior Notes lenders to require immediate repayment of all principal, interest, fees and other amounts payable thereunder. A default under the Amended Credit Agreement would have also triggered a cross-default for our A/R Securitization Program, which would have permitted the lender to terminate the A/R Securitization Program and triggered collateralization requirements for outstanding letter of credit obligations. Had a default occurred, we may not have been granted waivers or have been able to reach agreement on amendments under our Amended Credit Agreement.

On November 9, 2018, we delivered a notice to PNC Bank, National Association, to terminate the Amended Credit Agreement, which was effective on November 15, 2018. The Amended Credit Agreement would have required us to pay over $3.0 million in additional commitment and administrative fees during the remaining term of the Amended Credit Agreement through May 2021, which will now be avoided. There were no borrowings or undrawn letters of credit under the Amended Credit Agreement. As a result of the decrease in borrowing capacity and the subsequent termination of the Amended Credit Agreement, we recorded a non-cash write-off of certain deferred financing costs in the amount of $5.5 million during the year ended December 31, 2018. These costs were written off against Interest expense on the Consolidated Statement of Operations and Comprehensive Income (Loss). See Item 8.

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We were in compliance with the covenants contained in the Credit Agreement as of December 31, 2017. As of December 31, 2017, we had no borrowings under the Credit Agreement. There were no undrawn letters of credit under the Credit Agreement as all issued letters of credit had been transferred to the A/R Securitization Program as of December 31, 2017.

Off-Balance Sheet Arrangements

In the normal course of business, we are party to a number of arrangements that secure our performance under certain legal obligations. These arrangements include letters of credit and surety bonds. We use these arrangements primarily to comply with federal and state laws that require us to secure the performance of certain long-term obligations, such as mine closure or reclamation costs, coal lease obligations, state workers compensation, and federal black lung liabilities. These arrangements are typically renewable annually. Liabilities related to these arrangements are not reflected in our Consolidated Balance Sheets.

As of December 31, we used surety bonds to secure outstanding obligations as follows (in millions):

	2018	2017
Reclamation obligations - surety bonds (1)	$ 386.0	$ 397.5
Lease obligations (2)	21.1	24.9
Other obligations (3)	0.5	0.5
Total off-balance sheet obligations	$ 407.6	$ 422.9

(1) Reclamation obligations include amounts to secure performance related to our outstanding obligations to reclaim areas disturbed by our mining activities and are a requirement under our state mining permits.

(2) Lease obligations include amounts generally required as a condition to state or federal coal leases; the amounts vary and are mandated by the governing agency.

(3) Other obligations include amounts required for exploration permits, water well construction and monitoring, exporting, and other miscellaneous items as mandated by applicable governing agencies.

Our outstanding surety bonds in respect of our reclamation, lease, and other obligations were $407.6 million as of December 31, 2018 and are required by law. These obligations are backed by collateral of 6.3%, or $25.7 million, in the form of letters of credit under our A/R Securitization Program. Over the past few years, there has been heightened regulatory pressure on reclamation bonding and self-bonding in particular. In January 2017, we received approval to remove the final $10 million of self-bonding that existed as of December 31, 2016, and exited self-bonding in the first quarter of 2017. State statutes regulate and determine the calculation of the amounts of the bonds that we are required to hold. We do not believe that these state-mandated estimates are a true reflection of what our actual reclamation costs will be. Reclamation bond amounts represent an estimate of the near-term reclamation liability that assumes reclamation activities will be performed by a third party during the next one to five years. Because this evaluation is near-term, it is recalculated on a frequent basis, often annually. The basis for calculating bond requirements is substantially different than the requirements that apply to the determination of our asset retirement obligation (ARO) liability in our Consolidated Balance Sheets, which is determined in accordance with U.S. GAAP. The state calculates our specific bond requirements considering assumed costs that the state would incur if they were required to complete the reclamation on our behalf. Additionally, where a multi-year bond, such as a three to five-year bond, is put into place, the state regulatory authority requires that the reclamation liability be calculated for the highest cost scenario over that period.

The carrying amount of our reclamation obligations, as determined in accordance with U.S. GAAP, which are reported in our Consolidated Balance Sheets as ARO liabilities, was $93.6 million as of December 31, 2018, $1.0 million of which is classified as a current liability. We estimate our ARO liabilities based on disturbed acreage to date and the estimated cost of a third party to perform the work. The estimated ARO liabilities are based on engineering studies and our engineering expertise related to the reclamation requirements. We assume that reclamation will be completed after the end of the mine life based on our current reclamation area profiles, which may be a different land disturbance assumption than the state requires, as we generally perform reclamation concurrently with our mining activities. Finally, the carrying amount of our ARO liabilities reflects discounting of estimated reclamation costs using credit-adjusted, risk-free rates. For a discussion of the risks relating to our reclamation obligations, see Item 1A Risk Factors Risks Related to Our Business and Industry

*If the assumptions underlying our reclamation and mine closure obligations are materially inaccurate, our costs could be significantly greater than anticipated***.**

Because we are required by state and federal law to have these bonds or letters of credit in place before mining can commence, or continue, our failure to maintain surety bonds, letters of credit, or other guarantees or security arrangements would materially adversely affect our ability to mine or lease coal. That failure could result from a variety of factors including lack of availability, higher expense or unfavorable market terms, disputes with third-party surety bond issuers and demands for additional collateral by third-party surety bond issuers. For a discussion of the risks relating to our surety bonds, see Item 1A Risk Factors Risks Related to Our Business and Industry *Failure to maintain our surety bonds on acceptable terms could affect our ability to secure reclamation and coal lease obligations and materially adversely affect our ability to mine or lease coal.* See Note 21 of Notes to Consolidated Financial Statements in Item 8.

Contractual Obligations

As of December 31, 2018, we had the following contractual obligations (in millions):

	Total	2019	2020-2021	2022-2023	Thereafter
Senior notes (1)	$ 346.8	$	$ 290.4	$	$ 56.4
Interest related to long-term obligations(2)	124.3	38.4	76.9	7.2	1.8
Transportation obligations (3)(4)	80.8	29.4	38.9	12.5	
Operating and capital lease obligations	6.2	3.2	2.6		0.4
Capital expenditure and other obligations	1.9	1.9			
Total	$ 560.0	$ 72.9	$ 408.8	$ 19.7	$ 58.6

(1) Includes the 2021 Notes and the 2024 Notes.

(2) As of December 31, 2018, we had outstanding commitments for interest related to our senior notes. See Note 16 of Notes to Consolidated Financial Statements in Item 8.

(3) Includes undiscounted port take-or-pay commitments as agreed to in July 2018 for 2018-2022. We have the right to terminate our commitments at any time in exchange for a buyout payment. These amounts are considered minimum payments on services. The per tonne loading charges reflect these advance payments. See Note 6 of Notes to Consolidated Financial Statements in Item 8.

(4) Includes undiscounted rail take-or-pay commitments as agreed to in January 2018 for 2018-2020. We have the right to terminate our commitments at any time in exchange for a buyout payment. If we do not meet the required portion of our future nominated tons, there would be incremental liquidated damages due under the agreement.

This table does not include our estimated AROs. As discussed in Critical Accounting Policies and Estimates Asset Retirement Obligations below, the current and noncurrent carrying amount of our AROs involves a number of estimates, including the amount and timing of the payments to satisfy these obligations. The timing of payments is based on numerous factors, including projected mine closing dates. Based on our assumptions, the carrying amount of our AROs (excluding concurrent reclamation and amounts due in the current period) as determined in accordance with U.S. GAAP was $92.6 million as of December 31, 2018. See Note 17 of Notes to Consolidated Financial Statements in Item 8.

Critical Accounting Policies and Estimates

The preparation of Consolidated Financial Statements and related disclosures in accordance with U.S. GAAP requires us to make judgments, estimates, and assumptions that affect the reported amounts of assets, liabilities, and revenue and expenses, as well as the disclosure of contingent assets and liabilities. We base our judgments, estimates, and assumptions on historical information and other known factors that we deem relevant. Estimates are inherently subjective, as significant management judgment is required regarding the assumptions utilized to calculate accounting estimates in our Consolidated Financial Statements, including the notes thereto. Actual results could differ materially from the amounts reported based on variability in factors affecting our Consolidated Financial Statements. Our significant accounting policies are described in Note 3 of Notes to

Consolidated Financial Statements in Item 8. This section describes those accounting policies and estimates that we believe are critical to understanding our Consolidated Financial Statements.

Impairment of Long-Lived Assets

The carrying amounts of our mineral properties, equipment, port access rights, and other long-lived assets are sensitive to declines in domestic and international coal prices. The cash flow models that we use to assess impairment include numerous assumptions such as our current estimates of forecast coal production, management s outlook on forward commodity prices, operating and development costs, and discount rates. If prices remain at current levels for an extended period of time or do not recover as anticipated, if regulatory changes adversely impact coal-fired electricity generation, or if we receive an unfavorable outcome of the litigation described in Note 21, we may incur additional impairment charges on certain of these assets.

We evaluate the recoverability of our long-lived assets when events or changes in circumstances indicate that the carrying amount of property, plant and equipment may not be recovered over its remaining service life. An asset impairment charge is recognized when the sum of estimated future cash flows associated with the operation and disposal of the asset, on an undiscounted basis, is less than the carrying amount of the asset. An impairment charge is measured as the amount by which the carrying amount of the asset exceeds its fair value. Fair value is measured using discounted cash flows based on estimates of coal reserves, coal prices, operating expenses, and capital costs or by reference to observable comparable transaction or replacement cost data. See Item 1A Risk Factors Risks Related to Our Business and Industry *We may not recover our investments in our mining, exploration, port access rights, development projects, and other assets, which may require us to recognize impairment charges related to those assets* and Note 7 of Notes to Consolidated Financial Statements in Item 8 for a description of recent impairments of our long-lived assets.

Asset Retirement Obligations

Our AROs arise from the SMCRA and similar state statutes. These regulations require that we, upon closure of a mine, restore the mine property in accordance with an approved reclamation plan issued in conjunction with our mining permit.

Our AROs are recorded when a mine site is disturbed by mining activities and as the extent of disturbance increases. AROs reflect costs associated with legally required mine reclamation and closure activities, including earthwork, vegetation, and demolition and are estimated 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 adjusted for estimated inflation and discounted at credit-adjusted, risk-free rates to arrive at a present value of estimated future reclamation costs. Upon initial recognition of the ARO, a corresponding amount is capitalized as part of the carrying value of the related long-lived asset. As changes in estimates occur (such as changes in estimated costs or timing of reclamation activities resulting from mine plan revisions or new LBAs), the ARO liability and related asset are adjusted to reflect the updated estimates. If a reduction of the ARO exceeds the carrying amount of the related asset retirement cost, the adjustment is recorded as a reduction of *Depreciation and depletion*. Annually, we analyze AROs on a mine-by-mine basis and, if necessary, adjust the balance to take into account any changes in estimates. In addition, on an interim basis, we may update the liability based on significant changes to the life of mine.

Seasonality

Our customers generally respond to seasonal variations in electricity demand based upon the number of heating degree days and cooling degree days. Due to utility stockpile management, our coal sales do not experience the same direct seasonal volatility. However, extended mild weather patterns can materially and adversely impact the demand and pricing for our coal. In addition, mild weather can reduce demand and therefore, the price for natural gas, which can displace coal in electricity generation. Our sales typically benefit from decreases in customers stockpiles due to high electricity demand. Conversely, when these stockpiles increase, demand and pricing for our coal will typically soften. Further, our ability to deliver coal is impacted by the seasons. For example, in the spring and summer of 2011, the Midwest region experienced severe flooding which disrupted rail service to mines in the PRB and affected the ability of those customers who were impacted by the flooding to take coal deliveries. Some scientists have opined that increasing concentrations of GHGs in the earth s atmosphere may produce climate changes, which increase the frequency and severity of storms, droughts

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and floods and other climatic events. If any such effects were to occur in areas where we or our clients operate, they could have an adverse effect on our assets and operations.

Global Climate Change

Enactment of current, proposed, or future laws or regulations regarding emissions from the combustion of coal by the U.S. or some of its states or by other countries, or other actions to limit such emissions, like the creation of mandatory use requirements for renewable fuel sources, will likely result in electricity generators further switching from coal to other fuel sources. Public concern and the political environment may also continue to materially and adversely impact future coal demand and usage to generate electricity, regardless of applicable legal and regulatory requirements. Additionally, the creation and issuance of subsidies designed to encourage use of alternative energy sources could further decrease the demand of coal as an energy source. The potential financial impact on us as a result of these factors will depend upon the degree to which electricity generators diminish their reliance on coal as a fuel source as a result thereof. That, in turn, will depend on a number of factors, including the appeal and design of the subsidies being offered, the specific requirements imposed by any such laws or regulations such as mandating use by utilities of renewable fuel sources, the time periods over which those laws or regulations would be phased in and the state of commercial development and deployment of carbon capture technologies, including storage, conversion, or other commercial use for captured carbon. In view of the significant uncertainty surrounding each of these factors, it is not possible for us to reasonably predict the impact that any such laws or regulations may have on our results of operations, financial condition or cash flows. However, such impacts may be significant. See Item 1 Business Environmental and Other Regulatory Matters Global Climate Change and Item 1A Risk Factors for additional discussion regarding how climate change and other environmental regulatory matters may materially adversely impact our business.

Newly Adopted Accounting Standards and Recently Issued Accounting Pronouncements

See Note 3 of Notes to Consolidated Financial Statements in Item 8 for a discussion of newly adopted accounting standards and recently issued accounting pronouncements.

Non-GAAP Financial Measures

EBITDA and Adjusted EBITDA are intended to provide additional information only and do not have any standard meaning prescribed by U.S. GAAP. A quantitative reconciliation of historical *Net income (loss)* to Adjusted EBITDA is found in the tables below.

EBITDA represents *Net income (loss)* before: (1) interest income (expense) net, (2) income tax provision, (3) depreciation and depletion, and (4) amortization. Adjusted EBITDA represents EBITDA as further adjusted for accretion, which represents non-cash increases in asset retirement obligation liabilities resulting from the passage of time, and specifically identified items that management believes do not directly reflect our core operations. For the periods presented herein, the specifically identified items are: (1) adjustments to exclude the changes in the Tax Receivable Agreement, (2) adjustments for derivative financial instruments, excluding fair value mark-to-market gains or losses and including derivative settlements, (3) adjustments to exclude non-cash impairment charges, (4) adjustments to exclude debt restructuring costs, (5) adjustments to exclude the gain from the sale of our

50% non-operating interest in the Decker Mine in September 2014, and (6) non-cash amortization expense related to transportation agreements with BNSF and Westshore. We enter into certain derivative financial instruments such as put options that require the payment of premiums at contract inception. The reduction in the premium value over time is reflected in the mark-to-market gains or losses. Our calculation of Adjusted EBITDA does not include premiums paid for derivative financial instruments; either at contract inception, as these payments pertain to future settlement periods, or in the period of contract settlement, as the payment occurred in a preceding period. In prior years the amortization of port and rail contract termination payments were included as part of EBITDA and Adjusted EBITDA because the cash payments approximated the amount of amortization being taken during the year. During 2017, management determined that the non-cash portion of amortization arising from payments made in prior years as well as the amortization of contract termination payments should be adjusted out of Adjusted EBITDA because the ongoing cash payments are now significantly smaller than the overall amortization of these payments and no longer reflect the transactional results. Because of the inherent uncertainty related to the items identified above, management does not believe it is able to provide a meaningful forecast of the comparable U.S. GAAP measures or reconciliation to any forecasted U.S. GAAP measure.

Adjusted EBITDA is an additional tool intended to assist our management in comparing our performance on a consistent basis for purposes of business decision making by removing the impact of certain items that management believes do not directly reflect our core operations. Adjusted EBITDA is a metric intended to assist management in evaluating operating performance, comparing performance across periods, planning and forecasting future business operations and helping determine levels of operating and capital investments. Period-to-period comparisons of Adjusted EBITDA are intended to help our management identify and assess additional trends potentially impacting our company that may not be shown solely by period-to-period comparisons of *Net income (loss)*. Consolidated Adjusted EBITDA is also used as part of our incentive compensation program for our executive officers and others.

We believe Adjusted EBITDA is also useful to investors, analysts and other external users of our Consolidated Financial Statements in evaluating our operating performance from period to period and comparing our performance to similar operating results of other relevant companies. Adjusted EBITDA allows investors to measure a company s operating performance without regard to items such as interest expense, taxes, depreciation and depletion, amortization and accretion and other specifically identified items that are not considered to directly reflect our core operations.

Our management recognizes that using Adjusted EBITDA as a performance measure has inherent limitations as compared to net income (loss) or other U.S. GAAP financial measures, as this non-GAAP measure excludes certain items, including items that are recurring in nature, which may be meaningful to investors. Adjusted EBITDA excludes interest expense and interest income; however, as we have historically borrowed money in order to finance transactions and operations and have invested available cash to generate interest income, interest expense and interest income are elements of our cost structure and influence our ability to generate revenue and returns for stockholders. Adjusted EBITDA excludes depreciation and depletion and amortization; however, as we use capital and intangible assets to generate revenue, depreciation, depletion and amortization are necessary elements of our costs and ability to generate revenue. Adjusted EBITDA also excludes accretion expense; however, as we are legally obligated to pay for costs associated with the reclamation and closure of our mine sites, the periodic accretion expense relating to these reclamation costs is a necessary element of our costs and ability to generate revenue. Adjusted EBITDA excludes income taxes; however, as we are organized as a corporation, the payment of taxes is a necessary element of our operations. Adjusted EBITDA excludes the changes in the TRA. Adjusted EBITDA excludes fair value mark-to-market gains or losses for derivative financial instruments and premiums paid at contract inception; however, Adjusted EBITDA includes contract settlement on derivative financial instruments. Adjusted EBITDA excludes adjustments to non-cash impairment charges. Adjusted EBITDA excludes debt restructuring costs. Adjusted EBITDA excludes the gain from the sale of the Decker Mine; however, the release of the reclamation and other liabilities was a significant benefit to us. Finally, Adjusted EBITDA excludes the amortization expense related to the payments made to amend the BNSF and Westshore agreements, which were capitalized as a deferred asset, at the end of 2015 and 2016 due to the decision at that time to not export coal. We have subsequently amended those agreements, to reflect the recovery of export prices and our decision to resume export sales, and the one time payments made to amend those contracts in December of 2016 and February of 2017 were added back to Adjusted EBITDA. However, the ongoing quarterly pre-payments and the other routine payments made for shipping and terminal costs were deducted from EBITDA, as these expenses represent a necessary element of our costs and ability to generate revenue since we are responsible for arranging transportation for export customers, as well as ensuring terminal capacity to take our exported coal.

As a result of these exclusions, Adjusted EBITDA should not be considered in isolation and does not purport to be an alternative to *Net income (loss)* or other U.S. GAAP financial measures as a measure of our operating performance.

When using Adjusted EBITDA as a performance measure, management intends to compensate for these limitations by comparing it to *Net income (loss)* in each period to allow for the comparison of the performance of the underlying core operations with the overall performance of the company on a full-cost, after-tax basis. Using Adjusted EBITDA and *Net income (loss)* to evaluate the business assists management and investors in (a) assessing our relative performance against our competitors and (b) monitoring our capacity to generate returns for stockholders.

Because not all companies use identical calculations, our presentation of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies.

A quantitative reconciliation for each of the periods presented of *Net income (loss)* to Adjusted EBITDA is as follows:

	Year Ended December 31, 2018	2017	2016	2015	2014
			(in millions)		
Net income (loss)(1)	$ (718.0)	$ (6.6)	$ 21.8	$ (204.9)	$ 79.0
Interest income	(1.2)	(0.5)	(0.1)	(0.2)	(0.3)
Interest expense	40.2	41.4	47.4	47.6	77.2
Income tax expense (benefit)	(1.9)	(29.5)	(2.2)	77.4	34.9
Depreciation and depletion	49.0	72.3	27.2	66.1	112.0
Amortization of port access rights				3.7	
EBITDA	(631.9)	77.0	94.1	(10.4)	302.8
Accretion	6.2	7.1	6.6	12.6	15.1
Tax agreement expense (benefit)(2)					(58.6)
Derivative financial instruments:					
Exclusion of fair value mark-to-market loss (gain)(3)	2.7	2.7	(8.2)	30.6	(7.8)
Settlements on derivative financial instruments(4)	(0.3)	(1.9)	(3.3)	(0.6)	24.7
Total derivative financial instruments	2.4	0.8	(11.5)	30.0	16.9
Impairments	684.7		4.6	91.5	
Gain on sale of Decker Mine interest					(74.3)
Debt restructuring costs			4.7		
Non-cash amortization of transportation agreements	6.0	20.1			
Adjusted EBITDA (1)	$ 67.3	$ 104.9	$ 98.6	$ 123.8	$ 201.9

(1) Includes a non-cash gain on the termination of our postretirement medical plan of $21.5 million for the year ended December 31, 2018. Excluding this non cash gain, Adjusted EBITDA would have been $45.8 million for the year ended December 31, 2018. See Note 19 of Notes to Consolidated Financial Statements in Item 8 for a discussion regarding the termination of our postretirement medical plan effective January 1, 2019.

(2) Changes to related deferred taxes are included in income tax expense.

(3) Fair value mark-to-market (gains) losses reflected in the Consolidated Statements of Operations and Comprehensive Income (Loss).

(4) Excludes premiums paid at option contract inception of $5.8 million and $4.0 million during the years ended December 31, 2015 and 2014, respectively, for original settlement dates in subsequent years.

See Note 12 of Notes to Consolidated Financial Statements in Item 8 for a discussion related to the fair value of derivative financial instruments.

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Adjusted EBITDA by Segment

	Year Ended December 31, 2018	2017	2016
Net income (loss) (1)	$ (718.0)	$ (6.6)	$ 21.8
Interest income	(1.2)	(0.5)	(0.1)
Interest expense	40.2	41.4	47.4
Other, net	0.6	0.9	1.0
Income tax (benefit) expense	(1.9)	(29.5)	(2.2)
(Income) loss from unconsolidated affiliates, net of tax	(0.3)	(0.7)	(0.7)
Net periodic postretirement benefit (income) cost, excluding service cost	(25.3)	(6.4)	(4.1)
Consolidated operating income (loss)	$ (705.9)	$ (1.4)	$ 63.2
Owned and Operated Mines			
Operating income (loss) (2)	$ (689.0)	$ 60.2	$ 122.1
Depreciation and depletion	47.6	71.0	29.1
Accretion	5.7	6.5	6.0
Derivative financial instruments:			
Exclusion of fair value mark-to-market loss (gain)	2.7	2.7	(8.1)
Settlements on derivative financial instruments	(0.3)	(1.9)	(10.4)
Total derivative financial instruments	2.4	0.8	(18.5)
Impairments	684.7		2.6
Net periodic postretirement benefit income (cost), excluding service cost	21.0	5.3	3.4
Other	(0.6)	(1.0)	(1.0)
Adjusted EBITDA	$ 71.8	$ 142.8	$ 143.7
Logistics and Related Activities			
Operating income (loss)	$ 15.5	$ (11.4)	$ (28.9)
Derivative financial instruments:			
Exclusion of fair value mark-to-market loss (gain)			(0.1)
Settlements on derivative financial instruments			7.1
Total derivative financial instruments			7.0
Non-cash amortization of transportation agreements	6.0	20.1	
Other		(0.1)	(1.7)
Adjusted EBITDA	$ 21.5	$ 8.6	$ (23.6)
Other Unallocated Operating Income (Loss)			
Other operating income (loss)	$ (31.9)	$ (50.2)	$ (29.4)
Elimination of intersegment operating income (loss)	$ (0.5)	$ 0.1	$ (0.6)

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(1) Includes a non-cash gain on the termination of our postretirement medical plan of $21.5 million for the year ended December 31, 2018. Excluding this non-cash gain, Adjusted EBITDA would have been $45.8 million for the year ended December 31, 2018. See Note 19 of Notes to Consolidated Financial Statements in Item 8 for a discussion regarding the termination of our postretirement medical plan effective January 1, 2019.

(2) The Owned and Operated Mines Segment includes a non-cash gain on the termination of our postretirement medical plan of $17.9 million for the year ended December 31, 2018. Excluding this non-cash gain, Adjusted EBITDA would have been $53.9 million for the year ended December 31, 2018.

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

We define market risk as the risk of economic loss as a consequence of the adverse movement of market rates and prices or credit standings. We believe our principal market risks are commodity price risk, interest rate risk, and credit risk.

Commodity Price Risk

Historically, we have principally managed the commodity price risk for our coal contract portfolio with long-term coal sales agreements of varying terms and durations. In recent years, our business has become more variable and less predictable because utilities are adjusting their purchasing pattern based on natural gas prices, weather, and other factors. Market risk includes the potential for changes in the market value of our coal portfolio, which includes index sales, export pricing, and PRB derivative financial instruments. As of March 2019, we had committed to sell approximately 44 million tons for 2019, of which 43 million tons are under fixed-price contracts.

We also face price risk involving other commodities used in our production process, primarily diesel fuel. Based on our projections of our usage of diesel fuel for the next 12 months, and assuming that the average cost of diesel fuel increases by 10%, we would incur additional fuel costs of approximately $5.8 million over the next 12 months. In July 2018, we entered into WTI derivative instruments to manage certain exposure to diesel fuel prices. The terms of the program are discussed in Note 13 of our Notes to Consolidated Financial Statements in Item 8.

Interest Rate Risk

Our A/R Securitization Program, certain of capital leases are subject to adjustable interest rates. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources. We had no outstanding borrowings under our A/R Securitization Program as of December 31, 2018. If we borrow funds under the A/R Securitization Program, we may be subject to increased sensitivity to interest rate movements. We previously had borrowing capacity available under our Amended Credit Agreement. On November 9, 2018, we delivered notice to PNC Bank, National Association, to terminate the Amended Credit Agreement, which was effective on November 15, 2018. See Terminated Credit Agreement above.

Some of the $2.5 million of borrowings under the capital leasing program are also subject to adjustable interest rates although any change to the rate would not have a significant impact on cash flow. Any future debt arrangements that we enter into may also have adjustable interest rates that may increase our sensitivity to interest rate movements.

Credit Risk

We are exposed to credit loss in the event of non-performance by our counterparties, which may include end-use customers, trading houses, brokers, and financial institutions that serve as counterparties to our derivative financial instruments and hold our investments. We attempt to manage this exposure by entering into agreements with counterparties that meet our credit standards and that are expected to fully satisfy their obligations under the contracts. These steps may not always be effective in addressing counterparty credit risk.

When appropriate (as determined by our credit management function), we have taken steps to reduce our credit exposure to customers that do not meet our credit standards or whose credit has deteriorated. These steps include obtaining letters of credit and requiring prepayments for shipments. See Item 1A Risk Factors Risks Related to Our Business and Industry *We are exposed to counterparty risk with our customers, trading partners, financial institutions, and other parties with whom we conduct business.*

Item 8. ***Financial Statements and Supplementary Data.***

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Cloud Peak Energy Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Cloud Peak Energy Inc. and its subsidiaries (the Company) as of December 31, 2018 and 2017, and the related consolidated statements of operations and comprehensive income (loss), of equity and of cash flows for each of the three years in the period ended December 31, 2018, including the related notes, and the financial statement schedule of valuation and qualifying accounts for each of the three years in the period ended December 31, 2018, appearing under Item 15(a)(2) (collectively referred to as the consolidated financial statements). We also have audited the Company s internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017**,** and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Substantial Doubt About the Company s Ability to Continue as a Going Concern

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the consolidated financial statements, the Company has experienced a reduction in available liquidity that raises substantial doubt about its ability to continue as a going concern. Management s plans in regard to these matters are also described in Note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinions

The Company s management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company s consolidated financial statements and on the Company s internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated 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 consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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/ **PricewaterhouseCoopers LLP**

Denver, Colorado

March 14, 2019

We have served as the Company s auditor since 2008.

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CLOUD PEAK ENERGY INC.

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

(in thousands, except per share data)

	Year Ended December 31, 2018	2017	2016
Revenue	$ 832,405	$ 887,706	$ 800,438
Costs and expenses			
Cost of product sold (exclusive of depreciation, depletion, and accretion, shown separately)	765,540	758,034	649,805
Depreciation and depletion	49,042	72,270	27,218
Accretion (Note 17)	6,171	7,072	6,645
(Gain) loss on derivative financial instruments (Note 13)	2,642	2,672	(8,180)
Selling, general and administrative expenses	29,835	48,528	51,533
Impairments (Note 7)	684,673		4,609
Debt restructuring costs		23	4,665
Other operating costs	420	532	941
Total costs and expenses	1,538,323	889,131	737,236
Operating income (loss)	(705,918)	(1,425)	63,202
Other income (expense)			
Net periodic postretirement benefit income (cost), excluding service costs (Note 19)	25,284	6,365	4,066
Interest income	1,222	485	138
Interest expense (Note 8)	(40,189)	(41,362)	(47,434)
Other, net	(558)	(885)	(1,001)
Total other income (expense)	(14,241)	(35,397)	(44,231)
Income (loss) before income tax provision and earnings from unconsolidated affiliates	(720,159)	(36,822)	18,971
Income tax benefit (expense) (Note 9)	1,917	29,470	2,213
Income (loss) from unconsolidated affiliates, net of tax (Note 10)	279	713	657
Net income (loss)	(717,963)	(6,639)	21,841
Other comprehensive income (loss)			
Postretirement medical plan amortization of prior service costs (Note 19)	(4,287)	(7,283)	(5,253)
Postretirement medical plan adjustments (Note 19)		(794)	(1,792)
Postretirement medical plan change (Note 19)	25,274		42,851
Postretirement medical plan termination (Note 19)	(21,510)		
Income tax on postretirement medical and pension changes			(971)
Other comprehensive income (loss)	(523)	(8,077)	34,835
Total comprehensive income (loss)	$ (718,486)	$ (14,716)	$ 56,676
Income (loss) per common share (Note 11)			
Basic	$ (9.49)	$ (0.09)	$ 0.36
Diluted	$ (9.49)	$ (0.09)	$ 0.35
Weighted-average shares outstanding - basic	75,665	72,907	61,328
Weighted-average shares outstanding - diluted	75,665	72,907	62,290

The accompanying notes are an integral part of these Consolidated Financial Statements.

CLOUD PEAK ENERGY INC.

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 91,196	$ 107,948
Accounts receivable	33,527	50,075
Due from related parties		122
Inventories, net	70,040	72,904
Income tax receivable	15,808	256
Other prepaid and deferred charges	27,527	36,964
Other assets	4,205	1,765
Total current assets	242,303	270,034
Noncurrent assets		
Property, plant and equipment, net	654,372	1,365,755
Goodwill		2,280
Income tax receivable	15,768	29,454
Other assets	16,213	31,178
Total assets	$ 928,656	$ 1,698,701
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 34,210	$ 29,832
Royalties and production and property taxes	53,232	54,327
Accrued expenses	26,385	32,818
Due to related parties	71	
Federal coal lease obligations	379	
Other liabilities	4,019	2,435
Total current liabilities	118,296	119,412
Noncurrent liabilities		
Senior notes	396,373	405,266
Federal coal lease obligations, net of current portion	1,404	
Asset retirement obligations, net of current portion	92,591	99,297
Accumulated postretirement benefit obligation, net of current portion		24,958
Royalties and production taxes	20,587	21,896
Other liabilities	5,731	20,063
Total liabilities	634,982	690,892
Commitments and Contingencies (Note 21)		
Equity		
Common stock ($0.01 par value; 200,000 shares authorized; 76,283 and 75,644 shares issued and 75,806 and 75,167 outstanding as of December 31, 2018 and December 31, 2017, respectively)	758	752
Treasury stock, at cost (477 shares as of both December 31, 2018 and December 31, 2017, respectively)	(6,498)	(6,498)
Additional paid-in capital	656,925	652,702
Retained earnings (accumulated deficit)	(370,795)	347,046
Accumulated other comprehensive income (loss)	13,284	13,807

Total equity		293,674		1,007,809
Total liabilities and equity	$	928,656	$	1,698,701

The accompanying notes are an integral part of these Consolidated Financial Statements.

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CLOUD PEAK ENERGY INC.

CONSOLIDATED STATEMENTS OF EQUITY

(in thousands)

	Common Stock		Treasury Stock		Additional Paid-In Capital	Retained Earnings/ (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
	Shares	Amount	Shares	Amount				
Balances as of December 31, 2015	61,170	$ 612	477	$ (6,498)	$ 574,874	$ 331,844	$ (12,951)	$ 887,881
Net income (loss)						21,841		21,841
Postretirement benefit adjustment, net of tax							34,835	34,835
Write-off of excess tax benefits related								
Employee stock purchases	134	1			457			458
Equity-based compensation expense					6,845			6,845
Restricted stock issuance, net of forfeitures	230	2			(2)			
Employee common stock withheld to cover withholding taxes	(69)				(199)			(199)
Balances as of December 31, 2016	61,465	615	477	(6,498)	581,975	353,685	21,884	951,661
Net income (loss)						(6,639)		(6,639)
Postretirement benefit adjustment, net of tax							(8,077)	(8,077)
Write-off of excess tax benefits related								
Employee stock purchases								
Equity-based compensation expense					6,803			6,803
Restricted stock issuance, net of forfeitures	268	3			(13)			(10)
Employee common stock withheld to cover withholding taxes	(66)	(1)			(288)			(289)
Equity offering	13,500	135			64,225			64,360
Balances as of December 31, 2017	75,167	752	477	(6,498)	652,702	347,046	13,807	1,007,809
Net income (loss)						(717,963)		(717,963)
Postretirement benefit adjustment, net of tax							(523)	(523)
Adoption of new accounting standard						122		121
Write-off of excess tax benefits related								
RSU/PSU terminations & retirements	137	1			(1)			
Equity-based compensation expense					5,631			5,631
Restricted stock issuance, net of forfeitures	502	5			(5)			

Employee common stock withheld to cover withholding taxes					(1,402)			(1,401)
Balances as of December 31, 2018	75,806	$ 758	477	$ (6,498)	$ 656,925	$ (370,795)	$ 13,284	$ 293,674

The accompanying notes are an integral part of these Consolidated Financial Statements.

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CLOUD PEAK ENERGY INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31, 2018	2017	2016
Cash flows from operating activities			
Net income (loss)	$ (717,963)	$ (6,639)	$ 21,841
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion, and amortization	49,042	72,270	27,218
Accretion	6,171	7,072	6,645
Impairments	684,673		4,609
Loss (income) from unconsolidated affiliates, net of tax	(279)	(713)	(657)
Distributions of income from unconsolidated affiliates	1,020	4,530	1,515
Deferred income taxes			(971)
Equity-based compensation expense	(5,515)	11,730	13,064
(Gain) loss on derivative financial instruments	2,642	2,672	(8,180)
Cash received (paid) on derivative financial instrument settlements		(1,920)	(3,305)
Non-cash interest expense related to early retirement of debt and refinancings	5,538	702	1,254
Net periodic postretirement benefit costs	(24,825)	(5,471)	(1,841)
Addback of debt restructuring costs		23	4,665
Payments for logistics contracts	(10,000)	(22,938)	(30,500)
Logistics throughput contract amortization expense	15,876	35,839	32,667
Other	3,009	7,818	3,798
Changes in operating assets and liabilities:			
Accounts receivable	16,548	(764)	(8,889)
Inventories, net	2,860	(4,359)	8,047
Income tax receivable	(2,081)	(29,454)	
Other assets	(2,440)	(10,680)	16,057
Other liabilities	(8,177)	(7,682)	(38,321)
Net cash provided by (used in) operating activities	16,099	52,036	48,716
Investing activities			
Purchases of property, plant and equipment	(14,191)	(13,097)	(33,639)
Cash paid for capitalized interest			(1,444)
Investment in development projects	(1,894)	(1,750)	(1,500)
Insurance proceeds			2,826
Other	186	195	659
Net cash provided by (used in) investing activities	(15,899)	(14,652)	(33,098)
Financing activities			
Principal payments on federal coal leases	(574)		
Repayment of senior notes		(62,094)	
Payment of debt refinancing costs		(408)	
Payment of deferred financing costs	(936)		(3,624)
Payment amortized to deferred gain	(12,800)	(12,395)	
Cash paid on tender of 2019 and 2024 senior notes			(18,335)
Payment of debt restructuring costs		(23)	(4,665)
Proceeds from issuance of common stock		68,850	

Cash paid for equity offering				(4,490)		
Other		(2,435)		(2,584)		(2,374)
Net cash provided by (used in) financing activities		(16,745)		(13,144)		(28,998)
Net increase (decrease) in cash, cash equivalents, and restricted cash		(16,545)		24,240		(13,380)
Cash, cash equivalents, and restricted cash at beginning of period		108,673		84,433		97,813
Cash, cash equivalents, and restricted cash at end of period	$	92,128	$	108,673	$	84,433

The accompanying notes are an integral part of these Consolidated Financial Statements.

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Business

We produce coal in the PRB. We operate some of the safest mines in the coal industry. According to the most current MSHA data, we have one of the lowest employee all injury incident rates among the largest U.S. coal producing companies. We currently operate solely in the PRB, the lowest cost region of the major coal producing regions in the U.S., where we own and operate three surface coal mines: the Antelope Mine, the Cordero Rojo Mine, and the Spring Creek Mine.

Our Antelope Mine and Cordero Rojo Mine are located in Wyoming and our Spring Creek Mine is located in Montana. Our mines produce subbituminous thermal coal with low sulfur content, and we sell our coal primarily to domestic and foreign electric utilities. Thermal coal is primarily consumed by electric utilities and industrial consumers as fuel for electricity generation. In 2018, the coal we produced generated approximately 2% of the electricity produced in the U.S. We do not produce any metallurgical coal. See Item 1. Business Mining Operations.

In addition, we have two development projects, both located in the Northern PRB. The Youngs Creek project is an undeveloped surface mine project located in Wyoming, seven miles south of our Spring Creek Mine, and contiguous with the Wyoming-Montana state line. The Big Metal project is located near the Youngs Creek project on the Crow Indian Reservation in southeast Montana. On June 7, 2018, Big Metal Coal Co. LLC (Big Metal) our wholly owned subsidiary, delivered notice to the Crow Tribe of Indians (Crow Tribe) to exercise the Upper Youngs Creek coal lease option and extend the coal lease options for the Squirrel Creek and Tanner Creek project areas. These two projects, in addition to the exercise of the aforementioned options, are described in more detail under Item 1. Business Development Projects. Any future development and coal production from these projects remains subject to significant risks and uncertainty. These development projects have been impaired. For additional information, see Note 7.

Our logistics business provides a variety of services designed to facilitate the sale and delivery of coal, primarily to Asian utility customers. These services include the purchase of coal from third parties or from our owned and operated mines, coordination of the transportation and delivery of purchased coal, negotiation of take-or-pay rail agreements and take-or-pay port agreements and demurrage settlement with vessel operators. See Note 6 for further discussion.

2. Basis of Presentation

Principles of Consolidation

We consolidate the accounts of entities in which we have a controlling financial interest under the voting control model. Investments in entities that we do not control, but have the ability to exercise significant influence over the investee s operating and financial policies, are accounted for under the equity method. The Consolidated Financial Statements have been prepared in conformity with accounting principles generally accepted in the Unites States of America (U.S. GAAP). All intercompany balances and transactions have been eliminated in the Consolidated Financial Statements.

Due to the tabular presentation of rounded amounts, certain tables reflect insignificant rounding differences.

Ability to Continue as a Going Concern

Our reduced liquidity, most notably with the termination of our Credit Agreement in November 2018 due to the limited availability thereunder based on the financial covenants, along with our forecasts projecting lower levels of operating cash flow due to depressed PRB thermal coal industry conditions and declines in logistic export prices, have limited our access to the capital markets. Our liquidity is now limited to cash and cash equivalents. Our forecasted cash from operations alone is insufficient to fund cash interest and capital expenditures. This has resulted in our conclusion that there is substantial doubt about our ability to continue as a going concern. These conditions are significant and our plans to address these circumstances include, but are not limited to, restructuring alternatives including asset sales, private debt restructuring or court supervised reorganization under Chapter 11 of the U.S. Bankruptcy Code and related financing needs, as described further in Note 26. As a result, we will continue to pursue these options to alleviate this

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

condition, but there can be no guarantees that we will be successful. Our consolidated financial statements have been prepared assuming we will continue as a going concern, which contemplates continuity of operations, realization of assets and the satisfaction of liabilities in the normal course of business. As a result, the accompanying consolidated financial statements do not include any adjustments relating to the recoverability and classification of assets and their carrying amounts, or the amount and classification of liabilities that may result should we be unable to continue as a going concern.

3. Significant Accounting Policies

Use of Estimates

The preparation of our Consolidated Financial Statements in conformity with U.S. GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expenses during the reporting periods. Significant estimates in these Consolidated Financial Statements include: assumptions about the amount and timing of future cash flows and related discount rates used in determining asset retirement obligations (AROs) and in testing long-lived assets and goodwill for impairment; the fair value of derivative financial instruments; the calculation of mineral reserves; equity-based compensation expense; reserves for contingencies and litigation; useful lives of long-lived assets; postretirement employee benefit obligations; the recognition and measurement of income tax benefits and related deferred tax asset valuation allowances; and allowances for inventory obsolescence and net realizable value. Actual results could differ materially from those estimates.

Revenue Recognition

We recognize revenue from a sale when control of a good or service transfers to the customer, which is evidenced by a present right to payment, title has transferred to the customer, the customer has the significant risks and rewards of ownership of the asset, the customer has accepted the asset, and physical possession of the asset has transferred to the customer.

Coal sales revenue include sales to customers of coal produced at our facilities and coal purchased from other companies. Coal sales are made to our customers under the terms of coal sales agreements. Under the typical terms of these coal sales agreements, title and risk of loss transfer to the customer at the time the coal is shipped, which is the point at which revenue is recognized. Certain contracts provide for title and risk of loss transfer at the point of destination, in which case revenue is recognized when it arrives at its destination.

Coal sales agreements typically contain coal quality specifications. With coal quality specifications in place, the raw coal sold by us to the customer at the delivery point must be substantially free of magnetic material and other foreign material impurities, and crushed to a maximum size as set forth in the respective coal sales agreement. Prior to billing the customer, price adjustments are made based on quality standards that are specified in the coal sales agreement, such as Btu factor, moisture, ash, and sodium content and can result in either increases or decreases in the value of the coal shipped.

Transportation and related costs are included in *Cost of product sold*, and amounts we bill to our customers for transportation are included in *Revenue,* both of which are included in the Consolidated Statements of Operations and Comprehensive Income (Loss).

Impairment of Long-Lived Assets

The carrying amounts of our mineral properties, equipment, and other long-lived assets are sensitive to declines in domestic and international coal prices. The cash flow models that we use to assess impairment include numerous assumptions such as our current estimates of forecast coal production, management s outlook on forward commodity prices, operating and development costs, and discount rates. If prices remain at current levels for an extended period of time or do not recover as anticipated, if regulatory changes adversely impact coal-fired electricity generation, or if we receive an unfavorable outcome of the litigation described in Note 21, we may incur additional impairment charges on certain of these assets.

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

We evaluate the recoverability of our long-lived assets when events or changes in circumstances indicate that the carrying amount of property, plant and equipment may not be recovered over its remaining service life. An asset impairment charge is recognized when the sum of estimated future cash flows associated with the operation and disposal of the asset, on an undiscounted basis, is less than the carrying amount of the asset. An impairment charge is measured as the amount by which the carrying amount of the asset exceeds its fair value. Fair value is measured using discounted cash flows based on estimates of coal reserves, coal prices, operating expenses, and capital costs or by reference to observable comparable transaction or replacement cost data. See Note 7 for a description of recent impairments of our long-lived assets.

Asset Retirement Obligations and Remediation Costs

We recognize liabilities for AROs where we have legal obligations associated with the retirement of long-lived assets. We recognize AROs at fair value at the time the obligations are incurred. Our AROs generally are incurred when a mine site is disturbed by mining activities and as the extent of disturbance increases. AROs reflect costs associated with legally required mine reclamation and closure activities, including earthwork, vegetation, and demolition and are estimated 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 adjusted for estimated inflation and discounted at credit-adjusted, risk-free rates to arrive at a present value of estimated future reclamation costs. The ARO amount is capitalized as part of the related mining property upon initial recognition and is included in *Depreciation and depletion* using the units-of-production method based on proven and probable reserves. As changes in estimates occur (such as changes in estimated costs or timing of reclamation activities resulting from mine plan revisions or new LBAs), the ARO liability and related asset are adjusted to reflect the updated estimates. If a reduction of the ARO exceeds the carrying amount of the related asset retirement cost, the adjustment is recorded as a reduction to *Depreciation and depletion* in the Consolidated Statements of Operations and Comprehensive Income (Loss).   Increases in ARO liabilities resulting from the passage of time are recognized as *Accretion* in the Consolidated Statements of Operations and Comprehensive Income (Loss). Other costs related to environmental remediation are charged to expense as incurred.

Cash and Cash Equivalents

We consider all highly-liquid investments with an original maturity of three months or less to be cash equivalents. Money market funds that meet all qualifying criteria for a money market fund under the Investment Company Act of 1940 are considered cash equivalents.

Allowance for Doubtful Accounts Receivable

We determine an allowance for doubtful accounts based on the aging of accounts receivable, historical experience, and management judgment. We write off accounts receivable against the allowance when we determine a balance is uncollectible and we no longer continue to actively pursue collection of the receivable. Based on our assessment of the above criteria, an allowance for doubtful accounts was not required as of December 31, 2018 and 2017.

Inventories, Net

Materials and Supplies

We state materials and supplies at average cost. We establish allowances for excess or obsolete materials and supplies inventory based on prior experience and estimates of future usage.

Coal Inventory

We state our coal inventory, which consists of coal stockpiles that may be sold in their current condition or may be further processed prior to shipment to a customer, at the lower of cost or net realizable value. Net realizable value represents the estimated future sales price based on spot coal prices and prices under long-term contracts, less the estimated costs to complete production and bring the product to sale. The cost of coal inventory reflects mining costs incurred up to the point of stockpiling the coal and includes labor, supplies,

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

equipment, applicable operating overhead, and depreciation, depletion, and amortization related to mining operations.

Prepaid Freight

Our logistics business incurs freight and related charges moving coal from the Spring Creek Mine to the port, as well as terminal handling charges and demurrage. These costs are included in *Other assets* in the Consolidated Balance Sheets until the revenue is recognized on the associated coal.

Property, Plant and Equipment

Plant and Equipment

We state plant and equipment at cost, less accumulated depreciation. Plant and equipment used in mining operations that are expected to remain in service for the life of the related mine are depreciated using the units-of-production method based on proven and probable reserves. Depreciation of other plant and equipment is computed using the straight-line method over the following estimated useful lives:

Buildings and improvements	5 to 25 years
Machinery and equipment	3 to 20 years
Furniture and fixtures	3 years

Mineral Rights

Mineral rights include both proven and probable reserves and non-reserve coal deposits. We state our mineral rights at cost, less accumulated depletion. We compute depletion of mineral rights using the units-of-production method based on proven and probable reserves. Non-reserve coal deposits are not depleted until they qualify as proven and probable reserves and the mining begins. Mineral rights are included in *Property, plant and equipment, net* in the Consolidated Balance Sheets.

Upon the award date of federal coal leases, pursuant to which payments are required to be made in equal annual installments, we recognize an asset for the related mineral rights in *Property, plant and equipment, net* and a corresponding liability for our future payment obligations in current and non-current liabilities. The amount recognized as an asset is the sum of the initial installment due at the effective date of the lease and the amount recognized in current and non-current liabilities, which reflects the present value of the remaining installments. We determine the present value of the remaining installments using an estimate of the credit-adjusted, risk-free rates that reflects our credit rating. Interest expense is recognized over the term of the lease based on the imputed interest rate that was used to determine the initial current and non-current liabilities amount on the effective date. Such interest may be capitalized while activities are in progress to prepare the acquired coal reserves for mining.

Land and Surface Rights

We purchase surface lands in order to gain access to our mineral rights. Land is typically acquired for amounts greater than its fair value as a result of the value of the coal beneath it. The value of the land is determined based on published agricultural values and is not depleted. The value of the surface rights is the amount paid in excess of the published agricultural value and is depleted over the useful life of the respective land parcel. Both land and surface rights are included in land and land improvements in *Property, plant and equipment, net* in the Consolidated Balance Sheets.

Capitalization of Interest

We capitalize interest costs on accumulated expenditures incurred in preparing capital projects for their intended use.

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Mine Development Costs

We capitalize costs of developing new mines where proven and probable reserves exist. We amortize mine development costs using the units-of-production method based on proven and probable reserves that are associated with the property being developed. Costs may include construction permits and licenses; mine design; construction of access roads, slopes and main entries; and removing overburden and waste materials to access the coal ore body in a new pit prior to the production phase, which commences when saleable coal, beyond a de minimis amount, is produced. Where multiple pits exist at a mining operation, overburden removal costs are capitalized if such costs are for the development of a new area that is separate and distinct from the existing production phase mines. Overburden removal costs that relate to the enlargement of an existing pit are expensed as incurred. Overburden removal costs incurred during the production phase are included as a cost of inventory to be recognized in *Cost of product sold* in the Consolidated Statements of Operations and Comprehensive Income (Loss) in the same period as the revenue from the sale of inventory. Additionally, mine development costs include the costs associated with AROs. Mine development costs are included in land, improvements, and mineral rights in *Property, plant and equipment, net* in the Consolidated Balance Sheets.

Repairs and Maintenance

We capitalize costs associated with major renewals and improvements. Expenditures to replace or completely rebuild major components of major equipment, which are required at predictable intervals to maintain or extend asset life or performance, are capitalized. These major components are capitalized separately from the major equipment and depreciated according to their own estimated useful life, rather than the estimated useful life of the major equipment. All other costs of repairs and maintenance are charged to expense as incurred.

Exploration Costs

We expense all direct costs incurred in identifying new resources and in converting resources to reserves at development and production stage projects. Exploration costs are included in *Cost of product sold* in the Consolidated Statements of Operations and Comprehensive Income (Loss) and consisted of the following for the years ended December 31 (in thousands):

	2018	2017	2016
Exploration costs	$ 597	$ 985	$ 1,179

Derivative Financial Instruments

We are exposed to various types of risk in the normal course of business, including fluctuations in the price at which we are able to sell our coal in the future and the price we are able to purchase diesel fuel used in our operations. We seek to mitigate some of the volatility of these fluctuations by using derivative financial instruments. We recognize all derivative financial instruments as assets or liabilities at their respective fair values in the Consolidated Balance Sheets. All derivative financial instruments are included in current assets or liabilities as we have the ability to settle the positions at any time. Gains or losses from changes in the fair value of derivative financial instruments are recognized immediately in the Consolidated Statements of Operations and Comprehensive Income (Loss) in *Operating income (loss)*. Assets and liabilities with the same counterparty, where right of offset is allowed, are recorded on a net basis in the Consolidated Balance Sheets.

Our derivative financial instruments do not qualify for hedge accounting; therefore, changes in the fair value of the derivative financial instruments are recorded in *Gain (loss) on derivative financial instruments* in the Consolidated Statements of Operations and Comprehensive Income (Loss) each period using mark-to-market accounting.

Fair Value of Financial Instruments

Our financial instruments include cash equivalents, accounts receivable, amounts due from related parties, accounts payable, and certain current liabilities. Due to the short-term nature of these instruments, we believe that their carrying amounts approximated fair value.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cash equivalents and derivative financial instruments are reported in our Consolidated Balance Sheets at fair value. We categorize assets and liabilities measured at fair value based on the observability of the inputs utilized in the valuation. See Notes 12 and 13.

Pensions and Other Postretirement Benefits

Our employees participate in defined contribution retirement plans, which require us to make contributions based on a percentage of compensation or to match employee contributions, subject to limitations. We recognize compensation expense for our required contributions as incurred.

In August 2018, we communicated the termination of our unfunded postretirement medical plan, effective January 1, 2019, to our employees. As a result of these changes, we recognized a non-cash net gain on the termination of the plan of $21.5 million for the year ended December 31, 2018. As a part of the termination, we will provide 2019 postretirement benefits to all eligible retirees that may be claimed for eligible expenses at any time during 2019. Employees who retired on, or after, January 1, 2019 are not eligible for postretirement benefits. See Note 19.

Income Taxes

We account for income taxes using a balance sheet approach in accordance with U.S. GAAP. Deferred income taxes are provided for temporary differences arising from differences between the financial statement and tax bases of assets and liabilities existing at each balance sheet date using enacted tax rates expected to be in effect when the related taxes are expected to be paid or recovered. A valuation allowance is established if it is more likely than not that a deferred tax asset will not be realized. In determining the appropriate valuation allowance, we consider projected realization of tax benefits based on expected levels of future taxable income, available tax planning strategies, and our overall deferred tax position. We recognize the benefit of uncertain tax positions at the greatest amount that is determined to be more likely than not of being realized. Interest and penalties related to income tax matters are included in *Income tax benefit (expense)* in the Consolidated Statements of Operations and Comprehensive Income (Loss).

Non-Income Based Taxes and Royalties

We are subject to certain production, severance, and extraction taxes and royalties that are charged based on coal production or coal sales. The taxes and royalties are paid to federal, state and local governments or to private parties based on legally established methodologies, rates, and timeframes. Amounts payable within one year are classified as current liabilities and are included in *Royalties and production taxes* in the Consolidated Balance Sheets. Amounts payable after one year are included in

Other liabilities, noncurrent, in the Consolidated Balance Sheets. We are open to federal and state audits on our non-income based taxes and royalties until statutes of limitations expire. Through the normal course of business, we receive audit findings and assessments, which may be resolved or disputed and appealed. If it is determined that it is more likely than not that adjustments to our filed positions are warranted, we record an accrual.

Equity-Based Compensation

We grant restricted stock units and performance-based share units to certain officers, employees and non-employee directors under our Long-Term Incentive Plan (LTIP) and have granted stock options in the past. We measure the cost of equity-based employee compensation based on the fair value of the award and recognize that cost over the period during which the recipient is required to provide services in exchange for the award, typically the vesting period. Awards granted to employees generally cliff vest over a three-year period while awards granted to non-employee directors vest upon their separation of service. The granting of restricted stock units results in recognition of compensation cost measured at the grant-date market price. Compensation cost for stock options is measured based on grant-date fair value of the award using the Black-Scholes option valuation model and for equity settled performance-based share units, a Monte Carlo simulation is utilized. For performance-based share units that were expected to be settled in cash upon any vesting, such as the 2016 grant, the performance criteria over the three-year performance period was not achieved and compensation cost is equal to its fair value as of the period-end based upon the share price and our relative total stockholder return,

CLOUD PEAK ENERGY INC.

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which was zero. These awards were classified as a liability and included within *Other liabilities* in the Consolidated Balance Sheets.

Earnings per Share

We compute basic earnings per share by dividing *Net income (loss)* by the weighted-average number of common shares outstanding during the period. Diluted earnings per share is computed using the weighted-average number of shares of common and potential dilutive common stock outstanding during the period. We apply the treasury stock method to determine potential dilutive common shares related to our stock options and non-vested stock awards.

Contingent Liabilities

We account for contingent liabilities related to litigation, claims, and assessments based on the specific facts and circumstances and our experience with similar matters. We record our best estimate of a loss when the loss is considered probable and the amount of loss is reasonably estimable. When a loss is probable and there is a range of the estimated loss with no best estimate in the range, we record our estimate of the minimum liability. As additional information becomes available, we revise our estimates as appropriate.

Recently Issued Accounting Pronouncements

From time to time, the Financial Accounting Standards Board (FASB) or other standard setting bodies issue new accounting pronouncements. Updates to the FASB Accounting Standards Codification are communicated through issuance of an Accounting Standards Update (ASU). Unless otherwise discussed, we believe that the impact of recently issued guidance will not be material to our Consolidated Financial Statements upon adoption.

In August 2018, the FASB issued ASU 2018-15, Intangibles   Goodwill and Other   Internal-Use Software, Customer s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract (ASU 2018-15), which requires a customer in a hosting arrangement that is a service contract to follow the internal-use software guidance to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The new guidance is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted. The amendments in this update should be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. We will adopt the new standard as of January 1, 2020 on a prospective basis.

In February 2018, the FASB issued ASU 2018-02, Income Statement Reporting Comprehensive Income - Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income (ASU 2018-02), which allows companies to make a one-time reclassification of the stranded tax effects (as defined by ASU 2018-02) from accumulated other comprehensive income to retained earnings as a result of the tax legislation enacted in December 2017, commonly known as the Tax Cuts and Jobs Act (TCJA), and requires certain disclosures about stranded tax effects. The new guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted. The amendments in this update should be applied either in the period of adoption or retrospectively to each period (or periods) in which the effects of the change in the U.S. federal corporate income tax rate in the TCJA is recognized. We will adopt the new standard as of January 1, 2019.

From February 2016 through July 2018, the FASB issued ASU 2016-02, Leases (ASC 842), which would require the lessee to recognize the assets and liabilities on all leases that may have not been recognized in the past, specifically, leases classified as operating leases under current U.S. GAAP (ASC 840). The core principal of ASC 842 is that a lessee should recognize both a lease liability for its obligation to make lease payments to the lessor and a right-of-use asset reflecting its right to use the underlying asset during the term of the lease. Under ASC 842, a lessee recognizes either an operating or a finance lease, with the pattern of expense recognition in the income statement differing depending on classification of the lease. There are also additional disclosure requirements under ASC 842, including expanded quantitative disclosures regarding the location and amounts related to operating and finance leases included in the financial statements, as well as

CLOUD PEAK ENERGY INC.

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qualitative disclosures about the nature of an entity s leases.

The new guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. We adopted the new standard effective January 1, 2019 and elected the optional transition practical expedient, which allows us to adopt the standard on the adoption date by recognizing a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. We will not retrospectively adjust prior periods, which will continue to be reported under ASC 840. Further, disclosures related to prior periods will also be reported under ASC 840. We will also elect the transitional package of practical expedients available within the new standard, which, among other things, allows a lessee to carry forward existing lease classification. Lastly, ASC 842 includes an accounting policy election whereby a lessee may choose not to apply ASC 842 to leases with terms of one year or less. Instead, a lessee recognizes the lease payments in the statement of operations on a straight-line basis over the term of the lease. We have made this policy election and leases of this nature will not be included on our Consolidated Balance Sheets.

During 2017 and 2018, we evaluated our contracts with our vendors under ASC 842. Based upon our review, the adoption of this standard will not have a material impact on our results of operations, financial position, and cash flows. The impact of ASC 842 is not material to our results due to our ownership of substantially all of our equipment and the fact that we have entered into very few operating leases. Additionally, the result of our review of our contracts with vendors yielded no change to our initial conclusion that these contracts did not contain a lease, as there were either no identified assets, or we did not obtain the right to control the use of an identified asset over a period of time. The adoption of ASC 842 will not have an impact on our accounting for capital leases, which will be classified as finance leases under ASC 842. In addition, the adoption of ASC 842 will not have an impact on our liquidity.

The following table reflects the adoption of ASC 842 on our Condensed Consolidated Balance Sheets as of January 1, 2019 (in thousands):

	Balance as of December 31, 2018	Adjustment Due to ASC 842	Balance as of January 1, 2019
Assets			
Right-of-use asset	$	$ 1,785	$ 1,785
Liabilities			
Lease liability	$	$ 1,785	$ 1,785
Accrued expenses	26,385	(106)	26,279
Other liabilities	5,731	(140)	5,591
Equity			
Retained earnings	$ (370,795)	$ 246	$ (370,549)

Recently Adopted Accounting Pronouncements

In August 2018, the FASB issued ASU 2018-13, Fair Value Measurement, Disclosure Framework Changes to the Disclosure Requirements for Fair Value Measurement (ASU 2018-13), which modifies the disclosure requirements on fair value measurement. The new guidance is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Early adoption is permitted. The guidance allows an entity to early adopt any removed or modified disclosures and delay adoption of the additional disclosures until their effective date. Certain amendments should be applied prospectively for only the most recent interim or annual period presented in the initial fiscal year of adoption, with all other amendments applied retrospectively to all periods presented upon adoption. We adopted this standard in September, 2018, which did not have a material impact on our disclosures. See Note 12 for our updated disclosure that reflects the early adoption of ASU 2018-13.

CLOUD PEAK ENERGY INC.

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In May 2017, the FASB issued ASU 2017-09, Compensation Stock Compensation Scope of Modification Accounting (ASU 2017-09), which provides guidance about the types of changes to terms or conditions of a share-based payment award that would require an entity to apply modification accounting. The new guidance is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. The amendments in this update should be applied prospectively to an award modified on or after the adoption date. We adopted this standard on January 1, 2018 with no impact on our Consolidated Financial Statements.

In March 2017, the FASB issued ASU 2017-07, Compensation Retirement Benefits Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Cost (ASU 2017-07), which requires separate presentation of service costs and all other components of net benefit costs on the income statement. Under ASU 2017-07, service cost is included in the same line item as other compensation costs arising from services rendered by employees during the period, with all other components of net benefit costs on the income statement outside of income from operations. The new guidance is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. We adopted this standard on January 1, 2018. We retrospectively adopted the presentation of service costs separate from the other components of net periodic costs. The interest costs and amortization of prior service costs have been reclassified from *Cost of product sold* and *Selling, general and administrative expenses* to *Net periodic postretirement benefit income (cost), excluding service cost*.

The effect of the retrospective presentation change related to the net periodic cost of our other postretirement employee benefits (OPEB) plan on our Consolidated Statement of Operations and Comprehensive Income (Loss) for the years ended December 31, 2017 and 2016 was as follows (in thousands):

	Year Ended December 31, 2017			Year Ended December 31, 2016		
	Previously Reported	Adjustment	As Revised	Previously Reported	Adjustment	As Revised
Cost of product sold	$ 752,715	$ 5,319	$ 758,034	$ 646,404	$ 3,401	$ 649,805
Selling, general and administrative expenses	$ 47,482	$ 1,046	$ 48,528	$ 50,868	$ 665	$ 51,533
Operating income (loss)	$ 4,940	$ (6,365)	$ (1,425)	$ 67,268	$ (4,066)	$ 63,202
Net periodic postretirement benefit income (cost), excluding service cost	$	$ 6,365	$ 6,365	$	$ 4,066	$ 4,066
Total other income (expense)	$ (41,762)	$ 6,365	$ (35,397)	$ (48,297)	$ 4,066	$ (44,231)

In January 2017, the FASB issued ASU 2017-04, Goodwill Simplifying the Test for Goodwill Impairment (ASU 2017-04), which eliminates the second step in the goodwill impairment test whereby a company measures an impairment loss by calculating the implied fair value of goodwill of a reporting unit and comparing it against its carrying value. As a result, a goodwill impairment loss will be calculated by comparing the fair value of a reporting unit with its carrying amount. The new guidance is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Early adoption is permitted. The amendments in this update should be applied prospectively, with added disclosure regarding the nature of and reason for the change in accounting principal. We early adopted this standard as of December 31, 2018 in conjunction with our fourth-quarter impairment analysis. See Note 7 for further information.

In November 2016, the FASB issued ASU 2016-18, Statement of Cash Flows Restricted Cash (ASU 2016-18), which requires the statement of cash flows to explain the change during the period in total cash, cash equivalents, and amounts generally described as restricted cash and restricted cash equivalents. The new guidance is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. The amendments in this update should be applied using a retrospective transition method to each period presented. We adopted this standard on January 1, 2018. Refer to Note 23, as well as the Consolidated Statements of Cash Flows, for further information regarding the reconciliation of cash, cash equivalents, restricted cash, and restricted cash equivalents.

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In October 2016, the FASB issued ASU 2016-16, Accounting for Income Taxes Intra-Entity Asset Transfers of Assets other than Inventory (ASU 2016-16), which would require the recognition of the tax expense from the sale of an asset other than inventory when the transfer occurs, rather than when the asset is sold to a third party or otherwise recovered through use. The new guidance is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. The amendments in this update should be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. We adopted this standard on January 1, 2018. We completed a review of our intra-entity transfers as of December 31, 2017, and determined that ASU 2016-16 does not have an impact on our Consolidated Financial Statements.

In August 2016, the FASB issued ASU 2016-15, Classification of Certain Cash Receipts and Cash Payments (ASU 2016-15), which standardizes cash flow statement classification of certain transactions, including cash payments for debt prepayment or extinguishment, proceeds from insurance claim settlements, and distributions received from equity method investments. The new guidance is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. The amendments in this update should be applied using a retrospective transition method to each period presented. If impracticable to apply the amendments retrospectively for some of the issues, the amendments for those issues would be applied prospectively as of the earliest date practicable. We adopted this standard on January 1, 2018, with no impact on our Consolidated Statements of Cash Flows.

From May 2014 through December 2016, the FASB issued several ASUs related to Revenue from Contracts with Customers (ASC 606). These ASUs are intended to provide greater insight into both revenue that has been recognized and revenue that is expected to be recognized in the future from existing contracts. The core principle of the new standard is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The new guidance is effective for interim and annual periods beginning after December 15, 2017. The two permitted transition methods under the new standard are the full retrospective method, in which case the standard would be applied to each prior reporting period presented and the cumulative effect of applying the standard would be recognized at the earliest period shown, or the modified retrospective method, in which case the cumulative effect of applying the standard would be recognized at the date of initial application. We have adopted the new standard as of January 1, 2018 and utilized the modified retrospective method. This approach allowed us to apply the new standard to (1) all new contracts entered into after January 1, 2018 and (2) all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance as of January 1, 2018 through a cumulative adjustment to equity. Consolidated revenue presented in our comparative financial statements for periods prior to January 1, 2018 has not been revised and continues to be reported under legacy revenue recognition guidance.

The following table reflects the adoption of ASC 606 on our Consolidated Balance Sheets as of January 1, 2018 (in thousands):

	Balance as of December 31, 2017	Adjustment Due to ASC 606	Balance as of January 1, 2018
Assets			
Accounts receivable	$ 50,075	$ 781	$ 50,856
Inventories, net	72,904	(660)	72,244

Equity			
Retained Earnings	$ 347,046	$ 121	$ 347,167

As part of the adoption of ASC 606, we did not recognize approximately 64,400 tons that were delivered in January 2018 in our tons sold figure for 2018. These tons were delivered on a contract where title transferred to the customer upon delivery, while risk of loss transferred at the shipping point, or the mine. Under legacy revenue recognition guidance, the revenue related to these tons was recognized upon delivery. However, under ASC 606, revenue is now recognized at the shipping point, as this is when control passes to the customer. As of December 31, 2017, these tons were appropriately placed back into inventory in accordance with legacy revenue

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recognition guidance. The revenue recognition process was complete upon adoption of ASC 606 on January 1, 2018. See Note 4 for further information.

4. Revenue

In accordance with the new revenue standard requirements, the impact of the adoption of ASC 606 on our Consolidated Statements of Operations and Comprehensive Income (Loss) and our Consolidated Balance Sheets is as follows (in thousands):

		December 31, 2018	
	As Reported	Balances Without the Adoption of ASC 606	Effect of Change Higher (Lower)
Accounts receivable	$ 33,527	$ 33,091	$ 436
Inventories, net	70,040	70,363	(323)
Retained earnings	(370,795)	(370,908)	113

		Year Ended December 31, 2018	
	As Reported	Balances Without the Adoption of ASC 606	Effect of Change Higher (Lower)
Revenue	$ 832,405	$ 832,750	$ (345)
Cost of product sold	765,540	765,877	(337)
Net income (loss)	(717,963)	(717,954)	(9)
Income (loss) per common share:			
Basic	$ (9.49)	$ (9.49)	$
Diluted	$ (9.49)	$ (9.49)	$

Revenue from Contracts with Customers

We account for a contract with a customer when the parties have approved the contract and are committed to performing their respective obligations, the rights of each party are identified, payment terms are identified, the contract has commercial substance, and collectability of consideration is probable. We recognize revenue when we satisfy a performance obligation by transferring control of a good or service to a customer.

Our revenue is derived from sales to customers of coal produced at our facilities and coal purchased from other companies. We categorize our customers by how we sell coal to them. Our mine customers purchase coal directly from our mine sites, where the sale occurs at the mine site and where title, risk of loss, and control typically pass to the customer at that point. This revenue is generally recorded in our Owned and Operated Mines Segment. Mine customers arrange for and bear the costs of transporting their coal from our mines to their plants or other specified discharge points. Our mine customers are typically domestic utility companies primarily located in the mid-west and south central U.S., although we also sell to other domestic utility companies, as well as to third-party brokers. Our coal sales agreements with our mine customers are generally fixed-price, fixed-volume supply contracts, or include a pre-determined escalation in price for each year. Some of our customer contracts may include variable pricing and volumes. Price re-opener and index provisions may allow either party to commence a renegotiation of the contract price at a pre-determined time. Price re-opener provisions may automatically set a new price based on prevailing market price or, in some instances, require us to negotiate a new price, sometimes within specified ranges of prices. In some agreements, if the parties do not agree on a new price, either party has an option to terminate the contract. The terms of our coal sales agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these contracts vary by customer.

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Our logistics customers purchase coal from us, along with logistics services to deliver the coal to the customer at a terminal or the customer s plant or other delivery point remote from our mine site. Title, risk of loss, and control pass to the customer at the remote delivery point. This revenue is recorded in our Logistics and Related Activities Segment. Our logistics services are designed to facilitate the sale and delivery of coal. These services include the purchase of coal from third parties or from our owned and operated mines, coordination of the transportation and delivery of purchased coal, negotiation of take-or-pay rail agreements and take-or-pay port agreements and demurrage settlements with vessel operators. We also bear the costs of transporting the coal to the delivery point. For our international customers, this means that we cover the costs associated with an export terminal located in the Pacific Northwest. Refer to Note 6 for further information. Our logistics customers located overseas are generally responsible for paying the cost of ocean freight, although occasionally we may arrange or be responsible for the cost of that transportation as well. Logistics customers are primarily foreign and domestic utility companies as well as third-party brokers. With respect to our international sales, at present, we are primarily focused on end-user customers. However, a portion of our sales are made to international traders who sell on to end-user customers. Our coal sales agreements with our domestic logistics customers are generally fixed-price, fixed-volume supply contracts with terms of one to three years, or less. The terms of our coal sales agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these contracts vary by customer. With our international logistics customers, we often enter into contracts that contain multi-year terms with future year pricing to be agreed upon, meaning that there is an expectation of sales, provided that mutual agreement on pricing can be reached. This is consistent with conventional industry standards for sales into the Asian Pacific region. We typically agree upon volumes and pricing under these international customer agreements one to six months in advance of shipment. Our Asian delivered shipments are typically priced broadly in line with a number of relevant international coal indices adjusted for energy content and other quality and delivery criteria. These indices have included the Newcastle benchmark price, as published by Global Coal and others, and the Platts Kalimantan 5000. Contracts with our logistics customers include terms similar to those described for our mine customers and may include terms relating to: demurrage fees for international contracts, fixed pricing for the current year of sales, and additional coal quality requirements.

Coal sales agreements with both mine and logistics customers typically contain coal quality specifications. With coal quality specifications in place, the raw coal sold by us to the customer at the delivery point must be substantially free of magnetic material and other foreign material impurities, and crushed to a maximum size as set forth in the respective coal sales agreement. Prior to billing the customer, price adjustments are made based on quality standards that are specified in the coal sales agreement, such as Btu factor, moisture, ash, and sodium content and can result in either increases or decreases in the value of the coal shipped.

Disaggregation of Revenue

In the following table, *Revenue* is disaggregated by primary geographic markets, as we believe this best depicts how the nature, amount, timing, and uncertainty of our revenue and cash flows are affected by economic factors (in thousands):

	Year Ended December 31,		
	2018	**2017**	**2016**
United States(1)	$ 562,273	$ 675,703	$ 767,343
South Korea(2)	236,132	184,135	14,181
Other(2)	34,000	27,868	18,914

Total revenue from external customers	$	832,405	$	887,706	$	800,438

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(1) The majority of our domestic revenue is attributable to the Owned and Operated segment.

(2) All South Korean revenue and the majority of Other geographical revenue is attributable to our Logistics and Related Activities segment.

We attribute revenue to individual countries based on the location of the physical delivery of the coal. All of our revenue for the years ended December 31, 2018 and 2017 originated in the United States.

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Performance Obligations

A performance obligation is a promise in a contract with a customer to provide distinct goods or services. Performance obligations are the unit of account for purposes of applying the revenue recognition standard and therefore determine when and how revenue is recognized. In most of our contracts, the customer contracts with us to provide coal that meets certain quality criteria, and, for our logistics customers, delivery of that coal to a certain destination. These promises are highly interrelated and interdependent, and cannot be transferred to the customer without the other promises in the contract also being fulfilled. As such, these promises are not separately identifiable within the context of the contract, and therefore, are not distinct. Therefore, the entire contract is accounted for as one performance obligation. We allocate the transaction price based on the base price per the contract, which is also the standalone selling price, increased or decreased for quality adjustments.

Under ASC 606, shipping and handling services may be considered a separate performance obligation if control of the goods transfers to the customer before shipment, but the entity has promised to ship the goods, or arrange for their shipment. In contrast, if control of a good does not transfer to the customer before shipment, shipping is not a promised service to the customer. This is because shipping is a fulfillment activity as the costs are incurred as part of transferring the goods to the customer. ASC 606 includes an accounting policy election that permits entities to account for shipping and handling activities that occur after the customer has obtained control of a good as fulfillment cost rather than as an additional promised service. We have made this accounting policy election, and will recognize the corresponding transportation expenses for contracts in which we arrange and pay for shipping costs when the customer has obtained control of the related coal.

We generally recognize revenue at a point in time as the customer does not have control over the asset at any point during the fulfillment of the contract. For the majority of our customers in our Owned and Operated Segment, this is supported by the fact that title and risk of loss transfer to the customer upon loading of the railcar at the mine. This is also the point at which physical possession of the coal transfers to the customer, as well as the significant risks and rewards in ownership of the coal. Similarly, for customers in our Logistics and Related Activity Segment, this is supported by the fact that title and risk of loss transfer to the customer when the coal is delivered to an agreed-upon destination or loaded and trimmed on a vessel. This is also the point at which physical possession of the coal transfers to the customer, as well as the significant risks and rewards in ownership of the coal.

In our Owned and Operated Segment, we have remaining performance obligations relating to fixed priced contracts of approximately $786 million, which represent the average fixed prices on our committed contracts as of December 31, 2018. We expect to recognize approximately 48% of this revenue through 2019, with the remainder recognized thereafter. We have remaining performance obligations relating to index priced contracts or contracts with price reopeners of approximately $278 million, which represent the average re-opener/indexed price on committed contracts as of December 31, 2018. We expect to recognize approximately 30% of this revenue through 2019, with the remainder recognized thereafter. In our Logistics and Related Activities segment, we have remaining performance obligations relating to our fixed price contracts of approximately $54 million, which we expect to recognize in 2019 and 2020.

The tons used to determine the remaining performance obligations are subject to adjustment in instances of force majeure and exercise of customer options to either take additional tons, or reduce tonnage, if such option exists in the customer contract. Furthermore, export tons are subject to adjustment upon loading of vessels at the port and therefore represent the estimated tons we anticipate shipping. The elimination of the purchase and sale of coal between reportable segments is not reflected above.

Contract Balances

Under ASC 606, the timing of when a performance obligation is satisfied can affect the presentation of accounts receivable, contract assets, and contract liabilities. The main distinction between accounts receivable and contract assets is whether consideration is conditional on something other than the passage of time. A receivable is an entity s right to consideration that is unconditional. Under the typical payment terms of our contracts with customers, the customer pays us a base price for the coal, increased or decreased for any quality adjustments. In our contracts with mine customers, adjustments are known at the time of invoicing as we conduct our own tests of quality. In contracts with our logistics customers, adjustments are also known at the time of

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billing as they are based on quality tests performed at the port. Amounts billed and due are recorded as trade accounts receivable and included in *Accounts receivable* on our Consolidated Balance Sheets. In cases where we invoice based on customers quality tests, we estimate the transaction price using our quality testing results. Historically, the differences between customers testing results and our testing results have been immaterial. We do not currently have any contracts in place where we would transfer coal in advance of knowing the final price of the coal sold, and thus do not have any contract assets recorded. Contract liabilities arise when consideration is received in advance of performance. This deferred revenue is included in *Accrued expenses* on our Consolidated Balance Sheets when consideration is received and revenue is not recognized until the performance obligation is satisfied. We are rarely paid in advance of performance and do not currently have any deferred revenue recorded on our Consolidated Balance Sheets.

Accounts receivable, net consisted of the following (in thousands):

		December 31, 2018		December 31, 2017
Trade accounts receivable	$	33,062	$	47,872
Other receivables		464		2,203
Accounts receivable, net	$	33,527	$	50,075

5. Segment Information

We have two reportable segments; our Owned and Operated Mines segment and our Logistics and Related Activities segment.

Our Owned and Operated Mines segment is characterized by the predominant focus on thermal coal production where the sale occurs at the mine site and where title and risk of loss generally pass to the customer at that point. This segment includes our Antelope Mine, Cordero Rojo Mine, and Spring Creek Mine. Sales in this segment are primarily to domestic electric utilities, although a portion is made to our Logistics and Related Activities segment. Sales between reportable segments are priced based on prevailing market prices for arm s length transactions. Our mines utilize surface mining extraction processes and are all located in the PRB. The gains and losses resulting from our domestic coal futures contracts and WTI derivative financial instruments are reported within this segment.

Our Logistics and Related Activities segment is characterized by the services we provide to our international and certain of our domestic customers where we deliver coal to the customer at a terminal or the customer s plant or other delivery point, remote from our mine site. Services provided include the purchase of coal from third parties or from our Owned and Operated Mines segment, at market prices, as well as the contracting and coordination of the transportation and other handling services from third-party operators, which are typically rail and terminal companies. Title and risk of loss are retained by the Logistics and Related Activities segment through the transportation and delivery process. Title and risk of loss pass to the customer in accordance with the contract and typically occur at a vessel loading terminal, a vessel unloading terminal or an end use facility. Risk associated with rail and terminal take-or-pay agreements is also borne by the Logistics and Related Activities segment. The gains and losses resulting from our international coal forward contracts, international coal put options, and U.S. On-Highway Diesel derivative financial instruments are reported within this segment. Amortization related to the amended port and rail take-or-pay agreements are included in this segment. See Note 6 for additional information about the amended transportation agreements. Incremental production taxes and royalties associated with the sales made by our Logistics and Related Activities segment are included in this segment for the current year. These taxes and royalties were immaterial in the prior years and have not been reclassified from the Owned and Operated Mines segment. Gains and losses associated with our former investment in the Gateway Pacific Terminal are included in our Logistics and Related Activities segment.

Our business activities that are not considered operating segments are included in Other although they are not required to be included in this footnote. They are provided for reconciliation purposes and include *Selling, general and administrative expenses* (SG&A) as well as results relating to broker activity.

Eliminations represent the purchase and sale of coal between reportable segments and the associated elimination of intercompany profit or loss in inventory and are provided for reconciliation purposes.

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The following table presents revenue, total assets, and capital expenditures by reportable segment for the years ended December 31 (in thousands):

	Owned and Operated Mines	Logistics and Related Activities	Other	Eliminations	Consolidated
Year Ended December 31, 2018					
Revenue	$ 615,241	$ 279,029	$ 11	$ (61,876)	$ 832,405
Total assets	735,022	29,327	164,879	(572)	928,656
Capital expenditures	18,250		425		18,675
Year Ended December 31, 2017					
Revenue	$ 715,889	$ 222,451	$ 4,234	$ (54,868)	$ 887,706
Total assets	1,460,512	49,085	188,781	323	1,698,701
Capital expenditures	13,997		2,004		16,001
Year Ended December 31, 2016					
Revenue	$ 738,579	$ 43,553	$ 30,305	$ (11,999)	$ 800,438
Total assets	1,516,881	51,586	146,623	(314)	1,714,776
Capital expenditures	37,156		2,175		39,331

As of December 31, 2018, 2017, and 2016, all of our long-lived assets were located in the U.S.

Adjusted EBITDA

EBITDA represents net income (loss) before: (1) interest income (expense) net, (2) income tax provision, (3) depreciation and depletion, and (4) amortization. Adjusted EBITDA represents EBITDA as further adjusted for accretion, which represents non-cash increases in asset retirement obligation liabilities resulting from the passage of time, and specifically identified items that management believes do not directly reflect our core operations. For the periods presented herein, the specifically identified items are: (1) adjustments for derivative financial instruments, excluding fair value mark-to-market gains or losses and including derivative settlements, (2) adjustments to exclude non-cash impairment charges, (3) adjustments to exclude debt restructuring costs, and (4) non-cash amortization expense related to transportation agreements with BNSF and Westshore. We enter into certain derivative financial instruments such as put options that require the payment of premiums at contract inception. The reduction in the premium value over time is reflected in the mark-to-market gains or losses. Our calculation of Adjusted EBITDA does not include premiums paid for derivative financial instruments; either at contract inception, as these payments pertain to future settlement periods, or in the period of contract settlement, as the payment occurred in a preceding period. In prior years the amortization of port and rail contract termination payments were included as part of EBITDA and Adjusted EBITDA because the cash payments approximated the amount of amortization being taken during the year. During 2017, management determined that the non-cash portion of amortization arising from payments made in prior years as well as the amortization of contract termination payments should be adjusted out of Adjusted EBITDA because the ongoing cash payments are now significantly smaller than the overall amortization of these payments and no longer reflect the transactional results.

Adjusted EBITDA is an additional tool intended to assist our management in comparing our performance on a consistent basis for purposes of business decision making by removing the impact of certain items that management believes do not directly reflect our core operations. Adjusted EBITDA is a metric intended to assist management in evaluating operating performance, comparing performance across periods, planning and forecasting future business operations and helping determine levels of operating and capital investments.

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The following table reconciles segment Adjusted EBITDA to *Income (loss) before income tax provision and earnings from unconsolidated affiliates* for the years ended December 31, (in thousands):

	2018	2017	2016
Adjusted EBITDA			
Owned and Operated Mines	$ 71,790	$ 142,814	$ 143,666
Logistics and Related Activities	21,486	8,614	(23,631)
Total Adjusted EBITDA for reportable segments	93,276	151,428	120,035
Unallocated net expenses	(25,960)	(46,485)	(21,461)
Adjustments to Income (loss) before income tax provision and earnings from unconsolidated affiliates			
Depreciation and depletion	(49,042)	(72,270)	(27,218)
Accretion	(6,171)	(7,072)	(6,645)
Impairments	(684,673)		(4,609)
Debt restructuring costs		(23)	(4,665)
Derivative financial instruments:			
Gain (loss) on derivative financial instruments (1)	(2,642)	(2,672)	8,180
Settlements on derivative financial instruments	256	1,920	3,305
Total derivative financial instruments	(2,386)	(752)	11,485
Interest expense, net	(38,967)	(40,877)	(47,296)
(Income) loss from unconsolidated affiliates, net of tax	(279)	(713)	(657)
Non-cash amortization of transportation agreements	(5,957)	(20,058)	
Income (loss) before income tax provision and earnings from unconsolidated affiliates	$ (720,159)	$ (36,822)	$ 18,971

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(1) *(Gain) loss on derivative financial instruments* reflected in the Consolidated Statements of Operations and Comprehensive Income (Loss).

6. Transportation Agreements

To ensure export terminal capacity for export sales, we enter into multi-year throughput agreements with export terminal companies and railroads. These types of take-or-pay agreements require us to pay for a minimum quantity of coal to be transported on the railway or through the terminal regardless of whether we sell any coal. If we fail to make sufficient export sales to meet our minimum obligations under the take-or-pay agreements, we are still obligated to make payments to the export terminal company and railroad.

We have a throughput contract with Westshore Terminals Limited Partnership (Westshore) for our anticipated export sales through their export terminal in Vancouver, British Columbia, and a similar contract with Burlington Northern Santa Fe Railroad (BNSF).

Current Agreements

In December 2016, we terminated our previous agreement with Westshore and entered into a new agreement effective January 1, 2017. In February 2017, we terminated our previous agreement with BNSF and entered into a new agreement effective April 1, 2017. These agreements provided for shipments in 2017 and 2018 and required minimum payments for those two years.

In December 2017, we extended the agreement with Westshore, through the end of 2020 with minimum payment commitments for each year. We further amended this agreement in July 2018 to extend through the end of 2022 and allow for greater capacity in 2021 and 2022 to 10.5 million total annual throughput tons. We retain the right to terminate our commitments at any time in exchange for a buyout payment. The termination payment varies throughout the period based upon an agreed schedule. Additionally, after the new Westshore agreement terminates and through 2024, if we choose to ship to export customers, we are required to offer to ship through

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Westshore up to a specified annual tonnage on terms similar to the new agreement before shipping through any other export terminal. Westshore has the right to accept or reject our offer in its sole discretion.

In January 2018, we extended the existing agreement with BNSF through the end of 2020 with minimum payment commitments for each year. We have the right to terminate our commitments for the remaining years at any time in exchange for buyout payments. We are currently in discussions with BNSF regarding an extension through December 2022 to support our increased port capacity for our Asian export business.

All termination payments made in prior years related to these agreements, including the payment related to historical agreements, have been deferred and are being amortized over the remaining life of the new agreements. As of December 31, 2018, there was $16.6 million recorded as a deferred asset for these agreements, of which $13.4 million and $3.2 million, were included in *Other prepaid and deferred charges and Other assets*, respectively, in the Consolidated Balance Sheets. As of December 31, 2017, there was $22.4 million recorded as a deferred asset for these agreements, of which $22.4 million was included in *Other prepaid and deferred* charges in the Consolidated Balance Sheets. We incurred $182.9 million and $162.4 million and $51.5 million in costs under our logistics agreements with Westshore and BNSF during the years ended December 31, 2018, 2017, and 2016, respectively, including amortization of $18.2 million, $35.8 million and $32.7 million in 2018, 2017 and 2016, respectively.

7. Impairments

Long-Lived Assets

During the fourth quarter of 2018 and through the filing date of this Form 10-K, we have experienced a number of adverse events that have negatively impacted our financial results, liquidity and future prospects, which include:

- Depressed PRB thermal coal industry conditions, specifically recent uneconomic 8400 Btu contracted coal prices,
- Logistics export pricing declined in the fourth quarter of 2018 to an uneconomic level
- Reduced cash flow projections for 2019, which includes impacts from the on-going operational issues in the fourth quarter of 2018 at our Antelope mine.

Depressed PRB thermal coal industry conditions, particularly for 8400 Btu coal produced by the Cordero Rojo Mine, was evidenced by the significant Btu discount for contracted 8400 Btu coal prices relative to 8800 Btu coal prices. While Cordero Rojo produced significant cash flows during 2018, the contracted coal prices for 2019, particularly as contracted during the fourth quarter, along with higher costs projected for 2019 at Cordero Rojo, resulted in an uneconomic forecast for the mine. Further contracting was suspended and planned production volumes were reduced. We are now fully contracted for the planned 2019 production volumes at Cordero Rojo Mine. Additionally, we are experiencing a strip ratio increase in 2019, which increases our forecasted costs, thereby increasing the impact of lower sales prices. As business plans and financial forecasts were updated and reviewed during the fourth quarter of 2018 and finalized in the first quarter of 2019, it was concluded that an asset impairment was required in the current period. The carrying book value amount related primarily to land access rights and mineral values, which was impaired by $372.4 million. The asset impairment charge does not alter the underlying land access and mineral rights.

The lower forecasted cash flows from Cordero Rojo combined with the fourth quarter decline in logistics export pricing lead directly to reduced cash flow projections for 2019. Specifically, export prices declined in the fourth quarter of 2018 to an uneconomic level. From September 30, 2018 to December 31, 2018, the Kalimantan index declined by 14 percent from $53.25 per tonne to $46.00 per tonne. While seaborne thermal coal prices are volatile, the recent price reductions resulted in a loss for our Logistics and Related Activities segment during the fourth quarter of 2018 and lowered our 2019 forecasted results. The negative cash flows forecasted for 2019 significantly limit our ability to access capital markets.

Our two development projects, the Youngs Creek project and the Big Metal project require significant development capital, which is not currently available to us. As business plans and financial forecasts were updated and reviewed during the fourth quarter of 2018 and finalized in the first quarter of 2019, along with the lack of access to the capital markets required to develop these projects, it was concluded that an asset impairment was required in the current period. The carrying book value

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amount related primarily to land access and mineral rights, which was impaired by $309.2 million. The asset impairment charge does not alter the underlying land access and mineral rights. An improved future outlook could provide the opportunity to reassess the potential development of these projects.

Management completed an impairment analysis during the second quarter of 2016, due to lower planned production estimates as well as continued weak coal prices. At that time, management s evaluation revealed that all costs related to the mines in our Owned and Operated mines segment were recoverable during the life of the mine. Certain individual assets were also evaluated and during the year ended December 31, 2016, we recorded impairments of $2.6 million in the Owned and Operated Mines segment, primarily for engineering costs related to the Overland Conveyor project at our Antelope Mine and $2.0 million related to a shovel that we no longer expected to use because of declining production.

No impairments of long-lived assets were recognized for the year ended December 31, 2017.

Goodwill

During the fourth quarter of 2018, we determined that the carrying amount of our remaining goodwill had exceeded its estimated fair value. The implied fair value of the goodwill remaining at the Antelope and Spring Creek mines was zero, requiring a $2.3 million impairment charge related to our Owned and Operated Mines segment, which is reflected in the year ended December 31, 2018.

8. Interest Expense

Interest expense consisted of the following (in thousands):

	Year Ended December 31, 2018	2017	2016
Senior notes	$ 25,502	$ 27,621	$ 37,481
Credit facility unutilized fee	2,211	3,795	4,132
Federal coal lease obligations imputed interest	455	350	342
	6,340	7,781	5,173

Amortization of deferred financing costs and original issue discount			
Other	143	233	257
Subtotal	34,651	39,780	47,385
Premium on early retirement of debt		880	
Write-off of deferred financing costs and original issue discount	5,538	702	1,254
Total cost of early retirement of debt and refinancings	5,538	1,582	1,254
Total interest expense	40,189	41,362	48,639
Less interest capitalized			(1,205)
Interest expense	$ 40,189	$ 41,362	$ 47,434

Debt issuance costs of $5.5 million related to the decrease in the Amended Credit Agreement borrowing capacity and the subsequent termination of the Amended Credit agreement in the fourth quarter of 2018 were written off in the year ended December 31, 2018. See Note 18 for further discussion.

In connection with the public offering discussed in Note 16, upon redemption of the 2019 Notes, we paid $1.5 million in accrued and unpaid interest, $0.9 million in premium on the early retirement of debt, and wrote off $0.7 million in deferred financing and original issue discount in the year ended December 31, 2017.

Debt issuance costs of $1.3 million related to the decrease in the Credit Agreement s borrowing capacity were written off in the third quarter of 2016. Additional debt issuance costs of $3.6 million were incurred in connection with the amended Credit Agreement in the third quarter of 2016. These costs were deferred and are

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being amortized to Interest expense in the Consolidated Statements of Operations and Comprehensive Income (Loss) over the remaining term of the Credit Agreement.

9. Income Taxes

Our *Income (loss) before income tax provision and earnings from unconsolidated affiliates* is earned solely in the U.S.

TCJA made significant changes to U.S. tax laws. We have historically been subject to the AMT under which taxes are imposed at a 20% rate on taxable income, subject to certain adjustments, and we had assumed that we would be subject to the AMT rate in future periods. As such, the elimination of the AMT and reduction in the federal corporate tax rate to 21% did not have a material impact on our estimates for cash taxes payable in the years following TCJA. The corporate rate reduction required a revaluation of our net deferred tax asset as of December 31, 2017. However, since we had a full valuation allowance on our net deferred tax asset, there was no revaluation impact to our income statement.

A material immediate impact of TCJA is the elimination of the AMT and the ability to offset our regular tax liability or claim refunds for taxable years 2018 through 2021 for our AMT credits carried forward from prior periods. We currently anticipate we will realize approximately $31.5 million in AMT value over the next four years with approximately half of this value realized in 2019 for taxable year 2018.

Income tax benefit (expense) consisted of the following for the years ended December 31 (in thousands):

	2018	2017	2016
Current:			
Federal	$ 2,082	$ 29,537	$ 1,494
State	(165)	(67)	(252)
Total current	1,917	29,470	1,242
Deferred:			
Federal			915
State			56
Total deferred			971
Total income tax benefit (expense)	$ 1,917	$ 29,470	$ 2,213

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We report the tax effects of differences between the tax bases of assets and liabilities and the financial statement carrying amounts of these items as deferred tax assets and deferred tax liabilities. Our deferred tax assets and liabilities consisted of the following as of December 31 (in thousands):

	2018	2017
Deferred income tax assets:		
Property, plant and equipment	$ 1,793	$
Mineral rights	71,666	
Accrued expense and liabilities	13,257	17,530
Pension and other postretirement benefits	270	5,898
Accrued reclamation and mine closure costs	19,937	22,229
Contract rights	37,209	38,793
Debt restructuring	9,550	12,762
Deferred interest	8,964	
Mark-to-market gain (loss)	538	52
Net operating loss carryforward	68,040	55,160
Other	4,259	866
Total deferred income tax assets	235,483	153,290
Less valuation allowance	(211,680)	(52,010)
Net deferred income tax asset	23,803	101,280
Deferred income tax liabilities:		
Property, plant and equipment		(33,420)
Inventories	(11,392)	(11,521)
Mineral rights		(44,878)
Throughput payments	(3,735)	(3,604)
Other	(8,676)	(7,857)
Total deferred income tax liabilities	(23,803)	(101,280)
Net deferred income tax assets (liabilities)	$	$

The estimated statutory income tax rates that are applied to our current and deferred income tax calculations are impacted significantly by the states in which we do business. Changes in apportionment laws or business conditions result in changes in the calculation of our current and deferred income taxes, including the valuation of our deferred tax assets and liabilities. Such adjustments can increase or decrease our net deferred tax assets at period end as well as the corresponding deferred tax expense or benefit during the period.

The realization of our deferred income tax assets depends on the existence of sufficient future taxable income. In 2015, after considering operating results as well as our projected results for the next few years, we determined that it was unlikely that we would realize our deferred tax assets. As a result, we increased our deferred tax valuation allowance to $119.0 million and reduced the carrying value of our deferred tax assets to zero. As of December 31, 2017, the deferred tax valuation allowance decreased by $67.0 million to $52.0 million in order to keep the carrying value of our deferred tax assets at zero. As of December 31, 2018, the deferred tax valuation allowance increased by $159.7 million to $211.7 million in order to keep the carrying value of our deferred tax assets at zero. The valuation allowance will be released once sustained profitable operations return.

As of December 31, 2018, we have a total federal net operating loss carryforward of $304.5 million, of which $242.2 million is scheduled to expire between 2029 and 2037 and $62.2 million, which is not scheduled to expire. We also have a combined state net operating loss carryforward of $89.5 million, which is scheduled to expire between 2022 and 2038.

In addition, we have an interest deduction carryforward in the amount of $39.7 million, which is not scheduled to expire.

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As of December 31, 2017, we had a federal net operating loss carryforward of $247.4 million, which was scheduled to expire between 2029 and 2037. We also had a combined state net operating loss carryforward of $68.9 million, which was scheduled to expire between 2022 and 2037.

The effective tax rate is reconciled to the U.S. federal statutory income tax rate for the years ended December 31 as follows:

	2018	2017	2016
United States federal statutory income tax rate	21.0%	35.0%	35.0%
State income taxes, net of federal tax benefit	1.3	2.2	1.2
Percentage depletion	0.2	12.9	(25.0)
Change in valuation allowance	(22.2)	48.5	(32.4)
AMT credit monetization - valuation allowance release	0.3	85.6	
Other non-deductible expenses	(0.1)	(2.1)	1.7
Stock compensation	(0.2)	(5.8)	12.1
Non-deductible goodwill impairment	(0.1)		
Deferred tax adjustments		(9.0)	(4.7)
Impact of US Tax Reform		(87.3)	
Other	0.1		0.4
Effective tax rate	0.3%	80.0%	(11.7)%

The difference between our statutory income tax rate and our effective income tax rate for the year ended December 31, 2018 is primarily the result of changes in federal tax laws releasing the valuation allowance on our AMT credit carry forwards and the change in valuation allowance to maintain the carrying amount of our deferred tax assets at zero. The difference between our statutory rate and the effective rate for the year ended December 31, 2017 was primarily the result of changes in federal tax laws releasing the valuation allowance on our AMT credit carry forwards and the change in valuation allowance to maintain the carrying amount of our deferred tax assets at zero. The difference between our statutory rate and the effective rate for the year ended December 31, 2016 was primarily the result of the increase to the valuation allowance to reduce the carrying amount of our deferred tax assets to zero.

Federal and state tax laws generally impose limitations on the utilization of tax attributes (e.g. net operating losses, IRC 163(j) interest deductions, etc.) in the event of an ownership change for tax purposes, as defined in Section 382 of the Internal Revenue Code. If our valuation allowance on our deferred tax assets would be released in future periods, and we experienced an ownership change, our ability to utilize our tax attributes may be limited. As described further in Note 11, on January 11, 2019, CPE Inc. entered into the Rights Agreement (the Rights Agreement) to diminish the risk that the Company s ability to use its net operating losses and certain other tax assets becomes limited. The Rights Agreement is designed to reduce the likelihood that the Company will experience ownership change under section 382 of the Internal Revenue Code by (i) discouraging any person or group from becoming a 4.95% shareholder and (ii) discouraging any existing 4.95% shareholder from acquiring additional shares of CPE Inc. s common stock.

As of December 31, 2018, 2017, and 2016, we had no uncertain tax positions that we expect to have a material impact on our Consolidated Financial Statements as a result of tax deductions taken during the year or in prior periods or due to settlements with taxing authorities or lapses of applicable statute of limitations. We are open to federal and state tax audits until the applicable statutes of limitations expire. The statute of limitations has expired for all federal and state returns filed for periods ending before 2012.

10. Equity Method Investments

Equity method investments include our 50% equity investment in Venture Fuels Partnership, a coal marketing company. We received $1.0 million and $4.5 million in distributions for the years ended December 31, 2018 and 2017, respectively, related to our investment in Venture Fuels Partnership. We received $1.5 million in distributions for the year ended December 31, 2016. We previously had a 49% ownership interest in the Gateway Pacific Terminal (GPT). In January 2017, SSA Marine, the majority interest holder and project developer,

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notified us of its intention to no longer pursue a coal terminal. As a result, we abandoned our ownership interest in the joint venture, and we no longer have any ownership interest or associated funding obligations for the joint venture. We wrote off our $6.0 million investment in GPT in the fourth quarter of 2015. Our equity method investments are included in noncurrent *Other assets* on the Consolidated Balance Sheets and had a carrying amount of the following as of December 31 (in thousands):

	2018	2017
Venture Fuels Partnership	$ 3,040	$ 3,774
Other	982	989
Total equity method investments	$ 4,022	$ 4,763

Income (loss) from unconsolidated affiliates, net of tax included the following for the years ended December 31 (in thousands):

	2018	2017	2016
Venture Fuels Partnership	$ 265	$ 700	$ 2,394
Gateway Pacific Terminal			(1,753)
Other	14	13	16
Income (loss) from unconsolidated affiliates, net of tax	$ 279	$ 713	$ 657

We have related party transactions with our equity method investments. Related party activity consists primarily of coal sales to Venture Fuels Partnership, for delivery of coal under arms-length commercial arrangements in the ordinary course of business.

The following table summarizes related party transactions for the years ended December 31 (in thousands):

	2018	2017	2016
Sales of coal to Venture Fuels Partnership	$ 9,582	$ 9,528	$ 11,922

11. Capital Stock and Earnings Per Share

Common Stock

Our common stock is traded on the NYSE under the symbol CLD.

On December 26, 2018, we were notified by the NYSE that the average closing price of shares of our common stock had fallen below $1.00 per share over a period of 30 consecutive trading days, which is the minimum average share price for continued listing on the NYSE under Section 802.01C of the NYSE Listed Company Manual. Under the NYSE s rules, we have six months following receipt of the notification to regain compliance with the minimum share price requirement. We can regain compliance at any time during the six-month cure period if our common stock has a closing share price of at least $1.00 per share on the last trading day of any calendar month during the period and also has an average closing share price of at least $1.00 per share over the 30-trading day period ending on the last trading day of that month or on the last day of the cure period.

While the notice from the NYSE has no immediate impact on the listing of our common stock, our common stock could be delisted from the NYSE if we are unable to regain compliance with the NYSE s minimum share price requirement by the end of the six-month cure period. We are considering all available options to regain compliance during this six-month period. In addition, our common stock could be delisted pursuant to Section 802.01 of the NYSE Listed Company Manual if the trading price of our common stock on the NYSE falls below $0.16 per share. In this event, we would not have an opportunity to cure the stock price deficiency, and our common stock would be delisted immediately and suspended from trading on the NYSE.

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Our Board adopted a Net Operating Loss (NOL) Stockholder Rights Agreement (the Rights Plan) designed to preserve substantial tax assets of our U.S. subsidiaries. The Rights Plan is intended to protect our tax benefits and to allow all of our existing stockholders to realize the long-term value of their investment in the Company. The Board adopted the Rights Plan after considering, among other matters, the estimated value of the tax benefits, the potential for diminution upon an ownership change, and the risk of an ownership change occurring. Our ability to use these tax benefits would be substantially limited if we were to experience an ownership change as defined under Section 382 of the Internal Revenue Code (Section 382). An ownership change would occur if stockholders that own (or are deemed to own) at least 5% or more of our outstanding common stock increased their cumulative ownership in the Company by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. The Rights Plan reduces the likelihood that changes in our investor base would limit the Company s future use of its tax benefits, which would significantly impair the value of the benefits to all stockholders. To implement the Rights Plan, the Board declared a non-taxable dividend of one preferred share purchase right (Rights) for each outstanding common stock of Cloud Peak Energy. The rights will be exercisable if a person or group acquires 4.95% or more of our common stock. The rights will also be exercisable if a person or group that already owns 4.95% or more of our common stock acquires additional shares (other than as a result of a dividend or a stock split). Our existing stockholders that beneficially own in excess of 4.95% of the common stock were grandfathered in at their current ownership level. If the rights become exercisable, all holders of rights, other than the person or group triggering the rights, will be entitled to purchase our common stock at a 50% discount. Rights held by the person or group triggering the rights will become void and will not be exercisable.

The Rights will trade with shares of our common stock and will expire on the first day after the Company s next annual meeting unless our stockholders ratify the Rights Plan at the next annual meeting, in which case the term of the Rights Plan is extended to three years. The Board may terminate the Rights Plan or redeem the rights prior to the time the rights are triggered.

Since the primary purpose of the Rights is to deter existing stockholders or new investors to acquire more than 4.95% of our outstanding common stock, we believe that it is unlikely that the Rights would get triggered or exercised. Accordingly, since the fair value of the Rights is mostly derived from the probability of the Rights being exercised, we determined the Rights fair value to be immaterial.

We have 200.0 million authorized shares of $0.01 par value common stock. The holders of our common stock are entitled to one vote for each share held of record on all matters submitted to a vote of the shareholders. Our shareholders do not have cumulative voting rights in the election of directors. Subject to preferences that may be granted to any then-outstanding preferred stock, holders of our common stock are entitled to receive rateably only those dividends that the Board of Directors may from time to time declare, and we may pay, on our outstanding shares in the manner and upon the terms and conditions provided by law. In general, in the event of our liquidation, dissolution or winding up, holders of our common stock are entitled to share rateably in our assets, if any, remaining after we pay our liabilities and distribute the liquidation preference of any then-outstanding preferred stock. Holders of our common stock have no pre-emptive or other subscription or conversion rights. There are no redemption or sinking fund provisions applicable to our common stock.

Dividend

We have not historically paid, and we do not anticipate that we will pay in the near term, cash dividends on CPE Inc. s common stock. Any determination to pay dividends to holders of CPE Inc. s common stock in the future will be at the discretion of our Board of Directors and will depend on many factors, including our financial condition; results of operations; general business conditions; contractual restrictions, including those under our debt instruments; capital requirements; business prospects; restrictions on the payment of dividends under Delaware Law; and any other factors our Board of Directors deems relevant.

Preferred Stock

Per our Amended and Restated Certificate of Incorporation, which was effective as of November 25, 2009, our Board of Directors is authorized to issue up to 20 million shares of preferred stock, $0.01 par value. The Board of Directors can determine the terms and rights, preferences, privileges and restrictions of each series. These rights, preferences, and privileges may include dividend rights, conversion rights, voting rights, terms of redemption, liquidation preferences, sinking fund terms, and the number of shares constituting any series or the

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designation of this series. There were no outstanding shares of preferred stock as of December 31, 2018 or 2017.

Treasury Stock

We allow employees to relinquish common stock to pay estimated taxes upon the vesting of restricted stock and upon the payout of performance units that settled in common stock. The value of the common stock withheld is based upon the closing price on the vesting date.

Earnings per Share

Dilutive potential shares of common stock include restricted stock and options issued under the LTIP. See Note 20. We apply the treasury stock method to determine dilution from restricted stock and options. 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 our performance units, the contingent feature results 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.

The following table summarizes the calculation of basic and diluted earnings per share for the years ended December 31 (in thousands, except per share amounts):

	2018	2017	2016
Numerator for calculation of basic earnings (loss) per share:			
Net income (loss)	$ (717,963)	$ (6,639)	$ 21,841
Denominator for basic income (loss) per share:			
Weighted-average shares outstanding	75,665	72,907	61,328
Basic earnings (loss) per share	$ (9.49)	$ (0.09)	$ 0.36
Numerator for calculation of diluted earnings (loss) per share:			
Net income (loss)	$ (717,963)	$ (6,639)	$ 21,841
Denominator for diluted earnings (loss) per share:			
Weighted-average shares outstanding	75,665	72,907	61,328
Dilutive effect of stock equivalents			962
Denominator for diluted earnings (loss) per share	75,665	72,907	62,290
Diluted earnings (loss) per share	$ (9.49)	$ (0.09)	$ 0.35

For the years ended December 31, the following were excluded from the diluted earnings per share calculation because they were anti-dilutive (in thousands):

	2018	2017	2016
Anti-dilutive stock equivalents	3,398	3,770	1,706

12. Fair Value of Financial Instruments

We use 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. The levels of the hierarchy, as defined below, give the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs.

- Level 1 is defined as observable inputs such as quoted prices in active markets for identical assets. Our Level 1 assets currently include money market funds.

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- Level 2 is defined as observable inputs other than Level 1 prices, including quoted prices for similar assets or liabilities in an active market, quoted prices for identical assets and liabilities in markets that are not active, or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities. Our Level 2 assets and liabilities include derivative financial instruments with fair values derived from quoted prices in over-the-counter markets or from prices received from direct broker quotes.

- Level 3 is defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. We had no Level 3 financial assets or liabilities as of December 31, 2018 or 2017.

The tables below set forth, by level, our financial assets and liabilities that are recorded at fair value in the accompanying Consolidated Balance Sheets (in thousands):

	Fair Value as of December 31, 2018		
Description	**Level 1**	**Level 2**	**Total**
Assets			
Money market funds (1)	$ 28,740	$	$ 28,740
Liabilities			
Derivative financial instruments(2)	$	$ 2,386	$ 2,386

	Fair Value as of December 31, 2017		
Description	**Level 1**	**Level 2**	**Total**
Assets			
Money market funds (1)	$ 49,102	$	$ 49,102

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(1) Included in *Cash and cash equivalents* in the Consolidated Balance Sheets along with $62.5 million and $58.8 million of demand deposits as of December 31, 2018 and 2017, respectively.

(2) See Note 13 for information on the (*Gain) loss on derivative financial instruments* recognized in the Consolidated Statements of Operations and Comprehensive Income (Loss).

13. Derivative Financial Instruments

Coal Contracts

From time to time, we use derivative financial instruments to help manage our exposure to market changes in coal prices. To manage our exposure in the international markets, we have used international coal forward contracts linked to forward Newcastle coal prices. We have used domestic coal futures contracts referenced to the 8800 Btu coal price sold from the PRB, as quoted on the Chicago Mercantile Exchange (CME), to help manage our exposure to market changes in domestic coal prices.

Under the international coal forward contracts, if the monthly average index price is lower than the contract price, we receive the difference, and if the monthly average index price is higher than the contract price, we pay the difference. For our 2016 positions, we executed offsetting contracts to lock in the amount we received each month. We have not held or entered into any international coal forward positions since our 2016 positions closed.

Under the domestic coal futures contracts, if the monthly average index price is higher than the contract price, we receive the difference, and if the monthly average index price is lower than the contract price, we pay the difference. Amounts due to us or to the CME as a result of changes in the market price of our open domestic coal futures contracts and to fulfill margin requirements are received or paid through our brokerage bank on a daily basis; therefore, there is no asset or liability on the Consolidated Balance Sheets. We have not held or entered into any domestic coal futures positions since our 2016 positions closed.

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WTI Derivatives

We use financial instruments, such as collars and swaps, to help manage our exposure to market changes in diesel fuel prices. The derivatives are indexed to the West Texas Intermediate (WTI) crude oil price as quoted on the New York Mercantile Exchange. As such, the nature of the derivatives do not directly offset market changes to our diesel costs.

In July 2018, we entered into collar agreements to fix a portion of our forecasted diesel costs for the remainder of 2018 and all of 2019. Under a collar agreement, we pay the difference between the monthly average index price and a floor price if the index price is below the floor, and we receive the difference between the ceiling price and the monthly average index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices. While we would not receive the full benefit of price decreases beyond the floor price, the collars mitigate the risk of crude oil price increases and thereby increased diesel costs that would otherwise have a negative impact on our cash flow.

As of December 31, 2018, we held the following WTI derivative financial instruments:

	Floor		Ceiling	
	Notional Amount (barrels in thousands)	**Weighted-Average per Barrel**	**Notional Amount (barrels in thousands)**	**Weighted-Average per Barrel**
2019 collar positions	252	$ 55.00	252	$ 76.00
Total	252	$ 55.00	252	$ 76.00

Under a swap agreement, if the monthly average index price is higher than the swap price, we receive the difference and if the monthly average index price is lower than the swap price, we pay the difference. We used swap agreements to fix a portion of our forecasted diesel costs for 2016 and all of our forecasted diesel costs for 2017. We currently do not hold any swap agreements.

U.S. On-Highway Diesel Derivatives

Additionally, we entered into swap positions indexed to the U.S. On-Highway Diesel prices to help fix a portion of the rail fuel surcharge for 2015 and 2016. These swap positions were intended to help manage risk around price fluctuations in the rail fuel surcharge for our rail transportation cost for coal shipments to Westshore. The rail fuel surcharge is priced using the Department of Energy s U.S. On-Highway Diesel Fuel Prices (U.S. On-Highway Diesel). Under the swap agreement, if the monthly average index price was higher than the swap price, we received the difference, and if the monthly average index price was lower than the swap price, we paid the difference. All of our U.S. On-Highway Diesel swap positions were closed as of December 31, 2015 as forecasted shipments were reduced to zero for 2016 under the amended port and rail agreements described in Note 6. We have not held or entered in to any U.S. On-Highway Diesel swap positions since our 2015 positions were closed.

Offsetting and Balance Sheet Presentation

	December 31, 2018					
	Gross Amounts Recognized		Gross Amounts Offset in the Consolidated Balance Sheets		Net Amounts Presented in the Consolidated Balance Sheets	
	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities
WTI derivative financial instruments		2,642				2,642
Total	$	$ 2,642	$	$	$	$ 2,642

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	December 31, 2017					
	Gross Amounts Recognized		Gross Amounts Offset in the Consolidated Balance Sheets		Net Amounts Presented in the Consolidated Balance Sheets	
	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities
WTI derivative financial instruments						
Total	$	$	$	$	$	$

Net amounts of derivative assets are included in *Derivative financial instruments* and net amounts of derivative liabilities are included in *Accrued expenses* in the Consolidated Balance Sheets. As of December 31, 2018, we had $3.4 million in cash collateral requirements, which is included in *Other Assets* on our Consolidated Balance Sheets. There were no cash collateral requirements as of December 31, 2017.

Derivative Gains and Losses

The *(Gain) loss on derivative financial instruments* recognized in the Consolidated Statements of Operations and Comprehensive Income (Loss) for the years ended December 31 were as follows (in thousands):

	2018	2017	2016
International coal forward contracts	$	$	$ (61)
Domestic coal futures contracts			(55)
WTI derivative financial instruments	2,642	2,672	(8,065)
Net derivative financial instruments loss (gain)	$ 2,642	$ 2,672	$ (8,180)

14. Inventories, Net

Inventories, net, consisted of the following as of December 31 (in thousands):

	2018	2017
Materials and supplies	$ 68,519	$ 68,461
Less: Obsolescence allowance	(1,089)	(1,094)
Material and supplies, net	67,430	67,367
Coal inventory	2,610	5,537
Inventories, net	$ 70,040	$ 72,904

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15. Property, Plant and Equipment, Net

Property, plant and equipment, net consisted of the following as of December 31 (in thousands):

		2018		2017
Land, surface rights, and mineral rights (1)	$	1,582,112	$	1,632,003
Mining equipment		927,689		914,195
Construction in progress		4,903		13,861
Other equipment		36,967		39,626
Buildings and improvements(2)		72,768		72,908
Total		2,624,439		2,672,593
Less: accumulated depreciation and depletion		(1,970,067)		(1,306,838)
Property, plant and equipment, net(3)	$	654,372	$	1,365,755

(1) Includes mineral rights of $9.7 million and $366.7 million as of December 31, 2018 and 2017, respectively, attributable to areas where we were not yet engaged in mining operations and, therefore, the mineral rights are not being depleted.

(2) Includes assets held for sale with a net book value of $1.8 million as of December 31, 2018, related to our office space located in Gillette, Wyoming, which sold for a gain of approximately $1.0 million in February 2019.

(3) Includes impairment charges. See Note 7 for further details.

During the years ended December 31, interest costs capitalized on mine development and construction projects totaled the following (in thousands):

		2018		2017		2016
Interest costs capitalized	$		$		$	1,205

Included in mining equipment above are capital leases under various lease schedules, which are subject to the master lease agreement, and are pre-payable at our option. Assets under capital lease consisted of the following as of December 31 (in thousands):

		2018		2017
Leased assets	$	13,967	$	13,967
Less: accumulated depreciation and depletion		8,987		7,032
Capital equipment lease assets, net	$	4,980	$	6,935

Our capital equipment lease obligations are included in *Other liabilities*. Future payments for these obligations for the years ended December 31 are as follows (in thousands):

2019	$	1,711
2020		858
2021		28
2022		
2023		
Total		2,597
Less: interest		91
Total principal payments		2,505
Less: current portion		1,633
Capital equipment lease obligations, net of current portion	$	872

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Interest on the variable rate capital leases is imputed based on the one-month LIBOR plus 1.95% for a rate of 4.41% and 3.45% as of December 31, 2018 and 2017, respectively. Due to the variable nature of the imputed interest, fair value is equal to carrying value.

16. Senior Notes

Exchange Offers

On October 17, 2016, our direct and indirect wholly-owned subsidiaries, CPE Resources and Cloud Peak Energy Finance Corp. (collectively, the Issuers), completed offers to exchange (the Exchange Offers) up to $400 million aggregate principal amount of their outstanding $300 million aggregate principal balance of 8.50% Senior Notes due 2019 (the 2019 Notes) and $200 million aggregate principal balance of 6.375% Senior Notes due 2024 (the 2024 Notes , together with the 2019 Notes, the Old Notes) for new 12.00% Second Lien Senior Secured Notes due 2021 to be issued by the Issuers (the 2021 Notes) and, in some cases, cash consideration, subject to the terms and conditions of the Exchange Offers. The primary purposes of the Exchange Offers were to extend the maturity of the 2019 Notes to November 2021, to reduce leverage by capturing the trading discounts on the Old Notes and to further our ongoing efforts to provide sufficient liquidity to manage through depressed PRB thermal coal industry conditions.

Holders of $237.9 million aggregate principal amount of the 2019 Notes and $143.6 million aggregate principal amount of the 2024 Notes tendered such notes pursuant to the Exchange Offers. On October 17, 2016, the Issuers accepted for exchange all such Old Notes validly tendered, issued $290.4 million aggregate principal amount of 2021 Notes, and made cash payments of $26.0 million in the aggregate (including $7.7 million in accrued and unpaid interest) to tendering holders of the Old Notes. The transaction resulted in recognition of $4.7 million in expenses for the year ended December 31, 2017. Upon completion of the Exchange Offers, $62.1 million aggregate principal amount of the 2019 Notes remained outstanding, while $56.4 million aggregate principal amount of the 2024 Notes remained outstanding.

The exchanges of the Old Notes for the 2021 Notes were accounted for as a troubled debt restructuring in 2016. As the future cash flows of the 2021 Notes were greater than the carrying amount of the Old Notes, no gain was recognized. The amount of extinguished debt is being amortized over the remaining life of the 2021 Notes using the effective interest method and recognized as a reduction of interest expense. The effective interest rate of the 2021 Notes is 6.46% compared to the stated rate of 12.00%. As a result, our reported interest expense will be significantly less than the contractual cash interest payments throughout the term of the 2021 Notes. Our current tax attributes are expected to offset any cash tax impacts from the Exchange Offers

Equity Offering and 2019 Note Redemption

On February 28, 2017, we issued 13.5 million shares of common stock through a registered underwritten public offering and received proceeds, net of underwriting discounts and commissions, of $64.7 million. We used the net proceeds from the offering to fund the full redemption of our remaining outstanding 2019 Notes. On March 31, 2017, we redeemed the 2019 Notes at a total cost of $64.5 million, reflecting a redemption price of 101.417% of the principal amount of $62.1 million, or $63.0 million, plus accrued and unpaid interest of $1.5 million. In addition, we wrote off $0.7 million in deferred financing costs and original issue discount as of the redemption date. The primary purpose of the redemption of the 2019 Notes was to reduce outstanding long-term debt and extend our nearest term maturity date to 2021.

Senior Notes

We refer to the 2021 Notes and the 2024 Notes collectively as the senior notes. The 2021 Notes and 2024 Notes bear interest at fixed annual rates of 12.00% and 6.375%, respectively. There are no mandatory redemption or sinking fund payments for the senior notes. Interest payments are due semi-annually on May 1 and November 1 for the 2021 Notes, and due semi-annually on March 15 and September 15 for the 2024 Notes. See Note 26 for a discussion on our interest payment obligation under the 2024 Notes. We may redeem some or all of the 2021 Notes by paying specified redemption prices in excess of their principal amount, plus accrued and unpaid interest, if any, prior to November 1, 2020, or by paying their principal amount thereafter, plus accrued and unpaid interest, if any. We may also redeem some or all of the 2024 Notes by paying specified redemption prices

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in excess of their principal amount, plus accrued and unpaid interest, if any, prior to March 15, 2022, or by paying their principal amount thereafter, plus accrued and unpaid interest, if any.

The 2021 Notes were issued with joint and several guarantees by CPE Inc. and by all of our existing and future domestic restricted subsidiaries, and secured by second-priority liens on substantially all of our assets. The termination of the Amended Credit Agreement in November 2018 may have resulted in a release of the guarantees and liens granted by all of our existing and future domestic restricted subsidiaries under the 2021 Notes indenture. The 2024 Notes were issued with joint and several guarantees by CPE Inc. and by all of our existing and future domestic restricted subsidiaries. The termination of the Amended Credit Agreement in November 2018 may have resulted in a release of the guarantees granted by all of our existing and future domestic restricted subsidiaries under the 2024 Notes indenture. However, we believe that holders of the 2021 Notes and 2024 Notes may challenge whether such releases described above occurred, or were permitted to have occurred under applicable law.

The indentures governing the senior notes, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional indebtedness and issue preferred equity; pay dividends or distributions; repurchase equity or repay subordinated indebtedness; make investments or certain other restricted payments; create liens; sell assets; enter into agreements that restrict dividends, distributions, or other payments from restricted subsidiaries; enter into transactions with affiliates; and consolidate, merge, or transfer all or substantially all of their assets and the assets of their restricted subsidiaries on a combined basis.

Upon the occurrence of certain transactions constituting a change in control as defined in the indentures, holders of our senior notes could require us to repurchase all outstanding senior notes at 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase.

Senior notes consisted of the following as of December 31 (in thousands):

	Carrying Value	Unamortized Discount and Debt Issuance Costs	2018 Unamortized Deferred Gain on Forgiven Debt	Principal	Fair Value (1)
12.00% second lien senior notes due 2021	$ 340,688	$ 9,845	$ (60,167)	$ 290,366	$ 177,123
6.375% senior notes due 2024	55,685	723		56,408	13,538
Total senior notes	$ 396,373	$ 10,568	$ (60,167)	$ 346,774	$ 190,661

	Carrying Value	Unamortized Discount and Debt	2017 Unamortized Deferred Gain on	Principal	Fair Value (1)

			Issuance Costs		Forgiven Debt				
12.00% second lien senior notes due 2021	$	349,719	$ 13,614	$	(72,967)		290,366	$	315,773
6.375% senior notes due 2024		55,547	861				56,408		45,973
Total senior notes	$	405,266	$ 14,475	$	(72,967)	$	346,774	$	361,746

(1) The fair value of the senior notes was based on observable market inputs, which are considered Level 2 in the fair value hierarchy.

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Future Maturities

Aggregate future maturities of long-term debt as of December 31, 2018 are as follows (in thousands):

2021	$	290,366
2024		56,408
Less unamortized debt issuance costs		(10,568)
Plus unamortized deferred gain		60,167
Total long-term debt	$	396,373

17. Asset Retirement Obligations

Changes in the carrying amount of our AROs were as follows (in thousands):

		2018		2017
Balance as of January 1	$	100,310	$	98,166
Accretion		6,171		7,072
Revisions to estimated future reclamation cash flows		(11,832)		(3,802)
Payments		(1,044)		(1,126)
Balance as of December 31		93,605		100,310
Less: current portion		(1,014)		(1,013)
Asset retirement obligation, net of current portion	$	92,591	$	99,297

The above amounts exclude $4.9 million and $3.3 million of concurrent reclamation, for our Owned and Operated Mines segment, for the years ended December 31, 2018 and 2017, respectively.

Revisions to estimated future reclamation cash flows reflect our regular updates to our estimated costs of closure activities throughout the lives of the respective mines and reflect changes in estimates of closure volumes, disturbed acreages, the timing of the reclamation activities, and third-party unit costs as of December 31, 2018 and 2017.

Downward revisions during the year ended December 31, 2018 related to our Antelope Mine and Cordero Rojo Mine were $1.5 million and $13.5 million, respectively. The revision at Cordero was primarily due to an extension in the mine life due to lower estimates of future production rates. Reductions to AROs resulting from such revisions generally result in a corresponding reduction to the related asset retirement cost in *Property, plant and equipment, net*, however, if the decrease to the asset retirement obligation exceeds the carrying amount of the related asset retirement costs, the resulting non-cash credit will reduce *Depreciation and depletion* in the Consolidated Statements of Operations and Comprehensive Income (Loss). We recorded a total of $14.7 million in revisions reducing depreciation and depletion for the year ended December 31, 2018. The Spring Creek mine experienced an upward revision of $4.5 million during the year ended December 31, 2018, due to an increase in fuel price. As of December 31, 2018, these revisions increased the related asset by $4.5 million.

Revisions during the year ended December 31, 2017 related to our Antelope Mine, Cordero Rojo Mine, and Spring Creek Mine were $2.7 million, $2.6 million, and $0.2 million, respectively. These downward revisions were primarily due to updated equipment and fuel cost guidance issued by the State of Wyoming as well as changes in each mine s life due to updated estimates of annual production rates. As of December 31, 2017, these revisions reduced the related asset by $2.3 million. The remaining $2.9 million reduced *Depreciation and depletion* for the year ended December 31, 2017.

18. Other Obligations

Federal Coal Lease Obligations

Our federal coal lease obligations, as reflected in the Consolidated Balance Sheets, consist of obligations payable to the Bureau of Land Management of the U.S. Department of the Interior for the West Antelope II South

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lease modification. The future payments for our federal coal lease obligations are $0.6 million per year through 2022. The balance of our federal coal lease obligations is $1.8 million as of December 31, 2018.

Accounts Receivable Securitization Program

In January 2013, we formed Cloud Peak Energy Receivables LLC, a special purpose, bankruptcy-remote 100% owned subsidiary, to purchase, subject to certain exclusions, in a true sale, trade receivables generated by certain of our subsidiaries without recourse (other than customary indemnification obligations for breaches of specific representations and warranties) and then transfer undivided interests of those accounts receivable to a financial institution for cash borrowings for our ultimate benefit. On February 11, 2013, we executed an Accounts Receivable Securitization Program (A/R Securitization Program) with a committed capacity of up to $75 million. The total borrowings are limited by eligible accounts receivable, as defined under the terms of the A/R Securitization Program. On January 31, 2017, the A/R Securitization Program was amended to extend the term of the A/R Securitization Program to January 23, 2020, allow for the ability to issue letters of credit, and revise the maximum borrowing capacity for both cash and letters of credit to $70 million. On May 24, 2018, the A/R Securitization Program was amended to extend the term of the A/R Securitization Program to May 24, 2021 from January 23, 2020. All other terms of the program remained substantially the same. As of December 31, 2018, the A/R Securitization Program would have allowed for $21.3 million of borrowing capacity, which was less than the undrawn face amount of letters of credit outstanding under the A/R Securitization Program of $25.7 million as of December 31, 2018. The $4.4 million difference between the borrowing capacity and the undrawn face amount of the letters of credit outstanding was cash-collateralized into a restricted cash account in early January 2019, thus bringing the borrowing capacity to zero. There were no borrowings outstanding from the A/R Securitization Program as of December 31, 2018 or December 31, 2017. Cloud Peak Energy Receivables LLC is included in our Consolidated Financial Statements.

Upon the execution of the amendment, we recorded $0.9 million of new deferred financing costs. The aggregate deferred financing costs are being amortized in a straight-line basis to interest expense over the remaining term of the A/R Securitization Program.

Terminated Credit Agreement

On February 21, 2014, CPE Resources entered into a five-year Credit Agreement with PNC Bank, National Association, as administrative agent, and a syndicate of lenders, which was amended on September 5, 2014, September 9, 2016 and May 24, 2018 (as amended, the Credit Agreement).

On September 9, 2016, we entered into a Second Amendment to the Credit Agreement (the Second Amendment), which replaced the quarterly EBITDA-based financial covenants that previously required us to (a) maintain defined minimum levels of interest coverage and (b) comply with a maximum net secured debt leverage ratio. These financial covenants were replaced with a new monthly minimum liquidity covenant that required us to maintain liquidity, as defined in the Credit Agreement, of not less than $125 million as of the last day of each month. The Second Amendment reduced the maximum borrowing capacity under the Credit Agreement to $400 million, from the previous maximum capacity of $500 million. It also revised the permitted debt covenant and permitted lien covenant to allow the issuance of second lien debt in an amount up to $350 million. Additionally, it revised various negative covenants and baskets that would apply to, among other things, the incurrence of debt, making investments, asset dispositions and restricted payments. Lastly, it established a requirement for deposit account control agreements with the administrative agent for certain of our deposit accounts.

On May 24, 2018, we entered into an Amended and Restated Credit Agreement (the Amended Credit Agreement) that amended and restated the existing Credit Agreement. The Amended Credit Agreement extended the maturity of the Credit Agreement from February 21, 2019 to May 24, 2021 and reduced the maximum borrowing capacity to $150 million from the previous maximum capacity of $400 million. The borrowing capacity under the Amended Credit Agreement was reduced by the undrawn face amount of letters of credit issued and outstanding under the Amended Credit Agreement, which could have been up to $70 million at any time. The Amended Credit Agreement also required quarterly financial covenants of (a) a ratio of first lien gross debt under the Amended Credit Agreement, capital leases and the A/R Securitization Program (including issued but undrawn letters of credit) to EBITDA (as defined in the Amended Credit Agreement) equal to or less than 1.75 to 1; (b) a ratio of EBITDA less capital expenditures to Fixed Charges (as defined in the Amended Credit

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Agreement) of not less than 1.15 to 1; and (c) a ratio of funded debt (excluding issued but undrawn letters of credit) less unrestricted cash to EBITDA equal to or less than (i) 4.00 to 1 through June 30, 2019, (ii) 3.50 to 1 from September 30, 2019 to December 31, 2019, (iii) 3.00 to 1 from March 31, 2020 to June 30, 2020 and (iv) 2.50 to 1 from September 30, 2020 to maturity. The Amended Credit Agreement also revised the minimum liquidity covenant to require minimum liquidity of not less than $100 million as of the last day of each fiscal quarter, which was reduced from the prior requirement under the Credit Agreement to maintain monthly liquidity of not less than $125 million. Lastly, it revised various negative covenants and baskets that would apply to, among other things, the incurrence of debt, making investments, asset dispositions, and restricted payments. The borrowing capacity was limited by the financial covenants, calculated on a quarterly basis, and fluctuated from quarter to quarter.

A default under the Amended Credit Agreement would have permitted the lenders to terminate their commitment to make cash advances or issue letters of credit, and require cash collateralization if there were any outstanding letters of credit obligations. A default and acceleration of obligations under the Amended Credit Agreement would have also triggered cross-defaults for our Senior Notes due 2021 and 2024, which would have permitted the Senior Notes lenders to require immediate repayment of all principal, interest, fees and other amounts payable thereunder. A default under the Amended Credit Agreement would have also triggered a cross-default for our A/R Securitization Program, which would have permitted the lender to terminate the A/R Securitization Program and triggered collateralization requirements for outstanding letter of credit obligations. Had a default occurred, we may not have been granted waivers or have been able to reach agreement on amendments under our Amended Credit Agreement.

On November 9, 2018, we delivered a notice to PNC Bank, National Association, to terminate the Amended Credit Agreement, which was effective on November 15, 2018. The Amended Credit Agreement would have required us to pay over $3.0 million in additional commitment and administrative fees during the remaining term of the Amended Credit Agreement through May 2021, which will now be avoided. There were no borrowings or undrawn letters of credit under the Amended Credit Agreement. As a result of the decrease in borrowing capacity and the subsequent termination of the Amended Credit Agreement, we recorded a non-cash write-off of certain deferred financing costs in the amount of $5.5 million. These costs were written off against Interest expense on the Consolidated Statement of Operations and Comprehensive Income (Loss).

We were in compliance with the covenants contained in the Credit Agreement as of December 31, 2017. As of December 31, 2017, we had no borrowings under the Credit Agreement. There were no undrawn letters of credit under the Credit Agreement as all issued letters of credit had been transferred to the A/R Securitization Program as of December 31, 2017.

Liquidity

Subsequent to the termination of the Credit Agreement, our liquidity was comprised of cash and cash equivalents, because the A/R Securitization Program was fully utilized to issue letters of credit as collateral for the reclamation surety bond providers. As of December 31, 2018, our total available liquidity was $91.2 million.

The Tax Cuts and Jobs Act (TCJA), made significant changes to U.S. tax laws. The material immediate impact of TCJA to us is the elimination of the corporate alternative minimum tax (AMT), and the ability to offset our regular tax liability or claim refunds for taxable years 2018 through 2021 for AMT credits carried forward from prior periods. We currently anticipate we will realize approximately $31.5 million in AMT value over the next four years with approximately half of this value realized in 2019 for taxable year 2018. See Note 9 for further discussion.

For a discussion on our ability to continue as a going concern, see Note 2.

Debt Issuance Costs

There were $1 million and $4.4 million of unamortized debt issuance costs as of December 31, 2018 and December 31, 2017, respectively, related to the A/R Securitization Program and the Credit Agreement included in noncurrent *Other assets* in the Consolidated Balance Sheets.

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19. Employee Benefit Plans

Our Consolidated Statements of Operations and Comprehensive Income (Loss) include expenses in connection with employee benefit plans, as follows for the years ended December 31 (in thousands):

	2018	2017	2016
Cloud Peak Energy defined contribution retirement plans	$ 6,072	$ 7,241	$ 10,312
Cloud Peak Energy retiree medical plan	(24,825)	(5,471)	(1,841)
Total	$ (18,753)	$ 1,770	$ 8,471

Cloud Peak Energy Defined Contribution Retirement Plans

We sponsor two defined contribution plans to assist eligible employees in providing for retirement. Our employees may elect to contribute a portion of their salary on a pre- or post-tax basis to their accounts. In 2018, we matched all employee contributions up to 8% of eligible compensation. Beginning January 1, 2019, we will match all employee contributions up to 4% of eligible compensation. All contributions are fully vested at the date of contribution. Total contributions for the years ended December 31 are as follows (in thousands):

	2018	2017	2016
Contributions	$ 6,072	$ 7,241	$ 10,312

Cloud Peak Energy Retiree Medical Plan

We provide certain postretirement medical coverage for eligible employees (the Retiree Medical Plan). Employees who are 55 years old and have completed ten years of service with us generally are entitled to receive benefits under the Retiree Medical Plan, except for employees who were eligible at the date of the IPO to receive benefits under the Rio Tinto retiree medical plan and elect to receive such benefits. Our retiree medical plan grants credit for service rendered by our employees to Rio Tinto prior to the IPO. This plan is unfunded.

In April 2016, we communicated certain changes in our Retiree Medical Plan to employees that became effective January 1, 2017. Changes included a decrease in the number of active employees that were eligible for the plan as well as moving to a fixed dollar subsidy amount away from a defined benefit plan. These plan changes reduced our accumulated postretirement benefit obligation by $47.7 million during the second quarter of 2016. The plan changes eliminated the old prior service cost base and established a new negative prior service cost base of approximately $41.1 million, which would have been amortized to income over 4.2 years.

In August 2018, we communicated the termination of our postretirement medical plan, effective January 1, 2019, to our employees. Employees who retire on, or after, January 1, 2019 will not be eligible for postretirement benefits. As part of the postretirement termination, we provided contributions for the remainder of 2018 and a lump-sum contribution for 2019 benefits to all eligible retirees. These changes reduced the number of employees who are eligible for the plan and, therefore, reduced our accumulated postretirement medical benefit obligation by $25.3 million. As a result of these changes, we recognized a non-cash net gain on the termination of the plan of $21.5 million for the year ended December 31, 2018 *in Net periodic postretirement benefit income (cost)*, *excluding service cost* on the Consolidated Statements of Operations and Comprehensive Income (Loss). An additional non-cash gain of $7.0 million will be released ratably through the plan termination date of December 31, 2019.

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Net periodic postretirement benefit costs included the following components for the years ended December 31 were as follows (in thousands):

	2018	2017	2016
Service cost	$ 459	$ 894	$ 2,225
Interest cost	513	918	1,187
Amortization of prior service cost (credit)	(4,287)	(7,283)	(5,253)
Postretirement medical plan termination (gain) loss	(21,510)		
Net periodic postretirement benefit cost (credit)	$ (24,825)	$ (5,471)	$ (1,841)

Annually, we remeasure and adjust the liability for the accumulated postretirement benefit obligation (APBO). Changes in the APBO include the following components as of December 31 (in thousands):

	2018	2017	2016
Beginning Balance	$ 25,891	$ 23,562	$ 61,407
Current period service costs	459	894	2,225
Interest costs	513	918	1,187
Plan amendment	(25,274)		(47,671)
Benefits paid, net of retiree contributions	(392)	(277)	(198)
Change in actuarial assumptions and actuarial loss		794	6,612
Ending Balance	1,197	25,891	23,562
Less current portion	1,197	933	612
Long-term APBO	$	$ 24,958	$ 22,950

20. Equity-Based Compensation

The Cloud Peak Energy Inc. 2009 Long Term Incentive Plan (LTIP) permits awards to our employees and eligible non-employee directors, which we generally grant in the first quarter of each year. The LTIP allows for the issuance of equity-based compensation in the form of restricted stock, restricted stock units, options, stock appreciation rights, dividend equivalent rights, performance awards, and share awards. Our stockholders have approved a pool of up to 11.5 million shares (which includes the 3.0 million shares approved by stockholders at our 2018 annual meeting) of CPE Inc. s common stock authorized for issuance in connection with equity-based awards under the LTIP, since its initial inception. As of December 31, 2018, 3.5 million shares were available for grant.

Generally, each form of equity-based compensation awarded to eligible employees cliff vests on the third anniversary of the grant date, subject to meeting any applicable performance criteria for the award. However, the awards will pro-rata vest sooner if an employee terminates employment with or stops providing services to us because of death, disability, redundancy or retirement (as such terms are defined in the award agreement or the LTIP, as applicable), or if an employee subject to an employment agreement is terminated for any other reason than for cause or leaves for good reason (as such terms are defined in the relevant employment agreement). In addition, the awards will fully vest if an employee is terminated without cause (or leaves for good reason, if the employee is subject to an employment agreement) within two years after a change in control (as such term is defined in the LTIP) occurs.

Total equity-based compensation expense recognized primarily within *Selling, general and administrative expenses* was as follows for the years ended December 31 (in thousands):

	2018	**2017**	**2016**
Total equity-based compensation expense	$ (5,515)	$ 11,730	$ 13,064

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Restricted Stock and Restricted Stock Units

We granted restricted stock and restricted stock units under the LTIP to eligible employees, and we granted restricted stock units to our non-employee directors. The restricted stock units granted to our directors generally vest upon their resignation or retirement (except for a removal for cause) or upon certain events constituting a change in control (as such term is defined in the award agreement). They will pro-rata vest if a director resigns or retires within one year of the date of grant.

A summary of restricted stock award activity is as follows (in thousands):

	Number		Weighted Average Grant-Date Fair Value (per share)
Non-vested units as of January 1, 2018	2,813	$	3.75
Granted	871		3.49
Vested	(544)		5.74
Forfeited	(279)		3.23
Non-vested units as of December 31, 2018	2,861	$	3.34

As of December 31, 2018, unrecognized compensation cost related to restricted stock awards was $2.3 million, which will be recognized over a weighted-average period of 1.8 years prior to vesting. The weighted average fair value of restricted stock awards granted during the years ended December 31, 2018, 2017, and 2016 was $3.49, $4.70, and $1.97 per share, respectively. The total fair value of restricted stock awards vested during the years ended December 31, 2018, 2017, and 2016 was $3.1 million, $2.2 million, and $2.4 million, respectively.

Performance Share Units

Performance share units granted represent the number of shares of common stock to be awarded based on the achievement of targeted performance levels related to pre-established total stockholder return goals over a three-year period and may range from 0% to 200% of the targeted amount.

In previous years, the performance units were settled in shares of common stock and the grant date fair value of the awards was calculated using a Monte Carlo simulation and amortized over the performance period. The 2016 grants were expected to be settled in cash upon any vesting in March 2019, and therefore, were accounted for as a liability award and included within *Other liabilities* within the Consolidated Balance Sheets and marked to market on a quarterly basis. This award did not achieve its performance target related to total shareholder return and therefore the payout will be zero. As such, all compensation expense associated with the 2016 PSUs was reversed in December 2018.

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A summary of performance share unit award activity is as follows (in thousands):

	Number	Weighted Average Grant-Date Fair Value (per share)
Non-vested units as of January 1, 2018	3,685	$ 4.08
Granted	1,153	4.05
Forfeited	(380)	3.93
Canceled		
Vested	(530)	9.66
Non-vested units as of December 31, 2018	3,928	$ 3.33

The assumptions used to estimate the fair value of the performance-based share units granted during the year ended December 31, are as follows:

	2018	2017
Risk-free interest rate	2.4%	1.5%
Expected volatility	78.9%	76.3%
Term (in years)	2.8	2.8
Fair Value (per share)	$ 4.05	$ 5.85

The weighted-average grant date fair values of the performance share units granted during the years ended December 31, 2018, 2017, and 2016 were $4.05, $5.85, and $1.95 per share, respectively. The total fair value of performance share units vested during the years ended December 31, 2018, 2017, and 2016 was $5.1 million, $2.1 million, and $1.5 million, respectively. During the year ended December 31, 2017, $4.9 million in expense was recognized related to the cash settled 2016 performance share units. As of December 31, 2018, $4.2 million of unrecognized compensation cost, which represents the unvested portion of the fair market value of performance share units granted, is expected to be recognized over a weighted-average vesting period of 1.8 years.

Non-Qualified Stock Options

Annually through 2014, we granted non-qualified stock options under the LTIP to certain employees. All unexercised options will expire ten years after the date of grant unless expiring earlier following a termination of employment as described below. Generally, vested options will expire 30 days after the date of the grantee s termination of employment with us (one year in the event of a termination due to the grantee s death, and 90 days following a qualifying termination within the two-year period following a change in control).

A summary of non-qualified stock option activity is as follows (in thousands, except per share amounts):

	Number		Weighted Average Exercise Price (per option)	Weighted Average Contractual Term (years)		Aggregate Intrinsic Value (1)
Options outstanding as of January 1, 2018	1,002	$	16.77	3.4	$	
Expired	(120)	$	17.76			
Options outstanding as of December 31, 2018	882	$	16.63	2.2	$	
Exercisable as of December 31, 2018	882	$	16.63	2.2	$	

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock exceeds the exercise price of the option at year-end.

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We used the Black-Scholes option-pricing model to determine the fair value of stock options. Determining the fair value of equity-based awards requires judgment, including estimating the expected term that stock options will be outstanding prior to exercise, and the associated volatility. There were no options exercised during the years ended December 31, 2018, 2017, and 2016.

Employee Stock Purchase Plan

In May 2011, our stockholders approved the Cloud Peak Energy Inc. Employee Stock Purchase Plan (ESPP). The ESPP permitted eligible employees to authorize payroll deductions on a voluntary basis to purchase shares of CPE Inc. s common stock at a discount from the market price. A maximum of 500,000 shares of common stock were reserved for sale under the ESPP. Offering periods under the ESPP have typically been one year commencing each September 1 and ending the following August 30. Employees were eligible to participate in the ESPP if employed by us for at least six months and were expected to work at least 1,000 hours of service per calendar year. Participating employees could contribute up to $200 of their eligible earnings during each pay period or $4,800 per plan year. The purchase price of common stock purchased under the ESPP was equal to the lesser of (i) 90% of the fair market value of CPE Inc. s common stock on the offering date and (ii) 90% of the fair market value of CPE Inc. s common stock on the last day of the annual option period. Following the offering period ended August 30, 2016, the maximum share pool under the ESPP was nearly exhausted and we determined not to commence a new offering period due to lack of shares.

Compensation costs related to the ESPP are as follows (in thousands):

	2018	2017	2016
Unrecognized compensation expense	$	$	$
Recognized compensation expense			90
Total ESPP compensation expense	$	$	$ 90

The fair value of each purchase right granted under the ESPP was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions:

	2016
Weighted-average fair value (per award)	$ 1.54
Assumptions:	
Risk-free interest rate	0.4%
Expected option life	1.0
Expected volatility	70.0%

21. Commitments and Contingencies

Commitments

Operating Leases

We occupy various facilities and lease certain equipment under various lease agreements. The minimum rental commitments under non-cancelable operating leases, with lease terms in excess of one year subsequent to December 31, 2018, are as follows (in thousands):

2019	$	1,525
2020		1,446
2021		201
2022		13
2023		13
Thereafter		370

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Rental expenses for the years ended December 31 were as follows (in thousands):

	2018	2017	2016
Rent expense	$ 2,148	$ 2,347	$ 2,183

Contingencies

Litigation

Administrative Appeals of the BLM s Approval of the West Antelope II South Lease Modification

Background On February 1, 2, and 5, 2018, the Powder River Basin Resource Council (PRBRC), the Sierra Club, and WildEarth Guardians (WildEarth), respectively, filed separate appeals with the Interior Board of Land Appeals (IBLA) challenging the Deputy State Wyoming BLM Director s November 11, 2017 decision, which was publicly noticed on Bureau of Land Management s (BLM) website on January 5, 2018 (2018 BLM Decision), to approve Antelope Coal LLC s (Antelope Coal) proposed modification of Antelope Coal s West Antelope II South (WAII South) lease. Antelope Coal is a 100% owned subsidiary of Cloud Peak Energy. The 2018 BLM Decision that is the subject of all three appeals approves the proposed amendment of WAII South lease. This lease modification, which was entered into on February 1, 2018, by BLM and Antelope Coal, adds coal underlying nearly 857 surface acres to Antelope Coal s existing federal leases. PRBRC, the Sierra Club, and WildEarth have asked the IBLA to vacate the 2018 BLM Decision and direct the BLM to prepare additional environmental analysis on the impacts of the lease modification.

The 2018 BLM Decision was issued after a previous August 15, 2014 decision (2014 BLM Decision) had been set aside by the IBLA following previous administrative appeals filed by PRBRC, WildEarth, and the Sierra Club. On February 7, 2017, the IBLA issued a decision setting aside the 2014 BLM Decision to issue the WAII South lease modification and remanding that decision to BLM on the narrow ground that the Wyoming High Plains District Manager lacked the appropriate delegation of authority to approve such a leasing decision. The IBLA specifically declined to address the merits of WildEarth s and PRBRC s claims challenging whether BLM s underlying environmental analysis was sufficient to support the agency s lease modification decision. On April 10, 2017, BLM filed a petition with the Director of the Department of Interior s Office of Hearings and Appeals (the OHA Director) asking the OHA Director to reverse the IBLA s February 7, 2017 decision and remand to the IBLA with instructions to decide the merits of the underlying WildEarth and PRBRC appeals. On

September 11, 2017, after full briefing by the parties, the OHA Director denied BLM s Petition for OHA Director Review thereby concluding the appeals and giving full force and effect to the IBLA s February 7, 2017 order remanding the matter to BLM and providing BLM with broad discretion on how to proceed. Upon remand, the BLM reapproved the WAII South lease modification through the 2018 BLM Decision.

Intervention by Cloud Peak Energy and State of Wyoming On February 16 and March 5, 2018, Antelope Coal and the State of Wyoming, respectively, moved to intervene in the PRBRC, WildEarth, and Sierra Club appeals as respondents to defend the 2018 BLM Decision. On April 10, 2018, the IBLA granted both motions to intervene.

Current Schedule. On March 21, 2018, BLM filed a Motion to Dismiss the Sierra Club appeal due to the Sierra Club s failure to file a Statement of Reasons by the briefing deadline. On February 27 and March 5, 2018, PRBRC and WildEarth, respectively, each filed a Statement of Reasons in their appeals. On March 29, March 30, and April 2, 2018, the State of Wyoming, BLM, and Antelope Coal, respectively, filed Answer briefs in the PRBRC appeal. On April 3, 5, and 9, 2018, the State of Wyoming, BLM, and Antelope Coal, respectively, filed Answer briefs in the WildEarth appeal. On April 11, 2018, PRBRC filed a reply brief and on April 12, 2018, BLM filed a clarification to PRBRC s Reply Brief. On June 6, 2018, the IBLA denied BLM s motion to dismiss Sierra Club s appeal and instead rejected Sierra Club s appeal on the merits and affirmed the underlying 2018 BLM s Decision. The IBLA has not yet ruled on the PRBRC or WildEarth appeals.

We believe the PRBRC and WildEarth pending appeals challenging the BLM s West Antelope II South lease modification Decision Record are without merit. Nevertheless, if the appellants claims are successful, the timing and ability of Cloud Peak Energy to mine the coal underlying the lease modification surface acres could be materially adversely impacted. We are unable to estimate a loss or range of loss for this contingency because (1)

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the challenges do not seek monetary relief, (2) the nature of the relief sought is to require the regulatory agency to address alleged deficiencies in complying with applicable regulatory and legal requirements and (3) even if the challenges are successful in whole or in part, the IBLA has broad discretion in determining the nature of the relief ultimately granted.

WildEarth s Regulatory Challenge to OSM s Approval Process for Antelope Mine Plan

Background On September 15, 2015, WildEarth filed a complaint in the Colorado District Court challenging the Department of Interior s and Office of Surface Mining Reclamation and Enforcement s (collectively, OSM) approvals of mine plans for four different coal mines, one of which is located in Colorado and three of which are located in Wyoming. The challenged approvals included one mine plan modification that was issued to Antelope Coal for the Antelope Mine in Wyoming. The plaintiff seeks to vacate existing, required regulatory approvals and to enjoin mining operations at Antelope Mine.

Intervention by Cloud Peak Energy and Others In November and December of 2015, the State of Wyoming and all the operators of the mines whose mine plans are being challenged Antelope Coal, New Mexico Coal Resources, LLC, Bowie Resources, LLC, and Thunder Basin Coal, L.L.C., moved to intervene as Defendants to defend the challenged mine plans. On February 18, 2016, the Colorado District Court granted all the parties intervention motions.

Current Schedule On November 25, 2015, the OSM filed a motion to sever WildEarth s complaint and transfer those claims against the two Wyoming mines (Antelope and Black Thunder) to the District of Wyoming and the New Mexico mine (El Segundo) to the District of New Mexico. Each of the prospective intervenors filed conditional responses in support of OSM s transfer motion, and WildEarth filed an opposition to OSM s transfer motion. On June 17, 2016, the Colorado District Court granted OSM s motion to sever and transfer WildEarth s claims against the Antelope and Black Thunder mine plans to the District of Wyoming and the El Segundo mine plan to the District of New Mexico. The challenges against the Antelope and Black Thunder mine plans, which are docketed as separate cases, have both been assigned to Judge Johnson of the District of Wyoming. Because Antelope Coal and Wyoming had each been granted intervention by the Colorado District Court, the Wyoming District Court acknowledged both parties as Intervenor-Defendants after WildEarth s challenge to the Antelope Mine was transferred to the District of Wyoming. On October 7, 2016, OSM filed its administrative record for the case challenging the Antelope mine plan. On October 21, 2016, WildEarth filed a motion to supplement the administrative record with three administrative documents prepared by other federal agencies. On November 4, 2016, OSM and Antelope Coal each filed opposition briefs. On December 1, 2016, after full briefing, the court denied WildEarth s motion to supplement the record. WildEarth filed its opening merits brief on January 27, 2017. Opposition briefs by OSM, Antelope

Coal, and the State of Wyoming were filed April 5, 2017. On June 2, 2017, WildEarth filed its reply brief. On August 22, 2017 and September 20, 2017, WildEarth filed two separate notices of supplemental authority. OSM and Antelope Coal each filed responses to WildEarth s first notice on September 6, 2017 and September 21, 2017, respectively. Antelope Coal and the State of Wyoming filed a joint response to WildEarth s second notice on October 27, 2017. The merits briefing has been completed and the parties are awaiting a decision from the court.

We believe WildEarth s challenge is without merit. Nevertheless, if WildEarth s claims against OSM s approval of the Antelope mine plan modification are successful, any court order granting the requested relief could have a material adverse impact on our shipments, financial results and liquidity, and could result in claims from third parties if we are unable to meet our commitments under pre-existing commercial agreements as a result of any required reductions or modifications to our mining activities. We are unable to estimate a loss or range of loss for this contingency because (1) the challenge does not seek monetary relief, (2) the nature of the relief sought is to require the regulatory agency to address alleged deficiencies in complying with applicable regulatory and legal requirements and (3) even if the challenges are successful in whole or in part, the court has broad discretion in determining the nature of the relief ultimately granted.

WildEarth s Regulatory Challenge to OSM s Approval Process for Spring Creek Mine Plan

Background On June 8, 2017, WildEarth and the Montana Environmental Information Center (MEIC) filed a complaint in the Montana District Court challenging OSM s re-approval of a mine plan modification that was

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issued to Cloud Peak Energy for the Spring Creek Mine in Montana. WildEarth and MEIC seek to vacate existing, required regulatory approvals and to enjoin mining operations at the Spring Creek Mine.

Intervention by Spring Creek Coal On August 31, 2017, Spring Creek Coal LLC moved to intervene in the WildEarth and MEIC s challenge to the mine plan. On September 26, 2017, the court granted Spring Creek Coal s intervention motion.

Current Schedule OSM answered the plaintiffs complaint on August 24, 2017. OSM lodged the administrative record with the court and served the record on all parties on January 17, 2018. Plaintiffs filed their motion for summary judgment on April 6, 2018. Federal Defendants filed their response and cross motion for summary judgment on June 1, 2018; and Spring Creek filed its opposition and cross motion on June 6, 2018. Plaintiffs filed their reply brief on June 29, 2018 and the reply briefs for the Federal Defendants and Spring Creek were filed on July 23, 2018 and July 25, 2018, respectively. Merits briefing has been completed. On February 11, 2019, Magistrate Judge Cavan issued his Findings of Fact and Recommendations of Law finding that OSM had failed to fully analyze the environmental impacts of approving the Spring Creek mining plan. He did not recommend vacatur of the current mine plan, but instead recommended that OSM be given 240 days to prepare a supplemental environmental analysis to address several alleged deficiencies while the current mine plan remains in effect. All parties have until March 14, 2019 to file any objections to the Magistrate s Order with District Judge Watters.

We believe WildEarth s and MEIC s challenge is without merit. Nevertheless, if WildEarth s and MEIC s claims against OSM s approval of the Spring Creek mine plan modification are successful, any court order granting the requested relief could have a material adverse impact on our shipments, financial results and liquidity, and could result in claims from third parties if we are unable to meet our commitments under pre-existing commercial agreements as a result of any required reductions or modifications to our mining activities. We are unable to estimate a loss or range of loss for this contingency because (1) the challenge does not seek monetary relief, (2) the nature of the relief sought is to require the regulatory agency to address alleged deficiencies in complying with applicable regulatory and legal requirements and (3) even if the challenges are successful in whole or in part, the court has broad discretion in determining the nature of the relief ultimately granted, including whether to adopt in whole or in part Magistrate Judge Cavan s recommendation that the current mine plan should remain in place while OSM prepares a supplemental environmental analysis.

California Climate Change Litigation

Background On July 17, 2017, three California local governments filed separate but largely identical complaints in California Superior Court, naming numerous fossil fuel companies as defendants (together, the California Climate Change Litigation). The Plaintiffs are the County of San Mateo, the County of Marin, and the City of Imperial Beach. Defendants include Rio Tinto PLC, Rio Tinto LTD, Rio Tinto Energy America Inc., Rio Tinto Minerals Inc., Rio Tinto Services Inc., Chevron Corp., Chevron U.S.A. Inc., ExxonMobil Corp, BP P.L.C., BP America, Inc., Royal Dutch Shell Company LLC, Citgo Petroleum Corp., ConocoPhillips, ConocoPhillips Company, Phillips 66, Peabody Energy Corp., Total E&P USA Inc., Total Specialties USA Inc., Arch Coal, Inc., ENI S.p.A., ENI Oil & Gas Inc., Statoil ASA, Anadarko Petroleum Corp., Occidental Petroleum Corp., Repsol S.A., Repsol Energy North America Corp., Repsol Trading USA Corp., Marathon Oil Company, Marathon Oil Corporation, Marathon Petroleum Corp., Hess Corp., Devon Energy Corp., Devon Energy Production Company, L.P., Encana Corp., and Apache Corp. Cloud Peak Energy is not a named defendant.

By way of summary only, Plaintiffs allege that defendants knowingly contributed to GHG emissions through the production and sale of fossil fuels that have adversely impacted the environment, thereby creating financial liabilities for the plaintiffs. Plaintiffs also allege that defendants engaged in a coordinated effort to conceal and deny their own knowledge of those climate change threats, discredit scientific evidence and create doubt in the minds of customers, consumers, regulators, the media, journalists, teachers and the public about the consequences of the impacts of their fossil fuel pollution. Based on these allegations, plaintiffs assert that defendants are liable under various causes of action including public nuisance, failure to warn, design defect, private nuisance, negligence, and trespass. Plaintiffs seek unspecified compensatory damages, equitable relief to abate the alleged nuisances, attorneys fees, punitive damages, disgorgement of profits, costs of suit and other relief as the court may deem proper.

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Indemnity Sought From Cloud Peak Energy by Rio Tinto In August 2017, Cloud Peak Energy received a notice from various Rio Tinto entities, including Rio Tinto Energy America Inc., Rio Tinto Minerals Inc., and Rio Tinto Services Inc., seeking indemnification from Cloud Peak Energy for liabilities in connection with the California Climate Change Litigation. Cloud Peak Energy entered into various agreements with Rio Tinto and its affiliates in connection with the 2009 IPO and separation from Rio Tinto. Under the Master Separation Agreement, Cloud Peak Energy agreed to indemnify Rio Tinto for certain liabilities relating to Cloud Peak Energy s business conducted prior to and after the closing of our separation from Rio Tinto, which may potentially include liabilities in connection with the California Climate Change Litigation.

Current Schedule On July 17, 2017, Plaintiffs filed their lawsuits in the Superior Court of the State of California for the County of San Mateo, the Superior Court of the State of California for the County of Marin, and the Superior Court for the County of Contra Costa, respectively. On August 24, 2017, the cases were removed to the U.S. District Court for the Northern District of California, where they were deemed related and assigned to Judge Vince Chhabria. Plaintiffs indicated that they intended to move to remand the cases back to state court, and the parties stipulated that Defendants would not be required to respond to the complaints until the Court ruled on the motion to remand. The Court signed that Stipulation and Order on September 22, 2017. On September 25, 2017, Plaintiffs filed their motion to remand. The Court granted Plaintiffs motion to remand on March 16, 2018. On March 26, 2018, Defendants filed (1) a Notice of Appeal to the U.S. Court of Appeals for the Ninth Circuit relating to the District Court s order granting remand, and (2) a motion to stay the remand order pending appeal. On April 9, 2018, Judge Chhabria granted Defendants motion to stay the remand order pending appeal.On June 6, 2018, Plaintiffs filed a motion to partially dismiss Defendants appeal, arguing the Court of Appeals lacked jurisdiction to consider certain aspects of the remand order. Defendants opposed the motion. On August 20, 2018, the Ninth Circuit motions panel referred Plaintiffs motion to partially dismiss to the merits panel for decision, and set a schedule for briefing on the merits. Defendants filed their opening brief on November 21, 2018 and Plaintiffs filed their answering brief on January 22, 2019.

If the Plaintiffs were to prevail in the California Climate Change Litigation and if we are required to indemnify Rio Tinto for any portion of the resulting liabilities, those amounts could be significant and could have a material adverse impact on our financial condition, results and liquidity. We are unable to estimate a loss or range of loss for this contingency because of the broad claims and unspecified damages alleged by the plaintiffs against a significant number of defendants and because of the early stage of the California Climate Change Litigation.

Challenge to BLM s Approval of Revised Resource Management Plans for MT and WY

Background On March 15, 2016, a group of environmental plaintiffs Western Organization of Resource Councils, Montana Environmental Information Center, Powder River Basin Resource Council, Northern Plains Resource Council, Sierra Club, and Natural Resources Defense Council filed a complaint in the U.S. District Court for Montana challenging the BLM s September 2015 approval of the Miles City, MT and Buffalo, WY, revised Resource Management Plans (RMPs). The Plaintiffs seek to vacate the 2015 RMPs, require BLM to undertake supplemental environmental analysis under the National Environmental Policy Act (NEPA), and enjoin BLM and the federal defendants from approving any new leases or project permits for coal or oil and gas resources within the two planning areas until BLM prepares a new NEPA analysis and revises its RMPs.

Intervention by Cloud Peak Energy and Others In February, March, and April, 2017, Cloud Peak Energy, the State of Wyoming, and Peabody Caballo Mining, LLC and BTU Western Resources, Inc. (Peabody), respectively, moved to intervene in the case. The Court granted all the parties intervention motions in March (Cloud Peak) and April (Wyoming and Peabody), 2017.

Current Schedule On March 26, 2018, the Court issued an Amended Opinion and Order (revising the Court s March 23, 2018 Order) granting the Plaintiffs Cross-Motion for Summary Judgment on three claims and granting Defendants and Defendant-Intervenors Cross-Motions for Summary Judgment on three claims. The Court held that BLM must prepare supplemental environmental impact statements for both the Miles City and Buffalo RMPs. The Court also directed BLM to incorporate the Court s conclusions in any pending or future coal or oil and gas leases or permits in the Miles City and Buffalo planning areas until BLM completes the supplemental NEPA analysis for both RMPs. The Court further ordered the parties to meet and confer in good faith in an attempt to reach an agreement regarding the appropriate remedy. The parties were ordered to submit

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separate briefs to the Court by May 25, 2018 recommending appropriate remedies in light of the Court s March 26th Order if they could not reach a voluntary agreement on remedy.

The parties were unable to reach agreement on the appropriate remedy and each filed a separate remedy brief on May 25, 2018. On June 14, 2018, Federal Defendants and Defendant- Intervenors each filed a motion seeking the Court s leave to file a brief in response to Plaintiffs remedies brief. Plaintiffs filed a joint opposition brief to these motions on June 28, 2018. On July 31, 2018, the Court issued a final remedy order that directed BLM to complete a new remedial environmental analysis (and related coal screening) by November 29, 2019. During the pendency of that supplemental analysis, BLM is also ordered to undertake a comprehensive environmental analysis for any new coal or oil & gas leasing decision in compliance with the Court s March 26, 2018 Order. The Court rejected Plaintiffs request for injunctive relief that would have impacted mining operations during the completion of BLM s supplemental environmental analysis.

On August 1, 2018, the Court entered judgment for the Plaintiffs on Claims 1, 3, and 5 of their complaint, and for Defendants and Defendant-Intervenors (including Cloud Peak Energy) on Claims 2, 4, and 6 of Plaintiffs complaint. The Court s judgment also implemented the Court s July 31, 2018 remedy order. On October 1, 2018, BLM filed a protective notice of appeal in the Montana District Court appealing that Court s August 1, 2018 judgment to the U.S. Court of Appeals for the Ninth Circuit. On October 11, 2018, the State of Wyoming filed a notice of appeal. On October 12, 2018, Plaintiffs filed a notice of cross-appeal. On October 15, 2018, Cloud Peak and Peabody each filed notices of appeal. On January 2, 2019, the Ninth Circuit issued an order granting the Federal Defendants and other parties motions to dismiss each of their appeals, thereby concluding all the parties appeals. On November 28, 2018, BLM published in the Federal Register administrative notices of intent to prepare the supplemental environmental analyses for the Buffalo, WY and Miles City, MT RMPs as directed by the Montana District Court.

We believe the Plaintiffs challenge is without merit. While the court ordered BLM to prepare supplemental environmental analyses for each RMP, it declined to grant any remedy that would disrupt or adversely impact the operations at any of the coal mines (including Cloud Peak s mines) within the two planning areas. Nevertheless, if Plaintiffs decided to challenge any subsequent planning decisions by BLM, and if they were successful in obtaining remedies adversely impacting the operations at any of Cloud Peak s mines, the timing and ability of Cloud Peak Energy to obtain leases and permit approvals could be materially adversely impacted.

Other Legal Proceedings

We are involved in other legal proceedings arising in the ordinary course of business and may become involved in additional proceedings from time to time. We believe that there are no other legal proceedings pending that are likely to have a material adverse effect on our consolidated financial condition, results of operations or cash flows. Nevertheless, we cannot predict the impact of future developments affecting our claims and lawsuits, and any resolution of a claim or lawsuit or an accrual within a particular fiscal period may materially and adversely impact our results of operations for that period. In addition to claims and lawsuits against us, our leases by application, leases by modification, permits, and other industry regulatory processes and approvals, including those applicable to the utility and coal logistics and transportation industries, may also continue to be subject to legal challenges that could materially and adversely impact our mining operations, results, and liquidity. These regulatory challenges may seek to vacate prior regulatory decisions and authorizations that are legally required for some or all of our current or planned mining activities. If we are required to reduce or modify our mining activities as a result of these challenges, the impact could have a material adverse effect on our shipments, financial results and liquidity, and could result in claims from third parties if we are unable to meet our commitments under pre-existing commercial agreements as a result of any such required reductions or modifications to our mining activities.

Tax Contingencies

Our income tax calculations are based on application of the respective U.S. federal or state tax laws. Our tax filings, however, are subject to audit by the respective tax authorities. Accordingly, we recognize tax benefits when it is more likely than not a position will be upheld by the tax authorities. To the extent the final tax liabilities

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are different from the amounts originally accrued, the increases or decreases are recorded as income tax expense.

Several non-income based production tax audits related to federal and state royalties and severance taxes are currently in progress. The financial statements reflect our best estimate of taxes and related interest and penalties due for potential adjustments that may result from the resolution of such tax audits. From time to time, we receive audit assessments and engage in settlement discussions with applicable tax authorities, which may result in adjustments to our estimates of taxes and related interest and penalties.

Concentrations of Risk and Major Customers

Approximately 81%, 87%, and 79% of our revenue for the years ended December 31, 2018, 2017, and 2016, respectively, were under multi-year contracts. While the majority of the contracts are fixed-price contracts, certain contracts have adjustment provisions for determining periodic price changes. There was no single customer that represented 10% or more of consolidated revenue in 2018, 2017, or 2016. We generally do not require collateral or other security on accounts receivable because our customers are comprised primarily of investment grade electric utilities. The credit risk is controlled through credit approvals and monitoring procedures.

Guarantees and Off-Balance Sheet Risk

In the normal course of business, we are party to guarantees and financial instruments with off-balance sheet risk, such as bank letters of credit, performance or surety bonds and indemnities, which are not reflected on the Consolidated Balance Sheets. In our past experience, virtually no claims have been made against these financial instruments. Management does not expect any material losses to result from these guarantees or off-balance sheet instruments.

U.S. federal and state laws require we secure certain of our obligations to reclaim lands used for mining and to secure coal lease obligations. The primary method we have used to meet these reclamation obligations and to secure coal lease obligations is to provide a third-party surety bond, typically through an insurance company, or provide a letter of credit, typically through a bank. Specific bond and/or letter of credit amounts may change over time, depending on the activity at the respective site and any specific requirements by federal or state laws. We also previously used self-bonding to secure performance of certain obligations in Wyoming. In January 2017, we received approval to remove the final $10 million of self-bonding that existed as of December 31, 2016 and exited self-bonding during the first quarter of 2017. As of December 31, 2018, we had $407.6 million of reclamation and lease bonds backed by collateral of $25.7 million in the form of letters of credit under our A/R Securitization Program used for mining, securing coal lease obligations, and for other operating requirements.

22. Accumulated Other Comprehensive Income (Loss)

The changes in *Accumulated Other Comprehensive Income (Loss)* (AOCI) related to our postretirement medical plan by component, net of tax are as follows (in thousands):

	2018	2017	2016
Beginning balance, January 1,	$ 13,807	$ 21,884	$ (12,951)
Other comprehensive income before reclassifications	19,341	(3,489)	38,144
Amounts reclassified from accumulated other comprehensive income	(19,864)	(4,588)	(3,309)
Net current period other comprehensive income (loss)	(523)	(8,077)	34,835
Ending balance, December 31,	$ 13,284	$ 13,807	$ 21,884

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The reclassifications out of AOCI are as follows for the years ended December 31 (in thousands):

Postretirement Medical Plan (1)	2018	2017	2016
Amortization of prior service costs (credits), before tax(2)	$ (4,287)	$ (7,283)	$ (5,253)
Postretirement medical plan termination	(21,510)		
Total before tax	(25,797)	(7,283)	(5,253)
Tax expense (benefit)	5,933	2,695	1,944
Amounts reclassified from AOCI	$ (19,864)	$ (4,588)	$ (3,309)

(1) See Note 19 for the computation of net periodic postretirement benefit costs.

(2) Presented in the Consolidated Statements of Operations and Comprehensive Income (Loss). The balances disclosed for the years ended December 31, 2017 and 2016 were previously included in *Cost of product sold* and *Selling, general, and administrative expenses*. See Note 3 for information regarding ASU 2017-07, which we adopted on January 1, 2018.

23. Supplemental Cash Flow Information

Restricted Cash

The following table provides a reconciliation of *Cash and cash equivalents* and restricted cash reported in the Consolidated Balance Sheets as of December 31, 2018, 2017 and 2016 that sum to the total of such amounts in the Consolidated Statements of Cash Flows:

	December 31, 2018	2017	2016
Cash and cash equivalents	$ 91,196	$ 107,948	$ 83,708
Restricted cash in other current assets	725	725	725
Restricted cash in other noncurrent assets	207		
Total cash, cash equivalents, and restricted cash shown in the statement of cash flows	$ 92,128	$ 108,673	$ 84,433

The restricted cash in other current assets represents amounts held related to our Company credit cards and worker s compensation trust.

The restricted cash in other noncurrent assets represents the difference between the borrowing capacity of the A/R Securitization Program and the undrawn face amount of the letters of credit that was cash-collateralized as of December 31, 2018 based on the prior month s calculation.

Other Cash Flow Information

The other cash flow information for the years ended December 31 were as follows (in thousands):

		2018		2017		2016
Supplemental cash flow disclosures						
Interest paid	$	28,790	$	33,681	$	39,560
Income taxes paid (refunded)	$	190	$	(1,459)	$	(8,443)
Supplemental non-cash investing and financing activities						
Capital expenditures included in accounts payable	$	233	$	1,154	$	3,227
Assets acquired under capital leases	$		$		$	964
Assets acquired under federal coal lease	$	2,356	$		$	
Debt restructuring of 2019 and 2024 senior notes	$		$		$	(290,366)
Debt issuance of 2021 senior notes	$		$		$	290,366

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24. Supplemental Guarantor/Non-Guarantor Financial Information

In accordance with the indentures governing the senior notes, CPE Inc. and certain of our 100% owned U.S. subsidiaries (the Guarantor Subsidiaries) have fully and unconditionally guaranteed the senior notes on a joint and several basis. These guarantees of the senior notes are subject to release in the following customary circumstances:

- a sale or other disposition (including by way of consolidation or merger or otherwise) of the Guarantor Subsidiary or the sale or other disposition of all or substantially all the assets of the Guarantor Subsidiary (other than to CPE Inc. or a Restricted Subsidiary (as defined in the applicable indenture) of CPE Inc. otherwise not in violation of the applicable indenture;

- a disposition of the majority of the capital stock of a Guarantor Subsidiary to a third person otherwise not in violation of the applicable indenture, after which the applicable Guarantor Subsidiary is no longer a Restricted Subsidiary;

- upon a liquidation or dissolution of a Guarantor Subsidiary so long as no default under the applicable indenture occurs as a result thereof;

- the designation in accordance with the applicable indenture of the Guarantor Subsidiary as an Unrestricted Subsidiary or the Guarantor Subsidiary otherwise ceases to be a Restricted Subsidiary of CPE Inc. in accordance with the applicable indenture;

- defeasance or discharge of such series of senior notes;

- the release, other than the discharge through payment by the Guarantor Subsidiary, of all other guarantees by such Restricted Subsidiary of Debt (as defined in the applicable indenture) of either issuer of the senior notes or the debt of another Guarantor Subsidiary under the Credit Agreement; or

- in the case of the indenture for the 2021 Notes, as set forth in the First Lien/Second Lien Intercreditor Agreement, dated October 17, 2016, among Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp., PNC Bank, National Association, as Senior Representative for the First Lien Credit Agreement Secured Parties and Wilmington Trust, National Association, as the Second Priority Representative for the Second Lien Indenture Secured Parties.

The following historical financial statement information is provided for CPE Inc. and the Guarantor/Non-Guarantor Subsidiaries:

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Supplemental Condensed Consolidating Statement of Operations and Comprehensive Income

(in thousands)

	Year Ended December 31, 2018					
	Parent Guarantor (CPE Inc.)	**Issuing Company (CPE Resources)**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Eliminations**	**Consolidated**
Revenue	$ 6,810	$	$ 832,405	$	$ (6,810)	$ 832,405
Costs and expenses						
Cost of product sold (exclusive of depreciation, depletion, and accretion, shown separately)		5	765,436	99		765,540
Depreciation and depletion		1,136	47,906			49,042
Accretion			6,171			6,171
(Gain) loss on derivative financial instruments			2,642			2,642
Selling, general and administrative expenses		36,645			(6,810)	29,835
Impairments			684,673			684,673
Other operating costs			420			420
Total costs and expenses		37,786	1,507,248	99	(6,810)	1,538,323
Operating income (loss)	6,810	(37,786)	(674,843)	(99)		(705,918)
Other income (expense)						
Net periodic postretirement benefit income (cost), excluding service cost		4,234	21,050			25,284
Interest income	3	1,213	6			1,222
Interest expense		(38,440)	(597)	(1,152)		(40,189)
Other, net		(426)	(558)	426		(558)
Total other (expense) income	3	(33,419)	19,901	(726)		(14,241)
Income (loss) before income tax provision and earnings from unconsolidated affiliates	6,813	(71,205)	(654,942)	(825)		(720,159)
Income tax benefit (expense)	(19,482)	20,542	670	187		1,917
Income (loss) from unconsolidated affiliates, net of tax		14	265			279
Earnings (losses) from consolidated affiliates, net of tax	(705,294)	(654,645)	(638)		1,360,577	
Net income (loss)	(717,963)	(705,294)	(654,645)	(638)	1,360,577	(717,963)

Other comprehensive income (loss)						
Postretirement medical plan amortization of prior service costs	(4,287)	(4,287)	(4,287)		8,574	(4,287)
Postretirement medical plan change	25,274	25,274	25,274		(50,548)	25,274
Postretirement medical plan termination	(21,510)	(21,510)	(21,510)		43,020	(21,510)
Income tax on retiree medical and pension changes						
Other comprehensive income (loss)	(523)	(523)	(523)		1,046	(523)
Total comprehensive income (loss)	$ (718,486)	$ (705,817)	$ (655,168)	$ (638)	$ 1,361,623	$ (718,486)

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Statement of Operations and Comprehensive Income

(in thousands)

	Year Ended December 31, 2017					
	Parent Guarantor (CPE Inc.)	Issuing Company (CPE Resources)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue	$ 7,721	$	$ 887,706	$	$ (7,721)	$ 887,706
Costs and expenses						
Cost of product sold (exclusive of depreciation, depletion, and accretion, shown separately)		13	758,016	5		758,034
Depreciation and depletion		897	71,373			72,270
Accretion			7,072			7,072
(Gain) loss on derivative financial instruments			2,672			2,672
Selling, general and administrative expenses		56,249			(7,721)	48,528
Debt restructuring costs		23				23
Other operating costs			532			532
Total costs and expenses		57,182	839,665	5	(7,721)	889,131
Operating income (loss)	7,721	(57,182)	48,041	(5)		(1,425)
Other income (expense)						
Net periodic postretirement benefit income (cost), excluding service cost		1,046	5,319			6,365
Interest income	1	484				485
Interest expense	(47)	(39,970)	(536)	(809)		(41,362)
Other, net		(227)	(886)	228		(885)
Total other income (expense)	(46)	(38,667)	3,897	(581)		(35,397)
Income (loss) before income tax provision and earnings from unconsolidated affiliates	7,675	(95,849)	51,938	(586)		(36,822)
Income tax benefit (expense)	(30,244)	62,757	(3,043)			29,470
Income (loss) from unconsolidated affiliates, net of tax		13	700			713
Earnings (losses) from consolidated affiliates, net of tax	15,930	49,009	(586)		(64,353)	
Net income (loss)	(6,639)	15,930	49,009	(586)	(64,353)	(6,639)
Other comprehensive income (loss)						

Postretirement medical plan amortization of prior service costs	(7,283)	(7,283)	(7,283)		14,566	(7,283)
Postretirement medical plan adjustment	(794)	(794)	(794)		1,588	(794)
Income tax on postretirement medical						
Other comprehensive income (loss)	(8,077)	(8,077)	(8,077)		16,154	(8,077)
Total comprehensive income (loss)	$ (14,716)	$ 7,853	$ 40,932	$ (586)	$ (48,199)	$ (14,716)

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CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Statement of Operations and Comprehensive Income

(in thousands)

	Year Ended December 31, 2016					
	Parent Guarantor (CPE Inc.)	Issuing Company (CPE Resources)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue	$ 8,274	$	$ 800,438	$	$ (8,274)	$ 800,438
Costs and expenses						
Cost of product sold (exclusive of depreciation, depletion, and accretion, shown separately)		122	649,683			649,805
Depreciation and depletion		1,172	26,046			27,218
Accretion			6,645			6,645
(Gain) loss on derivative financial instruments			(8,180)			(8,180)
Selling, general and administrative expenses		59,807			(8,274)	51,533
Impairments		2,048	2,561			4,609
Debt restructuring costs		4,665				4,665
Other operating costs			941			941
Total costs and expenses		67,814	677,696		(8,274)	737,236
Operating income (loss)	8,274	(67,814)	122,742			63,202
Other income (expense)						
Net periodic postretirement benefit income (cost), excluding service cost		665	3,401			4,066
Interest income	27	110	1			138
Interest expense	(244)	(46,318)	(489)	(383)		(47,434)
Other, net		(138)	(1,001)	138		(1,001)
Total other income (expense)	(217)	(45,681)	1,912	(245)		(44,231)
Income (loss) before income tax provision and earnings from unconsolidated affiliates	8,057	(113,495)	124,654	(245)		18,971
Income tax benefit (expense)	(6,278)	15,586	(7,095)			2,213
Income (loss) from unconsolidated affiliates, net of tax		16	641			657
Earnings (losses) from consolidated affiliates, net of tax	20,062	117,955	(245)		(137,772)	
Net income (loss)	21,841	20,062	117,955	(245)	(137,772)	21,841

Other comprehensive income (loss)						
Postretirement medical plan amortization of prior service costs	(5,253)	(5,253)	(5,253)		10,506	(5,253)
Postretirement medical plan adjustment	(1,792)	(1,792)	(1,792)		3,584	(1,792)
Postretirement medical plan change	42,851	42,851	42,851		(85,702)	42,851
Income tax on retiree medical and pension changes	(971)	(971)	(971)		1,942	(971)
Other comprehensive income (loss)	34,835	34,835	34,835		(69,670)	34,835
Total comprehensive income (loss)	$ 56,676	$ 54,897	$ 152,790	$ (245)	$ (207,442)	$ 56,676

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CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Balance Sheets

(in thousands)

	December 31, 2018					
	Parent Guarantor (CPE Inc.)	Issuing Company (CPE Resources)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS						
Current assets						
Cash and cash equivalents	$	$ 91,083	$ 113	$	$	$ 91,196
Accounts receivable		55	5,048	28,424		33,527
Due from related parties		61,960	35,025		(96,985)	
Inventories, net			70,040			70,040
Income tax receivable	15,808					15,808
Other prepaid and deferred charges	281		27,246			27,527
Other assets	1		4,204			4,205
Total current assets	16,090	153,096	141,678	28,424	(96,985)	242,303
Noncurrent assets						
Property, plant and equipment, net		2,735	651,637			654,372
Income tax receivable	15,768					15,768
Other assets	338,229	583,793	21,202	1,179	(928,190)	16,213
Total assets	$ 370,087	$ 739,626	$ 814,515	$ 29,603	$ (1,025,175)	$ 928,656
LIABILITIES AND MEMBER S EQUITY						
Current liabilities						
Accounts payable	$	$	$ 34,080	$ 130	$	$ 34,210
Royalties and production and property taxes			53,232			53,232
Accrued expenses	1,703	5,001	19,681			26,385
Due to related parties	74,710	71		22,275	(96,985)	71
Federal coal lease obligations			379			379
Other liabilities			4,019			4,019
Total current liabilities	76,413	5,072	111,391	22,405	(96,985)	118,296
Noncurrent liabilities						
Senior notes		396,373				396,373
Federal coal lease obligations, net of current portion			1,404			1,404
Asset retirement obligations, net of current portion			92,591			92,591
			20,587			20,587

Royalties and production taxes, net of current portion												
Other liabilities						5,731						5,731
Total liabilities		76,413		401,445		231,704		22,405		(96,985)		634,982
Commitments and Contingencies (Note 21)												
Total equity		293,674		338,181		582,811		7,198		(928,190)		293,674
Total liabilities and equity	$	370,087	$	739,626	$	814,515	$	29,603	$	(1,025,175)	$	928,656

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CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Balance Sheets

(in thousands)

	December 31, 2017					
	Parent Guarantor (CPE Inc.)	Issuing Company (CPE Resources)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS						
Current assets						
Cash and cash equivalents	$	$ 107,818	$ 130	$	$	$ 107,948
Accounts receivable			17,359	32,716		50,075
Due from related parties		46,350	23,044		(69,272)	122
Inventories, net			72,904			72,904
Income tax receivable	256					256
Other prepaid and deferred charges	283		36,681			36,964
Other assets			1,765			1,765
Total current assets	539	154,168	151,883	32,716	(69,272)	270,034
Noncurrent assets						
Property, plant and equipment, net		3,480	1,362,275			1,365,755
Goodwill			2,280			2,280
AMT tax receivable	29,454					29,454
Other assets	1,036,162	1,289,487	33,612	341	(2,328,424)	31,178
Total assets	$ 1,066,155	$ 1,447,135	$ 1,550,050	$ 33,057	$ (2,397,696)	$ 1,698,701
LIABILITIES AND MEMBER S EQUITY						
Current liabilities						
Accounts payable	$ 1	$ 24	$ 29,748	$ 59	$	$ 29,832
Royalties and production and property taxes			54,327			54,327
Accrued expenses	3,160	5,659	23,999			32,818
Due to related parties	44,039	71		25,162	(69,272)	
Other liabilities			2,435			2,435
Total current liabilities	47,200	5,754	110,509	25,221	(69,272)	119,412
Noncurrent liabilities						
Senior notes		405,266				405,266
Asset retirement obligations, net of current portion			99,297			99,297
Accumulated postretirement benefit obligation, net of current portion			24,958			24,958
			21,896			21,896

Royalties and production taxes, net of current portion						
Other liabilities	11,146		8,917			20,063
Total liabilities	58,346	411,020	265,577	25,221	(69,272)	690,892
Commitments and Contingencies (Note 21)						
Total equity	1,007,809	1,036,115	1,284,473	7,836	(2,328,424)	1,007,809
Total liabilities and equity	$ 1,066,155	$ 1,447,135	$ 1,550,050	$ 33,057	$ (2,397,696)	$ 1,698,701

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CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Statement of Cash Flows

(in thousands)

	Year Ended December 31, 2018					
	Parent Guarantor (CPE Inc.)	Issuing Company (CPE Resources)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$	$ (3,523)	$ 18,479	$ 1,143	$	$ 16,099
Investing activities						
Purchases of property, plant and equipment		(425)	(13,766)			(14,191)
Investment in development projects			(1,894)			(1,894)
Other		13	173			186
Net cash provided by (used in) investing activities		(412)	(15,487)			(15,899)
Financing activities						
Principal payments on federal coal leases			(574)			(574)
Payment of deferred financing costs				(936)		(936)
Payment amortized to deferred gain		(12,800)				(12,800)
Payment of debt restructuring costs						
Other			(2,435)			(2,435)
Net cash provided by (used in) financing activities		(12,800)	(3,009)	(936)		(16,745)
Net increase (decrease) in cash, cash equivalents, and restricted cash		(16,735)	(17)	207		(16,545)
Cash, cash equivalents, and restricted cash at beginning of period		107,818	854			108,673
Cash, cash equivalents, and restricted cash at the end of period	$	$ 91,083	$ 837	$ 207	$	$ 92,128

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Statement of Cash Flows

(in thousands)

	Year Ended December 31, 2017					
	Parent Guarantor (CPE Inc.)	**Issuing Company (CPE Resources)**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Eliminations**	**Consolidated**
Net cash provided by (used in) operating activities	$	$ 36,301	$ 15,327	$ 408	$	$ 52,036
Investing activities						
Purchases of property, plant and equipment		(2,004)	(11,093)			(13,097)
Cash paid for capitalized interest						
Investment in development projects			(1,750)			(1,750)
Insurance proceeds						
Other			195			195
Net cash provided by (used in) investing activities		(2,004)	(12,648)			(14,652)
Financing activities						
Repayment of senior notes		(62,094)				(62,094)
Payment of debt refinancing costs				(408)		(408)
Payment amortized to deferred gain		(12,395)				(12,395)
Payment of debt restructuring costs		(23)				(23)
Proceeds from issuance of common stock		68,850				68,850
Cash paid for equity offering		(4,490)				(4,490)
Other			(2,584)			(2,584)
Net cash provided by (used in) financing activities		(10,152)	(2,584)	(408)		(13,144)
Net increase (decrease) in cash, cash equivalents, and restricted cash		24,145	95			24,240
Cash, cash equivalents, and restricted cash at beginning of period		83,673	760			84,433
Cash, cash equivalents, and restricted cash at the end of period	$	$ 107,818	$ 855	$	$	$ 108,673

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CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Statement of Cash Flows

(in thousands)

	Year Ended December 31, 2016					
	Parent Guarantor (CPE Inc.)	Issuing Company (CPE Resources)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$	$ 25,246	$ 23,470	$	$	$ 48,716
Investing activities						
Purchases of property, plant and equipment		(2,003)	(31,636)			(33,639)
Cash paid for capitalized interest			(1,444)			(1,444)
Investment in port access rights						
Investment in development projects			(1,500)			(1,500)
Investment in unconsolidated affiliate						
Insurance proceeds			2,826			2,826
Other			659			659
Net cash provided by (used in) investing activities		(2,003)	(31,095)			(33,098)
Financing activities						
Payment of deferred financing costs		(3,624)				(3,624)
Cash paid to tender of 2019 and 2024 senior notes		(18,335)				(18,335)
Payment of debt restructuring costs		(4,665)				(4,665)
Other			(2,374)			(2,374)
Net cash provided by (used in) financing activities		(26,624)	(2,374)			(28,998)
Net increase (decrease) in cash cash equivalents, and restricted cash		(3,381)	(9,999)			(13,380)
Cash, cash equivalents, and restricted cash at beginning of period		87,054	10,759			97,813
Cash, cash equivalents, and restricted cash at the end of period	$	$ 83,673	$ 760	$	$	$ 84,433

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CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

25. Summary Unaudited Quarterly Financial Information

A summary of the unaudited quarterly results of operations for the years ended December 31, 2018 and 2017 is presented below (in thousands except per share amounts).

	Year Ended December 31, 2018			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$ 216,309	$ 205,698	$ 233,080	$ 177,318
Operating income (loss)	(371)	(20,649)	717	(685,615)
Net income (loss)	(7,738)	(29,872)	12,691	(693,044)
Income (loss) per common share:				
Basic	$ (0.10)	$ (0.39)	$ 0.17	$ (9.14)
Diluted	$ (0.10)	$ (0.39)	$ 0.16	$ (9.14)
Closing stock price	$ 2.91	$ 3.49	$ 2.30	$ 0.37

	Year Ended December 31, 2017			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$ 195,728	$ 229,201	$ 248,884	$ 213,893
Operating income (loss)(1)	(8,543)	892	10,257	(4,031)
Net income (loss)	(20,108)	(6,948)	2,577	17,839
Income (loss) per common share:				
Basic	$ (0.30)	$ (0.09)	$ 0.03	$ 0.24
Diluted	$ (0.30)	$ (0.09)	$ 0.03	$ 0.23
Closing stock price	$ 4.58	$ 3.53	$ 3.66	$ 4.45

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(1) *Operating income (loss)* for the quarterly periods of 2017 previously included all components of net benefit costs. Upon our adoption of ASU 2017-17 on January 1, 2018, only service costs remain in *Operating income (loss).* See Note 3 for information regarding ASU 2017-07.

During the third quarter of 2018, *Net income (loss)* included a $19.5 million non-cash gain related to the termination of the postretirement medical plan. During the fourth quarter, *Net income (loss)* included a non-cash impairment of $682.4 million related to the impairment of long-lived assets at our Cordero Rojo Mine and both our Youngs Creek and Big Metal Projects, and a non-cash impairment of $2.3 representing the remaining goodwill at our Antelope and Spring Creek mines, partially offset by a $2.0 million non-cash gain related to the termination of the postretirement medical plan.

During the first quarter of 2017, *Net income (loss)* included a charge of $0.9 million related to the early retirement of the 2019 Notes as well as a charge of $0.7 million related to the write-off of deferred financing costs and original issue discount on the 2019 Notes. During the third quarter of 2017, *Net income (loss)* included $3.1 million in *Revenue* for business interruption insurance proceeds related to a claim filed in 2016 for lost tonnage due to a customer force majeure. *Net income (loss)* for the fourth quarter of 2017 included non-cash adjustments of $2.8 million for *Depreciation and depletion* related to decreases in the ARO liability.

26. Subsequent Events

In January 2019, we announced an update to the previously-announced review of strategic alternatives, announcing the retention of Centerview Partners LLC as our investment banker, Vinson & Elkins LLP as our legal advisor, and FTI Consulting, Inc. as our financial advisor to assist the Company in its review of capital structure and restructuring alternatives. Our restructuring evaluation process is continuing. We are actively engaged in discussions with certain of our creditor groups financial and legal advisors regarding potential alternatives, including asset sales, a private debt restructuring or a court-supervised reorganization under Chapter 11 of the U.S. Bankruptcy Code and related financing needs.

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Subsequent to December 31, 2018, we received letters from certain of our third-party surety bond underwriters demanding increased collateral or replacement of their bonds. We are currently in discussions with our surety bond underwriters, however we cannot assure you these negotiations will be successful in avoiding increased collateral requirements. These surety bonds are required by the permits governing our mining operations.

CPE Resources has an interest payment obligation under the 2024 Notes of approximately $1.8 million, due on March 15, 2019. The indenture governing the 2024 Notes provides a 30-day grace period that extends the latest date for making this interest payment to April 14, 2019, before an Event of Default occurs under the indenture. We elected to not make this interest payment on the due date and plan to utilize the 30-day grace period provided by the indenture, to allow additional time to assess our restructuring alternatives. If we do not make this interest payment by April 14, 2019, an Event of Default would occur under the indenture governing the 2024 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2024 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2024 Notes. An Event of Default under the 2024 Notes for failure to pay interest would not result in a default under the 2021 Notes unless the 2024 Notes are accelerated. An Event of Default under the 2024 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance. We continue to evaluate alternatives associated with this interest payment.

On March 14, 2019, we entered into a Forbearance Agreement (the Forbearance Agreement) by and among Cloud Peak Energy Receivables LLC, CPE Resources and PNC Bank, National Association, as administrator, relating to our A/R Securitization Program, which provides that PNC Bank, National Association will not exercise any of its remedies upon a default under the A/R Securitization Program based on the existence of substantial doubt regarding our ability to continue as a going concern. Pursuant to the Forbearance Agreement, the forbearance period terminates on the earlier of (i) April 14, 2019 and (ii) the date on which any additional events of default may occur, as specified therein.

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

None.

Item 9A. ***Controls and Procedures.***

Disclosure Controls and Procedures

An evaluation was performed by management, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended) as of December 31, 2018. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were effective to ensure that information required to be disclosed in reports filed under the Securities and Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the specified time periods and accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures or our internal controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) or 15d-15(f) of the Securities Exchange Act of 1934, as amended. Internal control over financial reporting is a process designed under the supervision of the Chief Executive Officer and

Chief Financial Officer, and effected by our Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our Consolidated Financial Statements for external purposes in accordance with generally accepted accounting principles.

Because of 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.

Management conducted an evaluation 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 evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2018.

Our independent registered public accounting firm, PricewaterhouseCoopers LLP, has audited the effectiveness of our internal control over financial reporting as of December 31, 2018, as stated in their audit report included in Part II, Item 8.

Changes in Internal Control Over Financial Reporting

There were no changes in CPE Inc. s internal control over financial reporting during the quarter ended December 31, 2018, that have materially affected, or are reasonably likely to materially affect, CPE Inc. s internal control over financial reporting.

Item 9B. ***Other Information.***

On March 14, 2019, we entered into a Forbearance Agreement (the Forbearance Agreement) by and among Cloud Peak Energy Receivables LLC, CPE Resources and PNC Bank, National Association, as administrator, relating to our A/R Securitization Program, which provides that PNC Bank, National Association will not exercise any of its remedies upon a default under the A/R Securitization Program based on the existence of substantial doubt regarding our ability to continue as a going concern. Pursuant to the Forbearance Agreement, the forbearance period terminates on the earlier of (i) April 14, 2019 and (ii) the date on which any additional events of default may occur, as specified therein. For additional discussion and analysis, see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Developments.

The foregoing description of the Forbearance Agreement does not purport to be complete and is qualified in its entirety by reference to the full terms and conditions of the Forbearance Agreement, which is filed with this Form 10-K as Exhibit 10.32.

In addition, we elected not to make the interest payment under the 2024 Notes on the due date and plan to utilize the 30-day grace period provided by the indenture to allow additional time to assess our restructuring alternatives. If we do not make this interest payment by April 14, 2019, an Event of Default would occur under the indenture governing the 2024 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2024 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2024 Notes. An Event of Default under the 2024 Notes for failure to pay interest would not result in a default under the 2021 Notes unless the 2024 Notes are accelerated. An Event of Default under the 2024 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance. We continue to evaluate alternatives associated with this interest payment. For additional discussion and analysis, see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Developments.

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PART III

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

The following sets forth information concerning each member of the Board of Directors of Cloud Peak Energy, including their name, age, principal occupation or employment for at least the past five years and the period for which such person has served as a director of Cloud Peak Energy, as of March 5, 2019. There are no family relationships among any of our directors or executive officers.

As well as describing the experiences, qualifications, attributes and skills of the Company s directors, the following describes the experiences, qualifications, attributes and skills that caused the Nominating and Corporate Governance Committee and Board of Directors to determine that each of the directors nominated for election by our shareholders should be so nominated. In addition, there are no arrangements or understandings between any of our directors and any other person pursuant to which any person was selected as a director.

Name	Age	Position	Class	Director Tenure on Board	Director Gender
Jeane Hull	64	Director	I	2 year, 8 months	Female
William Owens	68	Director	I	9 years, 2 months	Male
William T. Fox III	73	Chairman of the Board	II	9 years, 5 months	Male
Robert Skaggs	64	Director	II	3 years, 8 months	Male
Colin Marshall	54	President, Chief Executive Officer and Director	III	10 years, 7 months	Male
Steven Nance	62	Director	III	9 years, 2 months	Male

Class I Directors

The following information is furnished regarding the Class I directors who will continue to serve on the Board of Directors until their respective successors are elected and qualified or until the earlier of their resignation or removal.

Jeane Hull has served as a director since July 2016. Ms. Hull retired from Peabody Energy Corporation (Peabody) in August 2015, where she served as Peabody s Executive Vice President and Chief Technical Officer with responsibility for global strategy and governance for health, safety and environment, supply chain, engineering, applied technologies and asset management functions. Ms. Hull joined Peabody in 2007 as the Senior Vice President of Engineering and Technical Services and managed the global delivery of engineering, environmental, geology and design and construction services. She also served as Peabody s Group Executive, Powder River Basin from 2008 to 2011 and assumed additional responsibility for Southwest Operations in 2010. Ms. Hull also serves on the board of directors of Interfor Corporation, a Toronto Stock Exchange listed lumber company with operations in Canada and the United States, since May 2014, and as a member of its governance committee and chair of its environmental and safety committee. In December 2017, Ms. Hull was appointed to the board of directors of Epiroc AB, a company spun off from Atlas Copco and listed on the Nasdaq Stockholm Exchange in 2018. A retired professional engineer, Ms. Hull holds a Bachelor of Science degree in civil engineering from South Dakota School of Mines and Technology and an M.B.A. from Nova Southeastern University in Florida.

Qualifications of Ms. Hull: Ms. Hull has over thirty years experience in leadership and operations roles in the mining industry. Her experience brings important expertise to the Board and its committees.

William Owens has served as a director since January 2010. Mr. Owens served as Governor of Colorado from 1999 to 2007 and as Colorado State Treasurer from 1995 to 1999. Since January 2016, Mr. Owens has served as a Senior Director with the law firm Greenberg Traurig. Mr. Owens has served on the board of directors, compensation and corporate governance committees of High Point Resources (formerly Bill Barrett Corporation) since 2010; and on the board of directors, compensation and corporate governance committees of Federal Signal Corporation, an industrial products company, since 2011. In addition, Mr. Owens has served as a member of the supervisory board of Credit Bank of Moscow, a medium-sized privately owned bank operating in Moscow, Russia and the Moscow region, since 2012, as chairman of its supervisory board since 2013, and as a member of its compensation, corporate governance and nominations committee and of its strategy and capital markets committee since 2013. Mr. Owens also served on the board of directors and audit committee of Key Energy Services, an oilfield services company, from 2007 to 2016. Mr. Owens earned a Bachelor of Science degree from Stephen F. Austin State University and a Master s degree in public affairs from the University of Texas.

Qualifications of Mr. Owens: Mr. Owens experience in managing in both the public and private sectors makes him well suited to provide advice to the Board, including regarding the political environment that has increasingly impacted our industry in recent years. He also has extensive experience in both the energy and natural resources sectors. Mr. Owens breadth of public and private experience, including service on other public and private boards, brings valuable expertise to the Board and its committees.

Class II Directors

The following information is furnished regarding the Class II directors who will continue to serve on the Board of Directors until their respective successors are elected and qualified or until the earlier of their resignation or removal.

William T. Fox III has served as Chairman of our Board since May 2016 and has been a director since October 2009. Mr. Fox was with Citigroup Inc., a global financial services company, and its predecessors for 36 years engaged in corporate finance focused on commercial and investment banking, and served as a Senior Credit Officer from 1978 until his retirement in 2003. From 1989 until his retirement in 2003, Mr. Fox served as Managing Director, Global Industry Head, Global Energy and Mining of Citigroup. Prior to that, Mr. Fox was Citigroup s Managing Director, North American Energy and Vice President, Petroleum Department. Mr. Fox served on the board of directors of Rowan Companies, Inc., a provider of international and domestic contract drilling services, from 2001 to 2016, where he served as the chairman of its audit committee, a member of its nominating and corporate governance committee and a member of its executive committee. Mr. Fox holds a Bachelor of Arts degree in economics from Trinity College and attended the Harvard Business School Program for Management Development.

Qualifications of Mr. Fox: Mr. Fox has over thirty years experience in commercial banking with a focus in lending to energy companies. In addition, his financial qualifications and experience provide essential skill sets to the Board and its committees.

Robert Skaggs has served as a director since July 2015. Mr. Skaggs has also served on the board of directors of DTE Energy, a diversified energy company based in Michigan (DTE), since 2017 and as a member of its nuclear oversight and finance committees. Mr. Skaggs previously served as chairman of the board and chief executive officer of Columbia Pipeline Group, Inc. (CPG), a natural gas pipeline and underground storage system company, and Columbia Pipeline Partners (CPPL) until they were acquired by TransCanada Corporation in July 2016. Prior to CPG s separation in July 2015 from NiSource Inc.

(NiSource), a Fortune 500 energy holding company engaged in natural gas and electric generation, transmission, storage and distribution, Mr. Skaggs served as chief executive officer of NiSource since 2005 and as its president since 2004. Mr. Skaggs earned a Bachelor of Arts degree in economics from Davidson College, a Juris Doctorate from West Virginia University and a Master s degree in business administration from Tulane University.

Qualifications of Mr. Skaggs: Through his background as a senior executive of large energy industry companies, Mr. Skaggs has extensive experience in developing regulatory strategies, as well as leading regulated commercial activities, and in federal governmental relations in the natural gas, electric and coal-fired generation industries, which brings important expertise and skill to the Board and its committees.

Class III Directors

The following information is furnished regarding the Class III directors who will continue to serve on the Board of Directors until their respective successors are elected and qualified or until the earlier of their resignation or removal.

Colin Marshall has served as our President and Chief Executive Officer and a director since July 2008. Effective January 18, 2018, he also served as our Chief Operating Officer until July 2018. Previously, he served as the president and chief executive officer of Rio Tinto Energy America Inc. (RTEA), an indirect subsidiary of Rio

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Tinto and the former parent company of CPE Resources, the company s wholly-owned subsidiary, from June 2006 until November 2009. Rio Tinto is the ultimate parent company of RTEA. From March 2004 to May 2006, Mr. Marshall served as General Manager of Rio Tinto s Pilbara Iron s west Pilbara iron ore operations in Tom Price, West Australia, from June 2001 to March 2004, he served as General Manager of RTEA s Cordero Rojo mine in Wyoming, and from August 2000 to June 2001, he served as Operations Manager of RTEA s Cordero Rojo mine. Mr. Marshall worked for Rio Tinto plc in London as an analyst in the Business Evaluation Department from 1992 to 1996. From 1996 to 2000, he was Finance Director of the Rio Tinto Pacific Coal business unit based in Brisbane, Australia. Mr. Marshall holds a Bachelor of Engineering degree and a Master s degree in mechanical engineering from Brunel University and a Master of Business Administration from the London Business School.

Qualifications of Mr. Marshall: In his position as President and Chief Executive Officer, making him the senior most executive of the company, Mr. Marshall provides the Board with a key perspective into the operations of the business, including the operations and marketing challenges it faces. Mr. Marshall has over twenty years financial and operational experience in the mining industry. Among other things in his background, from June 2001 to March 2004, Mr. Marshall served as General Manager of our Cordero Rojo mine in Wyoming, and from August 2000 to June 2001, he served as Operations Manager of Cordero Rojo. From 2004 to 2006, he was General Manager for Pilbara Iron overseeing five Rio Tinto iron ore mines located in northwest Australia.

Steven Nance has served as a director since January 2010. Mr. Nance has been the president and managing member of Steele Creek Energy, LLC, a company dealing primarily in oil and gas investments, since 2010. Mr. Nance was appointed to the board of directors of Newfield Exploration Company, an exploration and production company, in June 2013 and currently serves as lead director in addition to serving on its operations and reserves committee and chairing its nominating and governance committee. Mr. Nance served on the board of directors of The Williams Companies, Inc. from 2012 to 2016, where he served on its compensation committee and chaired its special safety committee. Mr. Nance served as president and sole director of Steele Creek Investment Company, the predecessor entity which held Mr. Nance s oil and gas ownership, from 1997 to November 2013 providing, from time to time, consulting services on matters such as oil and gas investments, succession planning, coaching and leadership development. From 2000 until 2007, Mr. Nance served as the president of Peoples Energy Production Company, an oil and gas exploration and production company. Mr. Nance holds a Bachelor of Science degree in petroleum engineering from Texas Tech University and is a registered professional engineer (inactive status).

Qualifications of Mr. Nance: Mr. Nance has over forty years experience in the oil and gas industry and has significant experience in senior executive positions, as well as merger and acquisition activities in these industries. Mr. Nance has experience in risk management and, along with his perspective as a former executive, brings a wealth of broad corporate knowledge to the Board and its committees.

Information About Executive Officers

This section provides information, as of March 5, 2019, regarding the background, business experience, attributes, qualifications and skills of our current executive officers, other than Mr. Marshall, our President and Chief Executive Officer who also serves as a director of the company. Refer to the table and disclosure under the caption Class III Directors above for biographical and related information regarding Mr. Marshall. There are no family relationships between any of our directors and executive officers. In addition, there are no arrangements or understandings between any of our executive officers and any other person pursuant to which any person was selected as an executive officer.

Name	Age	Position(s)
Heath Hill	48	Executive Vice President and Chief Financial Officer
Bruce Jones	60	Executive Vice President and Chief Operating Officer
Bryan Pechersky	48	Executive Vice President, General Counsel and Corporate Secretary
Amy Clemetson	46	Senior Vice President, Human Resources
Todd Myers	55	Senior Vice President, Marketing and Business Development
Kendall Carbone	53	Vice President and Chief Accounting Officer

Heath Hill has served as our Executive Vice President and Chief Financial Officer since March 2015 and prior to that he served as our Vice President and Chief Accounting Officer since September 2010. Previously, Mr. Hill served in various capacities with PricewaterhouseCoopers LLP, our independent auditors, from September 1998 to September 2010, including Senior Manager from September 2006 to September 2010, and Manager from September 2003 to September 2006. While with PricewaterhouseCoopers LLP, Mr. Hill s responsibilities included assurance services primarily related to SEC registrants, including annual audits of financial statements and internal controls, public debt offerings and IPO transactions. From June 2003 to June 2005 he held a position with PricewaterhouseCoopers in Germany serving U.S. registrants throughout Europe. Mr. Hill never worked on any engagements or projects for Cloud Peak Energy or its predecessor, Rio Tinto, while he was with PricewaterhouseCoopers LLP. Mr. Hill earned his Bachelor s degree in accounting from the University of Northern Colorado and is an active certified public accountant.

Bruce Jones has served as our Executive Vice President and Chief Operating Officer since July 2018. Prior to his appointment as Executive Vice President and Chief Operating Officer, Mr. Jones served as Senior Vice President, Technical Services from July 2013 to July 2018, with responsibilities in strategic and long-term mine planning, geological services, land management and environmental affairs. Prior to his appointment as Senior Vice President, Mr. Jones was General Manager of our Spring Creek Mine from March 2007 to July 2013. Before joining the Spring Creek Mine, Mr. Jones was the Operations Manager for Kennecott Utah Copper at the Bingham Canyon Mine in Bingham Canyon, Utah. Mr. Jones began his career as a mining engineer for Inspiration Coal, Inc. in 1982 and has worked in several sectors of the mining industry. During his career, Mr. Jones has held engineering and operations management positions at gold, copper and coal mining operations. Mr. Jones holds a Bachelor of Science degree in mining engineering from the University of Wisconsin-Platteville and a Master of Business Administration from the University of Utah. Mr. Jones is a registered professional engineer in Kentucky and Utah.

Bryan Pechersky has served as our Executive Vice President since January 2015, our General Counsel since January 2010 and our Corporate Secretary since March 2013. Prior to his promotion to Executive Vice President, he served as Senior Vice President beginning in 2010. Mr. Pechersky oversees our legal department and, since June 2016, our government affairs department. Previously, Mr. Pechersky was Senior Vice President, General Counsel and Secretary for Harte-Hanks, Inc., a worldwide, direct and targeted marketing company from March 2007 to January 2010. Prior to that, he also served as Senior Vice President, Secretary and Senior Corporate Counsel for Blockbuster Inc., a global movie and game entertainment retailer from October 2005 to March 2007, and was Deputy General Counsel and Secretary for Unocal Corporation, an international energy company acquired by Chevron Corporation in 2005, from March 2004 until October 2005. While in these capacities, Mr. Pechersky s responsibilities included advising on various legal, regulatory and compliance matters, transactions and other responsibilities that are common for a general counsel and corporate secretary. Mr. Pechersky was in private practice for approximately seven years with the international law firm Vinson & Elkins L.L.P. before joining Unocal Corporation. Mr. Pechersky also served as a Law Clerk to the Hon. Loretta A. Preska of the U.S. District Court for the Southern District of New York in 1995 and 1996. Mr. Pechersky earned his Bachelor s degree and Juris Doctorate from the University of Texas at Austin.

Amy Clemetson has served as our Senior Vice President, Human Resources since June 2017. Prior to her promotion to Senior Vice President, she served as Human Resources Director Field Operations since 2009. Ms. Clemetson transferred to human resources for the Company in 2003. Previously she served in operations starting with predecessor companies Kennecott Energy and RTEA in November 2001, prior to the creation of Cloud Peak Energy. Ms. Clemetson earned her Bachelor s Degree in Psychology with an emphasis in human resources from the University of Wyoming. She serves as Vice President on the Campco Federal Credit Union Board of Directors. She has also served as a Board member of Energy Capital Economic Development and Yes House Foundation.

Todd Myers has served as our Senior Vice President, Marketing and Business Development since June 2016. Prior to that appointment, he served as our Senior Vice President, Business Development beginning in July 2010. Previously, he served as President of Westmoreland Coal Sales Company and in other senior leadership positions with Westmoreland Coal in marketing and business development during two periods dating to 1989. In his various capacities with Westmoreland Coal, Mr. Myers s responsibilities included developing and implementing corporate merger and acquisition strategies, divesting coal related assets, negotiating complex transactions and other responsibilities generally attributable to the management of coal businesses. Mr. Myers also spent five years with RDI Consulting, a leading consulting firm in the coal and energy industries, where he led the environmental consulting practice. In 1987, Mr. Myers served as a staff assistant in the U.S. House of Representatives. Mr. Myers earned his Bachelor of Arts in political science from Pennsylvania State University in University Park, Pennsylvania, and his Masters in International Management from the Thunderbird Graduate School of Global Management in Glendale, Arizona.

Kendall Carbone has served as our Vice President and Chief Accounting Officer since March 2015 and previously as our Assistant Chief Accounting Officer since January 2015. Prior to joining Cloud Peak Energy, Ms. Carbone served as Vice President, Controller and Chief Accounting Officer for both Cool Planet Energy Systems, Inc. from 2013 to 2014 and QEP Resources, Inc. from 2010 to 2013. Ms. Carbone has extensive experience in the energy industry including bio-fuel, natural gas and oil refining as well as previous experience in mining. Ms. Carbone is a certified public accountant and holds a Master s degree in accounting from New York University and a Bachelor s degree in economics from Dartmouth College.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 (Exchange Act) and related rules of the Securities and Exchange Commission (the SEC) require our directors and Section 16 officers, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of ownership and reports of changes in ownership with the SEC. These persons are required by SEC regulations to furnish us with copies of all Section 16(a) reports that they file. We assist our directors and Section 16 officers in making their Section 16(a) filings pursuant to powers of attorney granted by our directors and Section 16 officers on the basis of information obtained from them and our records.

No director, Section 16 officer, beneficial owner of more than 10% of the outstanding common stock of the company, or any other person subject to Section 16 of the Exchange Act, failed to file on a timely basis during 2018. This is based solely upon a review of Forms 3, 4 and 5 and amendments thereto furnished to Cloud Peak Energy during and with respect to 2018, including those reports that we have filed on behalf of our directors and Section 16 officers pursuant to powers of attorney.

Corporate Governance

We believe strong corporate governance helps to ensure our company is managed for the long-term benefit of our stockholders. We believe effective corporate governance should include constructive conversations with our stockholders, and we maintain a robust investor relations program.

As part of our commitment to corporate governance leadership and our compliance with the listing standards of the NYSE and SEC regulations, we have adopted various charters, policies and procedures. The charters of our Audit Committee, Compensation Committee, Governance Committee, and Health, Safety, Environment and Communities Committee (HSEC Committee), as well as our Corporate Governance Guidelines, Code of Conduct, Code of Ethics for Principal Executive and Senior Financial Officers, Clawback Policy, Insider Trading Policy and certain other policies and procedures, are available on our website at *www.cloudpeakenergy.com* in the Corporate Governance subsection of the Investor Relations section. Additionally, stockholders can request copies of any of these documents, free of charge, by submitting a written request to Cloud Peak Energy Inc., Attn: General Counsel, 748 T-7 Road, Gillette, Wyoming 82718.

The Board reviews these materials annually and updates them based on changes in Delaware corporate law, the rules and listing standards of the NYSE and SEC regulations, as well as best practices suggested by recognized governance authorities. From time to time, we expect these materials will be modified in response to changing regulatory requirements, evolving practices, feedback from our stockholders and other stakeholders and otherwise as circumstances warrant. We encourage our stockholders to check our website periodically for the most recent versions of our governance materials.

Board Leadership Structure; Separate Chairman and CEO Positions

Cloud Peak Energy s Chairman of the Board and Chief Executive Officer (CEO) positions are separate. Our Board is composed of a majority of independent directors, and the Chairman of the Board is an independent director. The only member of our Board who is not considered independent is Mr. Marshall, our President and CEO. In addition, our Audit Committee, Compensation Committee and Governance Committee, each as described below, are composed of entirely independent directors, including the chairman of each committee. The Board believes that the

HSEC Committee is best served by including Mr. Marshall as a member and has appointed an independent director as the chairman of that committee.

The Board recognizes that one of its key responsibilities is to evaluate and determine its optimal leadership structure to provide independent oversight of management. The Board understands that there is no single, generally accepted approach to providing Board leadership and that given the dynamic and competitive environment in which we operate, the right Board leadership structure may vary as circumstances warrant. We believe the number of independent directors that make up our Board, along with the oversight provided by our independent Chairman of the Board, benefits both the company and our stockholders. The Board and independent directors consider the Board s leadership structure on a regular basis.

Board s Role in Risk Oversight

Generally speaking, the Board executes oversight responsibility for risk management directly and indirectly through its committees, as follows:

- The Audit Committee has primary responsibility for overseeing and discussing with management the process for identifying and classifying the company s principal risks and identifying appropriate steps to monitor and manage such exposures. The company s internal auditor, who reports directly to the Audit Committee and administratively to our Executive Vice President and Chief Financial Officer, performs risk assessments and conducts audits of high risk areas accordingly. The Audit Committee s meeting agendas are planned to include discussions of significant individual risk areas throughout the year. In addition, the Audit Committee has certain oversight responsibilities with respect to our overall legal compliance program. Our internal compliance committee is a cross-functional employee committee that oversees our corporate ethics and compliance programs and is appointed by, and reports directly to, our Audit Committee. The compliance committee consists of our CEO; Chief Operating Officer; General Counsel; Senior Vice President, Human Resources; and Director of Internal Audit.

- The Board s other committees (Compensation Committee, Governance Committee, and HSEC Committee) oversee risks associated with their respective areas of responsibility. For example, the Compensation Committee considers the risks associated with our compensation policies and practices, with respect to both executive compensation and compensation generally.

- The Board is kept abreast of its committees risk oversight and other activities via reports of the committee chairmen to the full Board. These reports are presented at regular Board meetings and include discussions of committee agenda topics, including matters involving risk oversight. In addition, Board members frequently attend all committee meetings regardless of membership on that committee, and the full Board is provided with all Board and standing committee meeting materials. For additional information about the activities and responsibilities of the Board s committees and the scope of the Board s delegation to its committees, refer to the respective committees charters, which are available on our website at *www.cloudpeakenergy.com* in the Corporate Governance subsection of the Investor Relations section.

- The Board s meetings are also planned to consider specific risk topics, including risks associated with our strategic plan, our capital structure and our significant business activities, and an overall corporate risk review presented by management. In addition, the Board receives detailed regular reports from members of our executive management team, which include discussions of the risks and exposures involved in their respective areas of responsibility. These reports are provided in connection with regular Board meetings and are discussed, as necessary, at Board meetings. Further, the Board s fulfillment of its oversight responsibility for risk management includes being informed between regular meetings of significant developments, including those that could affect our risk profile or other aspects of our business.

Diversity of Board Members

We do not maintain a separate policy regarding the diversity of our Board members. However, the charter of the Governance Committee provides that in recommending potential nominees to the Board, the Governance Committee will take diversity into account with the intent of creating a Board that consists of members with a broad spectrum of experience and expertise and with a reputation for integrity. Consistent with its charter, the Governance Committee

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and ultimately the Board seek nominees with distinct professional backgrounds, experience and perspectives so that the Board as a whole has the appropriate mix of skills, perspectives, personal and professional experiences and backgrounds necessary to fulfill the needs of the company with respect to the current issues it faces. When evaluating recommendations for potential nominees, the Governance Committee considers the contribution of existing directors, as well as the qualifications of new nominees.

Board of Directors and Board Committees

Our business is managed under the direction of our Board. The Board appoints the CEO, approves and monitors the fundamental financial and business strategies of our company, and provides a source of advice and counsel to management. The Board also oversees CEO succession planning and is responsible for ensuring that succession planning for other members of senior management is ongoing. In addition, the Board s responsibilities include reviewing and approving major corporate actions, working with management to identify the principal risks of the company s businesses and overseeing the implementation of appropriate risk management systems, as well as evaluating, through the Compensation Committee and the independent directors, the compensation of the CEO and other executive officers.

The Board meets on a regularly scheduled basis to review significant developments affecting our company, to act on matters requiring approval by the Board and to otherwise fulfill its responsibilities. It also holds special meetings when an important matter requires action or review by the Board between regularly scheduled meetings. The Board has the following separately designated standing committees:

- Audit Committee,
- Compensation Committee,
- Governance Committee, and
- HSEC Committee.

The following table provides membership and meeting information for the Board and each of the Board s standing committees during 2018 and also describes changes to the Board and its committees as of the date of this Form 10-K:

Director	Independent(1)	Audit Committee(2)	Compensation Committee	Governance Committee	HSEC Committee
William T. Fox III	Yes	Chair		Member	Member
Jeane Hull	Yes	Member	Member		Member

Colin Marshall	No				Member
Steven Nance	Yes		Member	Member	Chair
William Owens	Yes		Member	Chair	
Robert Skaggs	Yes	Member	Chair		
Number of In-Person and Telephonic Committee Meetings in 2018(3)		8	6	5	5
Number of In-Person and Telephonic Board Meetings in 2018(3)	13				

(1) The Board has determined whether the director is independent as described below under Independence of Directors.

(2) The Board has determined that each of Messrs. Fox and Skaggs is an audit committee financial expert as described below under Audit Committee Financial Experts and Financial Literacy.

(3) During 2018, each director participated in at least 75 percent of (a) all of the Board meetings that were held and (b) all meetings of each committee of which the director was a member that were held, in each case, during the period that the director served on the Board or the applicable committee.

A brief description of the principal functions of each of the Board s four standing committees follows. Each committee also has certain oversight responsibilities for risk management as described above. The Board retains the right to exercise the powers of any committee to the extent consistent with applicable rules and regulations, and may do so from time to time. For additional information, please refer to the Audit Committee Charter, the Compensation Committee Charter, the Governance Committee Charter, and the HSEC Committee Charter, which are available on our website at *www.cloudpeakenergy.com* in the Corporate Governance subsection of the Investor Relations section.

Audit Committee

The primary function of the Audit Committee is to assist the Board in fulfilling its responsibility to our stockholders, the investment community and governmental agencies that regulate our activities in its oversight of:

- The integrity of our financial statements, financial reports and other financial information filed with the SEC;

- The integrity and adequacy of our auditing, accounting and financial reporting processes and systems of internal control over financial reporting;

- Our compliance with legal and regulatory requirements, including internal controls designed for that purpose;

- The independence, qualifications and performance of our independent registered public accounting firm; and

- The performance of our internal audit function.

The Audit Committee provides an avenue of free, open and clear communication among the auditors, the internal audit function, management, the Audit Committee and the Board. The Audit Committee is also responsible for preparing the Audit Committee Report that SEC rules require be included in our annual proxy statement. The Audit Committee meets regularly in executive session with the Chief Financial Officer (CFO), internal auditor, General Counsel and external auditors, and as a committee. These executive sessions may include other non-employee directors.

Compensation Committee

General

The Compensation Committee determines and oversees the execution of the company s compensation philosophy and oversees the administration of the company s executive compensation program. The primary functions of the Compensation Committee are to:

- Review, evaluate and approve, or recommend to the Board or other independent directors of the Board, our agreements, plans, policies and programs to compensate our executive officers and directors;

- Oversee our plans, policies and programs to compensate our non-executive employees;

- Review and discuss with our management the Compensation Discussion and Analysis included in our annual proxy statement, and determine whether to recommend to the Board that the Compensation Discussion and Analysis be included in our annual proxy statement, in accordance with applicable rules and regulations;

- Produce the Compensation Committee Report as required by Item 407(e)(5) of Regulation S-K for inclusion in our annual proxy statement; and

- Otherwise discharge the Board s responsibilities relating to compensation of our executive officers and directors.

The Compensation Committee may, in its discretion and as appropriate, delegate duties and responsibilities to a member or to a subcommittee of the Compensation Committee. However, no subcommittee may be delegated any power or authority required by any law, regulation or listing standard to be exercised by the Compensation Committee as a whole. No subcommittees were formed or met in 2018.

The Compensation Committee meets in executive session as it deems appropriate to review and consider executive compensation matters without the presence of our executive officers. These executive sessions may include other independent directors and the Compensation Committee s independent compensation consultant.

Other Participants in the Executive Compensation Process

In addition to the members of the Compensation Committee and other members of the Board who may also be in attendance at the Compensation Committee s meetings, our CEO, our Senior Vice President, Human Resources and the Compensation Committee s independent compensation consultant, Aon Hewitt, also participated in and contributed to our executive compensation process during 2018. Ultimately, the Compensation Committee exercises its independent business judgment with respect to recommendations and opinions of other participants and advisors and the Compensation Committee (or our independent directors as a group) makes final determinations about our executive officer compensation.

CEO During its meetings throughout 2018, the Compensation Committee invited input from our CEO on executive compensation for 2018. In particular, Mr. Marshall provided the perspective of management to the Compensation Committee regarding executive compensation matters generally and the performance of the executive officers reporting to him. Mr. Marshall provided input on the company targets, and, for the executive officers reporting to him, the personal performance measurements related to our Annual Incentive Plan for 2018, base salary levels and other compensation matters. Mr. Marshall also reviewed his 2018 achievement against goals established for 2018. Mr. Marshall did not provide recommendations with respect to his own compensation amounts.

Compensation Committee s Consultant As in prior years, the Compensation Committee retained Aon Hewitt to assist with the evaluation of and determinations for our executive compensation program and other executive and director compensation matters for 2018. Under the terms of the engagement, Aon Hewitt reports directly to the Compensation Committee. Although Aon Hewitt also works in cooperation with management as required to gather information necessary to carry out its obligations to the Compensation Committee, Aon Hewitt does not have a separate engagement with our management; however, management has periodically engaged Radford, an Aon Hewitt affiliate, to provide equity valuation and other similar services from time to time for an immaterial service fee.

In connection with its engagement of Aon Hewitt and based on the information presented to it, the Compensation Committee assessed the independence of Aon Hewitt pursuant to applicable SEC and NYSE rules and concluded that Aon Hewitt s work for the Compensation Committee, and the immaterial services provided by Radford as described above, did not raise any conflict of interest for 2018. Please see Executive Compensation Compensation Discussion and Analysis for additional information regarding the scope of Aon Hewitt s engagement for 2018 and other matters related to our executive compensation program for 2018.

Nominating and Corporate Governance Committee

The primary functions of the Governance Committee are to:

- Advise the Board and make recommendations regarding appropriate corporate governance practices and assist the Board in implementing those practices;

- Assist the Board by identifying individuals qualified to become members of the Board, consistent with the criteria approved by the Board, and recommending director nominees to the Board for election at the annual meetings of stockholders or for appointment to fill vacancies on the Board;

- Advise the Board about the appropriate composition of the Board and its committees;

- Lead the Board in the annual performance evaluation of the Board, its committees and of management; and

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- Direct all matters relating to the succession of our CEO.

Health, Safety, Environment and Communities Committee

The primary functions of the HSEC Committee are to oversee:

- Our compliance with safety, health, environmental and sustainability-related laws and other regulatory requirements applicable to our business;

- Our initiatives to enhance sustainable business practices and our reputation as a responsible corporate citizen, including the promulgation and enforcement of policies, procedures and practices that promote the protection of the safety and health of our employees, contractors, customers, the public and the environment;

- The plans, programs and processes established by us to evaluate and manage safety, health, environmental and sustainability risks to our business, operations, products and reputation generally; and

- Our response to significant safety, health, environmental and sustainability-related public policy, legislative, regulatory, political and social issues, trends or incidents that may affect our business operations, financial performance or public image or the industry in which we operate.

Director Nomination Process; Proxy Access

The Governance Committee identifies and recommends to the Board the candidates for nomination as directors. Stockholders may propose nominees for consideration by our Governance Committee by submitting names and supporting information to Cloud Peak Energy Inc., Attn: Corporate Secretary, 748 T-7 Road, Gillette, Wyoming, 82718 in accordance with our Bylaws and applicable law. The Board approves the final choice of candidates for nomination and recommendation for election to our stockholders. In addition, our Bylaws provide that eligible stockholders who comply with the requirements of the proxy access provision set forth in our Bylaws may include their own nominee or nominees for director in our proxy statement. Specifically, the company s proxy access provision provides that a stockholder, or an unlimited group of stockholders, who has, or have:

- maintained continuous qualifying ownership of at least 3% of Cloud Peak Energy s outstanding common stock, for at least 3 years, and

- complied with the other requirements set forth in the Bylaws,

may submit, for inclusion in Cloud Peak Energy s proxy materials for an annual meeting of stockholders, a number of director nominees that together with all eligible stockholder nominees shall not exceed 25% of the total number of directors in office (rounded down to the nearest whole number).

The Governance Committee selects nominees for the Board, including any nominees proposed for consideration by our stockholders, in accordance with the procedures and criteria set forth in the Corporate Governance Guidelines and the Governance Committee s charter. The Board seeks a diverse group of candidates who possess the background, skills and expertise necessary to make a significant contribution to the Board and the company. In reviewing director candidates, the Governance Committee reviews each candidate s qualifications for membership on the Board and takes into account the qualities required to add value to the company and to the functioning of the Board and its committees such as independence, financial expertise, diversity, experience with businesses and other organizations of comparable size, the interplay of the candidate s experience with the experience of other Board members, the candidate s personal and professional integrity and business judgment, the candidate s willingness to commit the required time to serve as a Board member, the extent to which the candidate would be a desirable addition to the Board and its committees and any other factors it deems appropriate (including with respect to continuing directors, the director s past Board and committee meeting attendance and performance and length of Board service), as well as the expected qualities of Board members set forth in our Corporate Governance Guidelines and any applicable legal, regulatory and listing requirements.

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As provided by our Corporate Governance Guidelines, a Board member is expected to demonstrate high ethical standards and integrity in his or her personal and professional dealings, act honestly and in good faith with a view to the best interest of the company, devote sufficient time to the affairs of the company and exercise care, diligence and skill in fulfilling his or her responsibilities, both as a Board member and as a member of any of its standing committees. A Board member is also expected to provide independent judgment on a broad range of issues, understand and challenge the key business plans of the company, be willing to work in a team and be open to opinions of others, and raise the appropriate difficult questions and issues to facilitate active and effective participation in the deliberation of the Board and of each committee on which he or she serves. Further, each of the Board members should make all reasonable efforts to attend all Board and committee meetings, review the materials provided by management in advance of the Board and committee meetings, and inform the Chairman of the Board before accepting membership on any other board of directors or audit committees. A Board member should also inform the Chairman of the Board of any change in the director s interests that could affect the director s relationship to the company.

The Governance Committee and the Board may take into account the nature of and time involved in a director s service on other boards in evaluating the suitability of individual directors and making its recommendations to the Board or the company s stockholders, as applicable.

Director Retirement Policy

Our Corporate Governance Guidelines provide that a director who has attained the age of 75 prior to the annual meeting of stockholders in any year shall retire from office at such annual meeting unless the Board, in its discretion, approves an exception.

Independence of Directors

Pursuant to our Corporate Governance Guidelines and the rules of the NYSE, our Board is comprised of a majority of directors who satisfy the criteria for independent directors.

Annual questionnaires are used to gather input to assist the Governance Committee and the Board in their determinations of the independence of the non-employee directors. Based on the foregoing and on such other due consideration and diligence as it deemed appropriate, the Governance Committee presented its findings to the Board on the independence of (1) William T. Fox III, (2) William Owens, (3) Steven Nance, (4) Robert Skaggs, and (5) Jeane Hull, in each case, in accordance with the applicable federal securities laws, the SEC rules promulgated thereunder, and the applicable rules of the NYSE and our Guidelines on the Independence of the Directors (which may be found in Annex A to our Corporate Governance Guidelines).

The Board concluded that, other than in their capacity as directors, none of the non-employee directors had a material relationship with Cloud Peak Energy, either directly or as a partner, stockholder or officer of an organization that has a relationship with Cloud Peak Energy. The chart below shows the relationships, if any, that the Board considered when determining the independence of each non-employee director:

Non-Employee Board Member	Relationship Considered	Board Conclusion
Robert Skaggs	Mr. Skaggs serves as a non-employee director of DTE, a U.S. diversified energy company. In the ordinary course of business, we sell coal to numerous domestic utility customers, including DTE or its affiliates, and we conduct other ordinary course business with DTE.	The Board considered the nature and dollar amount of historical, ordinary course transactions between Cloud Peak Energy and DTE and the fact that Mr. Skaggs role for DTE is solely as a non-employee member of its board of directors and that he will not participate in these transactions and concluded that Mr. Skaggs did not have a material relationship that would compromise his independence to serve on our Board or the Board s committees.

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Non-Employee Board Member	Relationship Considered	Board Conclusion
Jeane Hull	Ms. Hull retired from her former position as an officer of Peabody in August 2015. Cloud Peak Energy has sold coal to, or purchased coal from, Peabody in the ordinary course of business in past years.	Due to the amounts involved in the ordinary course transactions with Peabody, the fact that Ms. Hull s employment with Peabody terminated prior to her appointment to the Board and the fact that Ms. Hull did not participate in those transactions, the Board determined that Ms. Hull did not have a material relationship with Cloud Peak Energy that would impair Ms. Hull s independence to serve on our Board or the Board s committees.
	In December 2017, Ms. Hull was appointed to the board of directors of Epiroc AB, a company spun off from Atlas Copco and listed on the Nasdaq Stockholm Exchange in 2018. In the ordinary course of business, we purchase mining parts from Atlas.	The Board considered the nature and dollar amount of historical, ordinary course transactions between Cloud Peak Energy and Atlas and the fact that Ms. Hull s role for Epiroc AB is solely as a non-employee member of its board of directors and that she will not participate in these transactions and concluded that Ms. Hull did not have a material relationship that would compromise her independence to serve on our Board or the Board s committees.

The Board further determined that (1) each director serving on the Audit Committee, Compensation Committee and Governance Committee is otherwise independent under applicable NYSE listing standards and our Guidelines on the Independence of the Directors for purposes of serving on the Board, Audit Committee, Compensation Committee and Governance Committee, as applicable, (2) each such non-employee director satisfies the additional audit committee independence standards under Rule 10A-3 of the Exchange Act and the additional independence requirements applicable specifically to compensation committee members under the NYSE s listing standards, and (3) each director serving on the Compensation Committee qualifies as an outside director under Section 162(m) of the Internal Revenue Code (which provision has since been amended by the Tax Cuts and Jobs Act) and a non-employee director under Rule 16b-3 of the Exchange Act.

Executive Sessions of Independent Directors

Our Corporate Governance Guidelines provide that every regular meeting of the Board will include one or more executive sessions at which no employee directors or other members of senior management are present in order to promote free and open discussion and communication among the non-employee directors. At least one executive session per year includes only independent directors. Currently, all of our non-employee directors are also considered to be independent directors. As a result, our independent directors hold an executive session at each quarterly Board meeting. The Chairman of the Board, who is an independent director, presides over all executive sessions of the Board. If, in the future, our Chairman of the Board were to be a person who is an executive of the company, in accordance with our Corporate Governance Guidelines, our Board would appoint a lead director from among the non-employee directors to preside over the executive sessions of the Board.

Board and Committee Evaluations

Each year, the Board and its committees perform a rigorous self-evaluation. The Governance Committee oversees this process. The evaluations solicit input from directors regarding the performance and effectiveness of the Board and its committees and provide an opportunity for directors to identify areas where improvements could be made. Individual director responses are submitted to our Corporate Secretary, who then compiles aggregated, anonymous results of the evaluations for review and discussion by the Board and its committees. The Board believes this process is effective to evaluate the Board, its committees and the contributions of its members, and identify opportunities for continuous improvement.

Audit Committee Financial Experts and Financial Literacy

The Board previously determined that current directors Messrs. Fox and Skaggs and Ms. Hull, the members of the Audit Committee, were each financially literate as interpreted by the Board in its business judgment based on applicable NYSE rules, and that Messrs. Fox and Skaggs each further qualified as an audit committee financial expert, as such term is defined in applicable SEC rules, and had accounting or related financial management experience, as defined by applicable NYSE rules and interpreted by the Board in its business judgment.

Communications with Non-Employee Directors and Other Board Communications

The Board provides a process, pursuant to its Policy Regarding Communications from Stockholders, to enhance the ability of stockholders and other interested parties to communicate directly with the non-employee directors as a group, the entire Board, Board committees or individual directors.

Stockholders and other interested parties may communicate by writing to: Cloud Peak Energy Inc., 748 T-7 Road, Gillette, Wyoming 82718, Attn: Corporate Secretary; or via the Internet at *www.cloudpeakenergy.com* by clicking on Contact the Board in the Corporate Governance subsection of the Investor Relations section. Stockholders may submit their communications to the Board or individual directors on a confidential or anonymous basis by sending the communication in a sealed envelope marked Confidential To be opened only by the Corporate Secretary of the Company. The Corporate Secretary will compile all communications submitted using the process described herein and forward such communications to such director or group of directors as he deems necessary or appropriate. The Corporate Secretary is not required to forward certain communications if it is determined that the communication is (1) unrelated to the duties and responsibilities of the Board, (2) unduly hostile, threatening or illegal, or (3) obscene or otherwise deemed to be inappropriate.

Stockholder communications that relate to accounting, internal accounting controls or auditing matters will be processed in accordance with our Accounting Complaints Policy. Concerns about accounting or auditing matters may be forwarded on a confidential or anonymous basis to the Audit Committee by writing to: Cloud Peak Energy Inc., 748 T-7 Road, Gillette, Wyoming 82718, Attn: General Counsel, as well as through the Ethics Hotline at (866) 528-0054.

Director Attendance at Annual Meetings

The Corporate Governance Guidelines provide that directors are expected to attend our annual meeting of stockholders. All of our directors at the time of the 2018 annual meeting of stockholders attended that meeting.

Policies on Business Conduct and Ethics

We have established a corporate compliance program as part of our commitment to responsible business practices in all of the communities in which we operate. The Board has adopted a Code of Conduct that applies to all of our directors, officers and employees, which, although not intended to cover every situation or circumstance that may arise, is designed to (1) provide basic principles and guidelines to assist directors, officers and employees in complying with the legal and ethical requirements governing the company s business conduct and (2) cover a wide range of business practices and procedures. In addition, we have adopted a Code of Ethics for Principal Executive and Senior Financial Officers mandating a commitment to financial integrity and to full and accurate financial disclosure in compliance with applicable accounting policies, laws and regulations. These two policies form the foundation of a compliance program that includes policies and procedures covering a variety of specific areas of professional conduct, including compliance with laws, conflicts of interest, confidentiality, public corporate disclosures, insider trading, anti-bribery, trade practices, protection and proper use of company assets, intellectual property, financial accounting, employment practices, health, safety and environment, and political contributions and payments.

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Both our Code of Conduct and our Code of Ethics for Principal Executive and Senior Financial Officers are available on our website at *www.cloudpeakenergy.com* in the Corporate Governance subsection of the Investor Relations section. In accordance with NYSE and SEC rules, we will disclose any future amendments to or waivers from our Code of Ethics for our Principal Executive and Senior Financial Officers as well as any waivers from our Code of Conduct for directors and executive officers by posting such information on our website within the time period required by applicable SEC and NYSE rules.

Indemnification of Officers and Directors

Our Bylaws require us to indemnify our officers and directors to the fullest extent permitted by the Delaware General Corporation Law. Our Bylaws also state that Cloud Peak Energy has the power to purchase and maintain insurance on behalf of any person who is or was or has agreed to become a director, officer, employee or agent of the company, or is or was serving at the request of the company as a director, officer, employee or agent of another corporation, partnership, limited liability company, joint venture, trust or other enterprise (including, without limitation, with respect to an employee benefit plan), against any liability asserted against the person and incurred by the person or on the person s behalf in any such capacity, or arising out of the person s status as such, whether or not the company would have the power to indemnify the person against such liability under our Bylaws or the Delaware General Corporation Law; provided, however, that such insurance is available on acceptable terms, as determined by a majority of the Board.

Item 11. *Executive Compensation.*

Compensation Committee Report

The material in this Report is not soliciting material, is not deemed filed with the SEC, and is not to be incorporated by reference into any filing under the Securities Act of 1933 (the Securities Act) or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in such filing.

The Compensation Committee of the Board of Directors has reviewed and discussed with management the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K and contained in this Form 10-K. Based on such review and discussions, the Compensation Committee recommended to the Board that the Compensation Discussion and Analysis be included in this Form 10-K.

Compensation Committee

Robert Skaggs, Chair
Jeane Hull
Steven Nance
William Owens

Compensation Discussion and Analysis

Within this Compensation Discussion and Analysis (CD&A), the term executive officers means our senior executives who are all listed above as an executive officer in Item 10 and also includes Mr. Marshall (who is listed above as a director in Item 10). The term named executive officers means the first five executive officers identified in the table below, each of whom were considered executive officers as of December 31, 2018, as well as Mr. Rivenes, who is deemed to be a named executive officer pursuant to SEC rules although he was no longer an employee or executive officer of Cloud Peak Energy as of December 31, 2018.

Named Executive Officer	Title
Colin Marshall	President, Chief Executive Officer and Director
Heath Hill	Executive Vice President and Chief Financial Officer
Bruce Jones	Executive Vice President and Chief Operating Officer
Bryan Pechersky	Executive Vice President, General Counsel and Corporate Secretary
Todd Myers	Senior Vice President, Marketing and Business Development
Gary Rivenes	Former Executive Vice President and Chief Operating Officer

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As disclosed in a Form 8-K filed on January 18, 2018, Mr. Rivenes final day as an employee of Cloud Peak Energy was April 17, 2018. From January 18, 2018 to July 11, 2018, Mr. Marshall served in the role of Chief Operating Officer (until such time as Mr. Jones was appointed to that role), but due to the fact that he was no longer in that position as of December 31, 2018 his title below will not reflect the duties he performed as Chief Operating Officer for a portion of the year. Prior to July 11, 2018, Mr. Jones served as our Senior Vice President, Technical Services.

Executive Summary

As further discussed above, we are reviewing our restructuring alternatives, including asset sales, a court-supervised restructuring proceeding under Chapter 11 of the United States Bankruptcy code and related financing needs during any such proceeding. As a result of the uncertainty of the coming year, our executive compensation program has been modified in various ways with respect to 2019 compensation. Our Compensation Committee took steps in the first quarter of 2019 to create compensation packages for our executive officers that would retain our leadership during this difficult time, while balancing our need to reduce costs. As of the date of this filing, we have made the following decisions with respect to 2019 compensation packages:

- We entered into individual retention agreements with each of our NEOs in January 2019 (the 2019 Retention Agreements). The 2019 Retention Agreements replace certain retention agreements that we had previously entered into in November 2018 with our then-current named executive officers (the Replaced Retention Agreements). The benefits under both the 2019 Retention Agreements and the Replaced Retention Agreements are described in more detail below under the heading Retention Agreements.

- We do not currently expect to grant annual equity-based awards to our NEOs during the 2019 calendar year.

- We do not currently expect to provide any increases in base salaries for our NEOs during the 2019 year.

- We have modified the 2019 annual cash incentive program. The 2019 annual cash incentive awards for the NEOs will be based solely on company performance metrics and will not have discretionary or individual performance metrics. The 2019 annual cash incentive award program for our NEOs will generally be paid in quarterly, rather than annual, payments, based upon our performance with respect to Adjusted EBITDA and safety metrics.

We are aware that the remainder of the 2019 year will bring challenges and uncertainty with respect to our executive compensation program. While we have implemented the compensation items described immediately above, it is possible that a bankruptcy court, if applicable, could modify, terminate or replace these programs later in the 2019 year. We anticipate that additional adjustments will be required during the 2019 year to adapt our programs to our changing needs.

The remainder of this CD&A will provide information on our 2018 compensation program for NEOs as required by SEC rules. The CD&A below provides a discussion of the compensation philosophy and objectives that existed for our executive compensation program in 2018 and how we evaluated and set our executives compensation for 2018. It is intended to provide qualitative information concerning how 2018 compensation was earned and awarded to our named executive officers and to give context to the data presented in the compensation tables included below in this Form 10-K. The design, philosophy and amounts discussed below for 2018 should be read in the context of our historical compensation program only and is not intended to provide information or expectations regarding 2019 compensation unless otherwise specifically noted.

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2018 Executive Compensation Program Overview

Our 2018 executive compensation program was designed to attract and retain highly competent, motivated executives and reward them for performance, consistent with creating long-term stockholder value. It consisted of a mix of three primary components, described below, which we believe appropriately rewarded our executive officers for their overall contribution to company performance, contained a substantial portion of at-risk, performance-based compensation, recognized the impact of ongoing depressed coal industry conditions on our financial and operational results and on our executive compensation program and aligned our executives interests with those of our stockholders with the ultimate objective of increasing long-term stockholder value.

Based on this philosophy we set targeted pay levels in 2018 that approximated the median of a peer group that was approved by our Compensation Committee, with the opportunity for above or below median compensation based on experience, responsibilities, competencies and individual performance. The pay ultimately realized was highly variable and dependent primarily upon (1) our financial and safety performance, (2) individual executive performance and (3) our multi-year absolute and relative stock price performance. Actual realized or realizable compensation to our executives has frequently been below target amounts and therefore resulted in significant compensation reductions compared to grant date targeted pay amounts.

The three primary components of our executive compensation program for 2018 were:

Primary Compensation Components	**Overview**
Base Salary	Competitive base salaries determined in large part through in-depth comparative analyses of comparable positions at our peer group companies and targeted to be approximately at the 50th percentile of our peer group, with the opportunity for above or below median base salaries based on experience, responsibilities, competencies and individual performance.
Annual Cash Incentive	Opportunity for an annual cash incentive award to align our executives with annual corporate and individual performance achievements with the ultimate payment amount based on a combination of Adjusted EBITDA (60% weighted), safety (20% weighted), and individual executive performance (20% weighted).
Long-Term Equity Incentive	A long term incentive plan and stock ownership guidelines and holding requirements to align our executives with longer term performance achievement and stockholder returns over time, and which consisted of relative and absolute TSR-Based PSUs (60% weighted) and time-based RSUs (40% weighted), with ownership and holding requirements based on a designated multiple of each executive s base salary.

With respect to the 2018 compensation program, the mix of fixed to at-risk compensation was as follows:

2018 Direct Compensation Components - CEO

2018 Direct Compensation Components - Average Other NEOs

Advisory Votes on Compensation

As recommended by our Board most recently in 2017, a majority of stockholders in 2017 expressed their preference for an advisory vote on executive compensation every year, and we have continued to implement that recommendation. Historically, we have generally received strong stockholder support in favor of our executive compensation program. In 2018 we again received significant support for our executive compensation program with an approval of 98%, and therefore did not make any material changes to our program in 2018 in response to that vote.

2018 Executive Compensation Philosophy and Objectives

Our 2018 executive compensation program was designed to reward our executive officers for their overall contribution to company performance, including the achievement of specific annual and long-term goals. The executive compensation program also sought to align executive officers interest with those of our stockholders by rewarding performance that met or exceeded established goals. Specifically, the 2018 program was designed to:

- Retain and attract a highly competent, motivated team of employees appropriately aligned with the long-term interest of our stockholders;

- Encompass safety and environmental stewardship as core elements of our compensation program;

- Encourage behavior that will enhance both current year performance and long-term growth of stockholder value;

- Target total compensation to be in a range around the 50th percentile of our peer group with the opportunity for above or below median compensation based on experience, responsibilities, competencies, individual performance and company performance;

- Provide as part of our total compensation base salary, the opportunity for a cash incentive and the opportunity for equity, linked to the long-term growth in total shareholder return (TSR);

- Achieve minimum performance thresholds prior to any incentive compensation being earned;

- Provide market competitive programs of health, welfare and retirement benefits to all employees on an equivalent basis; and

- Make equity ownership and retention guidelines for executives and directors a key component to ensure alignment with long-term stockholder interests.

The Compensation Committee reviews our compensation philosophy annually to review whether the goals and objectives are being met, and what, if any, changes may be needed to the philosophy. In recent years, the Compensation Committee s review has taken into account the impact of ongoing depressed coal industry conditions on our company s performance and on our executive compensation program.

Setting Executive Compensation for 2018; 2018 Peer Group

The Compensation Committee historically has engaged Aon Hewitt, its independent compensation consultant, to conduct a review of the company s executive officer compensation program in order to assist the Compensation Committee in determining whether any elements or amounts of the existing compensation program should be modified. In late 2017, Aon Hewitt presented the Compensation Committee with information regarding potential modifications to our annual incentive program and appropriate peer group companies with respect to the 2018 year, but Aon Hewitt was not engaged to provide in-depth analysis regarding the executive or director compensation programs for 2018.

In 2018, the Compensation Committee reviewed data prepared by Aon Hewitt regarding peers. In previous years we had used two separate peer groups, one for general comparison purposes and one more specifically focused on performance with respect to our equity awards. For 2018, the Compensation Committee combined the previously separate compensation peer group and performance peer group into a single peer group to be used for both executive and director compensation benchmarking comparisons and relative TSR performance for the performance share units. In connection with the Compensation Committee s decision, we established the following criteria for the new peer group:

- Publicly traded U.S. coal companies, and

- Publicly traded U.S. oil and gas exploration and production companies that are majority gas portfolio companies with revenue between one-third and three times our revenue.

We chose not to place a revenue criterion for the coal peers because they are our most direct competitors and there are limited U.S. public coal companies. While this means that we might have coal companies less than one-third our size or more than three times our size, we believe this is appropriate and use regression analysis when benchmarking to account for differences in the revenues of our peers. Gas-focused companies were chosen because natural gas is a competing fuel source with coal and natural gas prices are correlated with coal prices.

The above criteria resulted in the following combined compensation and performance peer group for 2018:

2018 Peer Group

1) Alliance Resource Partners, L.P.
2) Antero Resources Corporation
3) Arch Coal, Inc.
4) Cabot Oil & Gas Corporation
5) CONSOL Energy Inc.
6) Eclipse Resources Corporation
7) EQT Corporation
8) EXCO Resources, Inc.
9) Foresight Energy LP
10) Hallador Energy Company
11) Natural Resource Partners L.P.
12) Peabody Energy Corporation
13) Range Resources Corporation
14) Rhino Resource Partners LP
15) Rice Energy Inc.
16) Ultra Petroleum Corp.
17) Westmoreland Coal Company

Key Elements of Our 2018 Executive Compensation Program

2018 Base Salary

Base salaries are generally reviewed annually based upon a detailed review of the compensation for comparable positions of our peer group and other market data provided from time to time by the Compensation Committee s independent compensation consultant. In addition, the Compensation Committee assesses individual skills, performance, experience, responsibilities and time in position. For 2018, the Compensation Committee determined not to modify base salaries for our named executive officers for the

2018 year (other than in connection with Mr. Jones promotion). Below are the 2018 annual base salaries for our named executive officers:

Base Salary

Name	2018 Annual Base Salary	2017 Annual Base Salary
Colin Marshall	$ 765,000	$ 765,000
Heath Hill	$ 375,000	$ 375,000
Bruce Jones*	$ 400,000	$ 285,000
Bryan Pechersky	$ 360,000	$ 360,000
Todd Myers	$ 310,000	$ 310,000
Gary Rivenes	$ 470,000	$ 470,000

* Mr. Jones was promoted to the position of Executive Vice President and Chief Operating Officer effective July 11, 2018, at which time his salary was set at $400,000. Prior to that date he received a salary of $285,000 in his role as Senior Vice President, Technical Services.

2018 Annual Incentive Compensation and Process for Setting Performance Objectives

The 2018 annual cash bonuses were awarded under our Annual Incentive Plan (AIP), approved at the 2013 annual meeting of stockholders. Under the AIP, each executive has the potential to earn an annual cash incentive based upon a percentage of the executive s base salary (which was not increased from the 2017 to 2018 year). If performance targets are exceeded, maximum payouts of up to two times target are possible and if performance falls below threshold levels, no payouts are made. The 2018 AIP awards were paid based on actual performance against pre-established company targets that are approved in advance by the Compensation Committee and also included a personal performance component.

In setting the performance objectives for 2018, the Compensation Committee considered a variety of factors, including (i) the continued importance of safety in the company s culture and the desire to continuously improve the company s safety record, (ii) setting financial performance targets at a level that is rigorous and reflects the ongoing challenging external environment for the coal industry and weak demand and pricing, (iii) appropriately incentivizing and compensating executive officers, (iv) the importance of holding each executive accountable for his or her individual contribution to our success and aligning our executive pay to performance, (v) our general compensation philosophy, (vi) recent and projected company performance, and (vii) our operating goals and other strategic and financial objectives and market-competitive compensation practices. The measurement objectives for the 2018 AIP were established at the beginning of 2018 by the Compensation Committee. The Compensation Committee determined that the mix of performance measures that were used for previous AIP programs remained the best performance targets for the company to use in aligning the goals of the company with those of our named executive officers. There are three components that determined 2018 awards under the AIP, as well as the rigor of our target-setting:

AIP Metric	Weighting	Rigor of Target-Setting
Adjusted EBITDA	60%	**Performance targets have resulted in below-target payouts on the Adjusted EBITDA goal in three of the last five years.** In establishing Adjusted EBITDA targets for 2018, as in prior years, the Compensation Committee reviewed an array of sensitivity analyses to the key business drivers of Adjusted EBITDA. These sensitivity analyses sought to identify opportunities and risks for each of the key business drivers to establish rigorous threshold, target, and maximum Adjusted EBITDA levels. The Adjusted EBITDA goal for 2018 was higher than the actual achieved 2017 Adjusted EBITDA, but still reflected the expected continued challenging environment for coal demand and pricing for 2018 and corresponded to our budgeted Adjusted EBITDA in our 2018 annual operating plan. Key business drivers included sales volumes, coal prices and operating costs, including diesel fuel, labor and explosives costs, logistics revenues and transportation costs. Beginning in 2018, we introduced a cap on the Adjusted EBITDA component if there is declining

		year-over-year Adjusted EBITDA performance. The cap would limit the payout for this portion of the bonus at target unless and until the prior year s actual Adjusted EBITDA is exceeded.
Safety	20%	Our safety performance target and maximum payout levels require a substantial improvement over our three-year rolling safety achievement

		average to earn a payout on this component. Our threshold payout level is set at the rolling three-year average AIFR. Target and maximum levels were established by reducing the threshold number by 20% and 40%, respectively. Accordingly, despite our consistently strong safety performance, our executives may nevertheless receive below target bonus payouts or none at all for safety.
Personal Performance	20%	The personal performance component is evaluated against the responsibilities of each executive s position, achievement of annual departmental goals, feedback from peers and other co-workers, assessments of our independent directors, annual performance ratings and the executive s contributions, individually and as part of the executive team, to achieving company accomplishments during the year, and the executive s leadership for promoting and demonstrating our values in all activities and establishing a strong, ethical tone at the top of the company. In 2018, the executive team was responsible for, among other things, managing through ongoing challenging coal industry conditions and continuing to adjust our business and cost structure to depressed industry conditions, weak pricing and decreased predictability in future shipment rates.

The following table provides the 2018 target multiple, as well as potential payments which could have been made upon the achievement of a threshold, target or maximum level of performance for each of our named executive officers:

2018 Target AIP Opportunities

Name	2018 Target Award (% of Base Salary)	2018 Threshold: 50% of Target Award ($)	2018 Target: 100% of Target Award ($)	2018 Maximum: 200% of Target Award ($)
Colin Marshall	100	382,500	765,000	1,530,000
Heath Hill	75	140,625	281,250	562,500
Bruce Jones (1)	60/75	116,248	232,496	464,993
Bryan Pechersky	75	135,000	270,000	540,000
Todd Myers	60	93,000	186,000	372,000
Gary Rivenes (2)	75	176,257	352,514	705,027

1) Mr. Jones 2018 AIP will be pro-rated between the amounts applicable to him in his previous role from January 1, 2018 until his promotion date, and the amounts set following his promotion. The table above shows the numbers and target amounts for the combined roles.

2) Mr. Rivenes received a pro-rata portion of his AIP bonus for the 2018 in connection with his departure, paid at the same time as other executive officers February 15, 2019.

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The threshold, target and maximum for the Adjusted EBITDA and safety components, including actual results achieved for each component for 2018, are shown in the following table:

2018 Adjusted EBITDA and Safety Performance Targets

Metric	Threshold	Target	Maximum	Actual 2018 Result
Adjusted EBITDA (in millions)(1)	$ 65	$ 83	$ 110	$ 64
Safety (AIFR)(2)	0.38	0.30	0.23	0.27

(1) Refer to Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Non-GAAP Financial Measures in this Form 10-K for additional information regarding and a reconciliation of Adjusted EBITDA. As described above, despite actual results the Adjusted EBITDA component may be limited if there is declining year-over-year Adjusted EBITDA performance. The cap would limit the payout for this portion of the bonus at target unless and until the prior year s actual Adjusted EBITDA is exceeded.

(2) See below for a discussion of the differences between our AIFR calculation for the AIP compared to the MSHA methodology.

In general, we calculate our AIFR using the same methodology used to report monthly to MSHA, which is calculated by multiplying the number of reportable injuries times 200,000, divided by the total number of hours of employee exposure. The number we report to MSHA is required to include only the employees at our three mines and does not include contractors, visitors or employees at our non-mine sites. However, the safety number we use for our AIP is based on all our employees and includes contractors and all other visitors to all our sites to better reflect our core values and commitment to the safety of everyone involved in our business. As such, our number for purposes of our AIP target has often differed in past years from the MSHA number we reported publicly.

Personal performance for 2018 was evaluated and determined by the Compensation Committee and other independent directors using the considerations noted within the chart above. These factors were not individually weighted and were not exclusive. Rather, the Compensation Committee and independent directors made their ultimate determination for each executive in 2018 based on the totality of these and other factors, as determined in their judgment. As a result of the many factors evaluated for this component of our AIP and the fact that none of these factors are weighted, the amounts for each executive varied in 2018. As a result of this evaluation process, our named executive officers (other than Mr. Rivenes) received amounts ranging from 150% to 180% of their targeted amounts for their personal performance components.

The following table provides a quantitative supplemental breakdown of the three components that make up the named executive officers actual 2018 award under our AIP. Both the dollar amount of the award and the award as a percentage of each named executive officer s base salary are displayed for each component. Mr. Rivenes 2018 AIP was pro-rated for the portion of the year in which he provided services.

2018 AIP Performance Goal Achievement

	ADJUSTED EBITDA Weighting: 60% Result as % of Target: 0%	SAFETY Weighting: 20% Result as % of Target: 143%	PERSONAL PERFORMANCE Weighting: 20%			Total 2018 Award	
	Dollar Amount of Award($)	Dollar Amount of Award ($)	Result as % of Target	Dollar Amount of Award ($)	Total Performance Score (%)	($)	As a % of Base Salary
Colin Marshall	0	220,284	150	231,068	59	451,352	59
Heath Hill	0	80,987	150	84,952	59	165,939	44
Bruce Jones	0	67,070	150	70,353	59	137,423	40
Bryan Pechersky	0	77,699	180	97,804	65	175,503	49
Todd Myers	0	53,560	150	56,181	59	109,741	35
Gary Rivenes	0	29,646	0	0	29	29,646	17

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Long-Term Equity-Based Awards

The Cloud Peak Energy Inc. 2009 Long Term Incentive Plan (as amended, the LTIP) provides for the grant of a variety of equity-based awards. In 2018 we intended for a significant portion of our total compensation provided to our executive officers to consist of equity-based compensation. Since 2015 the Compensation Committee has provided a combination of restricted stock units (40%) and performance share units (60%) to our named executive officers.

The following table provides the LTIP target multiples for 2018 for each of the named executive officers:

Name	2018 Target as % of Base Salary	% of Target: Restricted Stock Units	% of Target: Performance Share Units (at Threshold)	% of Target: Performance Share Units (at Target)	% of Target: Performance Share Units (at Maximum)
Colin Marshall	200	40	30	60	120
Heath Hill	150	40	30	60	120
Bruce Jones	100	40	30	60	120
Bryan Pechersky	150	40	30	60	120
Todd Myers	100	40	30	60	120
Gary Rivenes	150	40	30	60	120

Equity Award Material Terms In 2018 we granted equity awards to our executives and certain other employees annually following our year-end earnings announcement. All outstanding equity awards vest on an accelerated basis in connection with certain types of terminations of employment following a change in control. For information regarding the terms of this accelerated vesting, please see Potential Payments Upon Termination or Change in Control; Double-Trigger Change in Control Requirements.

In determining awards for 2018, the Compensation Committee considered the number of shares then remaining under the LTIP, the anticipated needs for future settlement of 2018 awards, the potential dilution that would result from granting historical long-term incentive values at then-prevailing stock prices and alternatives to maintain current long term incentive award levels, investor feedback from outreach efforts, realized or estimated realizable pay amounts compared to target historical awards and the rigor of performance targets in the long-term executive compensation program. While maintaining the same long-term incentive target award values for 2018 and the same percentage split between restricted stock units and performance share units, the Compensation Committee also decided to grant the 2018 restricted stock units and performance share units with the flexibility to settle those awards upon vesting in shares of common stock, cash or a combination of common stock and cash.

Restricted Stock Units RSUs vest on the basis of time as determined by the Compensation Committee, which is three years in the case of all awards granted to date. As discussed above, for 2018, the Compensation Committee retains the discretion to pay any vested awards in shares of our common stock, cash or a combination of shares and

cash. A recipient will not receive dividend equivalents, if any, on RSUs until the RSUs have fully vested and, upon the vesting date, the recipient will be paid any dividend equivalents that may have accrued on the RSUs. To date, our company has never paid dividends on our common stock.

Performance Share Units The performance share units granted in 2018 are substantially similar to the 2017 performance share units. Our performance share units require a minimum relative stock performance compared to our Peer Group (at least rank 14 of 18 companies for our 2018 awards) below which no shares are earned. The awards also have a maximum opportunity above which no additional shares are earned (rank 2 and above for our 2018 awards). Payouts also depend on whether the company has a positive TSR for the performance period with the vesting level capped at 75% of target if there is a negative absolute TSR over the three-year performance period for the 2018 award. The cap on the 2018 awards is a reduction from the full target payment cap used with the 2017 performance shares. Performance share units are intended to provide market-competitive compensation to our executive officers and to align their incentives with our longer-term stock performance. The performance conditions are established by the Compensation Committee at the outset of the performance period, which is currently three years. The following table shows the performance levels and payout opportunities for the 2018-2020 performance cycle (without consideration of the cap explained above in the event of a negative TSR):

TSR Company Ranking	**Payout Percentage of Target Award**
Company 1	200%
Company 2	200%
Company 3	186%
Company 4	171%
Company 5	157%
Company 6	143%
Company 7	129%
Company 8	114%
Company 9	100%
Company 10	90%
Company 11	80%
Company 12	70%
Company 13	60%
Company 14	50%
Company 15	0%
Company 16	0%
Company 17	0%
Company 18	0%

The recipient will earn dividend equivalents, if any, on the performance share units, which will be reinvested into additional performance share units and will be subject to the same vesting conditions as the underlying performance share units. To date, our company has never paid dividends on our common stock. As discussed above in recent years, the Compensation Committee retains the discretion to pay any vested awards in shares of our common stock, cash or a combination of shares and cash.

The performance condition that the Compensation Committee determined to use in order to more closely align this element of the named executive officers compensation with our stockholders interests is relative total stockholder return (RTSR), which is calculated by comparing our TSR to the TSR of our applicable peer group over the performance period. TSR is calculated as follows:

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TSR(1) = $\frac{\text{End of Period Share Price - Beginning of Period Share Price + Dividends(2)}}{\text{Beginning of Period Share Price}}$

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(1) Share prices are calculated based on a multi-day average, as provided by the relevant award agreement.

(2) Assumes the reinvestment of dividends paid in the applicable shares during the performance period, as provided by the relevant award agreement.

Peer Group In 2018 we created the 2018 Peer Group for purposes of the TSR performance metrics used in our performance share units. The 2018 Peer Group companies are listed above.

Results of Completed PSU Performance Cycles The following table shows the actual vesting, if any, for our completed PSU award cycles. In addition to the below-target vesting for most of our historical cycles, the value of any vested shares reflects the substantial reduction in our stock price since the grant date targeted values. Accordingly, the Compensation Committee believes there is a strong pay for performance alignment in our long-term incentive plan.

Completed PSU Award Cycles (Calendar Years)	Cloud Peak Energy Relative TSR	Cloud Peak Energy Absolute TSR	Vesting (% of Target)	Payout Date (if applicable)
2016-2018	19th percentile	-60%	0%	N/A
2015-2017	61st percentile	-21%	100%	March 2018
2014-2016	51st percentile	-66%	51%	March 2017
2013-2015	43rd percentile	-88%	43%	March 2016
2012-2014	48th percentile	-50%	48%	March 2015
2011-2013	60th percentile	-23%	0%	N/A

Stock Ownership Guidelines and Holding Requirements In January 2011, the Compensation Committee established stock ownership guidelines for our executive officers and certain other employees. The guidelines, still in effect during 2018, were expressed in terms of the value of their equity holdings as a multiple of each named executive officer s base salary during the 2018 year, as follows:

Name	Stock Ownership Guideline	Dollar Value of Holding Requirement (based on year-end 2018 base salary)
Colin Marshall	5X Base Salary	$ 3,825,000

Heath Hill	3X Base Salary	$	1,125,000
Bruce Jones	3X Base Salary	$	1,200,000
Bryan Pechersky	3X Base Salary	$	1,080,000
Todd Myers	2X Base Salary	$	620,000
Gary Rivenes	3X Base Salary	$	1,410,000

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Equity interests that counted toward the satisfaction of the ownership guidelines included stock owned outright by the employee or jointly owned, unvested restricted stock or stock units, and, to the extent provided, stock owned in a company-sponsored retirement plan. Although the employees were not subject to a minimum number of years in which to achieve their ownership goals, they were generally prohibited from selling or transferring any stock granted by the company other than to pay the exercise price of stock options or to pay taxes owed as a result of vesting or settlement of an award prior to the time that they met the ownership guidelines. Per our Stock Ownership Guidelines, ownership was calculated based on an individual s annual base salary and the average share price of the seven trading days immediately prior to the date of the planned sale transaction. After meeting the ownership guidelines, they were also generally prohibited from selling or transferring stock granted by the company that would cause them to drop below their ownership guideline level unless the transaction was also related to the payment of exercise prices or taxes on equity awards.

Clawback Policy

Section 954 of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (the Dodd-Frank Act) requires the SEC to direct national securities exchanges to prohibit the listing of any security of an issuer that fails to develop and implement a clawback policy. Although these rules have not been finalized, in April 2013, the Board approved and adopted the Cloud Peak Energy Inc. Clawback Policy (the Clawback Policy). Under the Clawback Policy, if the Board determines, after conducting a reasonable investigation, any wrongful conduct such as fraud, gross negligence, or intentional misconduct was committed by, or attributable to, any current or former senior executive officer or employee who received an award or payout under the LTIP or the AIP was a significant contributing factor to the company having to restate all or a portion of its publicly reported financial statements due to material non-compliance with any financial reporting requirement under the U.S. federal securities laws (which shall exclude any restatement caused by a change in applicable accounting rules or interpretations), then the Board shall have the right to take, or cause to be taken, in its sole discretion, such action as it deems necessary to remedy the wrongful conduct and seek to prevent its recurrence. Remedies may result in the reduction, cancellation, forfeiture or recoupment of such grants if certain specified events occur, including, but not limited to, an accounting restatement due to the company s material non-compliance with financial reporting regulations.

On July 1, 2015, the SEC issued proposed clawback rules under the Dodd-Frank Act. The proposed rules require the adoption and disclosure of a clawback policy that provides that in the event a company is required to prepare an accounting restatement due to material noncompliance with any financial reporting requirement under securities laws, that company will recover from any of its current or former executive officers who received incentive-based compensation during the preceding three-year period based on the erroneous data any such compensation in excess of what would have been paid under the accounting restatement. We will continue to monitor developments as these rules are finalized and implemented and we will evaluate any necessary changes to our current Clawback Policy.

Insider Trading Policy; Prohibitions Against Hedging and Pledging

In addition to addressing other customary topics, our Insider Trading Policy prohibits company employees, directors and officers from engaging in certain transactions, including transactions in company or subsidiary debt securities, short sales of company securities, publicly-traded options, any hedging transactions and margin accounts and pledged securities. This policy does not allow for any exception (e.g., waivers that provide for pre-clearance or pre-approval) to the above provisions.

Other Benefits

Retirement and Health and Welfare We offered the same types of retirement, health and welfare benefits to all of our employees in 2018, including to our executive officers, as part of our total executive compensation package. It was our objective to provide core benefits, including medical, retirement, life insurance, and paid time off to all our employees and executive officers.

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We maintain a 401(k) retirement plan that each of our named executive officers participated in during the 2018 year. With respect to the 2018 year participants, including the named executive officers, were eligible to receive an 8% match of deferrals. For the 2019 year, that match has been lowered to 4%. In 2018 we offered an optional health reimbursement arrangement for retirees, but this benefit will no longer be offered following the 2018 year.

We also maintained a non-qualified deferred compensation program (NQDC Plan) in 2018 for the executive officers and select other high-level employees. The NQDC Plan was put in place to continue our efforts to remain competitive with our benefit programs and is designed to allow the deferral of pre-tax compensation in excess of the limits imposed by the Internal Revenue Service under our 401(k). Participants are eligible to defer up to 80% of their base salary and 100% of their AIP bonus award earned during the year. Additional information regarding the material terms of the NQDC Plan is set forth under Executive Compensation Tables Nonqualified Deferred Compensation.

Employment Agreements Since our IPO in 2009, we have maintained employment agreements with all our named executive officers and other executive officers who report directly to our CEO. These employment agreements provide assurances as to position, responsibility, location of employment and certain compensation terms, which, if breached, would constitute good reason to terminate employment with us. Each agreement has a one-year term that will extend automatically for one year unless advance written notice by either party is provided. In addition, the agreements provide for:

- Specified minimum base salaries;
- Participation in all of our employee benefit plans on the same basis as our other senior management;
- Termination benefits, including, in specified circumstances, severance payments; and
- Annual bonuses pursuant to our AIP and grants pursuant to our LTIP.

We have not entered into separate severance agreements with our executive officers and instead rely on the terms of the executive s employment agreement and LTIP award agreements to dictate the terms of any severance and change in control arrangements. Our employment agreements do not provide for accelerated or enhanced cash payments or health and welfare benefits upon a change in control, but do provide for such payments upon the termination of the executive s position by the executive for good reason or by our company without cause, which are defined in the employment agreements. Each of the executive officer s LTIP award agreements set forth acceleration terms in the event of a termination within two years of a change in control or termination of the executive s position by the executive for good reason or by us without cause. Additional information is set forth below under Potential Payments upon Termination or Change in Control; Double-Trigger Change in Control Requirements.

Retention Agreements In November 2018 we entered into the Replaced Retention Agreements with each of the named executive officers (other than Mr. Rivenes). The Compensation Committee approved the retention program in recognition of the demonstrated work and commitment of the executive management team and the significant benefits to us of retaining the current named executive officers to continue assisting us in managing through ongoing challenges facing the U.S. coal industry. The retention agreements were also implemented in light of the additional uncertainty associated with our review of potential strategic alternatives. Following the 2018 year we entered into the 2019 Retention Agreements with the named executive officers (other than Mr. Rivenes). Benefits potentially payable pursuant to both the Replaced Retention Agreements and the 2019 Retention Agreements are described below under the heading Potential Payments Upon Termination or Change in Control.

Perquisites It is our policy to not grant perquisites to our named executive officers as a matter of good practice, although the Compensation Committee reserves the right to grant perquisites in the future if it finds that doing so furthers its compensation goals and objectives.

Tax Deductibility of Certain Executive Compensation

In previous years pursuant to Section 162(m) of the Code (Section 162(m)), certain compensation paid to our CEO and our three most highly compensated executive officers (other than our CFO) in excess of $1 million was not tax deductible, except to the extent it constituted performance-based compensation. In December 2017, Section

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162(m) was modified by the Tax Cuts and Jobs Act to delete the exception for performance-based compensation over the $1,000,000 limit, thus decisions relating to the 2018 year were not impacted by Section 162(m) matters. Nevertheless, the Compensation Committee will continue to consider the pay-for-performance alignment of our executive compensation program in making its determinations.

Compensation Risk Assessment

In accordance with the requirements of Item 402(s) of Regulation S-K, to the extent that risks may arise from our compensation policies and practices for our employees that are reasonably likely to have a material adverse effect on us, we are required to discuss our policies and practices for compensating our employees (including our employees that are not named executive officers) as they relate to our risk management practices and risk-taking incentives. We have determined that our compensation policies and practices for our employees, including our named executive officers, are not reasonably likely to have a material adverse effect on us. Our Compensation Committee routinely assesses our compensation policies and practices and takes this consideration into account as part of its review.

Important Note Regarding Compensation Tables

The following compensation tables have been prepared pursuant to SEC rules. Although some amounts (e.g., salary and non-equity incentive plan compensation) represent actual dollars paid to an executive, other amounts are estimates based on certain assumptions about future circumstances (e.g., payments upon termination of an executive s employment) or they may represent dollar amounts recognized for financial statement reporting purposes in accordance with accounting rules, but do not represent actual dollars received by the executive (e.g., dollar values of stock awards and option awards). The footnotes and other explanations to the Summary Compensation table and the other tables herein contain important estimates, assumptions and other information regarding the amounts set forth in the tables and should be considered together with the quantitative information in the tables.

Executive Compensation Tables

The following table sets forth information regarding compensation for each of our named executive officers for fiscal years 2016 through 2018, to the extent that the executive was a named executive officer for such year.

2018 Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Stock Awards ($)(1)	Non-Equity Incentive Plan Compensation ($)(2)	All Other Compensation ($)(3)	Total ($)

Colin Marshall(4)	2018	765,003	1,738,639	451,352	131,544	3,086,537
President and Chief Executive	2017	765,003	2,674,835	856,804	130,312	4,426,954
Officer	2016	765,003	2,295,008	1,063,354	131,324	4,254,689
Heath Hill	2018	375,003	639,206	165,939	58,125	1,238,273
Executive Vice President and	2017	375,003	874,130	329,065	55,771	1,633,969
Chief Financial Officer	2016	375,003	750,005	390,941	53,500	1,569,449
Bruce Jones	2018	339,407	323,861	137,423	46,245	846,936
Executive Vice President and						
Chief Operating Officer						
Bryan Pechersky	2018	360,006	613,643	175,503	59,112	1,208,264
Executive Vice President,	2017	360,006	839,171	356,406	49,042	1,604,625
General Counsel and Corporate						
Secretary	2016	360,006	540,008	298,085	52,272	1,250,371
Todd Myers	2018	310,003	352,275	109,741	46,005	818,024
Senior Vice President,	2017	310,003	361,303	245,523	46,095	962,924
Marketing and Business						
Development	2016	310,003	310,001	256,683	44,723	921,410
Gary Rivenes(5)	2018	179,612	801,161	29,646	877,565	1,887,985
Former Executive Vice	2017	470,018	1,095,608	341,938	69,970	1,977,534
President and Chief Operating						
Officer	2016	470,018	940,033	497,044	73,114	1,980,209

(1) The amounts reported in the Stock Awards column for 2018 reflect the aggregate grant date fair value of the RSU and PSU awards granted under the LTIP during fiscal 2018, computed in accordance with FASB ASC Topic 718, excluding the effect of estimated forfeitures. The value of PSUs are based upon the estimated outcome of the market condition applicable to the awards as of the time of grant as required by FASB ASC Topic 718, which was calculated using $4.05 per share. If the grant date estimate was calculated using maximum levels, the PSUs granted in 2018 would have been included at the following grant date fair value amounts: $2,253,274 for Mr. Marshall; $828,411 for Mr. Hill; $795,282 for Mr. Pechersky; $456,548 for Mr. Myers; $419,726 for Mr. Jones and $1,038,307 for Mr. Rivenes. Further details of the methods and assumptions used for purposes of valuing these awards are included in Note 20 of the Notes to Consolidated Financial Statements included in this Form 10-K.

(2) For 2018, the amounts shown represent payments earned by each named executive officer under our AIP for performance during the year. Actual payments were made February 15, 2019.

(3) The amounts shown in the All Other Compensation column with respect to 2018 are more fully described in the 2018 All Other Compensation table included below.

(4) Mr. Marshall does not receive any additional compensation for his service on the Board. He also served in the role of Chief Operating Officer from January 18, 2018 until Mr. Jones appointment to that role on July 11, 2018.

(5) As disclosed in a Form 8-K filed on January 18, 2018, Mr. Rivenes final day as an employee of Cloud Peak Energy was April 17, 2018. In connection with this termination of employment he received the severance benefits detailed in the 2018 All Other Compensation table below.

2018 All Other Compensation

Name	Company Contrib. to 401(k) Plan ($)	Company Contrib. to NQDC Plan ($)	Other(a) ($)	Total ($)
Colin Marshall	22,000	107,745	1,799	131,544
Heath Hill	18,500	37,826	1,799	58,125
Bruce Jones	22,000	22,800	1,445	46,245
Bryan Pechersky	18,500	38,813	1,799	59,112
Todd Myers	22,000	22,442	1,563	46,005
Gary Rivenes	18,500	23,224	835,841	877,565

(a) Includes a $100 annual safety award for not having any individual workplace injuries for each named executive officer other than Mr. Rivenes. The remainder for each of the named executive officers amounts include the premium paid for life insurance policies. This column also includes severance benefits for Mr. Rivenes as follows: a lump sum cash payment of $822,532, and the value of continued medical benefits of $12,775.

2018 Grants of Plan Based Awards

The following table reflects AIP awards, PSUs and RSUs granted to each of our named executive officers in 2018. Mr. Rivenes forfeited certain portions of the incentive awards he received for the 2018 year in connection with his termination of employment.

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Name (a)	Type of Award(1)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards(2) Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Estimated Future Payouts Under Equity Incentive Plan Awards(3) Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Awards: Number of Shares of Stock or Units (#) (i)(4)	Grant Date Fair Value of Stock and Option Awards ($) (l)(5)
Colin Marshall	AIP		382,502	765,003	1,530,006					
	RSU	3/2/2018							185,455	612,002
	PSU	3/2/2018				139,091	278,182	556,364		1,126,637
Heath Hill	AIP		140,626	281,252	562,505					
	RSU	3/2/2018							68,182	225,001
	PSU	3/2/2018				51,136	102,273	204,546		414,206
Bruce Jones	AIP		116,248	232,496	464,993					
	RSU	3/2/2018							35,545	113,999
	PSU	3/2/2018				25,909	51,818	103,636		209,863
Bryan Pechersky	AIP		135,002	270,005	540,009					
	RSU	3/2/2018							65,455	216,002
	PSU	3/2/2018				49,091	98,183	196,366		397,641
Todd Myers	AIP		93,001	186,002	372,004					
	RSU	3/2/2018							37,576	124,001
	PSU	3/2/2018				28,182	56,364	112,728		228,274
Gary Rivenes	AIP		176,257	352,514	705,027					
	RSU	3/2/2018							85,457	282,008
	PSU	3/2/2018				64,093	128,186	256,372		519,153

(1) Type of Award: AIP = Cash payment under the Annual Incentive Plan; PSU = Performance share units granted under the LTIP; RSU = Restricted stock units granted under the LTIP.

(2) The amounts in columns (c), (d), and (e) represent the threshold, target and maximum payment levels with respect to the 2018 annual cash incentive awards under our AIP. Actual bonus payouts for 2018, which were made February 15, 2019, are reflected in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table.

(3) The amounts in columns (f), (g), and (h) represent the threshold, target and maximum number of shares of our common stock that may be earned with respect to grants of PSU in 2018 under our LTIP. Actual vested awards may be settled in cash, shares or a combination thereof in the discretion of the Compensation Committee.

(4) The amounts reported in column (i) are the number of time-based RSUs granted to each named executive officer in 2018 under our LTIP. Actual vested awards may be settled in cash, shares or a combination thereof in the discretion of the Compensation Committee.

(5) Amounts for RSUs and PSUs represent each award s grant date fair value computed in accordance with FASB ASC Topic 718. The value of PSUs is based upon the estimated outcome of the market condition applicable to the awards as required by FASB ASC Topic 718. See footnote (1) the Summary Compensation Table for additional information about the assumptions used in calculating these amounts.

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

Since our IPO in 2009, we have maintained employment agreements with each of our named executive officers. For a discussion regarding the material terms, please refer to Potential Payments Upon Termination or Change in Control; Double-Trigger Change in Control Requirements below.

With respect to our AIP and LTIP, the treatment of awards granted under each, in the event of certain terminations of employment and/or upon the occurrence of a change in control, is described below under Potential Payments Upon Termination or Change in Control; Double-Trigger Change in Control Requirements.

2018 Outstanding Equity Awards at Year End

The table below sets forth information regarding outstanding equity awards held at the end of 2018 by our named executive officers. Refer to Security Ownership of Management and Principal Stockholders for additional information regarding beneficial ownership of our named executive officers other than Mr. Rivenes.

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	Option Awards(1)				Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable(1)	Number of Securities Underlying Unexercised Options (#) Unexercisable(1)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)(2)(4)	Market Value of Shares or Units of Stock That Have Not Vested ($)(3)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)(4)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(3)(4)
Colin Marshall								
2009 NQ	367,924		15.00	11/20/2019				
2011 NQ	42,101		20.99	3/8/2021				
2012 NQ	58,011		17.00	3/15/2022				
2013 NQ	63,678		17.50	3/11/2023				
2014 NQ	62,377		19.35	3/14/2024				
2016 RSU					470,771	174,185		
2016 PSU					353,078	130,639		
2017 RSU					200,437	74,162		
2017 PSU							150,328	55,621
2018 RSU					185,455	68,618		
2018 PSU							139,091	51,464
Heath Hill								
2011 NQ	2,354		$ 20.99	3/8/2021				
2012 NQ	3,563		$ 17.00	3/15/2022				
2013 NQ	3,848		$ 17.50	3/11/2023				
2014 NQ	3,769		$ 19.35	3/14/2024				
2016 RSU					153,847	56,923		
2016 PSU					115,386	42,693		
2017 RSU					65,502	24,236		
2017 PSU							49,127	18,177
2018 RSU					68,182	25,227		
2018 PSU							51,137	18,921
Bruce Jones								
2009 NQ	19,811		15.00	11/20/2019				
2011 NQ	2,157		20.99	3/8/2021				
2012 NQ	3,071		17.00	3/15/2022				
2013 NQ	3,291		17.50	3/11/2023				
2014 NQ	7,727		19.35	3/14/2024				
2016 RSU					58,461	21,631		
2016 PSU					43,846	16,223		
2017 RSU					24,890	9,209		
2017 PSU							18,668	6,907
2018 RSU					34,545	12,782		
2018 PSU							25,909	9,586
Bryan Pechersky								
2010 NQ	53,418		16.20	3/3/2020				
2011 NQ	6,014		20.99	3/8/2021				
2012 NQ	8,977		17.00	3/15/2022				
2013 NQ	10,039		17.50	3/11/2023				
2014 NQ	9,834		19.35	3/14/2024				
2016 RSU					110,771	40,985		
2016 PSU					83,078	30,739		
2017 RSU					62,883	23,267		

2017 PSU							47,162	17,450
2018 RSU					65,455	24,218		
2018 PSU							49,092	18,164
Todd Myers								
2011 NQ	5,212		20.99	3/8/2021				
2012 NQ	7,734		17.00	3/15/2022				
2013 NQ	8,605		17.50	3/11/2023				
2014 NQ	8,429		19.35	3/14/2024				

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	Option Awards(1)				Stock Awards			
Name	**Number of Securities Underlying Unexercised Options (#) Exercisable(1)**	**Number of Securities Underlying Unexercised Options (#) Unexercisable(1)**	**Option Exercise Price ($)**	**Option Expiration Date**	**Number of Shares or Units of Stock That Have Not Vested (#)(2)(4)**	**Market Value of Shares or Units of Stock That Have Not Vested ($)(3)**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)(4)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(3)(4)**
2016 RSU					63,590	23,528		
2016 PSU					47,693	17,646		
2017 RSU					27,074	10,017		
2017 PSU							20,306	7,513
2018 RSU					37,576	13,903		
2018 PSU							28,182	10,427
Gary Rivenes								
2016 PSU					102,225	37,823		
2017 PSU							23,055	8,530
2018 PSU							2,690	995

(1) We have not granted option awards since 2014. Historical option awards vested with respect to 100% of the underlying shares on the third anniversary of the date of grant. The 2009 option awards (2009 NQ) vested in full on November 20, 2012, the 2011 option awards (2011 NQ) vested in full on March 8, 2014, the 2012 option awards (2012 NQ) vested in full on March 15, 2015, the 2013 option awards (2013 NQ) vested in full on March 11, 2016, and the 2014 option awards (2014 NQ) vested in full on March 14, 2017, in each case, subject to the continued employment of the named executive officer through the applicable vesting date. With the exception of Mr. Pechersky who joined our company in 2010, no awards were granted to our named executives in 2010. His 2010 option awards (2010 NQ) vested in full on March 3, 2013. The treatment of outstanding option awards in the event of certain terminations of employment and/or upon the occurrence of a change in control is described below under Potential Payments Upon Termination or Change in Control; Double-Trigger Change in Control Requirements.

(2) Restricted stock units vest with respect to 100% of the shares subject to the award on the third anniversary of the date of grant. The 2016 restricted stock units (2016 RSU) vested in full on March 4, 2019, the 2017 restricted stock units (2017 RSU) will vest in full on March 3, 2020, and the 2018 restricted stock units (2018 RSU) will vest in full on March 2, 2021, in each case, subject to the continued employment of the named executive officers through the applicable vesting date. The treatment of outstanding restricted stock units in the event of certain terminations of employment and/or upon the occurrence of a change in control is described below under Potential Payments Upon Termination or Change in Control; Double-Trigger Change in Control Requirements.

(3) Represents the market value of outstanding awards and units based on the closing price of $0.37 per share of our common stock on December 31, 2018.

(4) The 2016 award of performance share units (2016 PSU) has a three-year performance period that began on January 1, 2016 and ended on December 31, 2018; the 2017 award of performance share units (2017 PSU) has a three-year performance period that began on January 1, 2017 and ends on December 31, 2019 and the 2018 award of performance share units (2018 PSU) has a three-year performance period that began on January 1, 2018 and ends on December 31, 2020. Following the end of each performance period, the award will remain subject to continued services until the performance period may be certified. As of December 31, 2018, our TSR with respect to the 2016 PSU award resulted in 0% of the target number of awards becoming eligible to vest due to the satisfaction of the performance condition, but due to the fact that performance was

not certified as of December 31, 2018, the awards were still deemed outstanding on that date and required to be reported at the threshold value of potential payments. The threshold number of awards that could have vested on December 31, 2018 remained subject to time-based vesting conditions until March 4, 2019; therefore those awards have been moved to the Stock Awards - Number of Shares or Units of Stock That Have Not Vested column because the time-based vesting condition was not satisfied as of year-end 2018. None of our named executive officers will receive a settlement of the 2016 PSUs. As of December 31, 2018, with respect to the 2017 PSU awards, the awards were calculated to reflect the assumed 0% vesting of those awards, but as noted above, the disclosure rules require that we reflect the threshold value (50%) of performance awards still outstanding as of December 31, 2018. With respect to the 2018 PSUs, the awards were calculated to reflect the assumed 50% vesting of those awards based on our -60% absolute TSR for 2018 (which ranked us at 14 out of 17 against our peers). The treatment of outstanding performance share unit awards in the event of certain terminations of employment and/or upon the occurrence of a change in control is described below under Potential Payments Upon Termination or Change in Control; Double-Trigger Change in Control Requirements. On March 4, 2019, the 2016 RSUs vested and the 2016 PSU awards were forfeited; however, this table is representative of outstanding equity awards held as of December 31, 2018.

2018 Option Exercises and Stock Vested

The table below sets forth information regarding the outstanding awards under our LTIP held by named executive officers which vested during 2018. None of the named executive officers exercised any stock options during the 2018 year.

	Stock Awards	
Name	**Number of Shares Acquired on Vesting (#)(1)**	**Value Realized on Vesting ($)(2)**
Colin Marshall	288,317	951,446
Heath Hill	87,938	290,195
Bruce Jones	35,803	118,150
Bryan Pechersky	67,840	223,872
Todd Myers	38,945	128,519
Gary Rivenes (3)	288,718	923,763

(1) The number of shares acquired is reported on a gross basis. We withheld the necessary number of shares of common stock in order to satisfy withholding taxes from stock awards, thus the named executive officers actually received a lower number of shares of our common stock than the numbers reported in this table.

(2) The value realized on vesting is calculated based upon the applicable closing market price of the number of shares acquired (on a gross basis) on the applicable vesting date for each award. It does not represent cash amounts received.

(3) Mr. Rivenes received pro-rata vesting of certain equity awards in connection with this termination of employment.

No Pension Benefits

We do not sponsor or maintain any plans that provide for specified retirement payments or benefits, such as tax-qualified defined benefit plans or supplemental executive retirement plans.

Nonqualified Deferred Compensation

The named executive officers were eligible to participate in our tax-qualified 401(k) plan in 2018, which was available to all employees generally. In addition, the named executive officers were eligible to participate in our NQDC Plan in 2018. The NQDC Plan is designed to allow the deferral of pre-tax compensation in excess of the limits imposed by the Internal Revenue Service under our 401(k). Participants are eligible to defer up to 80% of their base salary and 100% of their AIP bonus award earned during the year. Similar to our 401(k) plan with respect to the 2018 year, participants were eligible to receive a dollar-for-dollar company match of up to 8% of their deferrals.

Participants are entitled to elect investment of their accounts under the NQDC Plan. Investment alternatives under the NQDC Plan are substantially similar to the types of investments available under our 401(k) plan; all of which are mutual funds available to the public. Participants are credited with the returns actually earned with respect to those underlying mutual funds. Consequently, no above market or preferential earnings are provided under the NQDC Plan and none of the earnings reported in the Nonqualified Deferred Compensation Table below are included in the Summary Compensation Table set forth above. Participants may change their investment options on a daily basis.

Executives may choose how and when to receive payments under the NQDC Plan. Payments under the NQDC Plan will be made on the earlier to occur of termination of service or an earlier scheduled date. The NQDC Plan provides for payments of benefits upon a participant s retirement or disability in cash, an annuity contract or other property unless the participant makes an alternative benefit election to receive substantially equal annual installments over up to 15 years of his or her elective deferrals. In the event a participant terminates service other than by reason of retirement, death, or disability, the participant s elective deferrals will be distributed in cash, an annuity contract, or other property; however, the participant must have five years of service or more to receive distributions as elected upon termination. If the executive has less than five years of service with us, distributions following his or her separation will be made in a lump-sum distribution only. A participant incurs a disability under the NQDC Plan when he or she is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or will last continuously for not less than 12 months or is receiving income replacement benefits for at least three months under one of our accident and health plans due to physical or mental impairment reasonably expected to result in death or last at least 12 months. Retirement means termination after having attained age 55 and completed at least 10 years of service or age 65 or older.

In the event that the participant dies prior to commencement of a distribution, distribution will be made to the participant s beneficiary in cash or other property but not in the form of an annuity contract. If the participant dies after commencement of a benefit, his or her beneficiary will continue to receive payments (if applicable) in accordance with the form previously elected by the participant.

A participant may also elect a distribution date prior to termination for his or her deferral contributions to the extent such contributions are not invested in a fund that includes distribution in the form of an annuity contract. However, the commencement date with respect to deferrals in a given year must be no earlier than two years from the last day of the year in which the deferrals were made. The distribution may be made in cash or substantially equal annual installments over a period up to five years.

The distribution for any participant who is a specified employee within the meaning of Section 409A of the Internal Revenue Code (Section 409A) will be delayed for six months to the extent required by Section 409A.

The NQDC Plan also permits hardship distributions. A distribution will be made to the extent a participant has experienced a financial hardship within the meaning of Section 409A(a)(2)(v) of the Internal Revenue Code.

The following table provides information for each of our named executive officers regarding contributions, earnings and year-end account balances under the NQDC Plan for 2018. Mr. Rivenes did not have an account in the NQDC Plan at the end of the 2018 year.

Name	**Executive Contributions in Last FY ($)(1)**	**Company Contributions in Last FY ($)(2)**	**Aggregate Earnings (or Losses) in Last FY($)(3)**	**Aggregate Withdrawals / Distributions in Last FY ($)(4)**	**Aggregate Balance at Last FYE ($)(5)**
Colin Marshall	129,745	107,745	(33,301)	250,947	582,575
Heath Hill	56,326	37,826	(12,926)	59,747	242,552
Bruce Jones	44,800	22,800	(21,887)		417,276
Bryan Pechersky	57,313	38,813	(15,134)	82,440	219,429
Todd Myers	44,442	22,442	(1,284)	113,685	169,803

(1) Amounts reported in this column were deferred at the election of the named executive officer and are also included in the amounts reported in the Salary or Non-Equity Incentive Plan Compensation columns of

the Summary Compensation Table for 2018.

(2) Amounts reported in this column are also included in the All Other Compensation column of the Summary Compensation Table for 2018.

(3) Amounts reported in this column represent aggregate earnings (or losses) on investments made in the NQDC Plan that accrued during 2018 on amounts of salary and/or cash incentive deferred at the election of the named executive officer and the contributions made by us for each named executive officer. Amounts reflect changes in the market value of the investment holdings.

(4) Amounts reported in this column reflect scheduled withdrawals that occurred during the 2018 year, as previously elected by the executive.

(5) The aggregate balance for each named executive officer reflects the cumulative value, as of December 31, 2018, of the contributions to the NQDC Plan made by that named executive officer and by us for the named executive officer s account, and any earnings (or losses) on those amounts, since the named executive officer began participating in the plan. Of the amounts reported in this column, the following amounts were reported as compensation in the Summary Compensation Table for the years noted below:

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	2017 ($)	2016 ($)	2015 ($)	2014 ($)	2013 ($)	2012 ($)	2011 ($)
Colin Marshall	129,745	189,084	241,470	224,115	199,205	231,072	95,688
Heath Hill	56,326	59,225	39,022				
Bruce Jones	44,800						
Bryan Pechersky	57,313	57,226	71,158	67,725	68,887	58,345	
Todd Myers	44,442	44,716					

Potential Payments Upon Termination or Change in Control; Double-Trigger Change in Control Requirements

During 2018 our named executive officers were entitled to payments, benefits, and accelerated vesting of certain equity awards upon a termination of employment under certain circumstances and, in certain limited cases, additional equity may vest if such termination is following a change in control. These potential payments and benefits were provided pursuant to the terms of their employment agreements with us and the LTIP award agreements, although the employment agreements make no distinction for a change in control event in the case of any cash or medical benefit awards. In addition, the named executive officers could have received benefits from their Replaced Retention Agreements that were put in place at the end of 2018. We believe the severance and change in control provisions that were in effect during 2018 created important retention tools for us as a component of our overall executive compensation program, they helped attract and retain skilled professionals in our industry, and they allowed management to focus its attention and energy on our business without any distractions regarding the effects of any potential change in control. We do not provide tax gross-ups upon a change in control.

The following paragraphs describe the termination entitlements under the terms of our employment agreements, LTIP award agreements and the Replaced Retention Agreements with each of Mr. Marshall and our other named executive officers as of December 31, 2018. The subsequent tables also describe future potential benefits in connection with a change in control, as provided in the LTIP award agreements. As noted above within the CD&A, we are continuing to evaluate our executive compensation program for 2019, and a bankruptcy court, if applicable, would also have the authority to modify, terminate or replace our compensation programs. As of the date of this filing, no changes have been made to the LTIP award agreements, the 2019 Retention Agreements or employment agreements described below, other than each of the NEO s waiver of good reason for not receiving an equity-based compensation award during the 2019 year.

Colin Marshall Employment Agreement

If Mr. Marshall resigns for good reason or is terminated by us without cause, he will be entitled to receive as severance, in addition to any amounts earned and unpaid through the date of termination:

- A lump sum payment equal to two (2) times the sum of (A) his base salary and (B) his target annual bonus under our AIP for the year of termination; and

- A pro rata annual bonus to be calculated based on our actual performance at the end of the performance year and reduced by an amount equal to the number of days actually worked, divided by 365.

Mr. Marshall is also entitled to the continuation of medical benefits on the same terms as active employees for 18 months (or until such time as Mr. Marshall becomes eligible for medical benefits from a subsequent employer that are at least equal to those provided by us) and such payments will be in lieu of our COBRA obligations. As a condition to receiving the severance and continuation of medical benefits, Mr. Marshall must (a) execute, deliver and not revoke a general release of claims and (b) abide by restrictive covenants as detailed below. The payments described above will generally be payable to Mr. Marshall within the 30-day period following his termination of employment (with the portion relating to the pro rata bonus to become payable no later than 120 days following the date that the performance period for the bonus ends), but if he is a specified employee for purposes of Section 409A at the time of his termination, we will delay those payments for a period of six months following his termination to the extent required by Section 409A.

If Mr. Marshall s employment terminates due to death or disability, other than amounts earned and unpaid through the date of termination, he or his estate will only be entitled to the pro rata bonus for the year of such termination plus the amounts due him or his estate from his elected benefits. Terminations of employment that are

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due to our termination of Mr. Marshall for cause, or his resignation without good reason will only result in the payment of amounts earned and unpaid through the date of such a termination.

His employment agreement requires Mr. Marshall to abide by a perpetual restrictive covenant relating to non-disclosure. The agreement also includes covenants relating to non-solicitation and non-competition during Mr. Marshall s employment term and until the one-year period following the termination of his employment. Mr. Marshall will also be required to sign a waiver and release of claims in our favor at the time of his termination of employment in order to receive the severance payments and benefits that could become payable to him if Mr. Marshall resigns for good reason or is terminated by us without cause.

Other Named Executive Officers Employment Agreements

If any of our other named executive officers resign for good reason or is terminated by us without cause, he or she will be entitled to receive as severance, in addition to any amounts earned and unpaid through the date of termination:

- A lump sum payment equal to one (1) times the sum of (A) base salary and (B) his or her target annual bonus under our AIP for the year of termination; and

- A pro rata annual bonus to be calculated based on our actual performance at the end of the performance year and reduced by an amount equal to the number of days actually worked, divided by 365.

In addition, such other named executive officer is also entitled to the continuation of medical benefits on the same terms as active employees for 12 months (or until such time as the executive becomes eligible for medical benefits from a subsequent employer that are at least equal to those provided by us) and such payments will be in lieu of our COBRA obligations. As a condition to receiving the severance and continuation of medical benefits, the named executive officer must (a) execute, deliver and not revoke a general release of claims and (b) abide by restrictive covenants as detailed below. The payments described above will generally be payable to the executive within the 30-day period following the executive s termination of employment (with the portion relating to the pro rata bonus to become payable no later than 120 days following the date that the performance period for the bonus ends), but if the executive is a specified employee for purposes of Section 409A at the time of his or her termination, we will delay those payments for a period of six months following his or her termination to the extent required by Section 409A.

If a named executive officer s employment terminates due to death or disability, other than amounts earned and unpaid through the date of termination, the executive or the executive s estate will only be entitled to the pro rata bonus for the year of such termination, plus the amounts due the executive or the executive s estate from his or her elected benefits. Terminations of employment that are due to our termination of the executive officer for cause, or the executive s resignation without good reason will only result in the payment of amounts earned and unpaid through the date of such a termination.

The employment agreements require each named executive officer to abide by a perpetual restrictive covenant relating to non-disclosure. The agreements also include covenants relating to non-solicitation and non-competition during the employment term until the one-year period following the termination of employment. The executive officers will also be required to sign a waiver and release of claims in our favor at the time of his or her termination of employment in order to receive the severance payments and benefits that could become payable to him or her if the executive resigns for good cause or is terminated by us without cause.

Retention Agreements

Each of the named executive officers (other than Mr. Rivenes) entered into a Replaced Retention Agreement with us in November 2018. Each executive s original Replaced Retention Agreement was effective on November 9, 2018 and extended through July 1, 2020. The agreements provided for the payment of up to 100% of each executive s current base salary in five separate payments, in accordance with the terms and conditions of the agreement: four quarterly payments of 15% of each executive s respective base salary from July 1, 2019 through April 1, 2020 and one quarterly payment of 40% of each executive s base salary on July 1, 2020.

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Certain termination events could have also resulted in accelerated payments pursuant to the Replaced Retention Agreements in effect as of December 31, 2018. In the event that a named executive officer s employment with us or our affiliates was terminated by reason of death, disability, by us without cause, or by the executive for good reason prior to the last retention payment pursuant to the November 2018 agreements, the executive (or the executive s beneficiary) was entitled to receive the following:

- For a termination by us without cause or by the executive for good reason, all remaining unpaid retention payments pursuant to the Replaced Retention Agreement; and

- For a termination due to death or disability, a pro-rata portion of any unpaid retention payments, calculated by multiplying the applicable retention payment amounts by a fraction (the numerator of which was the number of days that had passed between the immediately preceding retention payment date and the date of executive s termination of employment, and the denominator of which was 90).

In January 2019, we entered into the new 2019 Retention Agreements with the named executive officers that replaced the November 2018 agreements. At the time of the replacement, no payments had been made to any named executive officer pursuant to the Replaced Retention Agreements. The 2019 Retention Agreements are not designed to provide for any payments or benefits to the named executive officers upon a termination of employment or a change in control. Each 2019 Retention Agreement provides for a lump sum cash payment of a one-time retention bonus to the applicable executive as soon as practicable following the executive s execution of the agreement, in the following amounts: 150% of current annualized base salary for Mr. Marshall ($1,147,500); 115% of current annualized base salary for each of Messrs. Jones, Hill and Pechersky ($460,000, $431,250 and $414,000, respectively); and 100% of current annualized base salary for Mr. Myers ($310,000). If an executive s employment is terminated by us for cause or the Executive resigns without good reason, in either case, prior to the Retention Date (defined below), the executive will be required to repay an amount equal to the retention bonus less any amounts withheld by us for income and employment taxes. The Retention Date is generally defined as the earlier to occur of (A) the first anniversary of the agreement, or (B) the consummation of a transaction, whether implemented out-of-court, in-court, or a combination thereof that either (1) effectuates a recapitalization or restructuring of a material portion of the company s outstanding indebtedness or (2) involves an acquisition, merger, or other business combination pursuant to which a majority of the business, equity, or assets of the company is sold, purchased, or combined with another entity or company that is not an affiliate of the company.

The impact of certain terminations or change in control transactions on the 2019 Retention Agreements would be a potential repayment by the executives of amounts already paid to them pursuant to the agreements. Each 2019 Retention Agreement includes a general release of claims in favor of the company and its affiliates as a condition to payment of the retention bonus and a requirement that the executive comply with certain restrictive covenants. By executing the 2019 Retention Agreement, each of our named executive officers also agreed that in the event we do not grant an award of equity-based incentive awards during the 2019 calendar year, the failure to grant equity-based incentive awards would not trigger a good reason termination pursuant to his employment agreement.

Certain Definitions

For the purposes of the employment agreements, retention agreements and LTIP awards that were outstanding as of December 31, 2018, cause generally means (1) any conviction of, or plea of guilty or nolo contendere to (x) any felony (except for vehicular-related felonies, other than manslaughter or homicide) or (y) any crime (whether or not a felony) involving dishonesty, fraud, or breach of fiduciary duty; (2) willful misconduct by the executive in connection with the performance of services to us; (3) ongoing failure or refusal after written notice to faithfully and diligently perform the usual and customary duties of his or her employment; (4) failure or refusal to comply with our reasonable written policies, standards and regulations; or (5) a material breach by the executive of any terms related to his or her employment in any applicable agreement.

Good reason generally means (1) a material breach by us of any of the covenants in the employment agreement, (2) any material reduction in the base salary and, in the case of Mr. Marshall, any material reduction in the target participation levels in our incentive plans, (3) the relocation of the executive s principal place of employment that would increase the executive s one-way commute by more than seventy-five miles or (4) a material diminution in the executive s authority, duties, or responsibilities.

LTIP Awards; Double-Trigger Change in Control Requirements

Restricted Stock Units:

- As provided in the award agreements, if the executive s employment is terminated by us for cause or by the executive without good reason, then the executive will forfeit all unvested restricted stock units.

- In the event the executive s employment is terminated by us for any reason other than for cause or if the executive terminates his or her employment for good reason or his or her employment is terminated due death or disability, then, generally, a pro-rata portion (calculated by multiplying the total unvested portion for each award by the percentage of the three year vesting period for that award that the executive was employed with the company) of the unvested restricted stock units will vest.

- In the event the executive s employment is terminated due to retirement at or after age 65 (or early retirement at or after age 55 with 10 years of service with the company), then, generally, a portion (calculated by multiplying 1/3 by the number of full years that have lapsed from the date of grant through the date of termination) of the unvested restricted stock units will vest.

- In the event a named executive officer s employment is terminated by the company without cause or by the executive for good reason within two years of a change in control, all unvested restricted stock units will vest.

- In any other circumstance, accelerated vesting upon a change in control would only take place at the discretion of the Compensation Committee.

Performance Share Units:

- As provided in the award agreements, if the executive s employment is terminated by us for cause or by the executive without good reason, then the executive will forfeit all unvested performance share unit awards.

- In the event the executive s employment is terminated by us for any reason other than for cause or if the executive terminates his or her employment for good reason or his or her employment is terminated due to retirement at or after age 65 (or early retirement at or after age 55 with 10 years of service with the company), death or disability, then, generally, a pro-rata portion (calculated by multiplying the total number of shares that would have paid out had the executive been employed with us through the end of the performance period by the percentage of the three-year vesting period for that award that the executive was employed with us) of the performance share unit awards will vest based on, and subject to, our actual TSR performance.

- For the performance share units granted in 2016, as provided in the relevant award agreements, in the event of a change in control of the company, the surviving or successor entity is expected to assume the performance share unit award agreements. If these agreements are not assumed, the Compensation Committee may, in its sole discretion, modify the award, including, but not limited to, providing for the end of the performance period to be the date of the change in control. If the agreements are assumed and the executive s employment is terminated by the surviving entity for any reason other than for cause or if the executive terminates his or her employment for good reason within two years of a change in control, the awards will vest in full and pay out based on actual TSR performance.

- For the performance share units granted in 2017 and 2018, as provided in the relevant award agreements, in the event of a change in control of the company, the surviving or successor entity is expected to assume the performance share unit award agreements. If these agreements are not assumed and the Compensation Committee exercises its discretion to accelerate the award, such acceleration shall assume that the performance period ended as of the date of the change in control, and the award will be earned at the higher of (a) a pro-rated portion of the target level of performance (calculated by multiplying the target number of shares by the percentage of the three year vesting period for that award prior to the change in control) or (b) actual performance through

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the change in control. If the agreements are assumed and the executive s employment is terminated by the surviving entity for any reason other than for cause or if the executive terminates his or her employment for good reason within two years of a change in control, the awards will vest in full and pay out based on actual TSR performance.

Potential Termination and Change in Control Benefits Table

The following table illustrates an estimated amount of compensation or other benefits potentially payable to each of our named executive officers that are triggered upon termination of such executive s employment under various scenarios. We have assumed that all salary payments or any expenses the executive may be due have been paid currently. Any amount ultimately received will vary based on a variety of factors, including the reason for such executive s termination of employment, the date of such executive s termination of employment, and the executive s age upon termination of employment. The amounts shown assume that such termination was effective as of December 31, 2018, and, therefore, are estimates of the amounts that would have been paid to such executives upon their termination. The separation payments and benefits that Mr. Rivenes received in connection with his departure from Cloud Peak Energy in April 2018 are further described below. Actual amounts to be paid can only be determined at the time of such executive s termination from the company.

		No Change in Control(5)			Change in Control(6)			
	Voluntary Termination ($)	**Early Retirement(9) ($)**	**For Cause Termination ($)**	**Termination Without Cause or for Good Reason ($)**	**For Cause Termination ($)**	**Termination Without Cause or for Good Reason ($)**	**Death ($)**	**Disability ($)**
Colin Marshall								
Cash Severance(1)	0	0	0	3,060,012	0	3,060,012	0	50% of pay
Pro Rata Bonus(2)	0	0	0	451,352	0	451,352	451,352	451,352
Unvested Equity(3)								
Options	0	0	0	0	0	0	0	0
Restricted Stock Units	0	0	0	226,171	0	313,796	226,171	226,171
PSUs	0	0	0	339,256	0	470,693	339,256	339,256
Medical Benefits(4)	0	0	0	38,886	0	38,886	0	0
Estimated Total (10)	**0**	**0**	**0**	4,115,677	**0**	4,334,739	1,016,779	1,016,799
Heath Hill								
Cash Severance(1)	0	0	0	656,255	0	656,255	0	50% of pay
Pro Rata Bonus(2)	0	0	0	165,939	0	165,939	165,939	165,939
Unvested Equity(3)								
Options	0	0	0	0	0	0	0	0
Restricted Stock Units	0	0	0	74,682	0	105,323	74,682	74,682
PSUs	0	0	0	112,024	0	157,984	112,024	112,024
Medical Benefits(4)	0	0	0	25,924	0	25,924	0	0
Estimated Total (10)	**0**	**0**	**0**	1,034,824	**0**	1,111,425	352,645	352,645

Bruce Jones								
Cash Severance(1)	0	0	0	700,000	0	700,000	0	50% of pay
Pro Rata Bonus(2)	0	0	0	137,423	0	137,423	137,423	137,423
Unvested Equity(3)								
Options	0	0	0	0	0	0	0	0
Restricted Stock Units	0	0	0	29,257	0	43,185	29,257	29,257
PSUs	0	0	0	43,886	0	64,779	43,886	43,866
Medical Benefits(4)	0	0	0	25,924	0	25,924	0	0
Estimated Total (10)	**0**	**0**	**0**	936,489	**0**	971,311	210,565	210,565

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Bryan Pechersky								
Cash Severance(1)	0	0	0	630,011	0	630,011	0	50% of pay
Pro Rata Bonus(2)	0	0	0	175,503	0	175,503	175,503	175,503
Unvested Equity(3)								
Options	0	0	0	0	0	0	0	0
Restricted Stock Units	0	0	0	58,948	0	87,586	58,948	58,948
PSUs	0	0	0	88,423	0	131,378	88,423	88,423
Medical Benefits(4)	0	0	0	15,050	0	15,050	0	0
Estimated Total (10)	**0**	**0**	**0**	967,934	**0**	1,039,527	322,874	322,874
Todd Myers								
Cash Severance(1)	0	0	0	496,005	0	496,005	0	50% of pay
Pro Rata Bonus(2)	0	0	0	109,741	0	109,741	109,741	109,741
Unvested Equity(3)								
Options	0	0	0	0	0	0	0	0
Restricted Stock Units	0	0	0	31,824	0	46,974	31,824	31,824
PSUs	0	0	0	47,736	0	70,461	47,736	47,736
Medical Benefits(4)	0	0	0	25,924	0	25,924	0	0
Estimated Total (10)	**0**	**0**	**0**	711,229	**0**	749,106	189,301	189,301

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(1) As to Mr. Marshall, upon a termination without cause or for good reason, calculated as two times the sum of base salary plus target bonus. As to each of the other named executive officers, upon a termination without cause or for good reason, calculated as one times the sum of base salary plus target bonus.

(2) Amounts shown are based on the actual bonus earned by the named executive officer for the 2018 calendar year, which was paid February 15, 2019.

(3) Values are calculated based on the closing price of our common stock of $0.37 on December 31, 2018. We have not included any value for the acceleration of stock option awards, as all outstanding stock option awards were vested as of December 31, 2018. In general, PSUs are shown as accelerating vesting based on target levels. Under the no change in control scenario, this table assumes a pro-rata vesting of the target outstanding PSU awards. Under the change in control scenarios, this table assumes full vesting of all target outstanding PSU awards.

(4) Mr. Marshall is entitled to 18 months of continuous medical coverage under our then-current plans. Each of the other named executive officers is entitled to 12 months of continuous medical coverage under our then-current plans. Amounts shown reflect the current cost to the company to continue coverage for the named executive officer.

(5) Pursuant to each named executive officer s previously described employment agreement and LTIP award agreements, the named executive officer is entitled to pro rata vesting upon termination without cause or resignation for good reason (as defined above).

(6) As provided by the LTIP award agreements, all unvested equity-based awards vest in connection with a change in control only if the named executive officer is terminated within two years of a change in control without cause or for good reason or otherwise at the discretion of the Compensation Committee, including if the surviving company does not assume unvested PSUs. There is no distinction in the named executive officers previously described employment agreements for any cash or medical benefit continuation awards upon a change in control.

(7) Each of the named executive officers was eligible to receive payments under life insurance and accidental death and dismemberment policies provided by us to our employees. These amounts are not enumerated in the table above because these benefits are available to all employees generally and there is no discrimination in scope, terms, or operation in favor of our executive officers.

(8) Each of the named executive officers was eligible to receive 50% of his annualized base salary in disability payments, in accordance with the terms of our long-term disability insurance program as of December 31, 2018. These amounts are not enumerated in the table above because these benefits are available to all employees generally and there is no discrimination in scope, terms, or operation in favor of our executive officers.

(9) We have not listed potential payments to our executives upon retirement because none of our named executive officers reached retirement age of 65 as of December 31, 2018. Although the Compensation Committee retains the discretion to provide for retirement prior to age 65, we have assumed for purposes of the table above that such discretion would not be exercised.

(10) Although the Replaced Retention Agreements have since been terminated and replaced, because they were effective as of December 31, 2018, the Estimated Total in the table above could have included amounts payable pursuant to those arrangements as of December 31, 2018. If the Replaced Retention Agreements had been payable, the Estimated Total for each executive would have increased. Under the heading of Termination without Cause or Good Reason, whether in connection with a Change in Control or not, the Estimated Total would have increased by the following amounts: Mr. Marshall, $1,530,000; Mr. Hill, $750,000; Mr. Jones, $800,000; Mr. Pechersky, $720,000 and Mr. Meyers, $620,000. Under the headings Death and Disability, the Estimated Total would have increased by the following amounts: Mr. Marshall, $663,000; Mr. Hill, $32,500; Mr. Jones, $34,667; Mr. Pechersky, $31,200 and Mr. Meyers, $26,867.

Gary Rivenes Departure

As disclosed in a Form 8-K filed on January 18, 2018, Mr. Rivenes last day as an employee of Cloud Peak Energy was April 17, 2018 (the Termination Date). In connection with his departure, Mr. Rivenes received the severance benefits provided for in his employment agreement and accelerated vesting of certain outstanding equity awards provided for in his LTIP award agreements. Specifically, in addition to any accrued but unpaid amounts, Mr. Rivenes received:

- *Cash Severance*: a lump sum cash payment of $822,532, which consisted of one times his base salary and his target annual bonus for 2018 under the AIP;

- *Pro-Rata 2018 Bonus*: a pro-rata portion of his annual bonus for 2018 under the AIP based on actual performance, in the amount of $29,646;

- *Medical Benefits*: the continuation of medical benefits for up to 12 months following the Termination Date on the same terms as an active employee;

- *Restricted Stock Units*: pro-rata vesting of unvested restricted stock units; and

- *Performance Share Units*: potential pro-rata vesting of unvested performance share units, subject to our actual TSR performance at the end of the original performance periods.

Pursuant to his employment agreement, Mr. Rivenes will remain subject to various restrictive covenants following the Termination Date.

Compensation Committee Interlocks and Insider Participation

During 2018, Messrs. Nance, Owens and Skaggs (Current Compensation Committee Chair) and Ms. Hull served on the Compensation Committee. None of the members of the Compensation Committee is or has been an officer or employee of our company. All members of the Compensation Committee participate in decisions related to compensation of our executive officers. No interlocking relationship exists between our Board and the board of directors or compensation committee of any other company.

DIRECTOR COMPENSATION

Director Compensation Program

The Compensation Committee is responsible for recommending to the Board the form and amount of compensation for non-employee directors. The Compensation Committee may appoint subcommittees and delegate to a subcommittee such power and authority as it deems appropriate, but Compensation Committee did not appoint any subcommittees during 2018.

Changes to the Directors   Compensation Program for 2019

The Compensation Committee met in early 2019 to discuss and recommend the 2019 director compensation program to the Board. As of the date of this Form 10-K, the Compensation Committee has determined that the cash fees will be the same for 2019 as described below for the 2018 year. However, similar to the executive compensation program, the grant of equity-based compensation awards will be suspended for our directors for the 2019 calendar year and directors will instead receive a cash award equal to the target value of restricted stock units that would otherwise have been granted to them in 2019. We are discussing additional modifications and alternatives for the 2019 director compensation program, and given the uncertainty of the 2019 year and, if applicable, a bankruptcy court s ability to modify, terminate or replace compensation programs during our restructuring, there may be other modifications to the director compensation program that we are not aware of at this time. The remainder of this director compensation section will provide information on our 2018 director compensation program as required by SEC rules. The design, philosophy or amounts discussed below for 2018 should be read in the context of our historical compensation program only and is not intended to provide information or expectations regarding 2019 compensation unless otherwise specifically noted.

2018 Director s Compensation Program

Our total non-employee director compensation was generally targeted at the median of our peer group total director compensation. The Compensation Committee, supported by analyses and recommendations from its independent compensation consultant, Aon Hewitt, considered the cash and equity compensation for our non-employee directors, including the amount and type of compensation, using comparative data from our peer group and secondary source data from industry and other companies. The Compensation Committee also took into account the responsibilities of each committee, the time commitments required for each committee to comply with increasing regulatory requirements and other committee responsibilities, the need to attract and retain quality director candidates, our financial performance, and general market conditions.

The Compensation Committee met in early 2018 to discuss and recommend the 2018 director compensation program to the Board. The Compensation Committee discussed the current compensation program structure and amounts, historical adjustments to the compensation program, expectations for 2018 performance and industry conditions, and market survey data from Aon Hewitt, and decided not to recommend any increases to the compensation for our non-employee directors. The Compensation Committee also determined that the aggregate grant date value of all equity compensation granted to a non-employee director may not, in any calendar year, exceed $500,000 (determined by multiplying the fair market value of a share on the date of grant by the aggregate number of shares subject to such award), and the LTIP was amended accordingly with stockholder approval at the 2017 annual meeting.

Participating directors are eligible to elect to defer their cash fees into the NQDC Plan, but they do not receive matching contributions from us with respect to any amounts deferred.

Element	**Description**	**2018 Amount**		**2017 Amount**	
Annual Cash Fee for Board Service	Payable to the non-executive Chairman of our Board	$	110,000	$	110,000
	Payable to the non-employee directors of our Board	$	75,000	$	75,000
Annual Cash Fee for Committee Chairs	All Committee Chairs	$	18,000	$	18,000

Annual Cash Fee for Committee Members	All Committee Members	$ 9,000	$ 9,000
Annual Grant of Restricted Stock Units	Grants of restricted stock units to the non-employee directors of our Board Shares of common stock are deliverable in the event of the director s separation from service from the company due to the director s death, disability, non-reelection to the Board, resignation from the Board with the prior consent of the Governance Committee or for any other reason, other than for cause.	Restricted stock units Valued at $90,000 ($115,000 for the Chairman)	Restricted stock units valued at $90,000 ($115,000 for the Chairman)

The following table shows the actual 2018 compensation received by our non-employee directors. Mr. Marshall is compensated by us only in his capacity as an employee, and does not receive any additional compensation for his services as a director. The total compensation provided to Mr. Marshall for services during 2018 is set forth in the 2018 Summary Compensation Table.

2018 Compensation for Non-Employee Directors

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)(2)	Total ($)
William T. Fox III	146,000	115,003	261,003
Jeane Hull	102,000	90,000	192,000
Steven Nance	111,000	90,000	201,000
William Owens	102,000	90,000	192,000
Robert Skaggs	102,000	90,000	192,000

(1) Fees were paid in cash and include applicable annual retainers and committee fees earned in 2018 for each director.

(2) Amounts reflect the aggregate grant date fair value for fiscal 2018 under FASB ASC Topic 718, for grants of restricted stock units in 2018. Assumptions used in the calculation of these amounts are included in Note 20 of the Notes to Consolidated Financial Statements included in our this Form 10-K. Restricted stock units are granted with no exercise price and are payable upon the resignation or retirement of the director, subject to pro rata payment prior to the one-year anniversary of the grant date, unless deferred. The number of outstanding equity awards that each of our directors held as of December 31, 2018 is detailed below.

Director Stock Ownership Guidelines; No Shares Delivered Until Separation of Service

A portion of the 2018 directors fees was made in equity awards in the form of restricted stock units. During 2018 all non-employee directors were expected to hold a minimum of the equivalent of three times the annual cash retainer for a non-Chairman Board member in the form of (i) our common stock and/or (ii) unvested shares of restricted stock or restricted stock units.

In addition, the terms of our director restricted stock unit award agreements provide that, except in the case of a change of control, the underlying vested shares of common stock will not be delivered to a director until that director s separation of service from the Board. Beginning in 2017, directors were given the ability to further defer delivery of their vested shares of common stock by making an annual election. No underlying shares of common

stock may be sold or transferred by a director until delivery of those shares as provided by the applicable award agreement.

Equity Awards Outstanding at Year End

The following table shows the number of equity compensation awards held by our non-employee directors that had not been settled as of December 31, 2018.

Name	Number of Outstanding Shares of Restricted Stock Units (#)
William T. Fox III	113,361
Jeane Hull	81,099
Steven Nance	104,068
William Owens	104,068
Robert Skaggs	105,783

CEO PAY RATIO DISCLOSURES

Introduction

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, we are providing the following information about the relationship of the annual total compensation of our employees and the annual total compensation of our CEO Colin Marshall. The amounts and ratios described below have been prepared pursuant to applicable rules. Although some amounts may represent actual dollars paid to our CEO or that would be paid to our hypothetical median employee, other amounts are estimates based on certain assumptions or they may represent dollar amounts recognized for financial statement reporting purposes in accordance with accounting rules, but do not represent actual dollars received (e.g., dollar values of our CEO s stock awards). The explanations herein contain important estimates, assumptions and other information regarding our CEO pay ratio disclosures.

2018 CEO Pay Ratio

For 2018, our last completed fiscal year:

- **Estimated Median Employee Total Annual Compensation**: The median of the total annual compensation of all employees of our company (other than the CEO) was $80,733.

- **CEO Summary Compensation Table Total Annual Compensation**: The total annual compensation of our CEO, as reported in the Summary Compensation Table included previously, was $3,086,537.

- **CEO Pay Ratio**: Based on this information, for 2018 the ratio of the total annual compensation of Mr. Marshall to the median of the total annual compensation of all employees was reasonably estimated to be 36 to 1.

Primary Factors Impacting Ratio

The primary factors affecting this ratio include the following significant differences between the compensation program of the median employee and our CEO:

- the median employee does not receive any equity compensation under our LTIP;

- the median employee qualifies for a quarterly safe performance bonus rather than an AIP award, and

- the median employee is in a skilled labor position within operations at a lower hourly band rate.

Methodology Used To Identify Median Employee

To identity the median of the total annual compensation of all our employees, we took the following steps:

- We determined that, as of December 31, 2018, our employee population consisted of approximately 1,272 individuals with all of these individuals located in the United States (as reported in Item 1, Business, in this Form 10-K). This population consisted of our full-time, part-time, and temporary employees.

- We selected December 31, 2018 as our identification date for determining our median employee because it enabled us to make such identification in a reasonably efficient and economic manner by utilizing 2018 W-2 information plus year-end cafeteria plan amounts.

- We used a consistently applied compensation measure to identify our median employee by comparing the amount of salary or wages, bonuses and vesting value of equity awards reflected in our payroll records as reported to the Internal Revenue Service on Form W-2 for 2018.

- We identified our median employee by consistently applying this compensation measure to all of our employees included in our analysis. Because all of our employees, including our CEO, are located in the United States, we did not make any cost of living adjustments in identifying the median employee.

Methodology Used to Calculate Pay Ratio

To determine the total annual compensation of our median employee and our CEO, we took the following steps:

- After we identified our median employee, we combined all of the elements of such employee s compensation for the 2018 year in accordance with the requirements of Item 402(c)(2)(x) of Regulation S-K, resulting in total annual compensation of $85,288.

- With respect to the total annual compensation of our CEO, we used the amount reported in the Total column of our 2018 Summary Compensation Table included previously and incorporated herein by reference.

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

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:

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Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights (a)	Weighted-average exercise price of outstanding options, warrants, and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	5,587,843	$ 16.63	3,583,249(1)
Equity compensation plans not approved by security holders			
Total	5,587,843	$ 16.63	3,583,249(1)

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(1) Includes 3,546,864 shares under the Long Term Incentive Plan and 36,385 shares under our Employee Stock Purchase Plan (ESPP). Following the offering period ended August 30, 2016, the maximum share pool under the ESPP was nearly exhausted and we determined not to commence a new offering period due to lack of shares. Therefore the shares reflected here for the ESPP are not subject to any outstanding offering and will not be issued pursuant to the ESPP. Shares available for issuance under the Long Term Incentive Plan may be issued pursuant to restricted stock, restricted stock units, options, stock appreciation rights, dividend equivalent rights, performance awards, and share awards.

SECURITY OWNERSHIP OF MANAGEMENT AND PRINCIPAL STOCKHOLDERS

The following table sets forth information with respect to the number of shares of common stock beneficially owned by each person known by Cloud Peak Energy to beneficially own more than 5% of the outstanding shares of our common stock. Except as otherwise noted, (A) the persons named in the table have sole voting and investment power with respect to all shares beneficially owned by them, and (B) ownership is as of the dates noted below. As of February 28, 2019, there were 75,808,684 shares of our common stock outstanding.

Name and Address of Beneficial Owner	Number of Shares of Common Stock	Percent of Class
Renaissance Technologies LLC(1) 800 Third Avenue New York, NY 10022	7,016,967	9.26%
The Goldman Sachs Group, Inc.(2) 200 West Street New York, NY 10282	6,324,814	8.3%
Dimensional Fund Advisors LP(3) 6300 Bee Cave Road Austin, TX 78746	6,117,059	8.07%
Kopernik Global Investors, LLC(4) Two Harbour Place 302 Knights Run Avenue, Suite 1225 Tampa, FL 33602	5,886,843	7.77%

BlackRock, Inc.(5) 55 East 52nd Street New York, NY 10055	4,787,385	6.3%

(1) This information is based on a Schedule 13G/A filed with the SEC on February 13, 2019, by Renaissance Technologies LLC, in which it reported sole voting power as to 5,767,967 shares, sole dispositive power as to 5,776,796 shares and shared dispositive power as to 1,240,171 shares.

(2) This information is based on a Schedule 13G filed with the SEC on February 7, 2019, by The Goldman Sachs Group, Inc. in which it reported shared voting power as to 6,324,814 shares and shared dispositive power as to 6,324,814 shares.

(3) This information is based on a Schedule 13G/A filed with the SEC on February 8, 2019, by Dimensional Fund Advisors LP (Dimensional), in which it reported sole voting power as to 5,878,806 shares and sole dispositive

power as to 6,117,059 shares. Dimensional furnishes investment advice to four investment companies registered under the Investment Company Act of 1940, and serves as investment manager or sub-adviser to certain other commingled funds, group trusts and separate accounts (such investment companies, trusts and accounts, collectively referred to as the Funds). In certain cases, subsidiaries of Dimensional may act as an adviser or sub-adviser to certain Funds. In its role as investment advisor, sub-adviser and/or manager, Dimensional or its subsidiaries may possess voting and/or investment power over the securities that are owned by the Funds, and may be deemed to be the beneficial owner of the shares held by the Funds. However, all securities are owned by the Funds. Dimensional disclaims beneficial ownership of such securities.

(4) This information is based on a Schedule 13G/A filed with the SEC on February 13, 2019, by Kopernik Global Investors, LLC, in which it reported sole voting power as to 4,359,770 shares and sole dispositive power as to 5,886,843 shares.

(5) This information is based on a Schedule 13G/A filed with the SEC on February 11, 2019, by BlackRock, Inc., in which it reported sole voting power as to 4,611,172 shares and sole dispositive power as to 4,787,385 shares.

The following table sets forth information with respect to the number of shares of our common stock beneficially owned by (1) our named executive officers, which, for purposes of this Form 10-K, refers to the five executive officers included in the Summary Compensation Table below in this Form 10-K, (2) each current Cloud Peak Energy director and each nominee for director, and (3) all current Cloud Peak Energy directors and executive officers as a group. Except as otherwise noted, (a) the persons named in the table have sole voting and investment power with respect to all shares beneficially owned by them, and (b) ownership is as of February 28, 2019.

Name and Address(1) of Beneficial Owner	**Number of Shares of Common Stock(2)**	**Percent Of Class**
Colin Marshall	1,449,541	1.88%
Heath Hill	223,511	*
Bryan Pechersky	268,711	*
Todd Myers	130,027	*
Bruce Jones	132,349	*
William T. Fox III	122,048	*
Jeane Hull(3)	81,899	*
Steven Nance	111,442	*
William Owens	111,942	*
Robert Skaggs	105,783	*
All Current Executive Officers and Directors as a Group (13 persons)	2,798,828	3.7%

* Less than 1%.

(1) Address for beneficial owners shown in the table is: c/o Cloud Peak Energy Inc., 748 T-7 Road, Gillette, Wyoming 82718.

(2) Includes the following: (a) common stock underlying restricted stock units (referred to herein as RSUs or restricted stock units), including RSUs that may vest within 60 days of February 28, 2019, (b) no common stock underlying performance share units (referred to herein as PSUs or performance share units) that may vest within 60 days of February 28, 2019, as performance was not met for payment, and (c) shares issuable upon the exercise of outstanding stock options that are exercisable within 60 days of February 28, 2019, as follows:

Name	Common Stock Underlying Restricted Stock Units (RSUs)	Common Stock Underlying Performance Share Units (PSUs)	Shares Issuable Upon Exercise of Options**
Colin Marshall	470,771	0	594,091
Bruce Jones	58,461	0	36,057
Heath Hill	153,847	0	13,534
Bryan Pechersky	110,771	0	88,282
Todd Myers	63,590	0	29,980

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Name	Common Stock Underlying Restricted Stock Units (RSUs)	Common Stock Underlying Performance Share Units (PSUs)	Shares Issuable Upon Exercise of Options**
William T. Fox III	0		
Jeane Hull(3)	0		
Steven Nance	0		
William Owens	0		
Robert Skaggs	0		
Other Current Executive Officers as a Group	36,377	0	8,428

** As of February 28, 2019, all exercisable stock options had an exercise price greater than the market price of the underlying stock.

(3) Includes 800 shares held in a joint account with Ms. Hull s spouse.

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

Certain Relationships and Related Party Transactions

Pursuant to our Related Party Transactions Policy, our Audit Committee reviews and approves or ratifies transactions in excess of $100,000 of value in which we participate and in which a director, nominee for director, executive officer of the company or any immediate family member thereof, or beneficial holder of more than 5% of any class of our voting securities has or will have a direct or indirect material interest. After appropriate review (which includes consideration of the financial terms of the transaction), the Audit Committee is to approve only those related party transactions that are consistent with our Related Party Transactions Policy and on terms, taken as a whole, which the Audit Committee believes are no less favorable to us than could be obtained in an arms-length transaction with an unrelated third party, unless the Audit Committee determines that the transactions are not inconsistent with the best interests of the company.

We have related party transactions with our equity method investments. Related party activity consists primarily of coal sales to Venture Fuels Partnership, for delivery of coal under arms-length commercial arrangements in the ordinary course of business.

The following table summarizes related party transactions for the last three years ended December 31 (in thousands):

	2018	2017	2016
Sales of coal to Venture Fuels Partnership*	$ 9,582	$ 9,528	$ 11,922

* Represents both the amount involved in the transaction and the interest of Venture Fuels Partnership.

Director Independence

For information relating to director independence, see Item 10. Directors, Executive Officers and Corporate Governance Independence of Directors.

Item 14. ***Principal Accounting Fees and Services.***

Independent Auditor Fees and Services

The following table sets forth the aggregate fees billed by PricewaterhouseCoopers LLP or fees payable for professional services rendered in or related to 2017 and 2018.

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		2018		2017
Audit Fees(1)	$	1,837,860	$	1,808,450
Audit Related Fees	$		$	
Tax Fees(2)	$	375,000	$	80,000
All Other Fees(3)	$	2,700	$	2,700
Total	$	2,215,560	$	1,891,150

(1) Audit fees include fees for services performed to comply with generally accepted auditing standards, including the audit and review of financial statements, statutory and regulatory filings or engagements, comfort letters, attestation services (except those not required by statute or regulation), procedures related to audit of income tax provisions and related reserves, consents and assistance with and review of documents filed with the SEC.

(2) Tax fees include tax compliance and consulting services.

(3) All other fees are limited to software licensing fees.

Pre-Approval for Audit and Non-Audit Services

Pursuant to its charter, the Audit Committee has the responsibility to review and pre-approve, or to adopt appropriate procedures to pre-approve, audit and non-audit services to be performed for Cloud Peak Energy by its independent auditors. For 2017 and 2018, the Audit Committee did not pre-approve any non-audit services or delegate any pre-approval authority to a subcommittee, except for certain software licensing fees and permitted tax services. All fees reported above were pre-approved by the Audit Committee as required.

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PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) *The following documents are filed as part of this Report:*

(1) Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of December 31, 2018 and 2017

Consolidated Statements of Operations and Comprehensive Income (Loss) for the Years Ended December 31, 2018, 2017, and 2016

Consolidated Statements of Equity for the Years Ended December 31, 2018, 2017, and 2016

Consolidated Statements of Cash Flows for the Years Ended December 31, 2018, 2017, and 2016

Notes to Consolidated Financial Statements

(2) Financial Statement Schedules

Schedule II Valuation and Qualifying Accounts

(3) Exhibit List

(b) *Exhibits*

See Exhibit Index at page 204 of this report.

Item 16. ***Form 10-K Summary.***

None.

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SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

	Balance at Beginning of Year	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (in thousands)	Other Additions (Deductions)	Balance at End of Year
Reserves and allowances deducted from asset accounts:					
Deferred Income Tax Valuation Allowance (1)					
Year Ended December 31, 2018	$ 52,010	$	$	$ 159,670	$ 211,680
Year Ended December 31, 2017	$ 99,638	$	$	$ (47,628)	$ 52,010
Year Ended December 31, 2016	$ 118,957	$	$	$ (19,319)	$ 99,638
Reserve for Materials and Supplies					
Year Ended December 31, 2018	$ 1,094	$	$	$ (5)	$ 1,089
Year Ended December 31, 2017	$ 956	$	$	$ 138	$ 1,094
Year Ended December 31, 2016	$ 988	$	$	$ (32)	$ 956

(1) See also Note 9 of Notes to Consolidated Financial Statements in Item 8.

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EXHIBIT INDEX

The exhibits below are numbered in accordance with the Exhibit Table of Item 601 of Regulation S-K. The headings below are for convenience only and do not modify in any way the requirements of the Securities and Exchange Commission with regard to exhibits.

Exhibit Number	Description of Documents
	Acquisition Agreements
2.1	Purchase and Sale Agreement, dated as of June 29, 2012, among Arrowhead I LLC, Chevron U.S.A. Inc., CONSOL Energy Inc., Consolidation Coal Company and Reserve Coal Properties Company (Incorporated herein by reference to Exhibit 2.1 to CPE Inc. s Current Report on Form 8-K filed on July 2, 2012 (File No. 001-34547))
2.2	Purchase and Sale Agreement, dated as of June 29, 2012, among Chevron U.S.A. Inc. and Arrowhead I LLC (Incorporated herein by reference to Exhibit 2.2 to CPE Inc. s Current Report on Form 8-K filed on July 2, 2012 (File No. 001-34547))
2.3	Purchase and Sale Agreement, dated as of June 29, 2012, among CONSOL Energy Inc., Consolidation Coal Company, Reserve Coal Properties Company and Arrowhead I LLC (Incorporated herein by reference to Exhibit 2.3 to CPE Inc. s Current Report on Form 8-K filed on July 2, 2012 (File No. 001-34547))
	Corporate Documents
3.1	Amended and Restated Certificate of Incorporation of Cloud Peak Energy Inc. effective as of November 25, 2009 (Incorporated herein by reference to Exhibit 3.1 to CPE Inc. s Annual Report on Form 10-K filed on February 14, 2014 (File No. 001-34547))
3.2	Amended and Restated Bylaws of Cloud Peak Energy Inc., effective July 11, 2017 (incorporated by reference to Exhibit 3.2 to Cloud Peak Energy Inc. s Current Report on Form 8-K filed on July 11, 2017 (File No. 001-34547))
3.3	Form of Stock Certificate of Cloud Peak Energy Inc. (Incorporated herein by reference to Exhibit 4.1 to Amendment No. 5 to CPE Inc. s Form S-1 filed on November 16, 2009 (File No. 333-161293))
	Indenture
4.1	Indenture, dated as of March 11, 2014, among Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Incorporated by reference to Exhibit 4.2 to CPE Inc. s Current Report on Form 8-K filed on March 11, 2014 (File No. 001-34547))
4.2	First Supplemental Indenture, dated as of March 11, 2014, to the Indenture, dated as of March 11, 2014, among Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Incorporated by reference to Exhibit 4.3 to CPE Inc. s Current Report on Form 8-K filed on March 11, 2014 (File No. 001-34547))
4.3	Second Supplemental Indenture, dated as of September 1, 2015, to the Indenture, dated as of March 11, 2014, among Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Incorporated by reference to Exhibit 4.2 to CPE Inc. s Quarterly Report on 10-Q filed on October 27, 2015 (File No. 001-34547))

Exhibit Number	Description of Documents
4.4	Agreement of Resignation, Appointment and Acceptance, dated as of May 24, 2016, among Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp., Wells Fargo Bank, National Association, as resigning trustee, and Wilmington Trust, National Association, as successor trustee (incorporated by reference to Exhibit 4.1 to Cloud Peak Energy Inc. s Quarterly Report on 10-Q filed on July 29, 2016 (File No. 001-34547))
4.5	Indenture, dated October 17, 2016, among Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp., the guarantors party thereto and Wilmington Trust, National Association, as Trustee and Collateral Agent (incorporated by reference to Exhibit 4.1 to Cloud Peak Energy Inc. s Current Report on Form 8-K filed on October 17, 2016 (File No. 001-34547))
	Coal Leases
10.1	Federal Coal Lease WYW-151643: Antelope Coal Mine (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.2	Federal Coal Lease WYW-141435: Antelope Coal Mine (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.3	Federal Coal Lease WYW-0321780: Antelope Coal Mine (Incorporated herein by reference to Exhibit 10.3 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.4	Federal Coal Lease WYW-0322255: Antelope Coal Mine (Incorporated herein by reference to Exhibit 10.4 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.5	Federal Coal Lease WYW-163340: Antelope Coal LLC (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on July 1, 2011 (File No. 001-34547))
10.6	Federal Coal Lease WYW-177903: Antelope Coal LLC (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on August 12, 2011 (File No. 001-34547))
10.7	State of Wyoming Coal Lease No. 0-26695: Antelope Coal Mine (Incorporated herein by reference to Exhibit 10.5 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.8	Federal Coal Lease WYW-8385: Cordero-Rojo Mine (Incorporated herein by reference to Exhibit 10.6 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.9	Federal Coal Lease WYW-23929: Cordero-Rojo Mine (Incorporated herein by reference to Exhibit 10.7 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.10	Federal Coal Lease WYW-174407: Cordero-Rojo Mine (Incorporated herein by reference to Exhibit 10.8 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.11	Federal Coal Lease WYW-154432: Cordero-Rojo Mine (Incorporated herein by reference to Exhibit 10.9 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.12	State of Wyoming Coal Lease No. 0-26935-A: Cordero-Rojo Mine (Incorporated herein by reference to Exhibit 10.10 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.13	State of Wyoming Coal Lease No. 0-26936-A: Cordero-Rojo Mine (Incorporated herein by reference to Exhibit 10.11 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.14	Federal Coal Lease MTM-88405: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.12 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.15	

Modified Federal Coal Lease MTM-069782: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on June 18, 2010 (File No. 001-34547))

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Exhibit Number	Description of Documents
10.16	Federal Coal Lease MTM-94378: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.14 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.17	State of Montana Coal Lease No. C-1101-00: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.15 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.18	State of Montana Coal Lease No. C-1099-00: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.16 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.19	State of Montana Coal Lease No. C-1100-00: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.17 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.20	State of Montana Coal Lease No. C-1088-05: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.18 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
	IPO Agreements
10.21	Master Separation Agreement, dated as of November 19, 2009, by and among Cloud Peak Energy Inc., Cloud Peak Energy Resources LLC, Rio Tinto America Inc., Rio Tinto Energy America Inc. and Kennecott Management Services Company (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on November 25, 2009 (File No. 001-34547))
10.22	Management Services Agreement, dated as of November 19, 2009, by and between Cloud Peak Energy Inc. and Cloud Peak Energy Resources LLC (Incorporated herein by reference to Exhibit 10.9 to CPE Inc. s Current Report on Form 8-K filed on November 25, 2009 (File No. 001-34547))
10.23	Acceleration and Release Agreement, dated August 19, 2014, between Cloud Peak Energy Inc. and Rio Tinto Energy America Inc. (Incorporated by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on August 20, 2014 (File No. 001-34547))
	Credit Agreements and Security Agreements
10.24	Credit Agreement, dated as of February 21, 2014, by and among Cloud Peak Energy Resources LLC (and its subsidiaries listed on the signature page), PNC Bank, National Association, as administrative agent, and a syndicate of lenders (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on 8-K filed on February 21, 2014 (File No. 001-34547))
10.25	First Amendment to Credit Agreement, dated September 5, 2014, between Cloud Peak Energy Resources LLC, the guarantors party thereto, the lenders party thereto and PNC Bank, National Association, as Administrative Agent (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on 8-K filed on September 10, 2014 (File No. 001-34547))
10.26	Second Amendment to Credit Agreement, dated September 9, 2016, between Cloud Peak Energy Resources LLC, the guarantors party thereto, the lenders party thereto and PNC Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.1 to Cloud Peak Energy Inc. s Current Report on Form 8-K filed on September 12, 2016 (File No. 001-34547))
10.27	Guarantee and Security Agreement, dated as of February 21, 2014, by and between Cloud Peak Energy Resources LLC (and its subsidiaries listed on the signature page) and PNC Bank, National Association (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on 8-K filed on February 21, 2014 (File No. 001-34547))

Exhibit Number	Description of Documents
10.28	Security Agreement Supplement, dated as of March 11, 2014, between Cloud Peak Energy Inc. and PNC Bank, National Association, as administrative agent (Incorporated herein by reference to Exhibit 10.3 to CPE Inc. s Quarterly Report on 10-Q filed on April 30, 2014 (File No. 001-34547))
10.29	Security Agreement, dated October 17, 2016, among Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp., the guarantors party thereto and Wilmington Trust, National Association, as Collateral Agent (incorporated by reference to Exhibit 10.1 to Cloud Peak Energy Inc. s Current Report on Form 8-K filed on October 17, 2016 (File No. 001-34547))
10.30	First Lien/Second Lien Intercreditor Agreement, dated October 17, 2016, among Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp., PNC Bank, National Association, as Senior Representative for the First Lien Credit Agreement Secured Parties and Wilmington Trust, National Association, as the Second Priority Representative for the Second Lien Indenture Secured Parties (incorporated by reference to Exhibit 10.2 to Cloud Peak Energy Inc. s Current Report on Form 8-K filed on October 17, 2016 (File No. 001-34547))
	Receivables Agreements
10.31	Amended and Restated Receivables Purchase Agreement, dated as of January 31 2017, by and among Cloud Peak Energy Receivables LLC, Cloud Peak Energy Resources LLC, PNC Bank, National Association, as administrator (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on February 1, 2017 (File No. 001-34547))
10.32*	Forbearance Agreement, dated as of March 14, 2019, by and among Cloud Peak Energy Receivables LLC, Cloud Peak Energy Resources LLC, and PNC Bank, National Association as the Administrator, a Purchaser, a Purchaser Agent and the LC Bank
	LTIP
10.33	Cloud Peak Energy Inc. 2009 Long Term Incentive Plan, as amended and restated effective March 3, 2017 (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on March 6, 2017 (File No. 001-34547)
10.34	Amendment No. 1 to the Cloud Peak Energy Inc. 2009 Long Term Incentive Plan (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on May 10, 2017 (File No. 001-34547))
10.35	Amendment No. 2 to the Cloud Peak Energy Inc. 2009 Long Term Incentive Plan (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on May 9, 2018 (File No. 001-34547))
	Forms of LTIP Award Agreements
10.36	Form of Cloud Peak Energy Inc. 2009 Long Term Incentive Plan IPO Nonqualified Stock Option Agreement (Incorporated herein by reference to Exhibit 10.33 to Amendment No. 5 to CPE Inc. s Form S-1 filed on November 16, 2009 (File No. 333-161293))
10.37	Form of 2011 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Nonqualified Stock Option Agreement (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on Form 8-K filed on March 9, 2011 (File No. 001-34547))
10.38	Form of 2011 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Director Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.48 to CPE Inc. s Annual Report on Form 10-K filed on February 25, 2011 (File No. 001-34547))

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Exhibit Number	Description of Documents
10.39	Form of 2012 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Nonqualified Stock Option Agreement (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on Form 8-K filed on March 16, 2012 (File No. 001-34547))
10.40	Form of 2012 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Director Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.44 to CPE Inc. s Annual Report on Form 10-K filed on February 18, 2015 (File No. 001-34547))
10.41	Form of 2013 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Nonqualified Stock Option Agreement (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on Form 8-K filed on March 11, 2013 (File No. 001-34547))
10.42	Form of 2013 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Director Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.44 to CPE Inc. s Annual Report on Form 10-K filed on February 14, 2013 (File No. 001-34547))
10.43	Form of 2014 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Nonqualified Stock Option Agreement (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on 8-K filed on March 14, 2014 (File No. 001-34547))
10.44	Form of 2014 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Director Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.52 to CPE Inc. s Annual Report on Form 10-K filed on February 18, 2015 (File No. 001-34547))
10.45	Form of 2015 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Director Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.48 to CPE Inc. s Annual Report on Form 10-K filed on February 15, 2017 (File No. 001-34547))
10.46	Form of 2015 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Performance Share Unit Award Agreement (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on 8-K filed on March 3, 2015 (File No. 001-34547))
10.47	Form of 2015 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on 8-K filed on March 3, 2015 (File No. 001-34547))
10.48	Form of 2016 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Director Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.54 to CPE Inc. s Annual Report on Form 10-K filed on February 17, 2016 (File No. 001-34547))
10.49	Form of 2016 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Performance Share Unit Award Agreement (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on 8-K filed on March 7, 2016 (File No. 001-34547))
10.50	Form of 2016 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on 8-K filed on March 7, 2016 (File No. 001-34547))
10.51	Form of 2017 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Performance Share Unit Award Agreement (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on 8-K filed on March 6, 2017 (File No. 001-34547))
10.52	Form of 2017 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.3 to CPE Inc. s Current Report on 8-K filed on March 6, 2017 (File No. 001-34547))

10.53	Form of 2017 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Director Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.54 to CPE Inc. s Annual Report on Form 10-K filed on February 15, 2017 (File No. 001-34547))
10.54	Form of 2018 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Director Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.55 to CPE Inc. s Annual Report on Form 10-K filed on February 16, 2018 (File No. 001-34547))

Exhibit Number	Description of Documents
10.55	Form of 2018 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Performance Share Unit Award Agreement (Incorporated herein by reference to Exhibit 10.3 to CPE Inc. s Current Report on 8-K filed on March 5, 2018 (File No. 001-34547))
10.56	Form of 2018 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.4 to CPE Inc. s Current Report on 8-K filed on March 5, 2018 (File No. 001-34547))
	Annual Incentive Plan
10.57	Cloud Peak Energy Inc. 2013 Annual Incentive Plan (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on May 15, 2013 (File No. 001-34547))
	Deferred Compensation Plan
10.58	Amended and Restated Deferred Compensation Plan for Cloud Peak Energy Resources LLC, effective April 1, 2016 (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Quarterly Report on Form 10-Q filed on July 29, 2016 (File No. 001-34547))
	ESPP
10.59	Second Amended and Restated Employee Stock Purchase Plan dated February 13, 2017 (Incorporated herein by reference to Exhibit 10.57 to CPE Inc. s Annual Report on Form 10-K filed on February 15, 2017 (File No. 001-34547))
	Employment Agreements
10.60	Employment Agreement between Cloud Peak Energy Inc. and Colin Marshall dated as of November 14, 2009 (Incorporated herein by reference to Exhibit 10.40 to CPE Inc. s Annual Report on Form 10-K filed on March 17, 2010 (File No. 001-34547))
10.61	Employment Agreement between Cloud Peak Energy Inc. and Gary Rivenes dated as of November 14, 2009 (Incorporated herein by reference to Exhibit 10.43 to CPE Inc. s Annual Report on Form 10-K filed on March 17, 2010 (File No. 001-34547))
10.62	Employment Agreement between Cloud Peak Energy Inc. and Bryan Pechersky dated as of March 3, 2010 (Incorporated herein by reference to Exhibit 10.46 to CPE Inc. s Annual Report on Form 10-K filed on March 17, 2010 (File No. 001-34547))
10.63	Employment Agreement between Cloud Peak Energy Inc. and Todd A. Myers dated as of July 6, 2010 (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Quarterly Report on Form 10-Q filed on August 5, 2010 (File No. 001-34547))
10.64	Employment Agreement between Cloud Peak Energy Inc. and Bruce Jones dated as of July 8, 2013 (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Quarterly Report on Form 10-Q filed on July 31, 2013 (File No. 001-34547))
10.65	Employment Agreement between Cloud Peak Energy Inc. and Heath Hill, dated as of March 16, 2015 (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on March 17, 2015 (File No. 001-34547))
10.66	Employment Agreement between Cloud Peak Energy Inc. and Amy Clemetson, dated as of June 17, 2017 (Incorporated herein by reference to Exhibit 10.3 to CPE Inc. s Quarterly Report on Form 10-Q filed on July 27, 2017 (File No. 001-34547))

Exhibit Number	Description of Documents
10.67	Form of Executive Retention Agreement dated January 29, 2019 (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on January 29, 2019 (File No. 001-34547))
	Other Exhibits
21.1*	List of Subsidiaries
23.1*	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm
23.2*	Consent of J.T Boyd Company
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
95.1*	Mine Safety Disclosure
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Calculation Linkbase Document
101.LAB*	XBRL Taxonomy Label Linkbase Document
101.PRE*	XBRL Taxonomy Presentation Linkbase Document
101.DEF*	XBRL Taxonomy Definition Document

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* Filed or furnished herewith, as applicable

Management contract or compensatory plan or arrangement

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.

CLOUD PEAK ENERGY INC.

Date: March 15, 2019	By:	/s/ COLIN MARSHALL Colin Marshall
		President and Chief Executive Officer *Principal Executive Officer*

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

Name and Signatures	Title	Date
/s/ COLIN MARSHALL **Colin Marshall**	President and Chief Executive Officer *(Principal Executive Officer)*	March 15, 2019
/s/ HEATH A. HILL **Heath A. Hill**	Executive Vice President and Chief Financial Officer *(Principal Financial Officer)*	March 15, 2019
/s/ KENDALL K. CARBONE **Kendall K. Carbone**	Vice President and Chief Accounting Officer *(Principal Accounting Officer)*	March 15, 2019
/s/ WILLIAM T. FOX III **William T. Fox III**	*(Chairman of the Board of Directors)*	March 15, 2019
/s/ JEANE L. HULL **Jeane L. Hull**	*(Director)*	March 15, 2019
/s/ STEVEN W. NANCE **Steven W. Nance**	*(Director)*	March 15, 2019
/s/ WILLIAM F. OWENS **William F. Owens**	*(Director)*	March 15, 2019
/s/ ROBERT SKAGGS **Robert Skaggs**	*(Director)*	March 15, 2019