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

Form 10-K

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

For the fiscal year ended December 31, 2018

or

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

For the transition period from to

Commission file number: 000-52547

Royal Energy Resources, Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**11-3480036** (I.R.S. Employer Identification No.)
56 Broad Street, Suite 2 **Charleston, SC** (Address of principal executive offices)	**29401** (Zip Code)

Registrant's telephone number, including area code: **(843) 900-7693**

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

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $0.00001 par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [ ] 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 [ ] 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 [ ]

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

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

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

Large accelerated filer	[ ]	Accelerated filer	[ ]	Non-accelerated filer (Do not check if a smaller reporting company)	[ ]	Smaller reporting company	[X]

Emerging growth company [ ]

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

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

As of June 30, 2018, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the registrant's equity held by non-affiliates of the registrant was approximately $18.4 million based on the closing price of the registrant's common stock on the OTC Markets Bulletin Board on such date. As of March 20, 2019, the registrant had 18,579,293 shares of common stock (including 914,797 shares held by its consolidated subsidiary, Rhino Resource Partners, LP) and 51,000 shares of Series A Convertible Preferred Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

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

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GLOSSARY OF KEY TERMS

ash: Inorganic material consisting of iron, alumina, sodium and other incombustible matter that are contained in coal. The composition of the ash can affect the burning characteristics of coal.

assigned reserves: Proven and probable reserves that have the permits and infrastructure necessary for mining.

as received: Represents an analysis of a sample as received at a laboratory.

Btu: *British thermal unit, or Btu,* is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

Central Appalachia: Coal producing area in eastern Kentucky, western Virginia and southern West Virginia.

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

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.

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

GAAP: Generally accepted accounting principles in the United States.

high-vol metallurgical coal: Metallurgical coal that has a volatility content of 32% or greater of its total weight.

limestone: A rock predominantly composed of the mineral calcite (calcium carbonate ($CaCO_3$)).

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

low-vol metallurgical coal: Metallurgical coal that has a volatility content of 17% to 22% of its total weight.

mid-vol metallurgical coal: Metallurgical coal that has a volatility content of 23% to 31% of its total weight.

Metallurgical, or "met", coal: The various grades of coal suitable for carbonization to make coke for steel manufacture. Its quality depends on four important criteria: volatility, which affects coke yield; the level of impurities including sulfur and ash, which affects coke quality; composition, which affects coke strength; and basic characteristics, which affect coke oven safety. Metallurgical coal typically has a particularly high Btu but low ash and sulfur content.

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 stage work. However, this coal does not qualify as a commercially viable coal reserve as prescribed by standards of the SEC 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 limitations, or both.

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

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 also remove some of the coal's sulfur content.

probable (indicated) coal reserves: Coal reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling, and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

proven (measured) coal reserves: Coal 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 "re-contouring" or reshaping the land to its approximate original contour, restoring topsoil and planting native grass and shrubs. Reclamation operations are typically conducted concurrently with mining operations, but the majority of reclamation costs are incurred once mining operations cease. Reclamation is closely regulated by both state and federal laws.

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

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

sulfur: One of the elements present in varying quantities in coal that contributes to environmental degradation when coal is burned. Sulfur dioxide (SO2) is produced as a gaseous by-product of coal combustion.

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.

tons: A "short" or net ton is equal to 2,000 pounds. A "long" or British ton is 2,240 pounds. A "metric" tonne is approximately 2,205 pounds. The short ton is the unit of measure referred to in this report.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This report contains "forward-looking statements." Statements included in this report that are not historical facts, that address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as statements regarding our future financial position, expectations with respect to our liquidity, capital resources and ability to continue as a going concern, plans for growth of the business, future capital expenditures, references to future goals or intentions or other such references are forward-looking statements. These statements can be identified by the use of forward-looking terminology, including "may," "believe," "expect," "anticipate," "estimate," "continue," or similar words. These statements are made by us based on our past experience and our perception of historical trends, current conditions and expected future developments as well as other considerations we believe are reasonable as and when made. Whether actual results and developments in the future will conform to our expectations is subject to numerous risks and uncertainties, many of which are beyond our control. Therefore, actual outcomes and results could materially differ from what is expressed, implied or forecast in these statements. Known material factors that could cause our actual results to differ from those in the forward-looking statements are those described in "Part 1, Item 1A. Risk Factors." The following factors are among those that may cause actual results to differ materially from our forward-looking statements:

- our ability to maintain adequate cash flow and to obtain additional financing necessary to fund our capital expenditures, meet working capital needs and maintain and grow our operations;
- our future levels of indebtedness and compliance with debt covenants;
- declines in coal prices, which depend upon several factors such as the supply of domestic and foreign coal, the demand for domestic and foreign coal, governmental regulations, price and availability of alternative fuels for electricity generation and prevailing economic conditions;
- declines in demand for electricity and coal;
- current and future environmental laws and regulations, which could materially increase operating costs or limit our ability to produce and sell coal;
- extensive government regulation of mine operations, especially with respect to mine safety and health, which imposes significant actual and potential costs;
- difficulties in obtaining and/or renewing permits necessary for operations;
- a variety of operating risks, such as unfavorable geologic conditions, adverse weather conditions and natural disasters, mining and processing equipment unavailability, failures and unexpected maintenance problems and accidents, including fire and explosions from methane;
- poor mining conditions resulting from the effects of prior mining;
- the availability and costs of key supplies and commodities such as steel, diesel fuel and explosives;
- fluctuations in transportation costs or disruptions in transportation services, which could increase competition or impair our ability to supply coal;
- a shortage of skilled labor, increased labor costs or work stoppages;
- our ability to secure or acquire new or replacement high-quality coal reserves that are economically recoverable;
- material inaccuracies in our estimates of coal reserves and non-reserve coal deposits;
- existing and future laws and regulations regulating the emission of sulfur dioxide and other compounds, which could affect coal consumers and reduce demand for coal;
- federal and state laws restricting the emissions of greenhouse gases;
- our ability to acquire or failure to maintain, obtain or renew surety bonds used to secure obligations to reclaim mined property;
- our dependence on a few customers and our ability to find and retain customers under favorable supply contracts;

- changes in consumption patterns by utilities away from the use of coal, such as changes resulting from low natural gas prices;
- changes in governmental regulation of the electric utility industry;
- defects in title in properties that we own or losses of any of our leasehold interests;
- our ability to retain and attract senior management and other key personnel;
- material inaccuracy of assumptions underlying reclamation and mine closure obligations; and
- weakness in global economic conditions.

Readers are cautioned not to place undue reliance on forward-looking statements. The forward-looking statements speak only as of the date made, and we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I

Unless the context clearly indicates otherwise, references in this report to "Royal," "we," "our," "us" or similar terms refer to Royal Energy Resources, Inc. and its subsidiaries. Unless the context clearly indicates otherwise, references in this report to "Rhino" or "the Partnership" or similar terms refer to Rhino Resource Partners, LP and its subsidiaries.

Item 1. Business.

We were originally organized in Delaware on March 22, 1999, with the name Webmarketing, Inc. On July 7, 2004, we revived our charter and changed our name to World Marketing, Inc. In December 2007, we changed our name to Royal Energy Resources, Inc.

Prior to March 2015, we were controlled by Jacob Roth, and pursued gold, silver, copper and rare earth metals mining concessions in Romania and mining leases in the United States. In a series of transactions occurring between January and April 2015, William L. Tuorto acquired control of our common stock from Mr. Roth. Mr. Roth and his affiliates resigned as our directors and officers, and Mr. Tuorto and his nominees became our directors and officers. We also disposed of our past operations, and Mr. Tuorto has repositioned us to focus on the acquisition of natural resources assets, including coal, oil, gas and renewable energy. To that effect, we have entered into the following initial transactions:

- On April 17, 2015, we completed the acquisition of all issued and outstanding membership units of Blaze Minerals, LLC, a West Virginia limited liability company ("Blaze Minerals"), from Wastech, Inc. Blaze Minerals' sole asset consists of 40,976 net acres of coal and coal-bed methane mineral rights, located across 22 counties in West Virginia (the "Mineral Rights"). We acquired Blaze Minerals by the issuance of 2,803,621 shares of common stock. The shares were valued at $7,009,053 based upon a per share value of $2.50 per share, which was the price at which we issued our common stock in a private placement at the time. The value of the Mineral Rights was written down to $0 at December 31, 2017 due to deterioration in the market for coal properties in West Virginia, and the absence of current efforts to market or develop the Mineral Rights. In 2018, Blaze Minerals ceased to exist as a legal entity since its charter was revoked by the state of West Virginia and the time period lapsed to apply for reinstatement.

- On May 14, 2015, we entered into an Option Agreement to acquire substantially all the assets of Wellston Coal, LLC ("Wellston") for 500,000 shares of common stock. We paid a nominal sum for the option and had the right to complete the purchase through September 1, 2015 (which was later extended to December 31, 2016). Wellston owned approximately 1,600 acres of surface and 2,200 acres of mineral rights in McDowell County, West Virginia. We planned to close on the acquisition of Wellston after the satisfactory completion of due diligence on the assets and operations. On September 13, 2016, Wellston sold its assets to an unrelated third party, and we received a royalty of $1 per ton on the first 250,000 tons of coal mined from the property in consideration for a release of our lien on Wellston's assets.

- On May 29, 2015, we entered into an Option Agreement with Blaze Energy Corp. ("Blaze Energy") to acquire all of the membership units of Blaze Mining Company, LLC ("Blaze Mining"), which is a wholly-owned subsidiary of Blaze Energy. Under the Option Agreement, as amended, we had the right to complete the purchase through March 31, 2016 by the issuance of 1,272,858 shares of the Company's common stock and payment of $250,000 in cash. Blaze Mining controlled operations for and had the right to acquire 100% ownership of the Alpheus Coal Impoundment reclamation site in McDowell County, West Virginia under a contract with Gary Partners, LLC, which owned the property. On February 22, 2016, we facilitated a series of transactions wherein: (i) Blaze Mining and Blaze Energy entered into an Asset Purchase Agreement to acquire substantially all of the assets of Gary Partners, LLC; (ii) Blaze Mining entered into an Assignment Agreement to assign its rights under the Asset Purchase Agreement ARQ Gary Land, LLC, f/k/a Hendricks Gary Land, LLC ("ARQ"); and (iii) we and Blaze Energy entered into an Option Termination Agreement, as amended, whereby the following royalties granted to Blaze Mining under the Assignment Agreement were assigned to us: a $1.25 per ton royalty on raw coal or coal refuse mined or removed from the property, and a $1.75 per ton royalty on processed or refined coal or coal refuse mined or removed from the property (the "Royalties"). Pursuant to the Option Termination Agreement, the parties thereby agreed to terminate the Option Agreement by the issuance of 1,750,000 shares of our common stock to Blaze Energy in consideration for the payment by Blaze Energy of $350,000 to us and the assignment by Blaze Mining of the Royalties to us. The transactions closed on March 22, 2016. Pursuant to an Advisory Agreement with East Coast Management Group, LLC ("ECMG"), we agreed to compensate ECMG $200,000 in cash; $0.175 of the $1.25 royalty on raw coal or coal refuse; and $0.25 of the $1.75 royalty on processed or refined coal for its services in facilitating the Option Termination Agreement. The value of the investment was written down to $1.8 million at December 31, 2017 due to an option to sell such investment for $1.8 million to ARQ. In 2018 the option expired, and the Company wrote the investment down to $0.

- As described in more detail below, we acquired control of the Partnership on March 17, 2016.

  On November 10, 2017, we entered into an Overriding Royalty Agreement to acquire a perpetual $4.00 per ton royalty for coal transported through a coal transloading terminal on the Ohio River. The original consideration was $400,000 of our common stock, or 100,000 shares, which was later amended to be a ten year option to purchase 100,000 shares of our common stock for $4.00 per share.

- We are currently evaluating a number of additional coal mining assets for acquisition.

Acquisition of Rhino GP LLC and Rhino Resource Partners LP ("the Partnership" or "Rhino")

In the first quarter of 2016, Royal acquired control of the Partnership from Wexford Capital LP and certain of its affiliates (collectively, "Wexford") in two different closings for aggregate consideration of $4,500,000. In the closings, Royal acquired all of the membership interests of Rhino GP, LLC ("Rhino GP"), the Partnership's general partner, 676,912 common units (which represented 40% of the outstanding common units at the time) and 945,526 subordinated units (which represented 76.5% of the subordinated units at the time). In connection with the transaction, all of the directors of Rhino GP affiliated with Wexford resigned, and Royal appointed new directors.

On March 21, 2016, we entered into a Securities Purchase Agreement (the "SPA") with the Partnership, under which we purchased 6,000,000 newly issued common units of the Partnership for $1.50 per common unit, for a total investment in the Partnership of $9,000,000. Closing under the SPA occurred on March 22, 2016. We paid a cash payment of $2,000,000 and issued a promissory note in the amount of $7,000,000 to the Partnership, which was payable without interest on the following schedule: $3,000,000 on or before July 31, 2016; $2,000,000 on or before September 30, 2016; and $2,000,000 on or before December 31, 2016. On May 13, 2016 and September 30, 2016, we paid the Partnership $3.0 million and $2.0 million, respectively, for the promissory note installments that were due July 31, 2016 and September 30, 2016, respectively. On December 30, 2016, we and the Partnership agreed to extend the maturity date of the final installment of the note to December 31, 2018, and agreed that the note may be converted, at our option, at any time prior to December 31, 2018, into unregistered shares of our common stock at a price per share equal to seventy five percent (75%) of the volume weighted average closing price for the ninety (90) trading days preceding the date of conversion, provided that the average closing price shall be no less than $3.50 per share and no more than $7.50 per share. On September 1, 2017, we elected to convert the $2.0 million promissory note and an additional $2.1 million note (including accrued interest) assigned from Weston Energy LLC into shares of Royal common stock. Royal issued 914,797 shares of its common stock to the Partnership at a conversion price of $4.51 per share.

Pursuant to the Securities Purchase Agreement, on March 21, 2016, the Partnership and Royal entered into a registration rights agreement. The registration rights agreement grants Royal piggyback registration rights under certain circumstances with respect to the common units issued to Royal pursuant to the Securities Purchase Agreement.

Cedarview Loan

On June 12, 2017, we entered into a Secured Promissory Note dated May 31, 2017 with Cedarview Opportunities Master Fund, L.P. (the "Cedarview"), under which we borrowed $2,500,000 from Cedarview. The loan bears non-default interest at the rate of 14%, and default interest at the rate of 17% per annum. We and Cedarview simultaneously entered into a Pledge and Security Agreement dated May 31, 2017, under which we pledged 5,000,000 common units in Rhino as collateral for the loan. The loan is payable through quarterly payments of interest only until May 31, 2019, when the loan matures, at which time all principal and interest is due and payable. We deposited $350,000 of the loan proceeds into an escrow account, from which interest payments for the first year will be paid. After the first year, we are obligated to maintain at least one quarter of interest on the loan in the escrow account at all times. In consideration for Cedarview's agreement to make the loan, we transferred 25,000 common units of Rhino to Cedarview as a fee. We intended to use the proceeds to repay in full all loans made to us by E-Starts Money Co. in the principal amount of $578,593, and the balance for general corporate overhead, as well as costs associated with potential acquisitions of mineral resource companies, including legal and engineering due diligence, deposits, and down payments.

On March 5, 2019, the Company modified the terms of the Cedarview note. The Company agreed to pay $1 million of the note balance by May 31, 2019 with the remaining balance of $1.5 million and associated accrued interest due May 31, 2020. The Company has paid a $45,000 loan extension fee to execute this agreement. All other terms of the note remain the same.

About Rhino

History

The Partnership's predecessor was formed in April 2003 by Wexford Capital. The Partnership was formed in April 2010 to own and control the coal properties and related assets owned by Rhino Energy LLC. On October 5, 2010, the Partnership completed its IPO. The Partnership's common units were originally listed on the New York Stock Exchange under the symbol "RNO". In connection with the IPO, Wexford contributed their membership interests in Rhino Energy LLC to the Partnership, and in exchange it issued subordinated units representing limited partner interests in it and common units to Wexford and issued incentive distribution rights to the Partnership's general partner. In March 2016, Royal acquired the Partnership's general partner and a majority limited partner interest in the Partnership from Wexford.

Since the formation of the Partnership's predecessor in April 2003, it has completed numerous coal asset acquisitions with a total purchase price of approximately $357.5 million. Through these acquisitions and coal lease transactions, the Partnership has substantially increased its proven and probable coal reserves and non-reserve coal deposits. In addition, the Partnership has successfully grown its production through internal development projects.

On April 27, 2016, the NYSE filed with the SEC a notification of removal from listing and registration on Form 25 to delist the Partnership's common units and terminate the registration of its common units under Section 12(b) of the Securities Exchange Act of 1934. The delisting became effective on May 9, 2016. Rhino's common units trade on the OTCQB Marketplace under the ticker symbol "RHNO."

The Partnership is managed by the board of directors and executive officers of Rhino GP, its general partner. The Partnership's operations are conducted through, and its operating assets are owned by, the Partnership's wholly owned subsidiary, Rhino Energy LLC, and its subsidiaries.

Current Operations

The Partnership is a diversified coal producing limited partnership formed in Delaware that is focused on coal and energy related assets and activities. The Partnership produces, processes and sells high quality coal of various steam and metallurgical grades from multiple coal producing basins in the United States. The Partnership markets its steam coal primarily to electric utility companies as fuel for their steam powered generators. Customers for its metallurgical coal are primarily steel and coke producers who use its coal to produce coke, which is used as a raw material in the steel manufacturing process.

The Partnership has a geographically diverse asset base with coal reserves located in Central Appalachia, Northern Appalachia, the Illinois Basin and the Western Bituminous region. As of December 31, 2018, the Partnership controlled an estimated 268.5 million tons of proven and probable coal reserves, consisting of an estimated 214.0 million tons of steam coal and an estimated 54.5 million tons of metallurgical coal. Proven and probable coal reserves increased approximately 15.8 million tons from 2017 to 2018 primarily as the result of the revised economic feasibility of the Partnership's non-reserve coal deposits. In addition, as of December 31, 2018, the Partnership controlled an estimated 164.1 million tons of non-reserve coal deposits, which decreased primarily due to the reclassification of non-reserve coal deposits to proven and probable reserves. Periodically, the Partnership retains outside experts to independently verify its coal reserve and its non-reserve coal deposit estimates. The most recent audit by an independent engineering firm of its coal reserve and non-reserve coal deposit estimates was completed by Marshall Miller & Associates, Inc. as of December 31, 2018, and covered a majority of the coal reserves and non-reserve coal deposits that the Partnership controlled as of such date. The Partnership intends to continue to periodically retain outside experts to assist management with the verification of its estimates of our coal reserves and non-reserve coal deposits going forward.

The Partnership operates underground and surface mines located in Kentucky, Ohio, West Virginia and Utah. The number of mines that the Partnership operates will vary from time to time depending on a number of factors, including the existing demand for and price of coal, depletion of economically recoverable reserves and availability of experienced labor.

For the year ended December 31, 2018, the Partnership produced approximately 4.4 million tons of coal from continuing operations and sold approximately 4.6 million tons of coal from continuing operations.

The Partnership's principal business strategy is to safely, efficiently and profitably produce and sell both steam and metallurgical coal from its diverse asset base in order to resume, and, over time, increase its quarterly cash distributions. In addition, the Partnership continues to seek opportunities to expand and diversify its operations through strategic acquisitions, including the acquisition of long-term, cash generating natural resource assets. The Partnership believes that such assets will allow it to grow its cash available for distribution and enhance the stability of its cash flow.

Current Liquidity and Outlook of Rhino

As of December 31, 2018, the Partnership's available liquidity was $6.6 million. The Partnership also has a delayed draw term loan commitment in the amount of $35 million contingent upon the satisfaction of certain conditions precedent specified in the financing agreement discussed below.

On December 27, 2017, the Partnership entered into a Financing Agreement ("Financing Agreement"), which provides it with a multi-draw loan in the aggregate principal amount of $80 million. The total principal amount is divided into a $40 million commitment, the conditions for which were satisfied at the execution of the Financing Agreement and an additional $35 million commitment that is contingent upon the satisfaction of certain conditions precedent specified in the Financing Agreement. The Partnership used approximately $17.3 million of the net proceeds thereof to repay all amounts outstanding and terminate the Amended and Restated Credit Agreement with PNC Bank, National Association, as Administrative Agent. The Financing Agreement terminates on December 27, 2020. For more information about our new Financing Agreement, please read "— Recent Developments—Rhino - Financing Agreement."

The Partnership continues to take measures, including the suspension of cash distributions on their common and subordinated units and cost and productivity improvements, to enhance and preserve their liquidity so that the Partnership can fund their ongoing operations and necessary capital expenditures and meet their financial commitments and debt service obligations.

Recent Developments – Rhino

Financing Agreement

On December 27, 2017, the Partnership entered into the Financing Agreement pursuant to which Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent, CB Agent Services LLC, as Origination Agent and the parties identified as Lenders therein (the "Lenders") have agreed to provide the Partnership with a multi-draw term loan in the aggregate principal amount of $80 million, subject to the terms and conditions set forth in the Financing Agreement. The total principal amount is divided into a $40 million commitment, the conditions for which were satisfied at the execution of the Financing Agreement (the "Effective Date Term Loan Commitment") and an additional $35 million commitment that is contingent upon the satisfaction of certain conditions precedent specified in the Financing Agreement ("Delayed Draw Term Loan Commitment"). Loans made pursuant to the Financing Agreement will be secured by substantially all of the Partnership's assets. The Financing Agreement terminates on December 27, 2020.

On April 17, 2018, the Partnership amended the Financing Agreement to allow for certain activities including a sale leaseback of certain pieces of equipment, the due date for the lease consents was extended to June 30, 2018 and confirmation of the distribution to holders of the Series A preferred units of $6.0 million (accrued in our audited consolidated financial statements at December 31, 2017). Additionally, the amendments provided that the Partnership could sell additional shares of Mammoth Energy Services, Inc. (NASDAQ: TUSK) ("Mammoth, Inc.") and retain 50% of the proceeds with the other 50% used to reduce debt. The Partnership reduced the debt by $3.4 million with proceeds from the sale of Mammoth Inc. stock in the second quarter of 2018.

On July 27, 2018, the Partnership entered into a consent with its Lenders related to the Financing Agreement. The consent included the lenders agreement to make a $5 million loan from the Delayed Draw Term Loan Commitment, which was repaid in full on October 26, 2018 pursuant to the terms of the consent. The consent also included a waiver of the requirements relating to the use of proceeds of any sale of the shares of Mammoth Inc. set forth in the consent to the Financing Agreement, dated as of April 17, 2018 and also waived any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended June 30, 2018.

On November 8, 2018, the Partnership entered into a consent with its Lenders related to the Financing Agreement. The consent includes the lenders agreement to waive any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended September 30, 2018.

On December 20, 2018, the Partnership entered into a limited waiver and consent (the "Waiver") to the Financing Agreement. The Waiver relates to sales of certain real property in Western Colorado, the net proceeds of which are required to be used to reduce the debt under the Financing Agreement. As of the date of the Waiver, the Partnership had sold 9 individual lots in smaller transactions. Rather than transmitting net proceeds with respect to each individual transaction, the Partnership agreed with the Lenders in principle to delay repayment until an aggregate payment could be made at the end of 2018. On December 18, 2018, the Partnership used the sale proceeds of approximately $379,000 to reduce its debt to the Lenders. The Waiver (i) contains a ratification by the Lenders of the sale of the individual lots to date and waives the associated technical defaults under the Financing Agreement for not making immediate payments of net proceeds therefrom, (ii) permits the sale of certain specified additional lots and (iii) subject to Lender consent, permits the sale of other lots on a going forward basis. The net proceeds of future sales will be held by the Partnership until a later date to be determined by the Lenders.

On February 13, 2019, the Partnership entered into a second amendment ("Amendment") to the Financing Agreement. The Amendment provides the Lender's consent for the Partnership to pay a one-time cash distribution on February 14, 2019 to the Series A Preferred Unitholders an amount not to exceed approximately $3.2 million. The Amendment allows the Partnership to sell its remaining shares of Mammoth Energy Services, Inc. and utilize the proceeds for payment of the one-time cash distribution to the Series A Preferred Unitholders and waives the requirement to use such proceeds to prepay the outstanding principal amount outstanding under the Financing Agreement. The Amendment also waives any Event of Default that has or would otherwise arise under Section 9.01(c) of the Financing Agreement solely by reason of the Partnership failing to comply with the Fixed Charge Coverage Ratio covenant in Section 7.03(b) of the Financing Agreement for the fiscal quarter ending December 31, 2018. The Amendment includes an amendment fee of approximately $0.6 million payable by the Partnership on May 13, 2019 and an exit fee equal to 1% of the principal amount of the term loans made under the Financing Agreement that is payable on the earliest of (w) the final maturity date of the Financing Agreement, (x) the termination date of the Financing Agreement, (y) the acceleration of the obligations under the Financing Agreement for any reason, including, without limitation, acceleration in accordance with Section 9.01 of the Financing Agreement, including as a result of the commencement of an insolvency proceeding and (z) the date of any refinancing of the term loan under the Financing Agreement. The Amendment amends the definition of the Make-Whole Amount under the Financing Agreement to extend the date of the Make-Whole Amount period to December 31, 2019.

Common Unit Warrants

The Partnership entered into a warrant agreement with certain parties that are also parties to the Financing Agreement discussed above. The warrant agreement included the issuance of a total of 683,888 warrants of the Partnership's common units ("Common Unit Warrants") at an exercise price of $1.95 per unit, which was the closing price of the Partnership's units on the OTC market as of December 27, 2017. The Common Unit Warrants have a five year expiration date. The Common Unit Warrants and the Rhino common units after exercise are both transferable, subject to applicable US securities laws. The Common Unit Warrant exercise price is $1.95 per unit, but the price per unit will be reduced by future common unit distributions and other further adjustments in price included in the warrant agreement for transactions that are dilutive to the amount of Rhino's common units outstanding. The warrant agreement includes a provision for a cashless exercise where the warrant holders can receive a net number of common units. Per the warrant agreement, the warrants are detached from the Financing Agreement and fully transferable.

Letter of Credit Facility – PNC Bank

On December 27, 2017, the Partnership entered into a master letter of credit facility, security agreement and reimbursement agreement (the "LoC Facility Agreement") with PNC Bank, National Association ("PNC"), pursuant to which PNC agreed to provide the Partnership with a facility for the issuance of standby letters of credit used in the ordinary course of its business (the "LoC Facility"). The LoC Facility Agreement provided that the Partnership pay a quarterly fee at a rate equal to 5% per annum calculated based on the daily average of letters of credit outstanding under the LoC Facility, as well as administrative costs incurred by PNC and a $100,000 closing fee. The LoC Facility Agreement provided that the Partnership reimburse PNC for any drawing under a letter of credit by a specified beneficiary as soon as possible after payment was made. The Partnership's obligations under the LoC Facility Agreement were secured by a first lien security interest on a cash collateral account that was required to contain no less than 105% of the face value of the outstanding letters of credit. In the event the amount in such cash collateral account was insufficient to satisfy the Partnership's reimbursement obligations, the amount outstanding would bear interest at a rate per annum equal to the Base Rate (as that term was defined in the LoC Facility Agreement) plus 2.0%. The Partnership was to indemnify PNC for any losses which PNC may have incurred as a result of the issuance of a letter of credit or PNC's failure to honor any drawing under a letter of credit, subject in each case to certain exceptions. The Partnership provided cash collateral to its counterparties during the third quarter of 2018 and as of September 30, 2018, the LoC Facility was terminated. The Partnership had no outstanding letters of credit at December 31, 2018.

Distribution Suspension

Beginning with the quarter ended June 30, 2015 and continuing through the quarter ended December 31, 2018, the Partnership has suspended the cash distribution on its common units. For each of the quarters ended September 30, 2014, December 31, 2014 and March 31, 2015, the Partnership announced cash distributions per common unit at levels lower than the minimum quarterly distribution. The Partnership has not paid any distribution on its subordinated units for any quarter after the quarter ended March 31, 2012. The distribution suspension and prior reductions were the result of prolonged weakness in the coal markets, which has continued to adversely affect the Partnership's cash flow.

Pursuant to its partnership agreement, the Partnership's common units accrue arrearages every quarter when the distribution level is below the minimum level of $4.45 per unit. For each of the quarters ended September 30, 2014, December 31, 2014 and March 31, 2015, the Partnership announced cash distributions per common unit at levels lower than the minimum quarterly distribution. Beginning with the quarter ended June 30, 2015 and continuing through the quarter ended December 31, 2018, the Partnership has accumulated arrearages at December 31, 2018 related to the common unit distribution of approximately $673.1 million.

Coal Operations

Mining and Leasing Operations

As of December 31, 2018, the Partnership operated two mining complexes located in Central Appalachia (Tug River and Rob Fork). In addition during 2018, the Partnership operated one mining complex located in Northern Appalachia (Hopedale). The other Northern Appalachia mining complex, Sands Hill Mining, was sold in November 2017. In the Western Bituminous region, the Partnership operated one mining complex located in Emery and Carbon Counties, Utah (Castle Valley). The Partnership also operated a mining complex in the Illinois Basin, the Riveredge mine at its Pennyrile mining complex. (See Note 4 of the consolidated financial statements included elsewhere in this annual report for further information on the disposition of Sands Hill Mining)

The Partnership defines a mining complex as a central location for processing raw coal and loading coal into railroad cars, barges or trucks for shipment to customers. These mining complexes include five active preparation plants and/or loadouts, each of which receive, blend, process and ship coal that is produced from one or more of our active surface and underground mines. All of the preparation plants are modern plants that have both coarse and fine coal cleaning circuits.

Other Non-Mining Operations

In addition to the Partnership's mining operations, it operates various subsidiaries which provide auxiliary services for its coal mining operations. Rhino Services is responsible for mine-related construction, site and roadway maintenance and post-mining reclamation. Through Rhino Services, the Partnership plans and monitors each phase of its mining projects as well as the post-mining reclamation efforts. The Partnership also performs the majority of the its drilling and blasting activities at the Partnership's company-operated surface mines in-house rather than contracting to a third party.

Other Natural Resource Assets - Rhino

Oil and Natural Gas

In addition to its coal operations, the Partnership has invested in oil and natural gas assets and operations.

In December 2012, the Partnership made an initial investment in a new joint venture, Muskie Proppant LLC ("Muskie"), with affiliates of Wexford Capital. In November 2014, the Partnership contributed its investment interest in Muskie to Mammoth Energy Partners LP ("Mammoth") in return for a limited partner interest in Mammoth. In October 2016, the Partnership contributed its limited partner interests in Mammoth to Mammoth Energy Services, Inc. (NASDAQ: TUSK) ("Mammoth Inc.") in exchange for 234,300 shares of common stock of Mammoth, Inc.

In September 2014, the Partnership made an initial investment of $5.0 million in a new joint venture, Sturgeon Acquisitions LLC ("Sturgeon"), with affiliates of Wexford Capital and Gulfport Energy ("Gulfport"). The Partnership accounts for the investment in this joint venture and results of operations under the equity method. The Partnership recorded its proportionate portion of the operating (losses)/gains for this investment for the years ended December 31, 2017 of approximately $36,000. In June 2017, the Partnership contributed its limited partner interests in Sturgeon to Mammoth Inc. in exchange for 336,447 shares of common stock of Mammoth Inc. As of December 31, 2018, the Partnership owned 104,100 shares of Mammoth Inc.

As of December 31, 2018 and 2017, the Partnership has recorded its investment in Mammoth Inc. as a short-term asset, which the Partnership has classified as equity securities.

Coal Customers - Rhino

General

The Partnership's primary customers for its steam coal are electric utilities and industrial consumers, and the metallurgical coal the Partnership produces is sold primarily to domestic and international steel producers and coal brokers. For the year ended December 31, 2018, approximately 81% of its coal sales tons consisted of steam coal and approximately 19% consisted of metallurgical coal. For the year ended December 31, 2018, approximately 40% of its coal sales tons that the Partnership produced were sold to electric utilities. The majority of its electric utility customers purchase coal for terms of one to three years, but it also supplies coal on a spot basis for some of its customers. For the year ended December 31, 2018, the Partnership derived approximately 80% of its total coal revenues from sales to its ten largest customers, with affiliates of its top three customers accounting for approximately 40.4% of its coal revenues for that period.

Coal Supply Contracts

For the year ended December 31, 2018 and 2017, approximately 64% and 59%, respectively, of the Partnership's aggregate coal tons sold were sold through supply contracts. The Partnership expects to continue selling a significant portion of its coal under supply contracts. As of December 31, 2018, the Partnership had commitments under supply contracts to deliver annually scheduled base quantities as follows:

Year	Tons (in thousands)	Number of customers
2019	3,699	18
2020	1,979	6
2021	352	2

Some of the contracts have sales price adjustment provisions, subject to certain limitations and adjustments, based on a variety of factors and indices.

Quality and volumes for the coal are stipulated in coal supply contracts, and in some instances buyers have the option to vary annual or monthly volumes. Most of the Partnership's coal supply contracts contain provisions requiring it to deliver coal within certain ranges for specific coal characteristics such as heat content, sulfur, ash, hardness and ash fusion temperature. Failure to meet these specifications can result in economic penalties, suspension or cancellation of shipments or termination of the contracts. Some of its contracts specify approved locations from which coal may be sourced. Some of its contracts set out mechanisms for temporary reductions or delays in coal volumes in the event of a force majeure, including events such as strikes, adverse mining conditions, mine closures, or serious transportation problems that affect it or unanticipated plant outages that may affect the buyers.

The terms of its coal supply contracts result from competitive bidding procedures and extensive negotiations with customers. As a result, the terms of these contracts, including price adjustment features, price re-opener terms, coal quality requirements, quantity parameters, permitted sources of supply, future regulatory changes, extension options, force majeure, termination and assignment provisions, vary significantly by customer.

Transportation

The Partnership ships coal to its customers by rail, truck or barge. The majority of its coal is transported to customers by either the CSX Railroad or the Norfolk Southern Railroad in eastern Kentucky and by the Ohio Central Railroad or the Wheeling & Lake Erie Railroad in Ohio. The Partnership uses third-party trucking to transport coal to its customers in Utah. For its Pennyrile complex in western Kentucky, coal is transported to its customers via barge from its river loadout on the Green River located on its Pennyrile mining complex. In addition, coal from certain mines is within economical trucking distance to the Big Sandy River and/or the Ohio River and can be transported by barge. It is customary for customers to pay the transportation costs to their location.

The Partnership believes that it has good relationships with rail carriers and truck companies due, in part, to its modern coal-loading facilities at its loadouts and the working relationships and experience of its transportation and distribution employees.

Suppliers - Rhino

Principal supplies used in the Partnership's business include diesel fuel, explosives, maintenance and repair parts and services, roof control and support items, tires, conveyance structures, ventilation supplies and lubricants. The Partnership uses third-party suppliers for a significant portion of its equipment rebuilds and repairs and construction.

The Partnership has a centralized sourcing group for major supplier contract negotiation and administration, for the negotiation and purchase of major capital goods and to support the mining and coal preparation plants. The Partnership is not dependent on any one supplier in any region. The Partnership promotes competition between suppliers and seeks to develop relationships with those suppliers whose focus is on lowering its costs. The Partnership seeks suppliers who identify and concentrate on implementing continuous improvement opportunities within their area of expertise.

Competition - Rhino

The coal industry is highly competitive. There are numerous large and small producers in all coal producing regions of the United States and the Partnership competes with many of these producers. The Partnership's main competitors include: Alliance Resource Partners LP, Alpha Natural Resources, Inc., Arch Coal, Inc., Booth Energy Group, Blackhawk Mining, LLC, Murray Energy Corporation, Foresight Energy LP, and Wolverine Fuels, LLC.

The most important factors on which the Partnership competes are coal price, coal quality and characteristics, transportation costs and the reliability of supply. Demand for coal and the prices that the Partnership will be able to obtain for its coal are closely linked to coal consumption patterns of the domestic electric generation industry and international consumers. These coal consumption patterns are influenced by factors beyond its control, including demand for electricity, which is significantly dependent upon economic activity and summer and winter temperatures in the United States, government regulation, technological developments and the location, availability, quality and price of competing sources of fuel such as natural gas, oil and nuclear, and alternative energy sources such as hydroelectric power and wind power.

Segments

We operate as a single primary reportable segment relating to our coal investments. We have some general corporate assets that we break out separately as unallocated corporate assets in the segment disclosure. All of our revenues relate to the coal segment. See Part II. "Item 8. Financial Statements and Supplementary Data" for our segment disclosure.

Regulation and Laws

The Partnership's current operations are, and future coal mining operations that we acquire will be, subject to regulation by federal, state and local authorities on matters such as:

- employee health and safety;
- governmental approvals and other authorizations such as mine permits, as well as other licensing requirements;
- air quality standards;

- water quality standards;
- storage, treatment, use and disposal of petroleum products and other hazardous substances;
- plant and wildlife protection;
- reclamation and restoration of mining properties after mining is completed;
- the discharge of materials into the environment, including waterways or wetlands;
- storage and handling of explosives;
- wetlands protection;
- surface subsidence from underground mining;
- the effects, if any, that mining has on groundwater quality and availability; and
- legislatively mandated benefits for current and retired coal miners.

In addition, many of the Partnership's customers are subject to extensive regulation regarding the environmental impacts associated with the combustion or other use of coal, which could affect demand for their coal. The possibility exists that new laws or regulations, or new interpretations of existing laws or regulations, may be adopted that may have a significant impact on the Partnership's mining operations or their customers' ability to use coal. Moreover, environmental citizen groups frequently challenge coal mining, terminal construction, and other related projects.

The Partnership is committed to conducting mining operations in compliance with applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time. Violations, including violations of any permit or approval, can result in substantial civil and in severe cases, criminal fines and penalties, including revocation or suspension of mining permits. None of the violations to date have had a material impact on their operations or financial condition.

While it is not possible to quantify the costs of compliance with applicable federal and state laws and regulations, those costs have been and are expected to continue to be significant. Nonetheless, capital expenditures for environmental matters have not been material in recent years. The Partnership has accrued for the present value of estimated cost of reclamation and mine closings, including the cost of treating mine water discharge when necessary. The accruals for reclamation and mine closing costs are based upon permit requirements and the costs and timing of reclamation and mine closing procedures. Although management believes it has made adequate provisions for all expected reclamation and other costs associated with mine closures, future operating results would be adversely affected if the Partnership later determined these accruals to be insufficient. Compliance with these laws and regulations has substantially increased the cost of coal mining for all domestic coal producers

Mining Permits and Approvals

Numerous governmental permits or approvals are required for coal mining operations. When the Partnership applies for these permits and approvals, they are often required to assess the effect or impact that any proposed production of coal may have upon the environment. The permit application requirements may be costly and time consuming, and may delay or prevent commencement or continuation of mining operations in certain locations. In addition, these permits and approvals can result in the imposition of numerous restrictions on the time, place and manner in which coal mining operations are conducted. Future laws and regulations may emphasize more heavily the protection of the environment and, as a consequence, the Partnership's activities may be more closely regulated. Laws and regulations, as well as future interpretations or enforcement of existing laws and regulations, may require substantial increases in equipment and operating costs, or delays, interruptions or terminations of operations, the extent of any of which cannot be predicted. In addition, the permitting process for certain mining operations can extend over several years, and can be subject to judicial challenge, including by the public. Some required mining permits are becoming increasingly difficult to obtain in a timely manner, or at all. The Partnership may experience difficulty and/or delay in obtaining mining permits in the future.

Regulations provide that a mining permit can be refused or revoked if the permit applicant or permittee owns or controls, directly or indirectly through other entities, mining operations which have outstanding environmental violations. Although, like other coal companies, the Partnership has been cited for violations in the ordinary course of business. However, the Partnership has never had a permit suspended or revoked because of any violation, and the penalties assessed for these violations have not been material.

Before commencing mining on a particular property, the Partnership must obtain mining permits and approvals by state regulatory authorities of a reclamation plan for restoring, upon the completion of mining, the mined property to its approximate prior condition, productive use or other permitted condition.

Mine Health and Safety Laws

Stringent safety and health standards have been in effect since the adoption of the Coal Mine Health and Safety Act of 1969. The Federal Mine Safety and Health Act of 1977 (the "Mine Act"), and regulations adopted pursuant thereto, significantly expanded the enforcement of health and safety standards and imposed comprehensive safety and health standards on numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations and other matters. The Mine Safety and Health Administration ("MSHA") monitors compliance with these laws and regulations. In addition, the states where the Partnership operates also have state programs for mine safety and health regulation and enforcement. Federal and state safety and health regulations affecting the coal industry are complex, rigorous and comprehensive, and have a significant effect on the Partnership's operating costs.

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 scheme that may result in the issuance of an order requiring the immediate withdrawal of miners from the mine or shutting down a mine or any section of a mine or any piece of mine equipment. The Mine Act contains criminal liability provisions. For example, criminal liability may be imposed for corporate operators who knowingly or willfully authorize, order or carry out violations. 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.

The Partnership has developed a health and safety management system that, among other things, includes training regarding worker health and safety requirements including those arising under federal and state laws that apply to their mines. In addition, the Partnership's health and safety management system tracks the performance of each operational facility in meeting the requirements of safety laws and company safety policies. As an example of the resources they allocate to health and safety matters, their safety management system includes a company-wide safety director and local safety directors who oversee safety and compliance at operations on a day-to-day basis. The Partnership continually monitors the performance of their safety management system and from time-to-time modify that system to address findings or reflect new requirements or for other reasons. The Partnership has even integrated safety matters into their compensation and retention decisions. For instance, their bonus program includes a meaningful evaluation of each eligible employee's role in complying with, fostering and furthering their safety policies.

The Partnership evaluates a variety of safety-related metrics to assess the adequacy and performance of their safety management system. For example, the Partnership monitors and tracks performance in areas such as "accidents, reportable accidents, lost time accidents and the lost-time accident frequency rate" and a number of others. Each of these metrics provides insights and perspectives into various aspects of the Partnership's safety systems and performance at particular locations or mines generally and, among other things, can indicate where improvements are needed or further evaluation is warranted with regard to the system or its implementation. An important part of this evaluation is to assess their performance relative to certain national benchmarks.

For the year ended December 31, 2018 the Partnership's average MSHA violations per inspection day was 0.39 as compared to the most recent national average of 0.59 violations per inspection day for coal mining activity as reported by MSHA, or 33.89% below this national average.

Mining accidents in the last several years in West Virginia, Kentucky and Utah have received national attention and instigated responses at the state and national levels that have resulted in increased scrutiny of current safety practices and procedures at all mining operations, particularly underground mining operations. For example, in 2014, MSHA adopted a final rule to lower miners' exposure to respirable coal mine dust. The rule had a phased implementation schedule. The second phase of the 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. Additionally, in September 2015, MSHA issued a proposed rule requiring the installation of proximity detection systems on coal hauling machines and scoops. Proximity detection is a technology that uses electronic sensors to detect motion and the distance between a miner and a machine. These systems provide audible and visual warnings, and automatically stop moving machines when miners are in the machines' path. These and other new safety rules could result in increased compliance costs on their operations.

In addition, more stringent mine safety laws and regulations promulgated by these states and the federal government have included increased sanctions for non-compliance. For example, in 2006, the Mine Improvement and New Emergency Response Act of 2006, or MINER Act, was enacted. 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 in 2006, 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. For example, in July 2014, MSHA proposed a rule that revises its civil penalty assessment provisions and how regulators should approach calculating penalties, which, in some instances, could result in increased civil penalty assessments for medium and larger mine operators and contractors by 300 to 1,000 percent. MSHA proposed some revisions to the original proposed rule in February 2015, but, to date, has not taken any further action. Other states have proposed or passed similar bills, resolutions or regulations addressing enhanced mine safety practices and increased fines and penalties. Moreover, workplace accidents, such as the April 5, 2010, Upper Big Branch Mine incident, have resulted in more inspection hours at mine sites, increased number of inspections and increased issuance of the number and severity of enforcement actions and the passage of new laws and regulations. These trends are likely to continue.

In 2013, MSHA began implementing its recently released Pattern of Violation ("POV") regulations under the Mine Act. Under this regulation, MSHA eliminated the ninety (90) day window to take corrective action and engage in mitigation efforts for mine operators who met certain initial POV screening criteria. Additionally, MSHA will make POV determinations based upon enforcement actions as issued, rather than enforcement actions that have been rendered final following the opportunity for administrative or judicial review. After a mine operator has been placed on POV status, MSHA will thereafter issue an order withdrawing miners from the area affected by any enforcement action designated by MSHA as posing a significant and substantial, or S&S, hazard to the health and/or safety of miners. Further, once designated as a POV mine, a mine operator can be removed from POV status only upon: (1) a complete inspection of the entire mine with no S&S enforcement actions issued by MSHA; or (2) no POV-related withdrawal orders being issued by MSHA within ninety (90) days of the mine operator being placed on POV status. Although it remains to be seen how these new regulations will ultimately affect production at the Partnership's mines, they are consistent with the trend of more stringent enforcement.

From time to time, certain portions of individual mines have been required to suspend or shut down operations temporarily in order to address a compliance requirement or because of an accident. For instance, MSHA issues orders pursuant to Section 103(k) that, among other things, call for operations in the area of the mine at issue to suspend operations until compliance is restored. Likewise, if an accident occurs within a mine, the MSHA requirements call for all operations in that area to be suspended until the circumstance leading to the accident has been resolved. During the fiscal year ended December 31, 2018 (as in earlier years), the Partnership received such orders from government agencies and has experienced accidents within its mines requiring the suspension or shutdown of operations in those particular areas until the circumstances leading to the accident have been resolved. While the violations or other circumstances that caused such an accident were being addressed, other areas of the mine could and did remain operational. These circumstances did not require the Partnership to suspend operations on a mine-wide level or otherwise entail material financial or operational consequences for it. Any suspension of operations at any one of the Partnership's locations that may occur in the future may have material financial or operational consequences for us.

It is the Partnership's practice to contest notices of violations in cases in which it believes it has a good faith defense to the alleged violation or the proposed penalty and/or other legitimate grounds to challenge the alleged violation or the proposed penalty. The Partnership exercises substantial efforts toward achieving compliance at its mines. For example, it has further increased its focus with regard to health and safety at all of its mines. These efforts include hiring additional skilled personnel, providing training programs, hosting quarterly safety meetings with MSHA personnel and making capital expenditures in consultation with MSHA aimed at increasing mine safety. The Partnership believes that these efforts have contributed, and continue to contribute, positively to safety and compliance at the Partnership's mines. In "Part 1, Item 4. Mine Safety Disclosure" and in Exhibit 95.1 to this Annual Report on Form 10-K, the Partnership provides additional details on how they monitor safety performance and MSHA compliance, as well as provide the mine safety disclosures required pursuant to Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act.

Black Lung Laws

Under the Black Lung Benefits Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, coal mine operators must make payments of black lung benefits to current and former coal miners with black lung disease, some survivors of a miner who dies from this disease, and to fund a trust fund for the payment of benefits and medical expenses to claimants who last worked in the industry prior to January 1, 1970. To help fund these benefits, a tax is levied on production of $0.50 per ton for underground-mined coal and $0.25 per ton for surface-mined coal, but not to exceed 2.0% of the applicable sales price (rates effective January 1, 2019). This excise tax does not apply to coal that is exported outside of the United States. In 2018, the Partnership recorded approximately $2.5 million 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 the Partnership's costs expended in association with the federal black lung program. The Partnership may also be liable under state laws for black lung claims that are covered through either insurance policies or state programs.

Workers' Compensation

The Partnership is required to compensate employees for work-related injuries under various state workers' compensation laws. The states in which we operate consider changes in workers' compensation laws from time to time. Its costs will vary based on the number of accidents that occur at their mines and other facilities, and its costs of addressing these claims. The Partnership is insured under the Ohio State Workers Compensation Program for their operations in Ohio. Its remaining operations are insured through Rockwood Casualty Insurance Company.

Surface Mining Control and Reclamation Act ("SMCRA")

SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining, including the surface effects of underground coal mining. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of mining activities. In conjunction with mining the property, the Partnership reclaims and restores the mined areas by grading, shaping and preparing the soil for seeding. Upon completion of mining, reclamation generally is completed by seeding with grasses or planting trees for a variety of uses, as specified in the approved reclamation plan. We believe the Partnership is in compliance in all material respects with applicable regulations relating to reclamation.

SMCRA and similar state statutes require, among other things, that mined property be restored in accordance with specified standards and approved reclamation plans. The act requires that we restore the surface to approximate the original contours as soon as practicable upon the completion of surface mining operations. The mine operator must submit a bond or otherwise secure the performance of these reclamation obligations. Mine operators can also be responsible for replacing certain water supplies damaged by mining operations and repairing or compensating for damage to certain structures occurring on the surface as a result of mine subsidence, a consequence of long-wall mining and possibly other mining operations. In addition, the Abandoned Mine Lands Program, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore mines closed prior to SMCRA's adoption in 1977. The maximum tax for the period from October 1, 2012 through September 30, 2021, has been decreased to 28 cents per ton on surface mined coal and 12 cents per ton on underground mined coal. However, this fee is subject to change. Should this fee be increased in the future, given the market for coal, it is unlikely that coal mining companies would be able to recover all of these fees from their customers. As of December 31, 2018, the Company had accrued approximately $15.6 million for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. In addition, states from time to time have increased and may continue to increase their fees and taxes to fund reclamation of orphaned mine sites and abandoned mine drainage control on a statewide basis.

After a mine application is submitted, public notice or advertisement of the proposed permit action is required, which is followed by a public comment period. 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 years or even longer for the permit to be issued. The variability in time frame required to prepare the application and issue the permit can be attributed primarily to the various regulatory authorities' discretion in the handling of comments and objections relating to the project received from the general public and other agencies. Also, it is not uncommon for a permit to be delayed as a result of judicial challenges related to the specific permit or another related company's permit.

Federal laws and regulations also provide that a mining permit or modification can be delayed, refused or revoked if owners of specific percentages of ownership interests or controllers (i.e., officers and directors or other entities) of the applicant have, or are affiliated with another entity that has outstanding violations of SMCRA or state or tribal programs authorized by SMCRA. This condition is often referred to as being "permit blocked" under the federal Applicant Violator Systems, or AVS. Thus, non-compliance with SMCRA can provide the basis to deny the issuance of new mining permits or modifications of existing mining permits, although we know of no basis by which the Partnership would be (and it is not now) permit-blocked.

In addition, a February 2014 decision by the U.S. District Court for the District of Columbia invalidated the Office of Surface Mining Reclamation and Enforcement's ("OSM") 2008 Stream Buffer Zone Rule, which prohibited mining disturbances within 100 feet of streams, subject to various exemptions. In December 2016, the OSM published the final Stream Protection Rule, which, among other things, would require operators to test and monitor conditions of streams they might impact before, during and after mining. The final rule took effect in January 2017 and would have 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. However, in February 2017, both the House and the Senate passed measures to revoke the Stream Protection Rule under the Congressional Review Act ("CRA"), which gives Congress the ability to repeal regulations promulgated in the last 60 days of the congressional session. President Trump signed the resolution on February 16, 2017 and, pursuant to the CRA, the Stream Protection Rule "shall have no force or effect" and OSM cannot promulgate a substantially similar rule absent future legislation. Whether Congress will enact future legislation to require a new Stream Protection Rule remains uncertain. A new Stream Protection Rule, or other new SMCRA regulations, could result in additional material costs, obligations, and restrictions associated with the Partnership's operations.

Surety Bonds

Federal and state laws require a mine operator to secure the performance of its reclamation obligations required under SMCRA through the use of surety bonds or other approved forms of performance security to cover the costs the state would incur if the mine operator were unable to fulfill its obligations. It has become increasingly difficult for mining companies to secure new surety bonds without the posting of partial collateral. In August 2016, the OSMRE issued a Policy Advisory discouraging state regulatory authorities from approving self-bonding arrangements. The Policy Advisory indicated that the OSM would begin more closely reviewing instances in which states accept self-bonds for mining operations. In the same month, the OSM also announced that it was beginning the rulemaking process to strengthen regulations on self-bonding. In addition, surety bond costs have increased while the market terms of surety bond have generally become less favorable. It is possible that surety bonds issuers may refuse to renew bonds or may demand additional collateral upon those renewals. The Partnership's failure to maintain, or inability to acquire, surety bonds that are required by state and federal laws would have a material adverse effect on its ability to produce coal, which could affect its profitability and cash flow.

As of December 31, 2018, we had approximately $42.6 million in surety bonds outstanding to secure the performance of our reclamation obligations. Of the $42.6 million, approximately $0.4 million relates to surety bonds for Deane Mining, LLC and approximately $3.4 million relates to surety bonds for Sands Hill Mining, LLC, which in each case have not been transferred or replaced by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC as was agreed to by the parties as part of the transactions. We can provide no assurances that a surety company will underwrite the surety bonds of the purchasers of these entities, nor are we aware of the actual amount of reclamation at any given time. Further, if there was a claim under these surety bonds prior to the transfer or replacement of such bonds by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC, then we may be responsible to the surety company for any amounts it pays in respect of such claim. While the buyers are required to indemnify us for damages, including reclamation liabilities, pursuant the agreements governing the sales of these entities, we may not be successful in obtaining any indemnity or any amounts received may be inadequate.

Air Emissions

The federal Clean Air Act (the "CAA") and similar state and local laws and regulations, which regulate emissions into the air, affect coal mining operations both directly and indirectly. The CAA directly impacts the Partnership's coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, on sources that emit various hazardous and non-hazardous air pollutants. The CAA also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants and other industrial consumers of coal, including air emissions of sulfur dioxide, nitrogen oxides, particulates, mercury and other compounds. There have been a series of recent federal rulemakings from the U.S. Environmental Protection Agency, or EPA, which are focused on emissions from coal-fired electric generating facilities. For example, In June 2015, the United States Supreme Court decided Michigan v. the EPA, which held that the EPA should have considered the compliance costs associated with its Mercury and Air Toxics Standards, or MATS, in deciding to regulate power plants under Section 112(n)(1) of the Clean Air Act. The Court did not vacate the MATS rule, and MATS has remained in place. In April 2016, EPA published its final supplemental finding that it is "appropriate and necessary" to regulate coal and oil-fired units under Section 112 of the Clean Air Act. In August 2016, EPA denied two petitions for reconsideration of startup and shutdown provisions in MATS, leaving in place the startup and shutdown provisions finalized in November 2014. The MATS rule was expected to result in the retirement of certain older coal plants. It remains to be seen whether any power plants may reevaluate their decision to retire following the Supreme Court's decision and EPA's recent actions, or whether plants that have already installed certain controls to comply with MATS will continue to operate them at all times. Installation of additional emissions control technology and additional measures required under laws and regulations related to air emissions will make it more costly to operate coal-fired power plants and possibly other facilities that consume coal and, depending on the requirements of individual state implementation plans, or SIPs, could make coal a less attractive fuel alternative in the planning and building of power plants in the future.

In addition to the greenhouse gas ("GHG") regulations discussed below, air emission control programs that affect the Partnership's operations, directly or indirectly, through impacts to coal-fired utilities and other manufacturing plants, include, but are not limited to, the following:

- The EPA's Acid Rain Program, provided in Title IV of the CAA, regulates emissions of sulfur dioxide from electric generating facilities. Sulfur dioxide is a by-product of coal combustion. Affected facilities purchase or are otherwise allocated sulfur dioxide emissions allowances, which must be surrendered annually in an amount equal to a facility's sulfur dioxide emissions in that year. Affected facilities may sell or trade excess allowances to other facilities that require additional allowances to offset their sulfur dioxide emissions. In addition to purchasing or trading for additional sulfur dioxide allowances, affected power facilities can satisfy the requirements of the EPA's Acid Rain Program by switching to lower sulfur fuels, installing pollution control devices such as flue gas desulfurization systems, or "scrubbers," or by reducing electricity generating levels.

- On July 6, 2011, the EPA finalized the Cross State Air Pollution Rule ("CSAPR"), which requires the District of Columbia and 27 states from Texas eastward (not including the New England states or Delaware) 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 September 2016, EPA finalized the CSAPR Rule Update for the 2008 ozone national air quality standards ("NAAQS"). The rule aims to reduce summertime NOx emissions from power plants in 22 states in the eastern United States. Consolidated judicial challenges to the rule are now pending in the D.C. Circuit Court of Appeals.

- In addition, in January 2013, the EPA issued final MACT standards for several classes of boilers and process heaters, including large coal-fired boilers and process heaters (Boiler MACT), which require significant reductions in the emission of particulate matter, carbon monoxide, hydrogen chloride, dioxins and mercury. Various legal challenges were filed and EPA promulgated a revised final rule in November 2015. In December 2016, the D.C. Circuit remanded the Boiler MACT standards to the EPA requiring the agency to revise emissions standards for certain boiler subcategories. The court determined that the existing MACT standards should remain in place while the revised standards are being developed, but did not establish a deadline for the EPA to complete the rulemaking. In June 2017, the U.S. Supreme Court declined to review the D.C. Circuit ruling. We cannot predict the outcome of any legal challenges that may be filed in the future. Before reconsideration, the EPA estimated that the rule would affect 1,700 existing major source facilities with an estimated 14,316 boilers and process heaters. Some owners will make capital expenditures to retrofit boilers and process heaters, while a number of boilers and process heaters will be prematurely retired. The retirements are likely to reduce the demand for coal. The impact of the regulations will depend on the outcome of future legal challenges and EPA actions that cannot be determined at this time.

- The EPA has adopted new, more stringent NAAQS for ozone, fine particulate matter, nitrogen dioxide and sulfur dioxide. As a result, some states will be required to amend their existing SIPs to attain and maintain compliance with the new air quality standards. For example, in June 2010, the EPA issued a final rule setting forth a more stringent primary NAAQS applicable to sulfur dioxide. The rule also modifies the monitoring increment for the sulfur dioxide standard, establishing a 1-hour standard, and expands the sulfur dioxide monitoring network. Initial non-attainment determinations related to the 2010 sulfur dioxide rule were published in August 2013 with an effective date in October 2013. States with non-attainment areas had to submit their SIP revisions in April 2015, which must meet the modified standard by summer 2017. For all other areas, states will be required to submit “maintenance” SIPs. EPA finalized its PM2.5 NAAQS designations in December 2014. Individual states must now identify the sources of PM2.5 emissions and develop emission reduction plans, which may be state-specific or regional in scope. Nonattainment areas must meet the revised standard no later than 2021. More recently, in October 2015, the EPA lowered the NAAQS for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards. Significant additional emissions control expenditures will likely be required at coal-fired power plants and coke plants to meet the new standards. The EPA completed area designations for the 2015 ozone standards in July 2018. Because coal mining operations and coal-fired electric generating facilities emit particulate matter and sulfur dioxide, our mining operations and customers could be affected when the standards are implemented by the applicable states. Moreover, we could face adverse impacts on our business to the extent that these and any other new rules affecting coal-fired power plants result in reduced demand for coal.

In addition, over the years, the Department of Justice, on behalf of the EPA, has filed lawsuits against a number of coal-fired electric generating facilities alleging violations of the new source review provisions of the CAA. The EPA has alleged that certain modifications have been made to these facilities without first obtaining certain permits issued under the new source review program. Several of these lawsuits have settled, but others remain pending. Depending on the ultimate resolution of these cases, demand for the Partnership’s coal could be affected.

Non-government organizations have also petitioned EPA to regulate coal mines as stationary sources under the Clean Air Act. On May 13, 2014, the D.C. Circuit in WildEarth Guardians v. United States Environmental Protection Agency upheld EPA’s denial of one such petition. On July 18, 2014, the D.C. Circuit denied a petition to rehear that case en banc. We cannot guarantee that these groups will not make similar efforts in the future. If such efforts are successful, emissions of these or other materials associated with the Partnership’s mining operations could become subject to further regulation pursuant to existing laws such as the CAA. In that event, the Partnership may be required to install additional emissions control equipment or take other steps to lower emissions associated with its operations, thereby reducing its revenues and adversely affecting its operations.

Climate Change

One by-product of burning coal is carbon dioxide or CO_2, which EPA considers a GHG and a major source of concern with respect to climate change and global warming.

On the international level, the United States was one of almost 200 nations that agreed on December 12, 2015 to an international climate change agreement in Paris, France, that calls for countries to set their own GHG emission targets and be transparent about the measures each country will use to achieve its GHG emission targets; however, the agreement does not set binding GHG emission reduction targets. 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 coal.

At the Federal level, EPA has taken a number of steps to regulate GHG emissions. For example, in August 2015, the EPA issued its final Clean Power Plan (the "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 of the implementation of the CPP in February 2016. By its terms, this stay will remain in effect throughout the pendency of the appeals process. 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 the courts will rule on the legality of the CPP. Additionally, in October 2017 EPA proposed to repeal the CPP, although the final outcome of this action and the pending litigation regarding the CPP is uncertain at this time. In connection with the proposed repeal, EPA issued an Advance Notice of Proposed Rulemaking ("ANPRM") in December 2017 regarding emission guidelines to limit GHG emissions from existing electricity utility generating units. The ANPRM seeks comment regarding what the EPA should include in a potential new, existing-source regulation under the Clean Air Act of GHG emissions from electric utility generating units that it may propose. If the effort to repeal the rules is unsuccessful and the rules were upheld at the conclusion of the appellate process and were implemented in their current form or if the ANPRM results in a different proposal to control GHG emissions from electric utility generating units, demand for coal will likely be further decreased. The EPA also issued a final rule for new coal-fired power plants in August 2015, which essentially set performance standards for coal-fired power plants that requires partial carbon capture and sequestration ("CCS"). Additional legal challenges have been filed against the EPA's rules for new power plants. The EPA's GHG rules for new and existing power plants, taken together, have the potential to severely reduce demand for coal. In addition, passage of any comprehensive federal climate change and energy legislation could impact the demand for coal. Any reduction in the amount of coal consumed by North American electric power generators could reduce the price of coal that we mine and sell, thereby reducing the Partnership's revenues and materially and adversely affecting their business and results of operations.

Many states and regions have adopted greenhouse gas initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of greenhouse gases by certain facilities, including coal-fired electric generating facilities. For example, in 2005, ten northeastern states entered into the Regional Greenhouse Gas Initiative agreement ("RGGI") calling for implementation of a cap and trade program aimed at reducing carbon dioxide emissions from power plants in the participating states. The members of RGGI have established in statute and/or regulation a carbon dioxide trading program. Auctions for carbon dioxide allowances under the program began in September 2008. Though New Jersey withdrew from RGGI in 2011, since its inception, several additional northeastern states and Canadian provinces have joined as participants or observers.

Following the RGGI model, five Western states launched the Western Regional Climate Action Initiative to identify, evaluate and implement collective and cooperative methods of reducing greenhouse gases in the region to 15% below 2005 levels by 2020. These states were joined by two additional states and four Canadian provinces and became collectively known as the Western Climate Initiative Partners. However, in November 2011, six states withdrew, leaving California and the four Canadian provinces as members. At a January 12, 2012 stakeholder meeting, this group confirmed a commitment and timetable to create the largest carbon market in North America and provide a model to guide future efforts to establish national approaches in both Canada and the U.S. to reduce GHG emissions. It is likely that these regional efforts will continue.

Many coal-fired plants have already closed or announced plans to close and proposed new construction projects have also come under additional scrutiny with respect to GHG emissions. There have been an increasing number of protests and challenges to the permitting of new coal-fired power plants by environmental organizations and state regulators due to concerns related to greenhouse gas emissions. Other state regulatory authorities have also rejected the construction of new coal-fueled power plants based on the uncertainty surrounding the potential costs associated with GHG emissions from these plants under future laws limiting the emissions of carbon dioxide. In addition, several permits issued to new coal-fired power plants without limits on GHG emissions have been appealed to the EPA's Environmental Appeals Board. In addition, over 30 states have adopted mandatory "renewable portfolio standards," which require electric utilities to obtain a certain percentage of their electric generation portfolio from renewable resources by a certain date. These standards range generally from 10% to 30%, over time periods that generally extend from the present until between 2020 and 2030. Other states may adopt similar requirements, and federal legislation is a possibility in this area. To the extent these requirements affect the Partnership's current and prospective customers; they may reduce the demand for coal-fired power, and may affect long-term demand for their coal.

If mandatory restrictions on CO_2 emissions are imposed, the ability to capture and store large volumes of carbon dioxide emissions from coal-fired power plants may be a key mitigation technology to achieve emissions reductions while meeting projected energy demands. A number of recent legislative and regulatory initiatives to encourage the development and use of carbon capture and storage technology have been proposed or enacted. For example, in October 2015, the EPA released a rule that established, 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. The EPA has designated partial carbon capture and sequestration as the best system of emission reduction for newly constructed fossil fuel-fired steam generating units at power plants to employ to meet the standard. However, widespread cost-effective deployment of CCS will occur only if the technology is commercially available at economically competitive prices and supportive national policy frameworks are in place.

There have also been attempts to encourage greater regulation of coalbed methane because methane has a greater GHG effect than CO2. Methane from coal mines can give rise to safety concerns, and may require that various measures be taken to mitigate those risks. If new laws or regulations were introduced to reduce coalbed methane emissions, those rules could adversely affect the Partnership's costs of operations.

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.

Finally, some scientists have warned that increasing concentrations of greenhouse gases ("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 these warnings are correct, and if any such effects were to occur in areas where the Partnership or their customers operate, they could have an adverse effect on their assets and operations.

Clean Water Act

The Federal Clean Water Act (the "CWA") and similar state and local laws and regulations affect coal mining operations by imposing restrictions on the discharge of pollutants, including dredged or fill material, into waters of the U.S. The CWA establishes in-stream water quality and treatment standards for wastewater discharges that are applied to wastewater dischargers through Section 402 National Pollutant Discharge Elimination System ("NPDES") permits. Regular monitoring, as well as compliance with reporting requirements and performance standards, are preconditions for the issuance and renewal of Section 402 NPDES permits. Individual permits or general permits under Section 404 of the CWA are required to discharge dredged or fill materials into waters of the U.S. including wetlands, streams, and other areas meeting the regulatory definition. Expansion of EPA jurisdiction over these areas has the potential to adversely impact our operations. Considerable legal uncertainty exists surrounding the standard for what constitutes jurisdictional waters and wetlands subject to the protections and requirements of the Clean Water Act. A 2015 rulemaking by EPA to revise the standard was stayed nationwide by the U.S. Court of Appeals for the Sixth Circuit and stayed for certain primarily western states by a United States District Court in North Dakota. In January 2018, the Supreme Court determined that the circuit courts do not have jurisdiction to hear challenges to the 2015 rule, removing the basis for the Sixth Circuit to continue its nationwide stay. Additionally, EPA has promulgated a final rule that extends the applicability date of the 2015 rule for another two years in order to allow EPA to undertake a rulemaking on the question of what constitutes a water of the United States. In the meantime, judicial challenges to the 2015 rulemaking are likely to continue to work their way through the courts along with challenges to the recent rulemaking that extends the applicability date of the 2015 rule. For now, EPA and the Corps will continue to apply the existing standard for what constitutes a water of the United States as determined by the Supreme Court in the Rapanos case and post-Rapanos guidance. Should the 2015 rule take effect, or should a different rule expanding the definition of what constitutes a water of the United States be promulgated as a result of EPA and the Corps's rulemaking process, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The Partnership's surface coal mining and preparation plant operations typically require such permits to authorize activities such as the creation of slurry ponds, stream impoundments, and valley fills. The EPA, or a state that has been delegated such authority by the EPA, issues NPDES permits for the discharge of pollutants into navigable waters, while the U.S. Army Corps of Engineers (the "Corps") issues dredge and fill permits under Section 404 of the CWA. Where Section 402 NPDES permitting authority has been delegated to a state, the EPA retains a limited oversight role. The CWA also gives the EPA an oversight role in the Section 404 permitting program, including drafting substantive rules governing permit issuance by the Corps, providing comments on proposed permits, and, in some cases, exercising the authority to delay or pre-empt Corps issuance of a Section 404 permit. The EPA has recently asserted these authorities more forcefully to question, delay, and prevent issuance of some Section 402 and 404 permits for surface coal mining in Appalachia. Currently, significant uncertainty exists regarding the obtaining of permits under the CWA for coal mining operations in Appalachia due to various initiatives launched by the EPA regarding these permits.

For instance, even though the Commonwealth of Kentucky and the State of West Virginia have been delegated the authority to issue NPDES permits for coal mines in those states, the EPA is taking a more active role in its review of NPDES permit applications for coal mining operations in Appalachia. The EPA issued final guidance on July 21, 2011 that encouraged EPA Regions 3, 4 and 5 to object to the issuance of state program NPDES permits where the Region does not believe that the proposed permit satisfies the requirements of the CWA and with regard to state issued general Section 404 permits, support the previously drafted Enhanced Coordination Process ("ECP") among the EPA, the Corps, and the U.S. Department of the Interior for issuing Section 404 permits, whereby the EPA undertook a greater level of review of certain Section 404 permits than it had previously undertaken. The D.C. Circuit upheld EPA's use of the ECP in July 2014. Future application of the ECP, such as may be enacted following notice and comment rulemaking, would have the potential to delay issuance of permits for surface coal mines, or to change the conditions or restrictions imposed in those permits.

The EPA also has statutory "veto" power under Section 404(c) to effectively revoke a previously issued Section 404 permit if the EPA determines, after notice and an opportunity for a public hearing, that the permit will have an "unacceptable adverse effect." The Court previously upheld the EPA's ability to exercise this authority. Any future use of the EPA's Section 404 "veto" power could create uncertainty with regard to the Partnership's continued use of their current permits, as well as impose additional time and cost burdens on future operations, potentially adversely affecting their revenues.

The Corps is authorized to issue general "nationwide" permits for specific categories of activities that are similar in nature and that are determined to have minimal adverse environmental effects. The Partnership may no longer seek general permits under Nationwide Permit 21 ("NWP 21") because in February 2012, the Corps reinstated the use of NWP 21, but limited application of NWP 21 authorizations to discharges with impacts not greater than a half-acre of water, including no more than 300 linear feet of streambed, and disallowed the use of NWP 21 for valley fills. This limitation remains in place in the NWP 21 issued in January of 2017. If the 2017 NWP 21 cannot be used for any of the Partnership's proposed surface coal mining projects, the Partnership will have to obtain individual permits from the Corps subject to the additional EPA measures discussed below with the uncertainties and delays attendant to that process.

The Partnership currently has a number of Section 404 permit applications pending with the Corps. Not all of these permit applications seek approval for valley fills or other obvious "fills"; some relate to other activities, such as mining through streams and the associated post-mining reconstruction efforts. The Partnership sought to prepare all pending permit applications consistent with the requirements of the Section 404 program. The Partnership's five year plan of mining operations does not rely on the issuance of these pending permit applications. However, the Section 404 permitting requirements are complex, and regulatory scrutiny of these applications, particularly in Appalachia, has increased such that their applications may not be granted or, alternatively, the Corps may require material changes to their proposed operations before it grants permits. While the Partnership will continue to pursue the issuance of these permits in the ordinary course of their operations, to the extent that the permitting process creates significant delay or limits the Partnership's ability to pursue certain reserves beyond their current five year plan, their revenues may be negatively affected.

Total Maximum Daily Load ("TMDL") regulations under the CWA establish a process to calculate the maximum amount of a pollutant that an impaired water body can receive and still meet state water quality standards, and to allocate pollutant loads among the point and non-point pollutant sources discharging into that water body. Likewise, when water quality in a receiving stream is better than required, states are required to conduct an anti-degradation review before approving discharge permits. The adoption of new TMDLs and load allocations or any changes to anti-degradation policies for streams near the Partnership's coal mines could limit their ability to obtain NPDES permits, require more costly water treatment, and adversely affect their coal production.

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, and analogous state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. Some products used by coal companies in operations generate waste containing hazardous substances. The Partnership is not aware of any material liability associated with the release or disposal of hazardous substances from the Partnership's past or present mine sites.

The federal Resource Conservation and Recovery Act ("RCRA") and corresponding state laws regulating hazardous waste affect coal mining operations by imposing requirements for the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes. Many mining wastes are excluded from the regulatory definition of hazardous wastes, and coal mining operations covered by SMCRA permits are by statute exempted from RCRA permitting. RCRA also allows the EPA to require corrective action at sites where there is a release of hazardous wastes. In addition, each state has its own laws regarding the proper management and disposal of waste material. While these laws impose ongoing compliance obligations, such costs are not believed to have a material impact on the Partnership's operations.

In December 2014, 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. The rule leaves intact the Bevill exemption for beneficial uses of CCB, though it defers a final Bevill regulatory determination with respect to CCB that is disposed of in landfills or surface impoundments. Additionally, in December 2016, Congress passed the Water Infrastructure Improvements for the Nation Act, which provides for the establishment of state and EPA permit programs for the control of coal combustion residuals and authorizes states to incorporate EPA's final rule for coal combustion residuals or develop other criteria that are at least as protective as the final rule. The costs of complying with these new requirements may result in a material adverse effect on the Partnership's business, financial condition or results of operations, and could potentially increase its customers' operating costs, thereby reducing their ability to purchase coal as a result. In addition, contamination caused by the past disposal of CCB, including coal ash, can lead to material liability to its customers under RCRA or other federal or state laws and potentially reduce the demand for coal.

Endangered Species Act

The federal Endangered Species Act and counterpart state legislation protect species threatened with possible extinction. Protection of threatened and endangered species may have the effect of prohibiting or delaying the Partnership from obtaining mining permits and may include restrictions on timber harvesting, road building and other mining or agricultural activities in areas containing the affected species or their habitats. A number of species indigenous to the Partnership's properties are protected under the Endangered Species Act. Based on the species that have been identified to date and the current application of applicable laws and regulations, however, the Partnership does not believe there are any species protected under the Endangered Species Act that would materially and adversely affect its ability to mine coal from its properties in accordance with current mining plans.

Use of Explosives

The Partnership uses explosives in connection with its surface mining activities. The Federal Safe Explosives Act ("SEA") applies to all users of explosives. Knowing or willful violations of the SEA may result in fines, imprisonment, or both. In addition, violations of SEA may result in revocation of user permits and seizure or forfeiture of explosive materials.

The storage of explosives is also 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 in order to help determine whether there is a high level of security risk, such that a security vulnerability assessment and a site security plan will be required. It is possible that its use of explosives in connection with blasting operations may subject the Partnership to the Department of Homeland Security's chemical facility security regulatory program.

In December 2014, OSM announced its decision to propose a rule that will address all blast generated fumes and toxic gases. OSM has not yet issued a proposed rule to address these blasts. The Partnership is unable to predict the impact, if any, of these actions by the OSM, although the actions potentially could result in additional delays and costs associated with its blasting operations.

Other Environmental and Mine Safety Laws

The Partnership is also required to comply with numerous other federal, state and local environmental and mine safety laws and regulations in addition to those previously discussed. These additional laws include, for example, the Safe Drinking Water Act, the Toxic Substance Control Act and the Emergency Planning and Community Right-to-Know Act. The costs of compliance with these requirements is not expected to have a material adverse effect on the Partnership's business, financial condition or results of operations.

Federal Power Act – Grid Reliability Proposal

Pursuant to a direction from the Secretary of the Department of Energy, 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 in the future 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 the shuttering of 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 the FERC's decision to further study the issue of grid resiliency.

Employees

We and our subsidiaries employed 702 full-time employees as of December 31, 2018. None of the employees are subject to collective bargaining agreements. We believe that we have good relations with these employees and since its inception it has had no history of work stoppages or union organizing campaigns.

Available Information

Our internet address is *http://www.royalenergy.us* , and we make available free of charge on our website our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and Forms 3, 4 and 5 for our Section 16 filers (and amendments and exhibits, such as press releases, to such filings) as soon as reasonably practicable after we electronically file with or furnish such material to the SEC. Information on our website or any other website is not incorporated by reference into this report and does not constitute a part of this report.

We file or furnish annual, quarterly and current reports and other documents with the SEC under the Securities Exchange Act of 1934 (the "Exchange Act"). The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Additionally, the SEC's website, *http://www.sec.gov,* contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC.

Item 1A. Risk Factors.

In addition to the factors discussed elsewhere in this report, including the financial statements and related notes, you should consider carefully the risks and uncertainties described below. If any of these risks or uncertainties, as well as other risks and uncertainties that are not currently known to us or that we currently believe are not material, were to occur, our business, financial condition or results of operation could be materially adversely affected and you may lose all or a significant part of your investment.

Risks Inherent in Our Business

A decline in coal prices could adversely affect our results of operations and our ability to receive cash distributions from the Partnership.

Our results of operations and the value of our coal reserves are significantly dependent upon the prices we receive for our coal as well as our ability to improve productivity and control costs. Prices for coal tend to be cyclical; however, prices have become more volatile and depressed as a result of oversupply in the marketplace. The prices we receive for coal depend upon factors beyond our control, including:

- the supply of domestic and foreign coal;
- the demand for domestic and foreign coal, which is significantly affected by the level of consumption of steam coal by electric utilities and the level of consumption of metallurgical coal by steel producers;
- the price and availability of alternative fuels for electricity generation;
- the proximity to, and capacity of, transportation facilities;
- domestic and foreign governmental regulations, particularly those relating to the environment, climate change, health and safety;
- the level of domestic and foreign taxes;
- weather conditions;
- terrorist attacks and the global and domestic repercussions from terrorist activities; and
- prevailing economic conditions.

Any adverse change in these factors could result in weaker demand and lower prices for our products. In addition, global financial and credit market disruptions, have had an impact on the coal industry generally and may continue to do so. The demand for electricity and steel may remain at low levels or further decline if economic conditions remain weak. If these trends continue, we may not be able to sell all of the coal we are capable of producing or sell our coal at prices comparable to recent years.

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 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. A substantial or extended decline in the prices we receive for our coal supply contracts could materially and adversely affect our results of operations.

The Partnership performed a comprehensive review of our coal mining operation as well as potential future development projects for the year ended December 31, 2018 to ascertain any potential impairment losses. We did not record any impairment losses for coal properties, mine development costs or coal mining equipment and related facilities for the year ended December 31, 2018.

The Partnership performed a comprehensive review of its current coal mining operation as well as potential future development projects for the year ended December 31, 2017 to ascertain any potential impairment losses. The Partnership engaged an independent third party to perform a fair market value appraisal on certain parcels of land that it owns in Mesa County, Colorado. The parcels appraised for $6.0 million compared to the carrying value of $6.8 million. The Partnership recorded an impairment loss of $0.8 million, which is recorded on the Asset impairment and related charges line of the consolidated statements of operations and comprehensive income. No other coal properties, mine development costs or other coal mining equipment and related facilities were impaired as of December 31, 2017.

The Partnership also recorded an impairment charge of $21.8 million related to the call option received from a third party to acquire substantially all of the outstanding common stock of Armstrong Energy, Inc. On October 31, 2017, Armstrong Energy filed Chapter 11 petitions in the Eastern District of Missouri's United States Bankruptcy Court. Per the Chapter 11 petitions, Armstrong Energy filed a detailed restructuring plan as part of the Chapter 11 proceedings. On February 9, 2018, the U.S. Bankruptcy Court confirmed Armstrong Energy's Chapter 11 reorganization plan and as such we concluded that the call option had no carrying value. An impairment charge of $21.8 million related to the call option has been recorded on the Asset impairment and related charges line of the consolidated statements of operations and comprehensive income.

We completed a comprehensive review of all coal assets beyond those related to the Partnership and identified one impairment in 2018 and various impairments in 2017. Based on the impairment analysis, we concluded that the ARQ royalty interest was impaired. As production from this property had not begun at December 31, 2018 or December 31, 2017, we conducted an impairment assessment. At December 31, 2018, the Company adjusted the value to $0. At December 31, 2017, the Company adjusted the value to $1.8 million based on an option that we granted to ARQ to purchase the royalty interest, which triggered a fourth quarter 2017 impairment loss of $2.6 million. The option subsequently expired leading to the remaining 2018 impairment charge.

Additionally, at December 31, 2017, management determined that its investment in Blaze Minerals was impaired and removed the entire investment and associated assets from the consolidated financial statements. Accordingly, we recorded an additional asset impairment loss of $7 million in the fourth quarter of 2017.

We could be negatively impacted by the competitiveness of the global markets in which we compete and declines in the market demand for coal.

We compete with coal producers in various regions of the United States and overseas for domestic and international sales. The domestic demand for, and prices of, our coal primarily depend on coal consumption patterns of the domestic electric utility industry and the domestic steel industry. Consumption by the domestic electric utility industry is affected by the demand for electricity, environmental and other governmental regulations, technological developments and the price of competing coal and alternative fuel sources, such as natural gas, nuclear, hydroelectric and wind power and other renewable energy sources. Consumption by the domestic steel industry is primarily affected by economic growth and the demand for steel used in construction as well as appliances and automobiles. The competitive environment for coal is impacted by a number of the largest markets in the world, including the United States, China, Japan and India, where demand for both electricity and steel has supported prices for steam and metallurgical coal. The economic stability of these markets has a significant effect on the demand for coal and the level of competition in supplying these markets. The cost of ocean transportation and the value of the U.S. dollar in relation to foreign currencies significantly impact the relative attractiveness of our coal as we compete on price with foreign coal producing sources. During the last several years, the U.S. coal industry has experienced increased consolidation, which has contributed to the industry becoming more competitive. Increased competition by coal producers or producers of alternate fuels could decrease the demand for, or pricing of, or both, for our coal, adversely impacting our results of operations and cash available for distribution.

Any change in consumption patterns by utilities away from the use of coal, such as resulting from current low natural gas prices, could affect our ability to sell the coal we produce, which could adversely affect our results of operations and our ability to receive cash distributions from the Partnership.

Steam coal accounted for approximately 81% of our coal sales volume for the year ended December 31, 2018. The majority of our sales of steam coal during this period were to electric utilities for use primarily as fuel for domestic electricity consumption. The amount of coal consumed by the domestic electric utility industry is affected primarily by the overall demand for electricity, environmental and other governmental regulations, and the price and availability of competing fuels for power plants such as nuclear, natural gas and oil as well as alternative sources of energy. We compete generally with producers of other fuels, such as natural gas and oil. A decline in price for these fuels could cause demand for coal to decrease and adversely affect the price of our coal. For example, sustained low natural gas prices have led, in some instances, to decreased coal consumption by electricity-generating utilities. If alternative energy sources, such as nuclear, hydroelectric, wind or solar, become more cost-competitive on an overall basis, demand for coal could decrease and the price of coal could be materially and adversely affected. Further, legislation requiring, subsidizing or providing tax benefits for the use of alternative energy sources and fuels, or legislation providing financing or incentives to encourage continuing technological advances in this area, could further enable alternative energy sources to become more competitive with coal. A decrease in coal consumption by the domestic electric utility industry could adversely affect the price of coal, which could materially adversely affect our results of operations and our ability to receive cash distributions from the Partnership.

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

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate issues, are resulting in increased regulation of coal combustion in many jurisdictions, unfavorable lending policies by 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, 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 also pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. In California, for example, legislation was signed into law in October 2015 that requires California's state pension funds to divest investments in companies that generate 50% or more of their revenue from coal mining by July 2017. 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.

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."

The net effect of these 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.

Our mining operations are subject to extensive and costly environmental laws and regulations, and such current and future laws and regulations could materially increase our operating costs or limit our ability to produce and sell coal.

The coal mining industry is subject to numerous and extensive federal, state and local environmental laws and regulations, including laws and regulations pertaining to permitting and licensing requirements, air quality standards, plant and wildlife protection, reclamation and restoration of mining properties, the discharge of materials into the environment, the storage, treatment and disposal of wastes, protection of wetlands, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. The costs, liabilities and requirements associated with these laws and regulations are significant and time-consuming and may delay commencement or continuation of our operations. Moreover, the possibility exists that new laws or regulations (or new judicial interpretations or enforcement policies of existing laws and regulations) could materially affect our mining operations, results of operations and our ability to receive cash distributions from the Partnership, either through direct impacts such as those regulating our existing mining operations, or indirect impacts such as those that discourage or limit our customers' use of coal. Violations of applicable laws and regulations would subject us to administrative, civil and criminal penalties and a range of other possible sanctions. The enforcement of laws and regulations governing the coal mining industry has increased substantially. As a result, the consequences for any noncompliance may become more significant in the future.

Our operations use petroleum products, coal processing chemicals and other materials that may be considered "hazardous materials" under applicable environmental laws and have the potential to generate other materials, all of which may affect runoff or drainage water. In the event of environmental contamination or a release of these materials, we could become subject to claims for toxic torts, natural resource damages and other damages and for the investigation and cleanup of soil, surface water, groundwater, and other media, as well as abandoned and closed mines located on property we operate. Such claims may arise out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire.

The government extensively regulates mining operations, especially with respect to mine safety and health, which imposes significant actual and potential costs on us, and future regulation could increase those costs or limit our ability to produce coal.

Coal mining is subject to inherent risks to safety and health. As a result, the coal mining industry is subject to stringent safety and health standards. Fatal mining accidents in the United States in recent years have received national attention and have led to responses at the state and federal levels that have resulted in increased regulatory scrutiny of coal mining operations, particularly underground mining operations. More stringent state and federal mine safety laws and regulations have included increased sanctions for non-compliance. Moreover, future workplace accidents are likely to result in more stringent enforcement and possibly the passage of new laws and regulations.

Within the last few years, the industry has seen enactment of the Federal Mine Improvement and New Emergency Response Act of 2006 (the "MINER Act"), subsequent additional legislation and regulation imposing significant new safety initiatives and the Dodd-Frank Act, which, among other things, imposes new mine safety information reporting requirements. The MINER Act significantly amended the Federal Mine Safety and Health Act of 1977 (the "Mine Act"), imposing more extensive and stringent compliance standards, increasing criminal penalties and establishing a maximum civil penalty for non-compliance, and expanding the scope of federal oversight, inspection, and enforcement activities. Following the passage of the MINER Act, the U.S. Mine Safety and Health Administration ("MSHA") issued new or more stringent rules and policies on a variety of topics, including:

- sealing off abandoned areas of underground coal mines;
- mine safety equipment, training and emergency reporting requirements;
- substantially increased civil penalties for regulatory violations;

- training and availability of mine rescue teams;
- underground "refuge alternatives" capable of sustaining trapped miners in the event of an emergency;
- flame-resistant conveyor belt, fire prevention and detection, and use of air from the belt entry; and
- post-accident two-way communications and electronic tracking systems.

For example, in 2014, MSHA adopted a final rule that reduces the permissible concentration of respirable dust in underground coal mines from the current standard of 2.0 milligrams per cubic meter of air to 1.5 milligram per cubic meter. The rule had a phased implementation schedule, and the third and final phase of the rule became effective in August 2016. Under the phased approach, operators were required to adopt new measures and procedures for dust sampling, record keeping, and medical surveillance. Additionally, in September 2015, MSHA issued a proposed rule requiring the installation of proximity detection systems coal hauling machines and scoops. The rulemaking record for this proposed rule was closed on December 15, 2016, but on January 9, 2017, MSHA published a notice reopening the record and extending the comment period for this proposed rule for 30 days. Proximity detection is a technology that uses electronic sensors to detect motion and the distance between a miner and a machine. These systems provide audible and visual warnings, and automatically stop moving machines when miners are in the machines' path. These and other new safety rules could result in increased compliance costs on our operations. Subsequent to passage of the MINER Act, various coal producing states, including West Virginia, Ohio and Kentucky, have enacted legislation addressing issues such as mine safety and accident reporting, increased civil and criminal penalties, and increased inspections and oversight. Other states may pass similar legislation in the future. Additional federal and state legislation that would further increase mine safety regulation, inspection and enforcement, particularly with respect to underground mining operations, has also been considered.

Although we are unable to quantify the full impact, implementing and complying with these new laws and regulations could have an adverse impact on our results of operations and our ability to receive cash distributions from the Partnership and could result in harsher sanctions in the event of any violations. Please read "Part 1, Item 1. Business—Regulation and Laws."

Penalties, fines or sanctions levied by MSHA could have a material adverse effect on our business, results of operations and cash available for distribution.

Surface and underground mines like ours and those of our competitors are continuously inspected by MSHA, which often leads to notices of violation. Recently, MSHA has been conducting more frequent and more comprehensive inspections. In addition, in July 2014, MSHA proposed a rule that revises its civil penalty assessment provisions and how regulators should approach calculating penalties, which, in some instances, could result in increased civil penalty assessments for medium and larger mine operators and contractors by 300% to 1,000%. MSHA issued a revised proposed rule in February 2015, but, to date, has not taken any further action. However, increased scrutiny by MSHA and enforcement against mining operations are likely to continue.

We have in the past, and may in the future, be subject to fines, penalties or sanctions resulting from alleged violations of MSHA regulations. Any of our mines could be subject to a temporary or extended shut down as a result of an alleged MSHA violation. Any future penalties, fines or sanctions could have a material adverse effect on our business, results of operations and cash available for distribution.

We may be unable to obtain and/or renew permits necessary for our operations, which could prevent us from mining certain reserves.

Numerous governmental permits and approvals are required for mining operations, and we can face delays, challenges to, and difficulties in acquiring, maintaining or renewing necessary permits and approvals, including environmental permits. The permitting rules, and the interpretations of these rules, are complex, change frequently, and are often subject to discretionary interpretations by regulators, all of which may make compliance more difficult or impractical, and may possibly preclude the continuance of ongoing mining operations or the development of future mining operations. For example, final guidance released by the CEQ regarding climate change considerations in the NEPA analyses may increase the likelihood of future challenges to the NEPA documents prepared for actions requiring federal approval. In addition, the public has certain statutory rights to comment upon and otherwise impact the permitting process, including through court intervention. Over the past few years, the length of time needed to bring a new surface mine into production has increased because of the increased time required to obtain necessary permits. The slowing pace at which permits are issued or renewed for new and existing mines has materially impacted production in Appalachia, but could also affect other regions in the future.

Section 402 National Pollutant Discharge Elimination System permits and Section 404 CWA permits are required to discharge wastewater and discharge dredged or fill material into waters of the United States (“WOTUS”). Expansion of EPA jurisdiction over these areas has the potential to adversely impact our operations. 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. Please read “Part I, Item 1. Business—Regulation and Laws—Clean Water Act.” For now, EPA and the Corps will continue to apply the existing standard for what constitutes a water of the United States as determined by the Supreme Court in the Rapanos case and post-Rapanos guidance. Should the 2015 rule take effect, or should a different rule expanding the definition of what constitutes a water of the United States be promulgated as a result of EPA and the Corps’s rulemaking process, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Our surface coal mining operations typically require such permits to authorize such activities as the creation of slurry ponds, stream impoundments, and valley fills. Although the CWA gives the EPA a limited oversight role in the Section 404 permitting program, the EPA has recently asserted its authorities more forcefully to question, delay, and prevent issuance of some Section 404 permits for surface coal mining in Appalachia. Currently, significant uncertainty exists regarding the obtaining of permits under the CWA for coal mining operations in Appalachia due to various initiatives launched by the EPA regarding these permits.

Our mining operations are subject to operating risks that could adversely affect production levels and operating costs.

Our mining operations are subject to conditions and events beyond our control that could disrupt operations, resulting in decreased production levels and increased costs.

These risks include:

- unfavorable geologic conditions, such as the thickness of the coal deposits and the amount of rock embedded in or overlying the coal deposit;
- inability to acquire or maintain necessary permits or mining or surface rights;
- changes in governmental regulation of the mining industry or the electric utility industry;
- adverse weather conditions and natural disasters;
- accidental mine water flooding;
- labor-related interruptions;
- transportation delays;
- mining and processing equipment unavailability and failures and unexpected maintenance problems; and
- accidents, including fire and explosions from methane.

Any of these conditions may increase the cost of mining and delay or halt production at particular mines for varying lengths of time, which in turn could adversely affect our results of operations and operating cash flow.

In general, mining accidents present a risk of various potential liabilities depending on the nature of the accident, the location, the proximity of employees or other persons to the accident scene and a range of other factors. Possible liabilities arising from a mining accident include workmen's compensation claims or civil lawsuits for workplace injuries, claims for personal injury or property damage by people living or working nearby and fines and penalties including possible criminal enforcement against us and certain of our employees. In addition, a significant accident that results in a mine shut-down could give rise to liabilities for failure to meet the requirements of coal supply agreements especially if the counterparties dispute our invocation of the force majeure provisions of those agreements. We maintain insurance coverage to mitigate the risks of certain of these liabilities, including business interruption insurance, but those policies are subject to various exclusions and limitations and we cannot assure you that we will receive coverage under those policies for any personal injury, property damage or business interruption claims that may arise out of such an accident. Moreover, certain potential liabilities such as fines and penalties are not insurable risks. Thus, a serious mine accident may result in material liabilities that adversely affect our results of operations and cash available for distribution.

Fluctuations in transportation costs or disruptions in transportation services could increase competition or impair our ability to supply coal to our customers, which could adversely affect our results of operations and our ability to receive cash distributions from the Partnership.

Transportation costs represent a significant portion of the total cost of coal for our customers and, as a result, the cost of transportation is a critical factor in a customer's purchasing decision. Increases in transportation costs could make coal a less competitive energy source or could make our coal production less competitive than coal produced from other sources.

Significant decreases in transportation costs could result in increased competition from coal producers in other regions. For instance, coordination of the many eastern U.S. coal loading facilities, the large number of small shipments, the steeper average grades of the terrain and a more unionized workforce are all issues that combine to make shipments originating in the eastern United States inherently more expensive on a per-mile basis than shipments originating in the western United States. Historically, high coal transportation rates from the western coal producing regions limited the use of western coal in certain eastern markets. The increased competition could have an adverse effect on our results of operations and our ability to receive cash distributions from the Partnership.

We depend primarily upon railroads, barges and trucks to deliver coal to our customers. Disruption of any of these services due to weather-related problems, strikes, lockouts, accidents, mechanical difficulties and other events could temporarily impair our ability to supply coal to our customers, which could adversely affect our results of operations and our ability to receive cash distributions from the Partnership.

In recent years, the states of Kentucky and West Virginia have increased enforcement of weight limits on coal trucks on their public roads. It is possible that other states may modify their laws to limit truck weight limits. Such legislation and enforcement efforts could result in shipment delays and increased costs. An increase in transportation costs could have an adverse effect on our ability to increase or to maintain production and could adversely affect our results of operations and cash available for distribution.

A shortage of skilled labor in the mining industry could reduce productivity and increase operating costs, which could adversely affect our results of operations and our ability to receive cash distributions from the Partnership.

Efficient coal mining using modern techniques and equipment requires skilled laborers. During periods of high demand for coal, the coal industry has experienced a shortage of skilled labor as well as rising labor and benefit costs, due in large part to demographic changes as existing miners retire at a faster rate than new miners are entering the workforce. If a shortage of experienced labor should occur or coal producers are unable to train enough skilled laborers, there could be an adverse impact on labor productivity, an increase in our costs and our ability to expand production may be limited. If coal prices decrease or our labor prices increase, our results of operations and our ability to receive cash distributions from the Partnership could be adversely affected.

Unexpected increases in raw material costs, such as steel, diesel fuel and explosives could adversely affect our results of operations.

Our coal mining operations are affected by commodity prices. We use significant amounts of steel, diesel fuel, explosives and other raw materials in our mining operations, and volatility in the prices for these raw materials could have a material adverse effect on our operations. Steel prices and the prices of scrap steel, natural gas and coking coal consumed in the production of iron and steel fluctuate significantly and may change unexpectedly. Additionally, a limited number of suppliers exist for explosives, and any of these suppliers may divert their products to other industries. Shortages in raw materials used in the manufacturing of explosives, which, in some cases, do not have ready substitutes, or the cancellation of supply contracts under which these raw materials are obtained, could increase the prices and limit the ability of us or our contractors to obtain these supplies. Future volatility in the price of steel, diesel fuel, explosives or other raw materials will impact our operating expenses and could adversely affect our results of operations and cash available for distribution.

If we are not able to acquire replacement coal reserves that are economically recoverable, our results of operations and our ability to receive cash distributions from the Partnership could be adversely affected.

Our results of operations and our ability to receive cash distributions from the Partnership depend substantially on obtaining coal reserves that have geological characteristics that enable them to be mined at competitive costs and to meet the coal quality needed by our customers. Because we deplete our reserves as we mine coal, our future success and growth will depend, in part, upon our ability to acquire additional coal reserves that are economically recoverable. If we fail to acquire or develop additional reserves, our existing reserves will eventually be depleted. Replacement reserves may not be available when required or, if available, may not be capable of being mined at costs comparable to those characteristic of the depleting mines. We may not be able to accurately assess the geological characteristics of any reserves that we acquire, which may adversely affect our results of operations and our ability to receive cash distributions from the Partnership. Exhaustion of reserves at particular mines with certain valuable coal characteristics also may have an adverse effect on our operating results that is disproportionate to the percentage of overall production represented by such mines. Our ability to obtain other reserves in the future could be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties, the lack of suitable acquisition candidates or the inability to acquire coal properties on commercially reasonable terms.

Inaccuracies in our estimates of coal reserves and non-reserve coal deposits could result in lower than expected revenues and higher than expected costs.

We base our coal reserve and non-reserve coal deposit estimates on engineering, economic and geological data assembled and analyzed by our staff, which is periodically audited by independent engineering firms. These estimates are also based on the expected cost of production and projected sale prices and assumptions concerning the permitability and advances in mining technology. The estimates of coal reserves and non-reserve coal deposits as to both quantity and quality are periodically updated to reflect the production of coal from the reserves, updated geologic models and mining recovery data, recently acquired coal reserves and estimated costs of production and sales prices. There are numerous factors and assumptions inherent in estimating quantities and qualities of coal reserves and non-reserve coal deposits and costs to mine recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves necessarily depend upon a number of variable factors and assumptions, all of which may vary considerably from actual results. These factors and assumptions relate to:

- quality of coal;
- geological and mining conditions and/or effects from prior mining that may not be fully identified by available exploration data or which may differ from our experience in areas where we currently mine;
- the percentage of coal in the ground ultimately recoverable;
- the assumed effects of regulation, including the issuance of required permits, taxes, including severance and excise taxes and royalties, and other payments to governmental agencies;
- historical production from the area compared with production from other similar producing areas;
- the timing for the development of reserves; and
- assumptions concerning equipment and productivity, future coal prices, operating costs, capital expenditures and development and reclamation costs.

For these reasons, estimates of the quantities and qualities of the economically recoverable coal attributable to any particular group of properties, classifications of coal reserves and non-reserve coal deposits based on risk of recovery, estimated cost of production and estimates of net cash flows expected from particular reserves as prepared by different engineers or by the same engineers at different times may vary materially due to changes in the above factors and assumptions. Actual production from identified coal reserve and non-reserve coal deposit areas or properties and revenues and expenditures associated with our mining operations may vary materially from estimates. Accordingly, these estimates may not reflect our actual coal reserves or non-reserve coal deposits. Any inaccuracy in our estimates related to our coal reserves and non-reserve coal deposits could result in lower than expected revenues and higher than expected costs, which could have a material adverse effect on our ability to make cash distributions.

The Partnership invests in non-coal natural resource assets, which could result in a material adverse effect on its results of operations and our ability to receive cash distributions from the Partnership.

Part of the Partnership's business strategy is to expand its operations through strategic acquisitions, which includes investing in non-coal natural resources assets. Its executive officers do not have experience investing in or operating non-coal natural resources assets and it may be unable to hire additional management with relevant expertise in operating such assets. Acquisitions of non-coal natural resource assets could expose the Partnership to new and additional operating and regulatory risks, including commodity price risk, which could result in a material adverse effect on its results of operations and our ability to receive cash distributions from the Partnership.

The amount of estimated maintenance capital expenditures the Partnership is required to deduct from operating surplus each quarter could increase in the future, resulting in a decrease in available cash from operating surplus that could be distributed to us by the Partnership.

The Partnership's partnership agreement requires that it deduct from operating surplus each quarter estimated maintenance capital expenditures as opposed to actual maintenance capital expenditures in order to reduce disparities in operating surplus caused by fluctuating maintenance capital expenditures, such as reserve replacement costs or refurbishment or replacement of mine equipment. Its annual estimated maintenance capital expenditures for purposes of calculating operating surplus is based on its estimates of the amounts of expenditures it will be required to make in the future to maintain its long-term operating capacity. Its partnership agreement does not cap the amount of maintenance capital expenditures that its general partner may estimate. The amount of its estimated maintenance capital expenditures may be more than its actual maintenance capital expenditures, which will reduce the amount of available cash from operating surplus that it would otherwise have available for distribution to unitholders, including Royal. The amount of estimated maintenance capital expenditures deducted from operating surplus is subject to review and change by the Partnership's board of directors at least once a year, with any change approved by the Partnership's conflicts committee.

Existing and future laws and regulations regulating the emission of sulfur dioxide and other compounds could affect coal consumers and as a result reduce the demand for our coal. A reduction in demand for our coal could adversely affect our results of operations and our ability to receive cash distributions from the Partnership.

Federal, state and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from electric power plants and other consumers of our coal. These laws and regulations can require significant emission control expenditures, and various new and proposed laws and regulations may require further emission reductions and associated emission control expenditures. A certain portion of our coal has a medium to high sulfur content, which results in increased sulfur dioxide emissions when combusted and therefore the use of our coal imposes certain additional costs on customers. Accordingly, these laws and regulations may affect demand and prices for our higher sulfur coal. Please read "Part I, Item 1. Business—Regulation and Laws."

Federal and state laws restricting the emissions of greenhouse gases in areas where we conduct our business or sell our coal could adversely affect our operations and demand for our coal.

One by-product of burning coal is CO_2, which EPA considers a GHG, and a major source of concern with respect to climate change and global warming. Global warming has garnered significant public attention, and measures have been implemented or proposed at the international, federal, state and regional levels to limit GHG emissions. Please read “Part I, Item 1. Business—Regulation and Laws—Climate Change.”

For example, on the international level, the United States is one of almost 200 nations that agreed on December 12, 2015 to an international climate change agreement in Paris, France, that calls for countries to set their own GHG emission targets and be transparent about the measures each country will use to achieve its GHG emission targets; however, the agreement does not set binding GHG emission reduction targets. . 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 coal.

At the federal level, EPA has finalized a number of rules related to GHG emissions. For example, the EPA issued 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 of the implementation of the CPP in February 2016. By its terms, this stay will remain in effect throughout the pendency of the appeals process. 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 will not affect EPA’s standards for new power plants. It is not yet clear how the courts will rule on the legality of the CPP. Additionally, in October 2017 EPA proposed to repeal the CPP, although the final outcome of this action and the pending litigation regarding the CPP is uncertain at this time. In connection with the proposed repeal, EPA issued an Advance Notice of Proposed Rulemaking (“ANPRM”) in December 2017 regarding emission guidelines to limit GHG emissions from existing electricity utility generating units. The ANPRM seeks comment regarding what the EPA should include in a potential new, existing-source regulation under the Clean Air Act of GHG emissions from electric utility generating units that it may propose. If the effort to repeal the rules is unsuccessful and the rules were upheld at the conclusion of the appellate process and were implemented in their current form, or if the ANPRM results in a different proposal to control GHG emissions from electric utility generating units, demand for coal will likely be further decreased. The EPA also issued a final rule for new coal-fired power plants in August 2015, which essentially set performance standards for coal-fired power plants that requires partial carbon capture and sequestration. Additional legal challenges have been filed against the EPA’s rules for new power plants. The EPA’s GHG rules for new and existing power plants, taken together, have the potential to severely reduce demand for coal. In addition, passage of any comprehensive federal climate change and energy legislation could impact the demand for coal. Any reduction in the amount of coal consumed by North American electric power generators could reduce the price of coal that the Partnership mines and sells, thereby reducing our revenues and materially and adversely affecting our business and results of operations.

Many states and regions have adopted greenhouse gas initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of greenhouse gases by certain facilities, including coal-fired electric generating facilities. For example, in 2005, ten northeastern states entered into the Regional Greenhouse Gas Initiative agreement (the “RGGI”), calling for implementation of a cap and trade program aimed at reducing carbon dioxide emissions from power plants in the participating states. . Following the RGGI model, several western states and Canadian provinces have confirmed a commitment and timetable to create a carbon market in North America. It is likely that these regional efforts will continue.

Many coal-fired plants have already closed or announced plans to close and proposed new construction projects have also come under additional scrutiny with respect to GHG emissions. There have been an increasing number of protests and challenges to the permitting of new coal-fired power plants by environmental organizations and state regulators due to concerns related to greenhouse gas emissions. Other state regulatory authorities have also rejected the construction of new coal-fueled power plants based on the uncertainty surrounding the potential costs associated with GHG emissions from these plants under future laws limiting the emissions of carbon dioxide. In addition, several permits issued to new coal-fired power plants without limits on GHG emissions have been appealed to the EPA’s Environmental Appeals Board. In addition, over 30 states have adopted mandatory “renewable portfolio standards,” which require electric utilities to obtain a certain percentage of their electric generation portfolio from renewable resources by a certain date. These standards range generally from 10% to 30%, over time periods that generally extend from the present until between 2020 and 2030. Other states may adopt similar requirements, and federal legislation is a possibility in this area. To the extent these requirements affect our current and prospective customers; they may reduce the demand for coal-fired power, and may affect long-term demand for our coal.

If mandatory restrictions on carbon dioxide emissions are imposed, the ability to capture and store large volumes of carbon dioxide emissions from coal-fired power plants may be a key mitigation technology to achieve emissions reductions while meeting projected energy demands. A number of recent legislative and regulatory initiatives to encourage the development and use of CCS technology have been proposed or enacted. For example, in October 2015, the EPA released a rule that established, for the first time, new source performance standards under the federal Clean Air Act for CO2 emissions from new fossil fuel-fired electric utility generating power plants. The EPA has designated partial carbon capture and sequestration as the best system of emission reduction for newly constructed fossil fuel-fired steam generating units at power plants to employ to meet the standard. However, widespread cost-effective deployment of CCS will occur only if the technology is commercially available at economically competitive prices and supportive national policy frameworks are in place.

In the meantime, the EPA and other regulators are using existing laws, including the federal Clean Air Act, to limit emissions of carbon dioxide and other GHGs from major sources, including coal-fired power plants that may require the use of "best available control technology" or "BACT." As state permitting authorities continue to consider GHG control requirements as part of major source permitting BACT requirements, costs associated with new facility permitting and use of coal could increase substantially. A growing concern is the possibility that BACT will be determined to be the use of an alternative fuel to coal.

As a result of these current and proposed laws, regulations and trends, electricity generators may elect to switch to other fuels that generate less GHG emissions, possibly further reducing demand for our coal, which could adversely affect our results of operations and our ability to receive cash distributions from the Partnership.

Finally, some scientists have warned 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 these warnings are correct, and if any such effects were to occur in areas where the Partnership or their customers operate, they could have an adverse effect on their assets and operations.

Federal and state laws require bonds to secure our obligations to reclaim mined property. Our inability to acquire or failure to maintain, obtain or renew these surety bonds could have an adverse effect on our ability to produce coal, which could adversely affect our results of operations and our ability to receive cash distributions from the Partnership.

We are required under federal and state laws to place and maintain bonds to secure our obligations to repair and return property to its approximate original state after it has been mined (often referred to as "reclamation") and to satisfy other miscellaneous obligations. Federal and state governments could increase bonding requirements in the future. In August 2016, the OSMRE issued a Policy Advisory discouraging state regulatory authorities from approving self-bonding arrangements. The Policy Advisory indicated that the OSMRE would begin more closely reviewing instances in which states accept self-bonds for mining operations. In the same month, the OSMRE also announced that it was beginning the rulemaking process to strengthen regulations on self-bonding. Certain business transactions, such as coal leases and other obligations, may also require bonding. We may have difficulty procuring or maintaining our surety bonds. Our bond issuers may demand higher fees, additional collateral, including supporting letters of credit or posting cash collateral or other terms less favorable to us upon those renewals. The failure to maintain or the inability to acquire sufficient surety bonds, as required by state and federal laws, could subject us to fines and penalties as well as the loss of our mining permits. Such failure could result from a variety of factors, including:

- the lack of availability, higher expense or unreasonable terms of new surety bonds;
- the ability of current and future surety bond issuers to increase required collateral; and
- the exercise by third-party surety bond holders of their right to refuse to renew the surety bonds.

We maintain surety bonds with third parties for reclamation expenses and other miscellaneous obligations. It is possible that we may in the future have difficulty maintaining our surety bonds for mine reclamation. Due to adverse economic conditions and the volatility of the financial markets, surety bond providers may be less willing to provide us with surety bonds or maintain existing surety bonds or may demand terms that are less favorable to us than the terms we currently receive. We may have greater difficulty satisfying the liquidity requirements under our existing surety bond contracts. As of December 31, 2018, we had approximately $42.6 million in surety bonds outstanding to secure the performance of our reclamation obligations. Of the $42.6 million, approximately $0.4 million relates to surety bonds for Deane Mining, LLC and approximately $3.4 million relates to surety bonds for Sands Hill Mining, LLC, which in each case have not been transferred or replaced by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC as was agreed to by the parties as part of the transactions. We can provide no assurances that a surety company will underwrite the surety bonds of the purchasers of these entities, nor are we aware of the actual amount of reclamation at any given time. Further, if there was a claim under these surety bonds prior to the transfer or replacement of such bonds by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC, then we may be responsible to the surety company for any amounts it pays in respect of such claim. While the buyers are required to indemnify us for damages, including reclamation liabilities, pursuant the agreements governing the sales of these entities, we may not be successful in obtaining any indemnity or any amounts received may be inadequate. If we do not maintain sufficient borrowing capacity or have other resources to satisfy our surety and bonding requirements, our operations could be adversely affected .

We depend on a few customers for a significant portion of our revenues. If a substantial portion of our supply contracts terminate or if any of these customers were to significantly reduce their purchases of coal from us, and we are unable to successfully renegotiate or replace these contracts on comparable terms, then our results of operations and our ability to receive cash distributions from the Partnership could be adversely affected.

We sell a material portion of our coal under supply contracts. As of December 31, 2018, we had sales commitments for approximately 74% of our estimated coal production (including purchased coal to supplement our production) for the year ending December 31, 2019. When our current contracts with customers expire, our customers may decide not to extend or enter into new contracts. Of our total future committed tons, under the terms of the supply contracts, we will ship 61% in 2019, and 33% in 2020, and 6% in 2021. We derived approximately 80.5% of our total coal revenues from coal sales to our ten largest customers for the year ended December 31, 2018, with affiliates of our top three customers accounting for approximately 40.4% of our coal revenues during that period.

In the absence of long-term contracts, our customers may decide to purchase fewer tons of coal than in the past or on different terms, including different pricing terms. Negotiations to extend existing contracts or enter into new long-term contracts with those and other customers may not be successful, and those customers may not continue to purchase coal from us under long-term coal supply contracts or may significantly reduce their purchases of coal from us. In addition, interruption in the purchases by or operations of our principal customers could significantly affect our results of operations and cash available for distribution. Unscheduled maintenance outages at our customers' power plants and unseasonably moderate weather are examples of conditions that might cause our customers to reduce their purchases. Our mines may have difficulty identifying alternative purchasers of their coal if their existing customers suspend or terminate their purchases. For additional information relating to these contracts, please read "Part I, Item 1. Business—Customers—Coal Supply Contracts."

Certain provisions in our long-term coal supply contracts may provide limited protection during adverse economic conditions, may result in economic penalties to us or permit the customer to terminate the contract.

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 such contracts. Price re-opener provisions typically require the parties to agree on a new price. Failure of the parties to agree on a price under a price re-opener provision can lead to termination of the contract. Any adjustment or renegotiations leading to a significantly lower contract price could adversely affect our results of operations and our ability to receive cash distributions from the Partnership.

Coal supply contracts also 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. Most of our coal supply contracts also contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as Btu, sulfur content, ash content, hardness and ash fusion temperature. Failure to meet these specifications could result in economic penalties, including price adjustments, the rejection of deliveries or termination of the contracts. In addition, certain of our coal supply contracts permit the customer to terminate the agreement in the event of changes in regulations affecting our industry that increase the price of coal beyond a specified limit.

Defects in title in the coal properties that we own or loss of any leasehold interests could limit our ability to mine these properties or result in significant unanticipated costs.

We conduct a significant part of our mining operations on leased properties. A title defect or the loss of any lease could adversely affect our ability to mine the associated coal reserves. Title to most of our owned and leased properties and the associated mineral rights is not usually verified until we make a commitment to develop a property, which may not occur until after we have obtained necessary permits and completed exploration of the property. In some cases, we rely on title information or representations and warranties provided by our grantors or lessors, as the case may be. Our right to mine some coal reserves would be adversely affected by defects in title or boundaries or if a lease expires. Any challenge to our title or leasehold interest could delay the exploration and development of the property and could ultimately result in the loss of some or all of our interest in the property. Mining operations from time to time may rely on a lease that we are unable to renew on terms at least as favorable, if at all. In such event, we may have to close down or significantly alter the sequence of mining operations or incur additional costs to obtain or renew such leases, which could adversely affect our future coal production. If we mine on property that we do not control, we could incur liability for such mining.

Our work force could become unionized in the future, which could adversely affect our production and labor costs and increase the risk of work stoppages.

Currently, none of our employees are represented under collective bargaining agreements. However, all of our work force may not remain union-free in the future. If some or all of our work force were to become unionized, it could adversely affect our productivity and labor costs and increase the risk of work stoppages.

If we sustain cyber-attacks or other security breaches that disrupt our operations, or that result in the unauthorized release of proprietary or confidential information, we could be exposed to significant liability, reputational harm, loss of revenue, increased costs or other risks.

We may be subject to security breaches which could result in unauthorized access to our facilities or to information we are trying to protect. Unauthorized physical access to one or more of our facilities or locations, or electronic access to our proprietary or confidential information could result in, among other things, unfavorable publicity, litigation by parties affected by such breach, disruptions to our operations, loss of customers, and financial obligations for damages related to the theft or misuse of such information, any of which could have a substantial impact on our results of operations, financial condition or cash flow.

We depend on key personnel for the success of our business.

We depend on the services of our senior management team and other key personnel, including senior management of the Partnership. The loss of the services of any member of senior management or key employee could have an adverse effect on our business. Furthermore, the loss of the services of certain key management of the Partnership could reduce its ability to make distributions to us. We may not be able to locate or employ on acceptable terms qualified replacements for senior management or other key employees if their services were no longer available.

If the assumptions underlying our reclamation and mine closure obligations are materially inaccurate, we could be required to expend greater amounts than anticipated.

The Federal Surface Mining Control and Reclamation Act of 1977 and counterpart state laws and regulations establish operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of underground mining. Estimates of our total reclamation and mine closing liabilities are based upon permit requirements and our engineering expertise related to these requirements. The estimate of ultimate reclamation liability is reviewed both periodically by our management and annually by independent third-party engineers. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly. Please read “Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Asset Retirement Obligations.”

The Partnership's debt levels may limit its flexibility in obtaining additional financing and in pursuing other business opportunities.

The Partnership's level of indebtedness could have important consequences to us, including the following:

- its ability to obtain additional financing, if necessary, for working capital, capital expenditures (including acquisitions) or other purposes may be impaired or such financing may not be available on favorable terms;
- covenants contained in its existing and future credit and debt arrangements will require that it meet financial tests that may affect its flexibility in planning for and reacting to changes in its business, including possible acquisition opportunities;
- it will need a portion of its cash flow to make principal and interest payments on its indebtedness, reducing the funds that would otherwise be available for operations, distributions to the Partnership's unitholders (including Royal) and future business opportunities;
- it may be more vulnerable to competitive pressures or a downturn in its business or the economy generally; and
- its flexibility in responding to changing business and economic conditions may be limited.

Increases in the Partnership's total indebtedness would increase its total interest expense, which would in turn reduce its forecasted cash available for distribution. As of December 31, 2017 its current portion of long-term debt that will be funded from cash flows from operating activities during 2018 was approximately $0.4 million. Its ability to service its indebtedness will depend upon, among other things, its future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond its control. If its operating results are not sufficient to service its current or future indebtedness, it will be forced to take actions such as reducing or delaying its business activities, acquisitions, investments, capital expenditures, and/or expense reimbursements to Royal, selling assets, restructuring or refinancing its indebtedness, or seeking additional equity capital or bankruptcy protection. The Partnership may not be able to effect any of these remedies on satisfactory terms, or at all.

The Partnership's financing agreement contains operating and financial restrictions that may restrict its business and financing activities and limit its ability to pay distributions upon the occurrence of certain events.

The operating and financial restrictions and covenants in the Partnership's credit agreement and any future financing agreements could restrict its ability to finance future operations or capital needs or to engage, expand or pursue its business activities. For example, its credit agreement restricts its ability to:

- incur additional indebtedness or guarantee other indebtedness;
- grant liens;
- make certain loans or investments;
- dispose of assets outside the ordinary course of business, including the issuance and sale of capital stock of its subsidiaries;
- change the line of business conducted by it or its subsidiaries;
- enter into a merger, consolidation or make acquisitions; or
- make distributions above certain amounts or if an event of default occurs.

In addition, its payment of principal and interest on its debt will reduce cash available for distribution on its units. Its credit agreement limits its ability to pay distributions upon the occurrence of the following events, among others, which would apply to it and its subsidiaries:

- failure to pay principal, interest or any other amount when due;
- breach of the representations or warranties in the credit agreement;
- failure to comply with the covenants in the credit agreement;
- cross-default to other indebtedness;
- bankruptcy or insolvency;
- failure to have adequate resources to maintain, and obtain, operating permits as necessary to conduct its operations substantially as contemplated by the mining plans used in preparing the financial projections; and
- a change of control.

Any subsequent refinancing of its current debt or any new debt could have similar restrictions. Its ability to comply with the covenants and restrictions contained in its credit agreement may be affected by events beyond its control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, its ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in its credit agreement, a significant portion of its indebtedness may become immediately due and payable, and its lenders' commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, its obligations under its credit agreement will be secured by substantially all of its assets, and if we are unable to repay its indebtedness under its credit agreement, the lenders could seek to foreclose on such assets. For more information, please read "Part I, Item 1. Business—Recent Developments—Financing Agreement."

Our business is subject to cybersecurity risks.

As is typical of modern businesses, we are reliant on the continuous and uninterrupted operation of its information technology ("IT") systems. User access of our sites and IT systems can be critical elements to our operations, as is cloud security and protection against cyber security incidents. Any IT failure pertaining to availability, access or system security could potentially result in disruption of our activities, and could adversely affect our reputation, operations or financial performance.

Potential risks to the our IT systems could include unauthorized attempts to extract business sensitive, confidential or personal information, denial of access extortion, corruption of information or disruption of business processes, or by inadvertent or intentional actions by the our employees or vendors. A cybersecurity incident resulting in a security breach or failure to identify a security threat could disrupt business and could result in the loss of sensitive, confidential information or other assets, as well as litigation, regulatory enforcement, violation of privacy or securities laws and regulations, and remediation costs, all of which could materially impact the our business or reputation.

Risks Inherent in an Investment in Us

Concentration of ownership among our existing directors, executive officers and principal stockholders may prevent new investors from influencing significant corporate decisions.

Our current directors and executive officers and their respective affiliates will, in the aggregate, beneficially own or control approximately 52.9% of our outstanding common stock and 100% of our outstanding Series A Preferred Stock. Because of the special voting rights of our Series A Preferred Stock (which is entitled to 54% of the total votes on any matter on which shareholders have a right to vote), William L. Tuorto currently controls 75.5% of the votes on any matter requiring a shareholder vote. As a result, these stockholders will be able to exercise a controlling influence over matters requiring stockholder approval, including the election of directors and approval of significant corporate transactions, and will have significant influence over our management and policies for the foreseeable future. Some of these persons or entities may have interests that are different from yours. For example, these stockholders may support proposals and actions with which you may disagree or which are not in your interests. The concentration of ownership could delay or prevent a change in control of our company or otherwise discourage a potential acquirer from attempting to obtain control of our company, which in turn could reduce the price of our common stock. In addition, these stockholders, some of which have representatives sitting on our board of directors, could use their voting control to maintain our existing management and directors in office, delay or prevent changes of control of our company, or support or reject other management and board of director proposals that are subject to stockholder approval, such as amendments to our employee stock plans and approvals of significant financing transactions.

There Is A Limited Market For Our Common Stock.

Our common stock is currently quoted on the OTCQB under the symbol "ROYE." The trading market for our common stock is limited. We are exploring a possible listing of our common stock on the NASDAQ, which may improve the trading market for our common stock. However, there is no assurance that we will be approved for listing or that the listing will improve the trading market for our common stock. A more active trading market for our common stock may never develop, or if such a market develops, it may not be sustained.

Our common stock, and the Partnership's common units, are currently traded on the OTCQB, which could adversely affect the market liquidity of our common stock and common units, respectively, and harm our business.

Our common stock trades on the OTCQB under the ticker symbol "ROYE." The Partnerships common units trade on the OTCQB under the ticker symbol "RHNO." Our common stock and the Partnership's common units will continue to trade on the OTCQB or one of the other over-the-counter markets.

Trading on the OTCQB or one of the other over-the-counter markets may result in a reduction in some or all of the following, each of which could have a material adverse effect on our shareholders and the Partnership's unitholders:

- The liquidity of our common stock or the Partnership's common units;
- The market price of our common stock or the Partnership's common units;
- our ability or the Partnership's ability to issue additional securities or obtain financing;
- the number of institutional and other investors that will consider investing in our common stock or the Partnership's common units; and
- the number of market makers in our common stock or the Partnership's common units;
- the availability of information concerning the trading prices and volume of our common stock or the Partnership's common units; and
- the number of broker-dealers willing to execute trades in our common stock or the Partnership's common units.

Further, since neither us nor the Partnership are traded on a national securities exchange, we are not subject to exchange rules, including rules requiring that either us or the Partnership meet certain corporate governance standards. Without required compliance of these corporate governance standards, investor interest in our common stock or the Partnership's common units may decrease.

The Partnership does not have sufficient cash to enable it to pay the minimum quarterly distribution on its common units following establishment of cash reserves and payment of costs and expenses, including reimbursement of expenses to its general partner.

Currently, Royal's only operations consist of the coal mining operations of the Partnership, although Royal currently receive royalties under a royalty agreement covering a coal transloading facility on the Ohio River. As a result, Royal is substantially dependent on the Partnership to generate cash flow that can be used to pay distributions or expense reimbursements that Royal can use to pay its own operating expenses and indebtedness. The Partnership's ability to generate operating cash flow that can be used to pay distributions or expense reimbursements to Royal is subject to all of the risks inherent in the Partnership's business, including covenants in the Partnership's Financing Agreement. If the Partnership is unable to pay distributions or expense reimbursements to Royal, Royal may not have sufficient funds to pay its own operating expenses or repay its indebtedness. If Royal is unable to receive sufficient distributions or expense reimbursements from the Partnership, Royal may have to raise capital from third parties to pay its liabilities. There is no assurance that Royal would be able to raise capital on terms that are not dilutive to existing shareholders, or at all.

Currently, the Partnership does not have sufficient cash each quarter to pay its minimum quarterly distribution of $4.45 per unit, or $17.80 per unit per year, which would require that it have available cash of approximately $58.6 million per quarter, or $234.2 million per year, based on the number of common and subordinated units outstanding as of December 31, 2018 and the general partner interest. Beginning with the quarter ended September 30, 2014, distributions on its common units were below the minimum level and, beginning with the quarter ended June 30, 2015, it suspended the quarterly distribution on its common units altogether, and has not paid any quarterly distributions since. The amount of cash it can distribute on its common and subordinated units principally depends upon the amount of cash it generates from its operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of coal the Partnership is able to produce from our properties, which could be adversely affected by, among other things, operating difficulties and unfavorable geologic conditions;
- the price at which it is able to sell coal, which is affected by the supply of and demand for domestic and foreign coal;
- the level of its operating costs, including reimbursement of expenses to its general partner and its affiliates. Its partnership agreement does not set a limit on the amount of expenses for which its general partner and its affiliates may be reimbursed;
- the proximity to and capacity of transportation facilities;
- the price and availability of alternative fuels;
- the impact of future environmental and climate change regulations, including those impacting coal-fired power plants;
- the level of worldwide energy and steel consumption;
- prevailing economic and market conditions;
- difficulties in collecting our receivables because of credit or financial problems of customers;
- the effects of new or expanded health and safety regulations;
- domestic and foreign governmental regulation, including changes in governmental regulation of the mining industry, the electric utility industry or the steel industry;
- changes in tax laws;
- weather conditions; and
- force majeure.

The failure of the Partnership to pay distributions on its common units could impair our ability to our obligations that are incurred outside of the Partnership, including our loan from Cedarview and our general and administrative expenses. In addition, the failure of the Partnership to pay distributions on its common units could be a factor in depressing the market value of its common units, which could result in dilution of our interest in the Partnership as a result of the conversion into common units of the Series A Preferred Units of the Partnership whose conversion price is based on the market price of the common units at the time of conversion.

Because the market may respond to our business operations and that of our competitors, our stock price will likely be volatile.

The OTCQB is a network of security dealers who buy and sell stock. The dealers are connected by a computer network that provides information on current "bids" and "asks", as well as volume information. We anticipate that the market price of our common stock will be subject to wide fluctuations in response to several factors, including: our ability to economically exploit our properties successfully; increased competition from competitors; and our financial condition and results of our operations.

We do not intend to pay dividends for the foreseeable future.

We have never declared or paid any dividends on our common stock. We intend to retain all of our earnings for the foreseeable future to finance the operation and expansion of our business, and we do not anticipate paying any cash dividends in the future. As a result, you may only receive a return on your investment in our common stock if the market price of our common stock increases. Our board of directors retains the discretion to change this policy.

An increase in interest rates may cause the market price of our common shares to decline.

Like all equity investments, an investment in our common shares is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally. Reduced demand for our common shares resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common shares to decline.

Additional equity or debt financing may be dilutive to existing stockholders or impose terms that are unfavorable to us or our existing stockholders.

We will need to raise substantial capital in order to finance the acquisition of coal properties, provide working capital, and create reserves against the many contingencies that are inherent in the mining industry. If we raise additional funds by issuing equity securities, our stockholders will experience dilution. Debt financing, if available, may involve arrangements that include covenants limiting or restricting our ability to take specific actions, such as incurring additional debt, making capital expenditures or declaring dividends. Any debt financing or additional equity that we raise may contain terms, such as liquidation and other preferences that are not favorable to us or our current stockholders.

We depend on key personnel and could be harmed by the loss of their services because of the limited number of qualified people in our industry.

Because of our small size, we require the continued service and performance of our management team, all of whom we consider to be key employees. Competition for highly qualified employees in the mining industry is intense. Our success will depend to a significant degree upon our ability to attract, train, and retain highly skilled directors, officers, management, business, financial, legal, marketing, sales, and technical personnel and upon the continued contributions of such people. In addition, we may not be able to retain our current key employees. The loss of the services of one or more of our key personnel and our failure to attract additional highly qualified personnel could impair our ability to expand our operations and provide service to our customers.

Under the terms of our Certificate of Incorporation, our Board of Directors is authorized to issue shares of preferred stock with rights and privileges superior to common stockholders without common stockholder approval.

Under the terms of our Certificate of Incorporation, our board of directors is authorized to issue shares of preferred stock in one or more classes or series without stockholder approval. The board has discretion to set the terms, preferences, conversion or other rights, voting powers, restrictions, limitations as to dividends or other distributions, qualifications and terms or conditions of redemption for each class or series of preferred stock. Accordingly, we may designate and issue additional shares or series of preferred stock that would rank senior to the shares of common stock as to dividend rights or rights upon our liquidation, winding-up, or dissolution.

Provisions in Our Certificate of Incorporation and Bylaws and Delaware law May Inhibit a Takeover of Us, Which Could Limit the Price Investors Might Be Willing to Pay in the Future for our Common Stock and Could Entrench Management.

Our certificate of incorporation and bylaws contain provisions that may discourage unsolicited takeover proposals that stockholders may consider to be in their best interests. Our board has authorized the issuance of 100,000 shares of one class of preferred stock, known as "Series A Preferred Stock." The Series A Preferred Stock has voting rights entitling it to 54% of the total votes on any matter on which stockholders are entitled to vote. In addition, we cannot authorize or issue any class of capital stock or bonds, debentures, notes or other securities or other obligations ranking senior to or on a parity with the Series A Preferred Stock without the approval of the Series A Preferred Stock voting as a separate class. Mr. Tuorto holds all of the outstanding shares of Series A Preferred Stock. As a result, at any meeting of shareholders Mr. Tuorto has a disproportionate voting power.

Mr. Tuorto's control of our Series A Preferred Stock may prevent our stockholders from replacing a majority of our board of directors at any shareholder meeting, which may entrench management and discourage unsolicited stockholder proposals that may be in the best interests of stockholders. Moreover, our board of directors has the ability to designate the terms of and issue new series of preferred stock without stockholder approval.

In addition, as a Delaware corporation, we are subject to Section 203 of the Delaware General Corporation Law, which generally prohibits a Delaware corporation from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless certain specific requirements are met as set forth in Section 203. Collectively, these provisions may make more difficult the removal of management and may discourage transactions that otherwise could involve payment of a premium over prevailing market prices for our securities.

The Series A preferred units of the Partnership are senior in right of distributions and liquidation and upon conversion, would result in the issuance of additional common units in the future, which could result in substantial dilution of our interest in the Partnership.

The Series A preferred units of the Partnership are a new class of partnership interests that rank senior to its common units with respect to distribution rights and rights upon liquidation. The Partnership is required to pay annual distributions on the Series A preferred units in an amount equal to the greater of (i) 50% of CAM Mining free cash flow (which is defined in our partnership agreement as (i) the total revenue of the our Central Appalachia business segment, minus (ii) the cost of operations (exclusive of depreciation, depletion and amortization) for the its Central Appalachia business segment, minus (iii) an amount equal to $6.50, multiplied by the aggregate number of met coal and steam coal tons sold by the Partnership from its Central Appalachia business segment) and (ii) an amount equal to the number of outstanding Series A preferred units multiplied by $0.80. If the Partnership fails to pay any or all of the distributions in respect of the Series A preferred units, such deficiency will accrue until paid in full and it will not be permitted to pay any distributions on Royal's partnership interests that rank junior to the Series A Preferred Units, including its common units. The preferred units also rank senior to the common units in right of liquidation, and will be entitled to receive a liquidation preference in any such case.

The Partnership may convert the Series A preferred units into common units at any time on or after the time at which the amount of aggregate distributions paid in respect of each Series A Preferred Unit exceeds $10.00 per unit. All unconverted Series A preferred units will convert into common units on December 31, 2021. The number of common units issued in any conversion will be based on the volume-weighted average closing price of the common units for 90 days preceding the date of conversion. Accordingly, the lower the trading price of the Partnership's common units over the 90 day measurement period, the greater the number of common units that will be issued upon conversion of the preferred units, which would result in greater dilution to our interest in the Partnership. Dilution has the following effects on our interest in the Partnership:

- our proportionate ownership interest in the Partnership will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of our ownership interest will be diminished; and
- the market price of our common units may decline.

Holders of the Partnership's Series A Preferred Units have substantial negative control rights.

For as long as the Series A preferred units are outstanding, the Partnership will be restricted from taking certain actions without the consent of the holders of a majority of the Series A preferred units, including: (i) the issuance of additional Series A preferred units, or securities that rank senior or equal to the Series A preferred units; (ii) the sale or transfer of CAM Mining, LLC or a material portion of its assets; (iii) the repurchase of common units, or the issuance of rights or warrants to holders of common units entitling them to purchase common units at less than fair market value; (iv) consummation of a spin off; (v) the incurrence, assumption or guaranty indebtedness for borrowed money in excess of $50.0 million except indebtedness relating to entities or assets that are acquired by the Partnership or its affiliates that is in existence at the time of such acquisition; or (vi) the modification of CAM Mining's accounting principles or the financial or operational reporting principles of the its Central Appalachia business segment, subject to certain exceptions. These consent rights effectively add a constituency to the Partnership's fundamental decision-making process, and failure to obtain such consent from the Series A preferred holders could prevent the Partnership from taking actions that its management or board of directors otherwise view as prudent or necessary for its business operations or the execution of its business strategy.

The market price of our common stock could be adversely affected by sales of substantial amounts of our common stock in the public or private markets, including sales by our officers and directors.

As of March 20, 2019, we had 18,579,293 shares of common stock (including 914,797 shares held by its consolidated subsidiary, Rhino Resource Partners, LP) and 51,000 shares of Series A Preferred Stock outstanding. All of the Series A Preferred Shares are convertible into common stock on a one for one basis. Approximately 50.5% of our common stock is owned or controlled by our officers and directors, including approximately 45.4% by William Tuorto and entities he controls. There is currently only a limited market for our commons stock. Sales by our large holders of a substantial number of shares of our common units in the public markets, or the perception that such sales might occur, could have a material adverse effect on the price of our common stock or could impair our ability to obtain capital through an offering of equity securities.

Income Tax Risks

We failed to timely file certain prior years' state and federal tax returns.

We failed to file federal and state tax returns on a timely basis since the tax year ending August 31, 2014. While we have since filed the federal returns and the state returns are in process, we acknowledge that past due penalties and interest may be due. We have recorded tax provisions based on our estimates, but the ultimate tax provisions could vary materially from the estimates provided in the accompanying consolidated financial statements.

We were deficient in filing an appropriate change in tax year from August year end to a December year end.

We failed to file a timely election to change our tax year end from August 31 to December 31. We have since filed a request to change our tax year end from August 31, to December 31. While we believe we have sufficient grounds to change our tax year end to December 31, since the Partnership has a December 31 year end for tax and financial reporting purposes, our request is subject to the discretionary approval of the IRS. If the IRS denies our request, the IRS could force us to amend tax returns to comply with our previous August 31 tax year end reporting period. Our ultimate tax obligation could vary materially based on the ultimate tax filing year due to substantial changes to the corporate tax rates and other corporate tax law provisions passed by Congress in December 2017 (See below for more information about the Act).

The Rhino investment may provide taxable income with no tax distributions.

During 2017, Royal had taxable income allocated from its ownership in Rhino, which we expect to offset, in part, against our prior year net operating losses. It is possible that taxable income generated by the Partnership allocation in future tax years will exceed our net operating loss offsets or tax distributions from the Partnership. If that occurs, we may need to raise capital or sell assets in order to generate funds to pay our taxes. There is no assurance that Royal would be able to raise capital on terms that are not dilutive to existing shareholders, or at all.

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

We are subject to income and other taxes in the U.S. As of December 31, 2018, we had gross deferred income tax assets, including net operating loss carryforwards for federal and state tax purposes, of $20.8 million and $10.2 million, respectively, as described further in "Note 14. Income Taxes" to the accompanying consolidated financial statements. At that date, we also had recorded a valuation allowance of $1.7 million. Although we may be able to utilize some or all of those deferred tax assets in the future if we have income of the appropriate character (subject to loss carryforward and tax credit expiry, in certain cases), there is no assurance that we will be able to do so.

Rhino's tax treatment depends on its status as a partnership for federal and state income tax purposes, as Rhino is not subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat Rhino as a corporation for federal income tax purposes, or it becomes subject to entity-level taxation for state tax purposes, then its cash available for distribution to unitholders, including Royal would be substantially reduced.

The anticipated after-tax economic benefit of Royal's investment in Rhino's common units depends largely on Rhino being treated as a partnership for U.S. federal income tax purposes. Despite the fact that Rhino is organized as a limited partnership under Delaware law, it will be treated as a corporation for federal income tax purposes unless it satisfies a "qualifying income" requirement. Based on current operations, Rhino believes that it satisfies the qualifying income requirement and will be treated as a partnership. Rhino may, however, decide that it is in its best interest to be treated as a corporation for federal income tax purposes. Failing to meet the qualifying income requirement, a change in current law, or an election to be treated as a corporation, could cause Rhino to be treated as a corporation for federal income tax purposes or otherwise subject it to taxation as an entity.

Additionally, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. Rhino currently owns assets and conducts business in several states that impose a margin or franchise tax. In the future, Rhino may expand its operations to other states. Imposition of a similar tax on it in jurisdictions to which it expands could substantially reduce its cash available for distribution to its unitholders, including. The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects it to additional amounts of entity level taxation for U.S. federal, state, local, or foreign income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law or interpretation on Rhino. Changes in current state law may subject Rhino to additional entity level taxation by individual states.

Although Rhino monitors its level of non-qualifying income closely and attempts to manage its operations to ensure compliance with the qualifying income requirement, given the continued low demand and low prices for met and steam coal, there is a risk that Rhino will not be able to continue to meet the qualifying income level necessary to maintain its status as a partnership for federal income tax purposes.

As a publicly traded partnership, Rhino may be treated as a corporation for federal income tax purposes unless 90% or more of its gross income in each year consists of certain identified types of "qualifying income." In addition to qualifying income, like many other publicly traded partnerships, Rhino also generates ancillary income that may not constitute qualifying income. Although Rhino monitors its level of gross income that may not constitute qualifying income closely and attempts to manage its operations to ensure compliance with the qualifying income requirement, given the continued low demand and low prices for met and steam coal, the sale of which generates qualifying income, there is a risk that Rhino will not be able to continue to meet the qualifying income level necessary to maintain its status as a publicly-traded partnership. To the extent Rhino becomes aware that it may not generate or have not generated sufficient qualifying income with respect to a tax period, Rhino can and would take action to preserve its treatment as a partnership for federal income tax purposes, including seeking relief from the IRS. Section 7704(e) of the Internal Revenue Code provides for the possibility of relief upon, among other things, determination by the IRS that such failure to meet the qualifying income requirement was inadvertent. However, Rhino is unaware of examples of such relief being sought by a publicly traded partnership.

The tax treatment of publicly traded partnerships or an investment in its common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, or an investment in common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that would affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which Rhino relies for its treatment as a partnership for U.S. federal income tax purposes.

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

However, any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for Rhino to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. Rhino is unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of our investment in its common units.

If the IRS contests the federal income tax positions Rhino takes, the value of its common units may be adversely impacted and the cost of any IRS contest may substantially reduce its cash available for distribution to its unitholders.

Rhino has not requested a ruling from the IRS with respect to its treatment as a partnership for U.S. federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions Rhino takes and it may be necessary to resort to administrative or court proceedings to sustain some or all of its positions. A court may not agree with some or all of the positions Rhino takes. Any contest with the IRS may materially and adversely impact the value of our investment in its common units and the price at which they trade. Moreover, the costs of any contest with the IRS will reduce Rhino's cash available for distribution to its unitholders, including Royal. Rhino has requested and obtained a favorable private letter ruling from the IRS to the effect that, based on facts presented in the private letter ruling request, income from management fees, cost reimbursements and cost-sharing payments related to its management and operation of mining, production, processing, and sale of coal and from energy infrastructure support services will constitute "qualifying income" within the meaning of Section 7704 of the Code.

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

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to its income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from Rhino. To the extent possible under the new rules, Rhino may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if Rhino is eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although Rhino may elect to have its unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in Rhino during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, its current unitholders, including Royal may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in Rhino during the tax year under audit. If, as a result of any such audit adjustment, Rhino is required to make payments of taxes, penalties and interest, its cash available for distribution to its unitholders might be substantially reduced and its current and former unitholders may be required to indemnify Rhino for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that Rhino paid on such unitholders' behalf. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

Rhino's unitholders are required to pay taxes on their share of their income even if they do not receive any cash distributions from Rhino.

Rhino's unitholders, including Royal, are required to pay federal income taxes and, in some cases, state and local income taxes, on their share of taxable income, whether or not they receive cash distributions from Rhino. The unitholders may not receive cash distributions from Rhino equal to their share of its taxable income or even equal to the actual tax due with respect to that income.

Rhino anticipates engaging in transactions to reduce its indebtedness and manage its liquidity that generate taxable income (including cancellation of indebtedness income) allocable to unitholders, and income tax liabilities arising therefrom may exceed the value of Royal's investment in Rhino.

In response to current market conditions, from time to time Rhino may consider engaging in transactions to deliver and manage its liquidity that would result in income and gain to its unitholders without a corresponding cash distribution. For example, Rhino may sell assets and use the proceeds to repay existing debt or fund capital expenditures, in which case, unitholders would be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, Rhino may pursue opportunities to reduce its existing debt, such as debt exchanges, debt repurchases, or modifications and extinguishment of its existing debt that would result in "cancellation of indebtedness income" (also referred to as "COD income") being allocated to its unitholders as ordinary taxable income. Royal may be allocated COD income, and income tax liabilities arising therefrom may exceed the current value of its investment in Rhino.

Because Royal is taxed as a corporation, it may have net operating losses to offset COD income. The ultimate tax effect of any such income allocations will depend on the unitholder's individual tax position, including, for example, the availability of any suspended passive losses that may offset some portion of the allocable COD income. Royal may, however, be allocated substantial amounts of ordinary income subject to taxation, without any ability to offset such allocated income against any capital losses attributable to Royal's ultimate disposition of its units.

Tax gain or loss on the disposition of its units could be more or less than expected.

If Royal sells Rhino's units, it will recognize a gain or loss equal to the difference between the amount realized and its tax basis in those units. Because distributions in excess of its allocable share of its net taxable income decrease its tax basis in its units, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to Royal if it sells such units at a price greater than its tax basis in those units, even if the price received is less than its original cost. In addition, because the amount realized would include Royal's share of its non-recourse liabilities, Royal may incur a tax liability in excess of the amount of cash received from the sale.

A substantial portion of the amount realized from the sale of Rhino units, whether or not representing gain, may be taxed as ordinary income to Royal due to potential recapture items, including depreciation recapture. Thus, Royal may recognize both ordinary income and capital loss from the sale of Rhino's units if the amount realized on a sale of units is less than its adjusted basis in the units.

Net capital loss may only offset capital gains. In the taxable period in which Royal sells Rhino's units, it may recognize ordinary income from its allocations of income and gain prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

Royal may be subject to limitations on its ability to deduct interest expense incurred by Rhino.

In general, Rhino is entitled to a deduction for interest paid or accrued on indebtedness properly allocable to its trade or business during its taxable year. However, under the Act, for taxable years beginning after December 31, 2017, its deduction for "business interest" is limited to the sum of its business interest income and 30% of its "adjusted taxable income." For the purposes of this limitation, its adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.

Rhino treats each purchaser of its common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because Rhino cannot match transferors and transferees of common units, Rhino has adopted certain methods of allocating depreciation and amortization deductions that may not conform to all aspects of the Treasury Regulations. A successful IRS challenge to the use of these methods could adversely affect the amount of tax benefits available to Royal. It also could affect the timing of these tax benefits or the amount of gain from its sale of common units and could have a negative impact on the value of its common units or result in audit adjustments to its tax returns.

Rhino generally prorates its items of income, gain, loss and deduction between transferors and transferees of its units each month based upon the ownership of its units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among its unitholders, including Royal.

Rhino generally prorates its items of income, gain, loss and deduction between transferors and transferees of its common units each month based upon the ownership of its units on the first day of each month (the "Allocation Date"), instead of on the basis of the date a particular common unit is transferred. Similarly, Rhino generally allocates gain or loss realized on the sale or other disposition of its assets or, in the discretion of Rhino, any other extraordinary item of income, gain, loss or deduction on the Allocation Date. Nonetheless, Rhino allocates certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of its proration method. If the IRS challenged its proration method, Rhino could be required to change its allocation of items of income, gain, loss and deduction among its unitholders, including Royal.

Rhino has adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, which could adversely affect the value of its common units.

In determining the items of income, gain, loss and deduction allocable to its unitholders, Rhino must routinely determine the fair market value of its assets. Although Rhino may, from time to time, consult with professional appraisers regarding valuation matters, Rhino makes many fair market value estimates using a methodology based on the market value of its common units as a means to measure the fair market value of its assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to its unitholders, including Royal. It also could affect the amount of gain from Royal's sale of common units and could have a negative impact on the value of Royal's investment in the common units or result in audit adjustments to Royal's tax returns without the benefit of additional deductions.

Other Business Risks

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

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

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

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

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties.

See “Part I, Item 1. Business” for information about our coal operations and other natural resource assets.

Coal Reserves and Non-Reserve Coal Deposits

We base our coal reserve and non-reserve coal deposit estimates on engineering, economic and geological data assembled and analyzed by our staff. These estimates are also based on the expected cost of production and projected sale prices and assumptions concerning the permitability and advances in mining technology. The estimates of coal reserves and non-reserve coal deposits as to both quantity and quality are periodically updated to reflect the production of coal from the reserves, updated geologic models and mining recovery data, coal reserves recently acquired and estimated costs of production and sales prices. Changes in mining methods may increase or decrease the recovery basis for a coal seam as will plant processing efficiency tests. We maintain reserve and non-reserve coal deposit information in secure computerized databases, as well as in hard copy. The ability to update and/or modify the estimates of our coal reserves and non-reserve coal deposits is restricted to a few individuals and the modifications are documented.

Periodically, we retain outside experts to independently verify our coal reserve and our non-reserve coal deposit estimates. The most recent audit by an independent engineering firm of our coal reserve and non-reserve coal deposit estimates was completed by Marshall Miller & Associates, Inc. as of December 31, 2018, and covered a majority of the coal reserves and non-reserve coal deposits that we controlled as of such date. We intend to continue to periodically retain outside experts to assist management with the verification of our estimates of our coal reserves and non-reserve coal deposits going forward.

As of December 31, 2018, we controlled an estimated 268.5 million tons of proven and probable coal reserves, consisting of an estimated 214.0 million tons of steam coal and an estimated 54.5 million tons of metallurgical coals. Proven and probable coal reserves increased approximately 15.8 million tons from 2017 to 2018 primarily as the result of the revised economic feasibility of our non-reserve coal deposits. In addition, as of December 31, 2018, we controlled an estimated 164.1 million tons of non-reserve coal deposits, which decreased primarily due to the reclassification of non-reserve coal deposits to proven and probable reserves. For the year ended December 31, 2018, we purchased and sold 331 tons of third-party coal.

Coal Reserves

The following table provides information as of December 31, 2018 on the type, amount and ownership of the coal reserves:

	Proven and Probable Coal Reserves (1)								
	Total	**Proven**	**Probable**	**Assigned**	**Unassigned**	**Owned**	**Leased**	**Steam (2)**	**Metallurgical (2)**
	(in million tons)								
	268.5	147.2	121.3	126.5	142.0	41.8	226.7	214.0	54.5
Percentage of total (3)		54.8%	45.2%	47.1%	52.9%	15.6%	84.4%	79.7%	20.3%

(1) Represents recoverable tons. The recoverable tonnage estimates take into account mining losses and coal wash plant losses of material from both mining dilution and any non-coal material found within the coal seams. Except for coal expected to be processed and sold on a direct-shipped basis, a specific wash plant recovery factor has been estimated from representative exploration data for each coal seam and applied on a mine-by-mine basis to the estimates. Actual wash plant recoveries vary depending on customer coal quality specifications.

(2) For purposes of this table, we have defined metallurgical coal reserves as reserves located in those seams that historically have been of sufficient quality and characteristics to be able to be used in the steel making process. All other coal reserves are defined as steam coal. However, some of the reserves in the metallurgical category can also be used as steam coal.

(3) Totals and percentages of totals are calculated based on actual amounts and not the rounded amounts presented in this table.

The majority of our leases have an initial term denominated in years but also provide for the term of the lease to continue until exhaustion of the "mineable and merchantable" coal in the lease area so long as the terms of the lease are complied with. Some of our leases have terms denominated in years rather than mine-to-exhaustion provisions, but in all such cases, we believe that the term of years will allow the recoverable reserves 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 lands and reserves of the lessors or grantors and the boundaries of our leased priorities are not completely verified until we prepare to mine those reserves.

The following table provides information on particular characteristics of our coal reserves as of December 31, 2018:

	As Received Basis (1)				Proven and Probable Coal Reserves (2)				
				S02/mm		Sulfur Content			
	% Ash	% Sulfur	Btu/lb.	Btu	Total	<1%	1-1.5%	>1.5%	Unknown
						(in million tons)			
	7.45%	2.29%	12,194	3.76	268.5	64.9	28.5	172.4	2.7
Percentage of total (3)						24.2%	10.6%	64.2%	1.0%

(1) As received basis represents average dry basis analytical test results which are normalized to a moisture content deemed to be representative of the saleable coal product.

(2) Represents recoverable tons.

(3) Totals and percentages of totals are calculated based on actual amounts and not the rounded amounts presented in this table

Non-Reserve Coal Deposits

The following table provides information on our non-reserve coal deposits as of December 31, 2018:

	Non-Reserve Coal Deposits		
		Tons	
	Tons	Owned	Leased
		(in million tons)	
Total	164.1	66.5	97.6
Percentage of total		40.52%	59.48%

Consistent with industry practice, we conduct only limited investigations of title to our coal properties prior to leasing. Title to lands and non-reserve coal deposits of the lessors or grantors and the boundaries of our leased priorities are not completely verified until we prepare to mine the coal.

Office Facilities

Our executive headquarters occupy leased office space at 56 Broad Street, Suite 2, Charleston, SC 29401 which provides for monthly lease payments of $1,400 per month.

The Partnership leases office space at 424 Lewis Hargett Circle, Lexington, Kentucky for its executives and administrative support staff. The Partnership executed an amendment to this lease in 2018 to extend the lease term for five additional years to July 31. 2023.

Item 3. Legal Proceedings.

We may, from time to time, be involved in various legal proceedings and claims arising out of our operations in the normal course of business. While many of these matters involve inherent uncertainty, we do not believe that we are a party to any legal proceedings or claims that will have a material adverse impact on our business, financial condition or results of operations.

Item 4. Mine Safety Disclosures.

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K for the year ended December 31, 2018 is included as Exhibit 95.1 to this report.

PART II

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

Our common stock, par value $0.00001 per share, is traded in the over-the-counter market and is quoted on the OTCQB under the symbol "ROYE.OB."

The following table sets forth the quarterly high and low daily close for our common stock as reported by the OTCQB for the two years ended December 31, 2018 and 2017. The bids reflect inter dealer prices without adjustments for retail mark-ups, mark-downs or commissions and may not represent actual transactions. There is a very limited market for the Company's common stock

	Price Range	
	High	**Low**
Year ended December 31, 2018		
Fourth Quarter	$ 3.09	$ 1.07
Third Quarter	$ 2.02	$ 2.02
Second Quarter	$ 5.00	$ 2.02
First Quarter	$ 5.00	$ 3.30
Year ended December 31, 2017		
Fourth Quarter	$ 4.95	$ 1.75
Third Quarter	$ 8.09	$ 1.75
Second Quarter	$ 7.50	$ 4.75
First Quarter	$ 8.50	$ 3.60

The OTCQB is a quotation service sponsored by the Financial Industry Regulatory Authority (FINRA) that displays real-time quotes and volume information in over-the-counter ("OTC") equity securities. The OTCQB does not impose listing standards or requirements, does not provide automatic trade executions and does not maintain relationships with quoted issuers. A company traded on the OTCQB may face loss of market makers and lack of readily available bid and ask prices for its stock and may experience a greater spread between the bid and ask price of its stock and a general loss of liquidity with its stock. In addition, certain investors have policies against purchasing or holding OTC securities. Both trading volume and the market value of our securities have been, and will continue to be, materially affected by the trading on the OTCQB.

Recent Sales of Unregistered Securities

During quarter ended December 31, 2018, we did not issue any shares of common stock in unregistered transactions.

Holders

As of March 20, 2019, we had 18,579,293 shares of common stock issued and outstanding stock (including 914,797 shares held by its consolidated subsidiary, Rhino Resource Partners, LP), and 51,000 shares of Series A Preferred Stock issued and outstanding. As of March 20, 2019, there are approximately 86 shareholders of record of our common stock, which does not include shareholders holding their shares in street name.

Dividend Policy

Our Board of Directors has never declared or paid a cash dividend. At this time, our Board of Directors does not anticipate paying dividends in the future. We are under no legal or contractual obligation to declare or to pay dividends, and the timing and amount of any future cash dividends and distributions is at the discretion of our Board of Directors and will depend, among other things, on our future after-tax earnings, operations, capital requirements, borrowing capacity, financial condition and general business conditions. We plan to retain any earnings for use in the operation of our business and to fund future growth.

Issuer Purchases of Equity Securities

During the quarter ended December 31, 2018, we did not purchase any shares of our common stock.

Item 6. Selected Financial Data

The registrant is a smaller reporting company and is not required to provide this information.

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

This Annual Report on Form 10-K includes forward looking statements ("Forward Looking Statements"). All statements other than statements of historical fact included in this report are Forward Looking Statements. In the normal course of its business, Royal Energy Resources, Inc. and its subsidiaries (the "Company,") in an effort to help keep its shareholders and the public informed about the Company's operations, may from time-to-time issue certain statements, either in writing or orally, that contains or may contain Forward-Looking Statements. Although the Company believes that the expectations reflected in such Forward Looking Statements are reasonable, it can give no assurance that such expectations will prove to have been correct. Generally, these statements relate to business plans or strategies, projected or anticipated benefits or other consequences of such plans or strategies, past and possible future, of acquisitions and projected or anticipated benefits from acquisitions made by or to be made by the Company, or projections involving anticipated revenues, earnings, levels of capital expenditures or other aspects of operating results. All phases of the Company's operations are subject to a number of uncertainties, risks and other influences, many of which are outside the control of the Company and any one of which, or a combination of which, could materially affect the results of the Company's proposed operations and whether Forward Looking Statements made by the Company ultimately prove to be accurate. Such important factors ("Important Factors") and other factors could cause actual results to differ materially from the Company's expectations which are disclosed in this report. All prior and subsequent written and oral Forward Looking Statements attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by the Important Factors described below that could cause actual results to differ materially from the Company's expectations as set forth in any Forward Looking Statement made by or on behalf of the Company.

Overview

Current management of the Company acquired control of the Company in March 2015, with the goal of using the Company as a vehicle to acquire undervalued natural resource assets. The Company has raised approximately $8.45 million through the sale of shares of common stock in private placements, $6.35 million through issuance of notes payable and is currently evaluating a number of possible acquisitions of operating coal mines and non-operating coal assets. Despite recent distress in the coal industry, industry experts still predict that coal will supply a significant percentage of the nation's energy needs for the foreseeable future, and thus overall demand for coal will remain significant. Also, demand for metallurgical coal has improved and metallurgical coal prices seem likely to stay in a range that will allow lower cost North American coal mines to produce profitably. Management believes there are a number of attractive acquisition candidates in the coal industry which can be operated profitably at current prices and under the current regulatory environment.

Royal Energy Resources, Inc. Purchase of Majority Control of Rhino Resource Partners LP

In the first quarter of 2016, Royal acquired control of the Partnership from Wexford Capital LP and certain of its affiliates (collectively, "Wexford") in two different closings for aggregate consideration of $4,500,000. In the closings, Royal acquired all of the membership interests of Rhino GP, LLC ("Rhino GP"), the Partnership's general partner, 676,912 common units (which represented 40% of the outstanding common units at the time) and 945,526 subordinated units (which represented 76.5% of the subordinated units at the time). In connection with the transaction, all of the directors of Rhino GP affiliated with Wexford resigned, and Royal appointed new directors.

On March 21, 2016, Rhino and Royal entered into a securities purchase agreement (the "Securities Purchase Agreement") pursuant to which Rhino issued 6,000,000 of its common units to Royal in a private placement at $1.50 per common unit for an aggregate purchase price of $9.0 million. Royal paid Rhino $2.0 million in cash and delivered a promissory note payable to the Partnership in the amount of $7.0 million. The promissory note is payable in three installments: (i) $3.0 million on July 31, 2016; (ii) $2.0 million on or before September 30, 2016 and (iii) $2.0 million on or before December 31, 2016. On May 13, 2016, the Company paid the $3,000,000 installment which was due on July 31, 2016, and on September 30, 2016 paid the $2,000,000 installment which was due on that date. On December 30, 2016, we and the Partnership agreed to extend the maturity date of the final installment of the note to December 31, 2018, and agreed that the note may be converted, at our option, at any time prior to December 31, 2018, into unregistered shares of our common stock at a price per share equal to seventy five percent (75%) of the volume weighted average closing price for the ninety (90) trading days preceding the date of conversion, provided that the average closing price shall be no less than $3.50 per share and no more than $7.50 per share. On September 1, 2017, we elected to convert the $2.0 million promissory note and an additional $2.1 million note (including accrued interest) assigned from Weston Energy LLC into shares of Royal common stock. Royal issued 914,797 shares of its common stock to the Partnership at a conversion price of $4.51 per share.

Overview after Rhino Acquisition

We are a diversified coal producing company formed in Delaware that is focused on coal and energy related assets and activities. We produce, process and sell high quality coal of various steam and metallurgical grades. We market our steam coal primarily to electric utility companies as fuel for their steam powered generators. Customers for our metallurgical coal are primarily steel and coke producers who use our coal to produce coke, which is used as a raw material in the steel manufacturing process.

As of December 31, 2018, we controlled an estimated 268.5 million tons of proven and probable coal reserves, consisting of an estimated 214.0 million tons of steam coal and an estimated 54.5 million tons of metallurgical coal. Proven and probable coal reserves increased approximately 15.8 million tons from 2017 to 2018 primarily as the result of the revised economic feasibility of our non-reserve coal deposits. In addition, as of December 31, 2018, we controlled an estimated 164.1 million tons of non-reserve coal deposits, which decreased primarily due to the reclassification of non-reserve coal deposits to proven and probable reserves. Periodically, we retain outside experts to independently verify our coal reserve and our non-reserve coal deposit estimates. The most recent audit by an independent engineering firm of our coal reserve and non-reserve coal deposit estimates was completed by Marshall Miller & Associates, Inc. as of December 31, 2018, and covered a majority of the coal reserves and non-reserve coal deposits that we controlled as of such date. We intend to continue to periodically retain outside experts to assist management with the verification of our estimates of our coal reserves and non-reserve coal deposits going forward.

Our principal business strategy is to safely, efficiently and profitably produce and sell both steam and metallurgical coal from our diverse asset base. In addition, we intend to continue to expand and potentially diversify our operations through strategic acquisitions, including the acquisition of long-term, cash generating natural resource assets. We believe that such assets will allow us to grow our cash and enhance stability of our cash flow.

For the year ended December 31, 2018, we generated revenues of approximately $248.0 million and net loss from continuing operations of approximately $23.4 million. For the year ended December 31, 2018, we produced approximately 4.4 million tons of coal and sold approximately 4.6 million tons of coal, approximately 64.0% of which were pursuant to long-term supply contracts.

Factors That Impact Our Business

Our results of operations in the near term could be impacted by a number of factors, including (1) our ability to fund our ongoing operations and necessary capital expenditures, (2) the availability of transportation for coal shipments, (3) poor mining conditions resulting from geological conditions or the effects of prior mining, (4) equipment problems at mining locations, (5) adverse weather conditions and natural disasters or (6) the availability and costs of key supplies and commodities such as steel, diesel fuel and explosives.

On a long-term basis, our results of operations could be impacted by, among other factors, (1) our ability to fund our ongoing operations and necessary capital expenditures, (2) changes in governmental regulation, (3) the availability and prices of competing electricity-generation fuels, (4) the world-wide demand for steel, which utilizes metallurgical coal and can affect the demand and prices of metallurgical coal that we produce, (5) our ability to secure or acquire high-quality coal reserves and (6) our ability to find buyers for coal under favorable supply contracts.

We have historically sold a majority of our coal through supply contracts and anticipate that we will continue to do so. As of December 31, 2018, we had commitments under supply contracts to deliver annually scheduled base quantities of coal as follows:

Year	Tons (in thousands)	Number of customers
2019	3,699	18
2020	1,979	6
2021	352	2

Some of the contracts have sales price adjustment provisions, subject to certain limitations and adjustments, based on a variety of factors and indices.

Results of Operations

As noted above, the Company completed the acquisition of control of Rhino on March 17, 2016. Accordingly, the Company began consolidating the operations of Rhino on that date.

Evaluating Our Results of Operations

Our management uses a variety of non-GAAP financial measurements to analyze our performance, including (1) Adjusted EBITDA, (2) coal revenues per ton and (3) cost of operations per ton.

Adjusted EBITDA.

The discussion of our results of operations below includes references to, and analysis of, our Adjusted EBITDA results. Adjusted EBITDA represents net income before deducting interest expense, income taxes and depreciation, depletion and amortization, while also excluding certain non-cash and/or non-recurring items. Adjusted EBITDA is used by management primarily as a measure of our operating performance. Adjusted EBITDA should not be considered an alternative to net income, income from operations, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Because not all companies calculate Adjusted EBITDA identically, our calculation may not be comparable to similarly titled measures of other companies. Please read "—Reconciliation of Adjusted EBITDA to Net Income" for reconciliations of Adjusted EBITDA to net income for each of the periods indicated.

Coal Revenues Per Ton.

Coal revenues per ton represents coal revenues divided by tons of coal sold. Coal revenues per ton is a key indicator of our effectiveness in obtaining favorable prices for our product.

Cost of Operations Per Ton.

Cost of operations per ton sold represents the cost of operations (exclusive of DD&A) divided by tons of coal sold. Management uses this measurement as a key indicator of the efficiency of operations.

Consolidated Information

We sold approximately 4.6 million tons of coal in the year ended December 31, 2018 as compared to approximately 4.1 million tons sold for the year ended December 31, 2017.

Summary

The following table sets forth certain information regarding our revenues, operating expenses, other income and expenses, and operational data on a historical basis for the years ended December 31, 2018 and 2017.

(in millions except per ton data and %)	Historical Year ended December 31, 2018	 Year Ended December 31, 2017
Statement of Operations Data:		
Total revenues	$ 247.9	$ 218.7
Costs and expenses:		
Cost of operations	211.8	177.2
Freight and handling costs	9.1	1.8
Depreciation, depletion and amortization	31.5	40.4
Asset impairment	1.8	32.2
Selling, general and administrative	16.3	13.1
Loss on sale/disposal of assets, net	-	-
Total costs and expenses	270.4	264.9
(Loss) from operations	(22.5)	(46.1)
Other income (expense):		
Interest expense	9.0	4.1
Gain on bargain purchase	-	(168.4)
Other (income) expense, net	(2.7)	(0.6)
Total other income (expense)	(6.3)	(165.0)
Net income/(loss) before income tax	(28.8)	118.9
Income tax provision (benefit)	(5.4)	30.0
Net income/(loss) before discontinued operations and non-controlling interest	$ (23.4)	$ 88.9
Other Financial Data		
Adjusted EBITDA	$ 20.2	$ 27.5

*Totals may not foot due to rounding

Revenues.

The following table presents revenues and coal revenues per ton for the years ended December 31, 2018 and 2017:

	Year Ended December 31, 2018	 2017	Increase (Decrease) $	 %*
	(in millions except per ton data and %)			
Coal revenues	$ 244.3	$ 217.2	$ 27.1	12%
Other revenues	3.7	1.5	2.2	147%
Total revenues	$ 247.9	$ 218.7	$ 29.3	13%
Coal revenues per ton*	$ 53.13	$ 52.64	$ .49	1%
Tons sold	4,598.0	4,125.6	472.4	11%

* Percentages and per ton amounts are calculated based on actual amounts and not the rounded amounts presented in this table.

Revenues

Our revenues increased to $247.9 million in the year ended December 31, 2018 as compared to $218.7 million in the year ended December 31, 2017. Coal revenues increased in 2018 compared to 2017 due to increased demand and higher prices for coal sold, especially our metallurgical coal. This increase was primarily due to the increase in demand for steam and met coal tons sold from our Central Appalachia operations. Coal revenues per ton was $53.13 for the year ended December 31, 2018, an increase of $0.49, or 1%, from $52.64 per ton for the year ended December 31, 2017. This increase in coal revenues per ton was primarily the result of higher contracted sales prices in place in 2018 at certain operations compared to the same period in 2017.

Costs and Expenses.

The following table presents costs and expenses (including the cost of purchased coal) and cost of operations per ton the years ended December 31, 2018 and 2017:

	Year ended December 31, 2018	Year ended December 31, 2017	Increase/ (Decrease) $	% *
	(in millions, except per ton data and %)			
Cost of operations (exclusive of depreciation, depletion and amortization shown separately below)	$ 211.8	$ 177.2	$ 34.6	20%
Freight and handling costs	9.1	1.8	7.3	406%
Depreciation, depletion and amortization	31.5	40.4	(8.9)	(22)%
Asset impairment	1.8	32.2	(30.4)	(94)%
Selling, general and administrative	16.3	13.1	3.2	24%
Cost of operations per ton*	$ 46.06	$ 42.93	$ 3.13	7%

* Percentages and per ton amounts are calculated based on actual amounts and not the rounded amounts presented in this table.

Cost of Operations .

Total cost of operations was $211.8 million for the year ended December 31, 2018 as compared to $177.2 million for the year ended December 31, 2017. The increase in costs was due in part to an increase in tons sold. Our cost of operations per ton was $46.06 for the year ended December 31, 2018, an increase of $3.13, or 7%, from the year ended December 31, 2017. The increase in the cost of operations was primarily due to increase in cost of production at our Central Appalachia operations as cost for diesel fuel, contract services and equipment maintenance increased in 2018.

Freight and Handling.

Total freight and handling cost for the year ended December 31, 2018 increased by $7.3 million to $9.1 million from $1.8 million for the year ended December 31, 2017. This increase in freight and handling costs was primarily the result of rail transportation costs as we executed more export coal sales in 2018 that require us to pay for railroad transportation to the port of export. We also incurred $1.1 million in demurrage charges due to rail transportation constraints that caused shipments to be delayed to the port of export.

Depreciation, Depletion and Amortization.

Total DD&A expense for the year ended December 31, 2018 was $31.5 million as compared to $40.4 million for the year ended December 31, 2017. The decrease was due to the timing of the revaluation of acquired Rhino assets which increased depreciation in 2017 by approximately $12.9 million.

Asset Impairment .

During the year ended December 31, 2018, we recorded an impairment charge of $1.8 million relating to the ARQ royalty interest. An underlying purchase option expired in 2018, and management determined market conditions indicated no value associated with this investment.

During the year ended December 31, 2017, we recorded an impairment charge of $21.8 million related to the call option received from a third party to acquire substantially all of the outstanding common stock of Armstrong Energy, Inc. On October 31, 2017, Armstrong Energy filed Chapter 11 petitions in the Eastern District of Missouri's United States Bankruptcy Court. Per the Chapter 11 petitions, Armstrong Energy filed a detailed restructuring plan as part of the Chapter 11 proceedings. On February 9, 2018, the U.S. Bankruptcy Court confirmed Armstrong Energy's Chapter 11 reorganization plan and as such we concluded that the call option had no carrying value. An impairment charge of $21.8 million related to the call option was recorded on the Asset impairment line of the consolidated statements of operations and comprehensive income. We also recorded asset impairments during the year ended December 31, 2017 on certain West Virginia coal assets of $9.6 million and land in Colorado of $0.8 million.

Selling, General and Administrative.

Selling, general and administrative ("SG&A") expense for the year ended December 31, 2018 increased to $16.3 million as compared to $13.1 million for the year ended December 31, 2017. The increase in expense is primarily due to the stock compensation expense of approximately $1.7 million incurred through a certain severance agreement with a former executive, and a $0.9 million bad debt expense in 2018.

Interest and other (Income)/Expense for the years ended December 2018 and 2017 are summarized as follows:

	Year Ended December 31,		**Increase/**	
	2018	**2017**	**(Decrease)**	**%**
	(in millions, except %)			
INTEREST AND OTHER (EXPENSE)/INCOME:				
Interest expense	$ (9.0)	$ (4.1)	(4.9)	(120)%
Interest income	0.1	0.1	-	-%
Other income, net	-	0.5	(0.5)	(100)%
Unrealized loss on marketable securities	(0.2)	-	(0.2)	n/a%
Gain on sale of marketable securities	2.8	-	2.8	n/a%
Bargain purchase gain	-	168.4	(168.4)	(100)%
Total interest and other (expense)/income	$ (6.3)	$ 165.0	(171.3)	(104)%

Interest Expense.

Interest expense for the year ended December 31, 2018 was $9.0 million as compared to $4.1 million for the year ended December 31, 2017, an increase of $4.9 million, or 120%. This increase was primarily due to higher outstanding debt balances during 2018 along with a higher average interest rate.

Gain on sale of Marketable Securities

In 2018, the Company sold shares of Mammoth stock for a realized gain of $2.8 million.

Gain from bargain purchase income .

During 2017, we completed the acquisition accounting of the Rhino acquisition which had been reflected using a provisional approach in 2016. The revaluation supported an excess in net assets acquired of $168.4 million compared to consideration provided. This excess has been reflected as a bargain purchase gain in 2017. Factors that contributed to the bargain purchase price were:

- The transaction was completed with a motivated seller that desired to restructure its operations in order to focus on its core operations and exit in an expedient manner non-core businesses that no longer fit its strategy.

- Non-competitive bid situation. The seller accepted the first offer and did not subject the process to an extensive bid process. The seller did not have the time to market the property to multiple potential buyers.

- Management was able to complete the acquisition in an expedient manner without the need for third party financing. The lack of required third party financing and management's expertise in completing similar transactions in the past gave the seller confidence that the transaction could be completed quickly and without difficulty.

Income tax provision.

Our effective tax rate for fiscal years 2018 and 2017 was 19% and 25%, respectively. Our tax rate is affected by recurring items and also affected by discrete items that may occur in any given year, but are not consistent from year to year. State income taxes and loss allocated to noncontrolling interest have the biggest impact on the effective rate and federal income tax rate. The Tax Act had a major impact on the 2017 effective tax rate.

Net income (loss) from continuing operations.

For the year ended December 31, 2018, total net loss was $23.4 million compared to a net income of approximately $88.9 million for the year ended December 31, 2017. For the year ended December 31, 2017, our total net income from continuing operations was positively impacted by the bargain purchase gain in 2017 and partially offset by the depreciation revaluation change and various impairment charges.

Loss (income) from discontinued operations.

The 2017 loss from discontinued operations reflects the November 2017 sale of the Sands Hill operation.

Adjusted EBITDA from Continuing Operations

Adjusted EBITDA for the year ended December 31, 2018 was $20.2 million, which was a $7.3 million decrease compared to the year ended December 31, 2017. Adjusted EBITDA decreased due to elevated costs at the Central Appalachia operations and lower contracted sales prices for tons sold at the Pennyrile operation. Please read "—Reconciliation of Adjusted EBITDA to Net Income" for reconciliations of Adjusted EBITDA from continuing operations to net income from continuing operations.

Reconciliation of Adjusted EBITDA

The following tables present reconciliations of Adjusted EBITDA to the most directly comparable GAAP financial measures for each of the periods indicated. Adjusted EBITDA excludes the effect of certain non-cash and/or non-recurring items. Adjusted EBITDA is used by management primarily as a measure of our operating performance. Adjusted EBITDA should not be considered an alternative to net income, income from operations, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Because not all companies calculate Adjusted EBITDA identically, our calculation may not be comparable to similarly titled measures of other companies.

	Year ended December 31, 2018		Year ended December 31, 2017	
Net (loss) income from continuing operations	$	(23.4)	$	88.9
Plus:				
DD&A		31.5		40.4
Interest expense		9.0		4.1
Income tax provision (benefit)		(5.4)		30.0
EBITDA from continuing operations†*		11.7		163.4
Plus: Non-cash asset impairment and other non-cash charges		1.8		32.2
Bargain purchase gain		-		(168.4)
Provision for doubtful accounts		0.9		-
Stock compensation		1.9		0.3
Cumulative effect from adoption of ASU 2016-01		3.7		-
Mark-to-market adjustment-unrealized loss		0.2		-
Adjusted EBITDA†*	$	20.2	$	27.5

† Calculated based on actual amounts and not the rounded amounts presented in this table.

* Totals may not foot due to rounding

We believe that the isolation and presentation of these specific items to arrive at Adjusted EBITDA is useful because it enhances investors' understanding of how we assess the performance of our business. We believe the adjustment of these items provides investors with additional information that they can utilize in evaluating our performance. Additionally, we believe the isolation of these items provides investors with enhanced comparability to prior and future periods of our operating results.

Liquidity and Capital Resources

Liquidity

As of December 31, 2018, our available liquidity was $6.6 million. We also have a delayed draw term loan commitment in the amount of $35 million contingent upon the satisfaction of certain conditions precedent specified in the financing agreement discussed below.

On December 27, 2017, we entered into the Financing Agreement, which provides us with a multi-draw loan in the aggregate principal amount of $80 million. The total principal amount is divided into a $40 million commitment, the conditions for which were satisfied at the execution of the financing agreement and an additional $35 million commitment that is contingent upon the satisfaction of certain conditions precedent specified in the financing agreement. We used approximately $17.3 million of the net proceeds thereof to repay all amounts outstanding and terminate the Amended and Restated Credit Agreement with PNC Bank. The Financing Agreement terminates on December 27, 2020. For more information about our financing agreement, please read "—Financing Agreement" below.

Our business is capital intensive and requires substantial capital expenditures for purchasing, upgrading and maintaining equipment used in developing and mining our reserves, as well as complying with applicable environmental and mine safety laws and regulations. Our principal liquidity requirements are to finance current operations, fund capital expenditures, including acquisitions from time to time, and service our debt. Historically, our sources of liquidity included cash generated by our operations, borrowings under our credit agreement and issuances of equity securities. Our ability to access the capital markets on economic terms in the future will be affected by general economic conditions, the domestic and global financial markets, our operational and financial performance, the value and performance of our equity securities, prevailing commodity prices and other macroeconomic factors outside of our control. Failure to obtain financing or to generate sufficient cash flow from operations could cause us to significantly reduce our spending and to alter our short- or long-term business plan. We may also be required to consider other options, such as selling assets or merger opportunities, and depending on the urgency of our liquidity constraints, we may be required to pursue such an option at an inopportune time.

We continue to take measures, including the suspension of cash distributions on Rhino's common and subordinated units and cost and productivity improvements, to enhance and preserve our liquidity so that we can fund our ongoing operations and necessary capital expenditures and meet our financial commitments and debt service obligations.

Cash Flows

Net cash provided by operating activities was $17.2 million for the year ended December 31, 2018 as compared to $13.7 million for the year ended December 31, 2017. This increase in cash provided by operating activities was primarily the result of favorable working capital changes including the benefit of lowering our inventory with increased coal sales and collections of the related accounts receivable balances.

Net cash used in investing activities was $7.7 million for the year ended December 31, 2018 as compared to net cash used in investing activities of $18.2 million for the year ended December 31, 2017. The decrease in cash used in investing activities was primarily due to the proceeds received from the sale of Mammoth Inc. shares partially offsetting the increase in capital expenditures for the year ended December 31, 2018.

Net cash used in financing activities was $26.0 million for the year ended December 31, 2018, which was primarily attributable to repayments on our Financing Agreement and payment of the distribution on the Series A preferred units. Net cash provided by financing activities was $27.6 million for the year ended December 31, 2017, which was primarily due to issuance of net proceeds from the Financing Agreement.

Capital Expenditures

Our mining operations require investments to expand, upgrade or enhance existing operations and to meet environmental and safety regulations. Maintenance capital expenditures are those capital expenditures required to maintain our long-term operating capacity. For example, maintenance capital expenditures include expenditures associated with the replacement of equipment and coal reserves, whether through the expansion of an existing mine or the acquisition or development of new reserves, to the extent such expenditures are made to maintain our long-term operating capacity. Expansion capital expenditures are those capital expenditures that we expect will increase our operating capacity over the long-term. Examples of expansion capital expenditures include the acquisition of reserves, acquisition of equipment for a new mine or the expansion of an existing mine to the extent such expenditures are expected to expand our long-term operating capacity.

Actual maintenance capital expenditures for the year ended December 31, 2018 were approximately $14.2 million. These amounts were primarily used to rebuild, repair or replace older mining equipment. Expansion capital expenditures for the year ended December 31, 2018 were approximately $10.2 million, which were primarily related to the purchase of additional equipment to expand production at one of our Central Appalachia mines. For the year ended December 31, 2019, we have budgeted $13 million to $16 million for maintenance capital expenditures and $2 million to $4 million for expansion capital expenditures.

Financing Agreement

On December 27, 2017, Rhino entered into a Financing Agreement with Cortland Capital Market Services LLC, as Collateral Agent and Administrative agent, CB Agent Services LLC, as Origination Agent and the parties identified as Lenders therein, pursuant to which Lenders have agreed to provide us with a multi-draw term loan in the aggregate principal amount of $80 million, subject to the terms and conditions set forth in the Financing Agreement. The total principal amount is divided into a $40 million commitment, the conditions for which were satisfied at the execution of the Financing Agreement and an additional $35 million commitment that is contingent upon the satisfaction of certain conditions precedent specified in the Financing Agreement. Loans made pursuant to the Financing Agreement will be secured by substantially all of our assets. The Financing Agreement terminates on December 27, 2020.

Loans made pursuant to the Financing Agreement will, at our option, either be “Reference Rate Loans” or “LIBOR Rate Loans.” Reference Rate Loans bear interest at the greatest of (a) 4.25% per annum, (b) the Federal Funds Rate plus 0.50% per annum, (c) the LIBOR Rate (calculated on a one-month basis) plus 1.00% per annum or (d) the Prime Rate (as published in the Wall Street Journal) or if no such rate is published, the interest rate published by the Federal Reserve Board as the “bank prime loan” rate or similar rate quoted therein, in each case, plus an applicable margin of 9.00% per annum (or 12.00% per annum if we have elected to capitalize an interest payment pursuant to the PIK Option, as described below). LIBOR Rate Loans bear interest at the greater of (x) the LIBOR for such interest period divided by 100% minus the maximum percentage prescribed by the Federal Reserve for determining the reserve requirements in effect with respect to eurocurrency liabilities for any Lender, if any, and (y) 1.00%, in each case, plus 10.00% per annum (or 13.00% per annum if we have elected to capitalize an interest payment pursuant to the PIK Option). Interest payments are due on a monthly basis for Reference Rate Loans and one-, two- or three-month periods, at our option, for LIBOR Rate Loans. If there is no event of default occurring or continuing, we may elect to defer payment on interest accruing at 6.00% per annum by capitalizing and adding such interest payment to the principal amount of the applicable term loan (the “PIK Option”).

Commencing December 31, 2018, the principal for each loan made under the Financing Agreement will be payable on a quarterly basis in an amount equal to $375,000 per quarter, with all remaining unpaid principal and accrued and unpaid interest due on December 27, 2020. In addition, we must make certain prepayments over the term of any loans outstanding, including: (i) the payment of 25% of Excess Cash Flow (as that term is defined in the Financing Agreement) for each fiscal year, commencing with respect to the year ending December 31, 2019, (ii) subject to certain exceptions, the payment of 100% of the net cash proceeds from the dispositions of certain assets, the incurrence of certain indebtedness or receipts of cash outside of the ordinary course of business, and (iii) the payment of the excess of the outstanding principal amount of term loans outstanding over the amount of the Collateral Coverage Amount (as that term is defined in the Financing Agreement). In addition, the Lenders are entitled to certain fees, including: (i) 1.50% per annum of the unused Delayed Draw Term Loan Commitment for as long as such commitment exists, (ii) for the 12-month period following the execution of the Financing Agreement, a make-whole amount equal to the interest and unused Delayed Draw Term Loan Commitment fees that would have been payable but for the occurrence of certain events, including among others, bankruptcy proceedings or the termination of the Financing Agreement by us, and (iii) audit and collateral monitoring fees and origination and exit fees.

The Financing Agreement requires us to comply with several affirmative covenants at any time loans are outstanding, including, among others: (i) the requirement to deliver monthly, quarterly and annual financial statements, (ii) the requirement to periodically deliver certificates indicating, among other things, (a) compliance with terms of Financing Agreement and ancillary loan documents, (b) inventory, accounts payable, sales and production numbers, (c) the calculation of the Collateral Coverage Amount (as that term is defined in the Financing Agreement), (d) projections for the business and (e) coal reserve amounts; (ii) the requirement to notify the Administrative Agent of certain events, including events of default under the Financing Agreement, dispositions, entry into material contracts, (iii) the requirement to maintain insurance, obtain permits, and comply with environmental and reclamation laws (iv) the requirement to sell up to $5.0 million of shares in Mammoth Energy Securities, Inc. and use the net proceeds therefrom to prepay outstanding term loans and (v) establish and maintain cash management services and establish a cash management account and deliver a control agreement with respect to such account to the Collateral Agent. The Financing Agreement also contains negative covenants that restrict our ability to, among other things: (i) incur liens or additional indebtedness or make investments or restricted payments, (ii) liquidate or merge with another entity, or dispose of assets, (iii) change the nature of our respective businesses; (iii) make capital expenditures in excess, or, with respect to maintenance capital expenditures, lower than, specified amounts, (iv) incur restrictions on the payment of dividends, (v) prepay or modify the terms of other indebtedness, (vi) permit the Collateral Coverage Amount to be less than the outstanding principal amount of the loans outstanding under the Financing Agreement or (vii) permit the trailing six month Fixed Charge Coverage Ratio to be less than 1.20 to 1.00 commencing with the six-month period ending June 30, 2018.

The Financing Agreement contains customary events of default, following which the Collateral Agent may, at the request of lenders, terminate or reduce all commitments and accelerate the maturity of all outstanding loans to become due and payable immediately together with accrued and unpaid interest thereon and exercise any such other rights as specified under the Financing Agreement and ancillary loan documents.

On April 17, 2018, we amended our Financing Agreement to allow for certain activities, including a sale leaseback of certain pieces of equipment, the extension of the due date for lease consents required under the Financing Agreement to June 30, 2018 and the distribution to holders of the Series A preferred units of $6.0 million (accrued in the consolidated financial statements at December 31, 2017). Additionally, the amendments provided that the Partnership could sell additional shares of Mammoth Inc. stock and retain 50% of the proceeds with the other 50% used to reduce debt. The Partnership reduced its outstanding debt by $3.4 million with proceeds from the sale of Mammoth Inc. stock in the second quarter of 2018.

On July 27, 2018, we entered into a consent with our Lenders related to the Financing Agreement. The consent included the lenders agreement to make a $5 million loan from the Delayed Draw Term Loan Commitment, which was repaid in full on October 26, 2018 pursuant to the terms of the consent. The consent also included a waiver of the requirements relating to the use of proceeds of any sale of the shares of Mammoth Inc. set forth in the consent to the Financing Agreement, dated as of April 17, 2018 and also waived any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended June 30, 2018.

On November 8, 2018, we entered into a consent with our Lenders related to the Financing Agreement. The consent includes the lenders agreement to waive any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended September 30, 2018.

On December 20, 2018, we entered into a limited consent and Waiver to the Financing Agreement. The Waiver relates to sales of certain real property in Western Colorado, the net proceeds of which are required to be used to reduce our debt under the Financing Agreement. As of the date of the Waiver, we had sold 9 individual lots in smaller transactions. Rather than transmitting net proceeds with respect to each individual transaction, we agreed with the Lenders in principle to delay repayment until an aggregate payment could be made at the end of 2018. On December 18, 2018, we used the sale proceeds of approximately $379,000 to reduce the debt. The Waiver (i) contains a ratification by the Lenders of the sale of the individual lots to date and waives the associated technical defaults under the Financing Agreement for not making immediate payments of net proceeds therefrom, (ii) permits the sale of certain specified additional lots and (iii) subject to Lender consent, permits the sale of other lots on a going forward basis. The net proceeds of future sales will be held by us until a later date to be determined by the Lenders.

On February 13, 2019, we entered into a second amendment to the Financing Agreement. The Amendment provides the Lender’s consent for us to pay a one-time cash distribution on February 14, 2019 to the Series A Preferred Unitholders not to exceed approximately $3.2 million. The Amendment allows us to sell our remaining shares of Mammoth Energy Services, Inc. and utilize the proceeds for payment of the one-time cash distribution to the Series A Preferred Unitholders and waives the requirement to use such proceeds to prepay the outstanding principal amount outstanding under the Financing Agreement. The Amendment also waives any Event of Default that has or would otherwise arise under Section 9.01(c) of the Financing Agreement solely by reason of us failing to comply with the Fixed Charge Coverage Ratio covenant in Section 7.03(b) of the Financing Agreement for the fiscal quarter ending December 31, 2018. The Amendment includes an amendment fee of approximately $0.6 million payable by us on May 13, 2019 and an exit fee equal to 1% of the principal amount of the term loans made under the Financing Agreement that is payable on the earliest of (w) the final maturity date of the Financing Agreement, (x) the termination date of the Financing Agreement, (y) the acceleration of the obligations under the Financing Agreement for any reason, including, without limitation, acceleration in accordance with Section 9.01 of the Financing Agreement, including as a result of the commencement of an insolvency proceeding and (z) the date of any refinancing of the term loan under the Financing Agreement. The Amendment amends the definition of the Make-Whole Amount under the Financing Agreement to extend the date of the Make-Whole Amount period to December 31, 2019.

At December 31, 2018, $29.0 million was outstanding under the financing agreement at a variable interest rate of Libor plus 10.00% (12.53% at December 31, 2018).

Common Unit Warrants

The Partnership entered into a warrant agreement with certain parties that are also parties to the Financing Agreement discussed above. The warrant agreement included the issuance of a total of 683,888 Common Unit Warrants at an exercise price of $1.95 per unit, which was the closing price of the Partnership’s common units on the OTC market as of December 27, 2017. The Common Unit Warrants have a five year expiration date. The Common Unit Warrants and the common units after exercise are both transferable, subject to applicable US securities laws. The Common Unit Warrant exercise price is $1.95 per unit, but the price per unit will be reduced by future common unit distributions and other further adjustments in price included in the warrant agreement for transactions that are dilutive to the amount of Rhino’s common units outstanding. The warrant agreement includes a provision for a cashless exercise where the warrant holders can receive a net number of common units. Per the warrant agreement, the warrants are detached from the Financing Agreement and fully transferable.

Letter of Credit Facility – PNC Bank

On December 27, 2017, we entered the LoC Facility Agreement with PNC, pursuant to which PNC agreed to provide us with the LoC Facility. The LoC Facility Agreement provided that we pay a quarterly fee at a rate equal to 5% per annum calculated based on the daily average of letters of credit outstanding under the LoC Facility, as well as administrative costs incurred by PNC and a $100,000 closing fee. The LoC Facility Agreement provided that we reimburse PNC for any drawing under a letter of credit by a specified beneficiary as soon as possible after payment was made. Our obligations under the LoC Facility Agreement were secured by a first lien security interest on a cash collateral account that was required to contain no less than 105% of the face value of the outstanding letters of credit. In the event the amount in such cash collateral account was insufficient to satisfy our reimbursement obligations, the amount outstanding would bear interest at a rate per annum equal to the Base Rate (as that term was defined in the LoC Facility Agreement) plus 2.0%. We would indemnify PNC for any losses which PNC may have incurred as a result of the issuance of a letter of credit or PNC's failure to honor any drawing under a letter of credit, subject in each case to certain exceptions. We provided cash collateral to our counterparties during the third quarter of 2018 and as of September 30, 2018, the LoC Facility was terminated. We had no outstanding letters of credit as of December 31, 2018.

Cedarview Loan

On June 12, 2017, we entered into a Secured Promissory Note dated May 31, 2017 with Cedarview Opportunities Master Fund, L.P. (the "Cedarview"), under which we borrowed $2,500,000 from Cedarview. The loan bears non-default interest at the rate of 14%, and default interest at the rate of 17% per annum. We and Cedarview simultaneously entered into a Pledge and Security Agreement dated May 31, 2017, under which we pledged 5,000,000 common units in Rhino as collateral for the loan. The loan is payable through quarterly payments of interest only until May 31, 2019, when the loan matures, at which time all principal and interest is due and payable. We deposited $350,000 of the loan proceeds into an escrow account, from which interest payments for the first year will be paid. After the first year, we are obligated to maintain at least one quarter of interest on the loan in the escrow account at all times. In consideration for Cedarview's agreement to make the loan, we transferred 25,000 common units of Rhino to Cedarview as a fee. We intended to use the proceeds to repay in full all loans made to us by E-Starts Money Co. in the principal amount of $578,593, and the balance for general corporate overhead, as well as costs associated with potential acquisitions of mineral resource companies, including legal and engineering due diligence, deposits, and down payments.

On March 5, 2019, the Company modified the terms of the Cedarview note. The Company agreed to $1.0 million of the note balance by May 31, 2019 with the remaining balance of $1.5 million and associated accrued interest due May 31, 2020. The Company has paid a $45,000 loan extension fee to execute this agreement. All other terms of the note remain the same. The Company plans to receive advance royalty payments to fund the May 31, 2019 payment; however, if necessary, the Company could liquidate some of its Rhino units to fund the difference.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to off-balance sheet arrangements that include guarantees and financial instruments with off-balance sheet risk, such as bank letters of credit and surety bonds. No liabilities related to these arrangements are reflected in our consolidated balance sheet, and we do not expect any material adverse effects on our financial condition, results of operations or cash flows to result from these off-balance sheet arrangements.

Federal and state laws require us to secure certain long-term obligations related to mine closure and reclamation costs. We typically secure these obligations by using surety bonds, an off-balance sheet instrument. The use of surety bonds is less expensive for us than the alternative of posting a 100% cash bond or a bank letter of credit. We then provide cash collateral to secure our surety bonding obligations in an amount up to a certain percentage of the aggregate bond liability that we negotiate with the surety companies. To the extent that surety bonds become unavailable, we would seek to secure our reclamation obligations with letters of credit, cash deposits or other suitable forms of collateral.

As of December 31, 2018, we had approximately $42.6 million in surety bonds outstanding to secure the performance of our reclamation obligations. Of the $42.6 million, approximately $0.4 million relates to surety bonds for Deane Mining, LLC and approximately $3.4 million relates to surety bonds for Sands Hill Mining, LLC, which in each case have not been transferred or replaced by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC as was agreed to by the parties as part of the transactions. We can provide no assurances that a surety company will underwrite the surety bonds of the purchasers of these entities, nor are we aware of the actual amount of reclamation at any given time. Further, if there was a claim under these surety bonds prior to the transfer or replacement of such bonds by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC, then we may be responsible to the surety company for any amounts it pays in respect of such claim. While the buyers are required to indemnify us for damages, including reclamation liabilities, pursuant the agreements governing the sales of these entities, we may not be successful in obtaining any indemnity or any amounts received may be inadequate. See Part I "Business—Regulation and Laws—Surety Bonds."

Critical Accounting Policies and Estimates

Our financial statements are prepared in accordance with accounting principles that are generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the reported amount of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities. Management evaluates its estimates and judgments on an on-going basis. Management bases its estimates and judgments on historical experience and other factors that are believed to be reasonable under the circumstances. Nevertheless, actual results may differ from the estimates used and judgments made. Note 2 to the consolidated financial statements included elsewhere in this annual report provides a summary of all significant accounting policies. We believe that of these significant accounting policies, the following may involve a higher degree of judgment or complexity.

Our income tax expense and deferred tax assets and liabilities reflect management's best assessment of estimated current and future taxes to be paid. We are subject to income taxes in the United States and various states. Significant judgments and estimates are required in determining the consolidated income tax expense.

Deferred income taxes arise from temporary differences between the tax basis of assets and liabilities and their reported amounts in the consolidated financial statements, which will result in taxable or deductible amounts in the future. In evaluating our ability to recover our deferred tax assets within the jurisdiction from which they arise, we consider all available positive and negative evidence, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax-planning strategies, and results of recent operations. In projecting future taxable income, we begin with historical results adjusted for the results of discontinued operations and incorporate assumptions about the amount of future state and federal pretax operating income adjusted for items that do not have tax consequences. The assumptions about future taxable income require significant judgment and are consistent with the plans and estimates we are using to manage the underlying businesses. In evaluating the objective evidence that historical results provide, we consider three years of cumulative operating income (loss).

The Company has loss carryforwards for U.S. federal income tax purposes of $21.3 million, $2.8 million of which that will expire from 2034 to 2036 and the balance has no expiration. Additionally, the Company has $10.4 million of loss carryforwards for state income tax purposes, $2.4 million of which that expire from 2035 to 2036 and the balance has no expiration. The alternative minimum tax credit carryforward for 2017 has been recorded as a deferred tax asset as it is fully refundable and can be utilized to offset regular tax during the years 2018 through 2021.

Income Taxes- Contingency

As discussed in Item 1A Risk Factors, we have failed to timely file certain federal and state tax returns. Additionally, we have failed to timely file the applicable IRS form to change our tax year end from August 31 to December 31. We completed all the required SEC filings to change our reporting year end date from August 31 to December 31. Our income tax estimates are predicated on a December 31 year end. If the IRS does not provide us relief for the non-timely filing of the tax year end change, it is possible our income tax expense, deferred tax liability and income tax obligations as presented in the accompanying consolidated financial statements are materially misstated.

We are currently updating all of our tax filings which may identify new facts that could materially change our net financial position and operating results. We applied to the Internal Revenue Service for a tax year filing change to December and requested that it be approved due in part to the Partnership's December year end. Since we have a controlling interest in the Partnership since March 2016, we believe this will help support approving our change in tax year retroactive to 2015; however, there are no guarantees that this relief will be provided. The ultimate resolution of these tax uncertainties could materially impact our accompanying consolidated financial statements.

Recent Accounting Pronouncements

Refer to Item 8. Note 2 of the notes to the consolidated financial statements for a discussion of recent accounting pronouncements, which is incorporated herein by reference. There are no known future impacts or material changes or trends of new accounting guidance beyond the disclosures provided in Note 2.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Registrant is a smaller reporting company and is not required to provide this information.

Item 8. Financial Statements and Supplementary Data.

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and notes thereto required for this Item are set forth on pages [ ] through [ ] of this report and are incorporated herein by reference.

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

None.

Item 9A. Controls and Procedures.

(a) Disclosure Controls and Procedures.

Our principal executive officer (CEO) and principal financial officer (CFO) undertook an evaluation of our disclosure controls and procedures as of the end of the period covered by this report. The CEO and CFO have concluded that our disclosure controls and procedures were not effective as of December 31, 2018 at the reasonable assurance level. For purposes of this section, the term “disclosure controls and procedures” means controls and other procedures of an issuer that are designed to ensure that information required to be disclosed by the issuer in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Exchange Act is accumulated and communicated to the issuer’s management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

(b) Management’s Report on Internal Control over Financial Reporting.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed under the supervision of our CEO and CFO, 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.

Under the supervision and with the participation of our management, including the CEO and CFO, we conducted an evaluation of the effectiveness of our internal control over financial reporting based upon the framework in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 Framework). Based on our evaluation under this framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2018 at the Partnership and its subsidiaries. However, management has concluded that its internal control over financial reporting was not effective at Royal and its subsidiaries (other than the Partnership) in the following areas:

Audit Committee Oversight : Royal (other than the Partnership) does not have an audit committee. When a company does not have an audit committee, the entire board of directors is considered the audit committee under the Securities Exchange Act of 1934. Royal's board of directors does not include any independent members. Royal does not have a member of the board of directors designated as our financial expert; nor does Royal have a code of business conduct and ethics, an audit charter or a whistleblower policy. Therefore, Royal does not have any independent oversight of our external financial reporting and internal control over financial reporting.

Tax Reporting Compliance : Royal has outsourced the preparation of its income tax returns. Royal has not filed state tax returns for the past four years. Management has attempted to adjust its book tax provision based on expected state income tax filings. It is possible the ultimate filings of these state tax returns could differ significantly from the book tax provision. Royal's noncompliance with state tax reporting indicates inadequate oversight of its external financial reporting and internal control over financial reporting.

(c) Changes in Internal Control Over Financial Reporting.

Starting in fiscal 2018, Royal instituted a number of changes to improve its financial reporting, including appointing top management of the Partnership to be top management of Royal, utilizing an outside resource to document management's assessment of its internal control over financial reporting and engaging a separate outside accounting firm to provided additional support for financial reporting, as well as tax analysis and preparation.

Royal has remediated various material weaknesses around segregation of duties and financial reporting reported in its Form 10-K for the fiscal year ended December 31, 2017. Other than the foregoing, there was no change in our system of internal control over financial reporting (as defined in Rules 13a- 15(f) and 15d- 15(f) under the Exchange Act) during the year ended December 31, 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Executive Officers and Directors

The following table shows information for the Partnership's and our executive officers and directors as of March 20, 2019:

Name	Age (as of 12/31/2018)	Position
William Tuorto	49	Chairman of the Board of Directors and Executive Chairman of Royal and Rhino
Brian Hughs	41	Chief Commercial Officer of Royal, and Director of Royal and Rhino
Richard A. Boone	64	Chief Executive Officer of Royal, and President, Chief Executive Officer and Director of Rhino
Wendell S. Morris	51	Chief Financial Officer of Royal, and Senior Vice President and Chief Financial Officer of Rhino
Reford C. Hunt	45	Senior Vice President and Chief Administrative Officer of Rhino
Whitney C. Kegley	43	Vice President, Secretary and General Counsel of Royal and Rhino
Brian T. Aug	47	Vice President of Sales of Rhino

William Tuorto. Mr. Tuorto has served as our Chairman since March 6, 2015. From March 6, 2015 to January 31, 2018, Mr. Tuorto served as our Chief Executive Officer. Effective as of January 31, 2018, Mr. Tuorto became our Executive Chairman. Mr. Tuorto has served as the Chairman of the Partnership's general partner since March 17, 2016, and as its Executive Chairman since December 30, 2016. Mr. Tuorto has been providing legal, financial, and consulting services to public companies for over 19 years. Privately, Mr. Tuorto is an investor and entrepreneur, with holdings in a wide-range portfolio of energy, technology, real estate and hospitality. Mr. Tuorto was awarded a Bachelor of Arts degree from The Citadel in 1991, graduating with honors, and distinguished nominee of the Fulbright Fellowship and Rhodes Scholarship. Mr. Tuorto received his Juris Doctor from the University of South Carolina School of Law in 1995. Mr. Tuorto was selected to serve as a director due to his in-depth business knowledge and investment experience.

Brian Hughs. Mr. Hughs has served as a director since October 13, 2015. From October 13, 2015 to January 31, 2018, Mr. Hughs also served as Vice President. Effective as of January 31, 2018, Mr. Hughs became our Chief Commercial Officer. Mr. Hughs has served as a director of the Partnership's general partner since March 17, 2016. Mr. Hughs has been in the private sector as a business owner and entrepreneur since 2001. Through Mr. Hughs' familial involvement in the exploration and production of oil and gas in northern Texas, he brings specialized knowledge and expertise in this field of prospective investments. Mr. Hughs was selected to serve as a director due to his in-depth business knowledge and investment experience.

Richard A. Boone. Mr. Boone has served as our Chief Executive Officer since January 31, 2018. Mr. Boone has served as President and Chief Executive Officer of the Partnership's general partner since December 30, 2016. Prior to December 2016, Mr. Boone served as the general partner's President since September 2016 and served as Executive Vice President and Chief Financial Officer since June 2014. Prior to June 2014, Mr. Boone served as Senior Vice President and Chief Financial Officer of the general partner since May 2010, and as Senior Vice President and Chief Financial Officer of Rhino Energy LLC since February 2005. Prior to joining Rhino Energy LLC, he served as Vice President and Corporate Controller of PinnOak Resources, LLC, a coal producer serving the steel making industry, since 2003. Prior to joining PinnOak Resources, LLC, he served as Vice President, Treasurer and Corporate Controller of Horizon Natural Resources Company, a producer of steam and metallurgical coal, since 1998. Mr. Boone has over 30 years of experience in the coal industry.

Wendell S. Morris. Mr. Morris has served as our Chief Financial Officer since January 31, 2018. Mr. Morris has served as the Senior Vice President and Chief Financial Officer of the Partnership's general partner since September 2016. From June 2015 to September 2016, Mr. Morris served as Vice President of Finance of the Partnership's general partner and prior to June 2015, Mr. Morris served as Vice President of External Reporting and Investor Relations of the Partnership's general partner. Prior to joining Rhino Energy LLC, Mr. Morris was employed by Lexmark International, Inc. where he held various financial and accounting positions.

Reford C. Hunt. Mr. Hunt has served as Senior Vice President and Chief Administrative Officer of the Partnership's general partner since January 2018. From August 2014 to January 2018, Mr. Hunt served as Senior Vice President of Business Development of the Partnership's general partner. From May 2010 to August 2014, Mr. Hunt served as Vice President of Technical Services of the Partnership's general partner. Since April 2005, Mr. Hunt has served in various capacities with Rhino Energy LLC and its subsidiaries, including as Chief Engineer and Director of Operations. Prior to joining Rhino Energy LLC, Mr. Hunt was employed by Sidney Coal Company, a subsidiary of Massey Energy Company, from 1997 to 2005. During his time at Sidney Coal Company as a Mining Engineer, he oversaw planning, engineering, and construction for various mining and preparation operations. In total, Mr. Hunt has approximately 18 years of experience in the coal industry.

Whitney C. Kegley. Ms. Kegley has served as our Vice President, Secretary and General Counsel since January 31, 2018. Ms. Kegley has served as Vice President, Secretary and General Counsel of the Partnership's general partner since July 2012. Prior to joining the Partnership's general partner, and beginning in April 2012, Ms. Kegley served as a partner with the law firm of Dinsmore & Shohl, LLP in their Lexington, KY office. Ms. Kegley concentrated her practice on mergers and acquisitions and general corporate law with an emphasis on mineral and energy law. From March 2009 to April 2012, Ms. Kegley was a member in the Lexington, KY office of McBrayer, McGinnis, Leslie & Kirkland, PLLC, where she concentrated on mergers and acquisitions and general corporate law with an emphasis on mineral and energy law. From August 1999 to March 2009, Ms. Kegley was employed by the law firm of Frost Brown Todd LLC where she held various positions.

Brian T. Aug. Mr. Aug has served as Vice President of Sales of the Partnership's general partner since August 2013. From April 2011 to August 2013, Mr. Aug served as Director of Sales and Marketing for Rhino Energy LLC. Prior to joining Rhino Energy LLC, he was Vice President of Marketing and Trading Analysis for Greenstar Global Energy, a US based corporation focused on the selling of US coals into India. From 1994 until 2010 he worked for Duke Energy Ohio, a Midwest utility with coal and natural gas power generation. The last 10 years of his career at Duke Energy Ohio was spent as Director of Fuels.

None of the above directors and executive officers has been involved in any legal proceedings as listed in Regulation S-K, Section 401(f).

Director Independence

None of the members of our board of directors are independent as defined under the independence standards established by the NYSE and the Exchange Act.

Meetings; Committees of the Board of Directors

Our board of directors held no formal meetings during the year ended December 31, 2018. There have been no material changes to the procedures by which security holders may recommend nominees to the board of directors.

We do not currently have independent directors nor an audit, nominating or compensation committee. We have not had such committees to date because we were not seeking to add independent directors to the board. We are in the process of identifying and appointing independent directors and will be establishing an audit, nominating and compensation committee. We will also establish charters for such committees.

We do not have any director who would qualify as an audit committee financial expert on our board.

Executive Sessions of Non-Management Directors; Procedure for Contacting the Board of Directors

We do not have any non-management directors, and therefore there have been no meetings of our board of directors without any members of management present.

We have not established a formal process for interested parties to contact our board of directors directly. However, contact information for our executive officers is published on our website at www.royalenergy.us , or in writing to Royal Energy Resources, Inc., 56 Broad Street, Suite 2, Charleston, South Carolina 29401, attention Chief Executive Officer. Information may be submitted confidentially and anonymously, although we may be obligated by law to disclose the information or identity of the person providing the information in connection with government or private legal actions and in certain other circumstances.

Code of Ethics

During 2018, our Board of Directors adopted a Code of Business Conduct and Ethics that applies to all of our officers, directors and employees. A copy of the code is available by writing to Royal Energy Resources, Inc., 56 Broad Street, Suite 2, Charleston, South Carolina 29401, attention Chief Executive Officer.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires directors, executive officer and persons who beneficially own more than 10% of a registered class of our equity securities to file with the SEC initial reports of ownership and reports or changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms that they file. Based upon a review of the copies of the forms furnished to us and written representations from certain reporting persons, we believe that, during the year ended December 31, 2018, none of our executive officers, directors or beneficial owners of more than 10% of any class of registered equity security failed to file on a timely basis any such report, except that William Tuorto failed to a file timely Form 4's reporting the acquisition of 500 shares of common stock through a market purchase on December 4, 2018, 575 shares of common stock through a market purchase on December 6, 2018, 500 shares of common stock through a market purchase on December 19, 2018, and 200 shares of common stock through a market purchase on December 20, 2019. All of the transactions have since been reported on a Form 4 or Form 5 filed by Mr. Tuorto.

Item 11. Executive Compensation

Introduction

For 2018, we are reporting as a smaller reporting company due to our market capitalization. In accordance with such rules, we are required to provide a Summary Compensation Table and an Outstanding Equity Awards at Fiscal Year End Table, as well as limited narrative disclosures with respect to our named executive officers. Further, our reporting obligations extend only to the individuals serving as our chief executive officer and our two other most highly compensated executive officers.

On March 17, 2016, we acquired control of the Partnership when we purchased the general partner of the Partnership, and a majority of the outstanding common and subordinated units of the Partnership. The general partner of the Partnership has the sole responsibility for conducting the Partnership's business and for managing its operations, and its board of directors and officers make decisions on the Partnership's behalf. The compensation committee of the board of directors of the general partner determines the compensation of the directors and officers of the general partner, including its named executive officers. The compensation payable to the officers of the general partner is paid by the general partner and reimbursed by the Partnership on a dollar-for-dollar basis.

For the fiscal year ending December 31, 2018, our named executive officers were:

- William Tuorto—Chairman, Executive Chairman and former Chief Executive Officer, and Executive Chairman and Director of the Partnership;
- Brian Hughs – Chief Commercial Officer and Director, and Director of the Partnership
- Richard A. Boone—Chief Executive Officer and President, Chief Executive Officer and Director of the Partnership;

With respect to the compensation disclosures and the tables that follow, these individuals are referred to as the "named executive officers."

Changes to Named Executive Officers

On January 31, 2018, William L. Tuorto resigned as Chief Executive Officer and Principal Executive Officer of the Company. At the same time, Mr. Tuorto's employment was amended to provide that he would continue to serve as Executive Chairman. Mr. Tuorto is also employed as Executive Chairman of the Partnership.

On January 31, 2018, Douglas C. Holsted resigned as Chief Financial Officer and Principal Financial Officer of the Company. Mr. Holsted remains a consultant to the Company, and a director of the Partnership.

On January 31, 2018, Brian Hughs' employment agreement was amended to change his title to Chief Commercial Officer.

On January 31, 2018, the Company appointed Richard A. Boone as its Chief Executive Officer and Principal Executive Officer. Mr. Boone also serves as Chief Executive Officer of the Partnership

Summary Compensation Table

The following table sets forth the cash and other compensation earned by each of our named executive officers for the years ended December 31, 2018 and 2017.

Name and Principal Position	Year	Salary ($) (1)	Bonus ($) (2)	Stock/Unit Awards ($) (3)	All Other Compensation ($)(4)	Total ($)
William Tuorto	2018	435,000	217,500	31,251	31,000	714,751
Executive Chairman of Royal, and Executive Chairman and Director of Rhino	2017	298,077	200,000	31,250	30,800	560,127
Richard A. Boone (5)	2018	350,000	30,000	31,251	30,800	442,051
Chief Executive Officer of Royal and President, Chief Executive Officer and Director of Rhino	2017	300,000	200,000	31,250	14,092	545,342
Brian Hughs	2018	406,250	152,323	31,251	20,000	609,824
Chief Commercial Officer and Director of Royal, and Director of Rhino	2017	335,208	414,000	31,250	20,000	800,458

(1) Mr. Tuorto agreed to waive salary under his employment agreement with Royal for 2017 and all subsequent periods until he elects to terminate the waiver.

(2) For fiscal 2018, the bonuses for Mr. Tuorto and Mr. Boone were accrued by the Partnership per the employment agreements of these officers, but had not been paid as of the filing of this Form 10-K. Mr. Hughs bonus for fiscal 2018 was paid by Royal. For fiscal 2017, bonuses for all officers other than Mr. Hughs were paid by the Partnership, and reflect the annual cash bonus awarded to each of the named executive officers per the terms of their employment agreements, which are described further below. The bonus for Mr. Hughs was paid by Royal.

(3) The amounts reported in the "Unit Awards" column reflect the aggregate grant date fair value of awards granted under the Partnership's Long-Term Incentive Plan (the "LTIP"), computed in accordance with FASB ASC Topic 718. We did not grant equity awards to our named executive officers during 2018 and 2017 in their employee capacity, although Messrs. Tuorto, Boone and Hughs received an equity award of units with market values of $31,251 and $31,250 for their services on the Partnership's Board during the 2018 and 2017 fiscal years, respectively.

(4) Amounts reflect, as applicable with respect to the named executive officers and as provided in the supplemental table below, the use of a company provided automobile and employer contributions to the 401(k) Plan. The value of automobile use is calculated as the monthly lease payment paid by us on behalf of the executive multiplied by the monthly percentage of personal use of the automobile by the executive. With respect to Messrs. Tuorto and Hughs only, amounts reflected include $20,000 of director fees paid each year by the Partnership for 2018 and 2017.

"Other compensation" derived by certain named executive officers from the Partnership is listed below:

Name	Automobile Use	Employer Contribution to Rhino 401(k) Plan
William Tuorto	$ -	$ 11,000
Richard A. Boone	3,106	11,000

Employment Agreements

We and the Partnership have entered into employment agreements with each of the named executive officers. Below is a summary of the employment agreements entered into by us and the Partnership:

Royal Energy Resources, Inc.

William L. Tuorto . We entered into an employment agreement with Mr. Tuorto dated October 13, 2015, which was amended as of January 31, 2018. As amended, Mr. Tuorto's employment agreement has the following terms and conditions:

Position	Executive Chairman and Director
Term	60 months
Annual Salary	$435,000 (retroactive to January 1, 2017 Mr. Tuorto has agreed to forgo his base salary until he elects to reinstate this provision. No clawback provisions for past compensation.)
Signing Bonus	$150,000, payable in shares of common stock
Benefits	Insurance and participation in any retirement plans to the extent provided to other employees
Vacation/Sick Leave	Three weeks per year
Covenants	Confidentiality, non-solicitation of employees and customers

Brian Hughs . We entered into an employment agreement with Mr. Hughs dated October 13, 2015 which was amended as of January 31, 2018. As amended, Mr. Hughs' employment agreement has the following terms and conditions:

Position	Director and Chief Commercial Officer
Term	60 months
Annual Salary	$350,000 years 1-3, $375,000 years 4-5
Signing Bonus	$150,000, payable in shares of common stock
One-time Bonus	$29,167 on second anniversary
Benefits	Insurance and participation in any retirement plans to the extent provided to other employees
Vacation/Sick Leave	Three weeks per year
Covenants	Confidentiality, non-solicitation of employees and customers

Richard A. Boone. We entered into an employment agreement with Mr. Boone dated January 31, 2018, effective as of January 1, 2018. Mr. Boone's employment agreement has the following terms and conditions:

Position	Chief Executive Officer
Term	12 months
Annual Salary	$50,000
Benefits	None
Covenants	Confidentiality, non-solicitation of employees and customers

Rhino Resource Partners, LP

William L. Tuorto . The Partnership entered into an employment agreement with Mr. Tuorto dated December 30, 2016, which was amended effective January 1, 2018. Mr. Tuorto's employment agreement has the following terms and conditions:

Position	Executive Chairman and Director
Term	48 months
Annual Salary	$435,000
Mandatory Bonus	50% of Base Salary
Discretionary Bonus	Up to 100% of Base Salary
Benefits	Health insurance, vacation and participation in any retirement plans, including 401K, made available to similarly situated employees
Vehicle Allowance	Use of vehicle
Covenants	Confidentiality, non-compete, non-solicitation of employees and customers

Richard A. Boone . We entered into an amended and restated employment agreement with Mr. Boone dated December 30, 2016. Mr. Boone's employment agreement has the following terms and conditions:

Position	Chief Executive Officer
Term	24 months
Annual Salary	$300,000
Mandatory Bonus	10% of Base Salary
Discretionary Bonus	Up to 100% of Base Salary
Benefits	Health insurance, vacation and participation in any retirement plans, including 401K, made available to similarly situated employees
Vehicle Allowance	Use of vehicle
Covenants	Confidentiality, non-compete, non-solicitation of employees and customers

The severance and change in control benefits provided by the employment agreements with the named executive officers are described below in the section titled "—Potential Payments Upon Termination or Change in Control—Employment Agreements." The employment agreements also contain certain confidentiality, noncompetition, and other restrictive covenants, which are also described in the section titled "—Potential Payments Upon Termination or Change in Control—Employment Agreements."

Outstanding Equity Awards at Fiscal Year End

None of the named executive officers have any unvested equity awards or unexercised options in either us or the Partnership as of December 31, 2018.

Potential Payments upon Termination or Change in Control

We and the Partnership have employment agreements with each of the named executive officers employed by us that contain provisions regarding payments to be made to such individuals upon an involuntary termination of their employment by us or the Partnership without "cause," their resignation for "good reason" or upon a "change of control," which are discussed below. The employment agreements are described in greater detail below and in the section above titled "—Compensation Discussion and Analysis—Employment Agreements."

Royal Energy Resources, Inc.

Under our employment agreements with Messrs. Tuorto, Boone and Hughs, if the employment of the executive is terminated by us for "for cause" or by the executive voluntarily without "good reason," then the executive will be entitled to receive his earned but unpaid base salary, payment with respect to accrued but unpaid vacation days, all benefits accrued and vested under any of our benefit plans, and reimbursement for any properly incurred business expenses (collectively, the "accrued obligations").

In addition to the foregoing, in the event the employment of Messrs. Tuorto and Hughs is terminated by us without "cause," by the executive for "good reason" or by the executive after a "change of control," Messrs. Tuorto and Hughs shall receive (a) severance payments equal to three years base salary, (b) medical coverage to the same extent as it provides to other executive officers for the lesser of two years or the date the officer receives medical coverage through a different employer, and (c) any unvested options, warrants, restricted stock awards or contingent stock rights shall vest. In the event the employment of Mr. Boone is terminated by us without "cause," by Mr. Boone for "good reason" or by Mr. Boone after a "change of control," Mr. Boone is entitled to receive the same compensation and benefits as Messrs. Tuorto and Hughs described above, except that (a) he is only entitled to severance equal to six months of his base salary, and (b) he is only entitled to medical coverage to the same extent as it provides to other executive officers for the lesser of three months or the date he receives medical coverage through a different employer.

Messrs. Tuorto, Boone and Hughs are subject to certain confidentiality and non-solicitation provisions contained in their employment agreements. The confidentiality covenants expire two years after the officer's employment terminates, unless the confidential information is a trade secret under applicable law, in which case the obligation runs in perpetuity. Messrs. Tuorto, Boone and Hughs are also subject to non-solicitation provisions that prevent them from soliciting any employees or independent contractors of us to terminate their services relationship, and prevent them from soliciting any customer of us to terminate their relationship with us or in any way reduce the amount of business they do with us. The non-solicitation of employee covenant expires two years after the officer's employment with us, and the non-solicitation of customers covenant expires five years after the officer's employment with us in the case of Messrs. Tuorto and Hughs, and one year after the officer's employment in the case of Mr. Boone.

For purposes of the employment agreements with Messrs. Tuorto and Hughs, the terms listed below have been defined as follows:

- "for cause" means the officer (a) fails or refuses in any material respect to perform any duties, consistent with his position or those which may reasonably be assigned to him by the Board or materially violates company policy or procedure; (b) is grossly negligent in the performance of his duties hereunder; (c) commits of any act of fraud, willful misappropriation of funds, embezzlement or dishonesty with respect to the Company; (d) is convicted of a felony or other criminal violation, which, in the reasonable judgment of the Company, could materially impair the Company from substantially meeting its business objectives; (e) engages in any other intentional misconduct adversely affecting the business or affairs of the Company in a material manner; or (f) dies or is disabled for three consecutive months in any calendar year to such an extent that the Executive is unable to perform substantially all of his essential duties for that time.

- "for good cause" means (a) any removal of the executive from his position without his being appointed to a comparable or higher position in the Company; (b) the assignment to the Executive of duties materially inconsistent with the status of a person with his title, and the Company fails to rescind such assignment within thirty (30) days following receipt of written notice to the Board of Directors of the Company from executive; (c) any failure to elect the executive as a member of our Board of Directors or the executive's removal from membership thereof; and (d) any requirement that the executive perform his duties from any location other than Charleston, South Carolina.

- "change of control" means (a) the acquisition by any individual, entity or group of 50% or more of our common stock by any person or entity who was not a stockholder at the time the employment agreement was entered into, or (b) the consummation of (i) a reorganization, merger or consolidation under which all of the persons who are beneficial owners of us prior to the transaction do not beneficially own at least 50% of our shares following the transaction, (ii) the complete liquidation or dissolution of us, or (iii) the sale or other disposition of all or substantially all of our assets, excluding a transfer to one of our subsidiaries.

For purposes of Mr. Boone's employment agreement, the terms "for cause" and "for good cause" have the meanings defined above, except that in Mr. Boone's case the term "for good cause" does not include a requirement that he be elected to our Board of Directors, and "for good cause" includes a requirement that he be required to perform his duties from any location other than Lexington, Kentucky, instead of Charleston, South Carolina.

Under the Partnership's employment agreements with Messrs. Tuorto and Boone, if the employment of the executive is terminated by us for "cause," by the executive voluntarily without "good reason," or due to the executive's "disability," then the executive will be entitled to receive his earned but unpaid base salary, payment with respect to accrued but unpaid vacation days, all benefits accrued and vested under any of our benefit plans, and reimbursement for any properly incurred business expenses (collectively, the "accrued obligations"). In addition to the foregoing, in the event the employment of Messrs. Tuorto or Boone is terminated by the Partnership without "cause" or by the executive for "good reason," Messrs. Tuorto and Boone shall receive their base salary for the period from termination through the expiration of their respective employment agreements, subject to the executive's timely execution and delivery (and non-revocation) of a release agreement for our benefit. In the event of the death of Mr. Tuorto or Boone, their estate will be entitled to receive the accrued obligations and a pro-rated annual discretionary bonus.

Messrs. Tuorto and Boone are subject to certain confidentiality, non-compete and non-solicitation provisions contained in their employment agreements. The confidentiality covenants are perpetual, while the non-compete and non-solicitation covenants apply during the term of their employment agreements and for one year (two years for non-solicitation) following Messrs. Tuorto's and Boone's termination for any reason. Both Mr. Tuorto's and Mr. Boone's employment agreements acknowledge their position and employment with Royal and specifically excepts them from the non-compete provision as it relates to Royal and its affiliates.

For purposes of the employment agreements with Messrs. Tuorto and Boone, the terms listed below have been defined as follows:

- "cause" means (a) failure of the executive to perform substantially his duties (other than a failure due to a "disability") within ten days after written notice from us, (b) executive's conviction of, or plea of guilty or no contest to a misdemeanor involving dishonesty or moral turpitude or any felony, (c) executive engaging in any illegal conduct, gross misconduct, or other material breach of the employment agreement that is materially and demonstratively injurious to us or (d) executive engaging in any act of dishonesty or fraud involving us or any of our affiliates.

- "disability" means the inability of executive to perform his normal duties as a result of a physical or mental injury or ailment for any consecutive 45 day period or for 90 days (whether or not consecutive) during any 365 day period.

- "good reason" means, without the executive's express written consent, (a) the assignment to the executive of duties inconsistent in any material respect with those of the executive's position (including status, office, title, and reporting requirements), or any other diminution in any material respect in such position, authority, duties or responsibilities, (b) a reduction in base salary, (c) a reduction in the executive's welfare, qualified retirement plan or paid time off benefits, other than a reduction as a result of a general change in any such plan or (d) any purported termination of the executive's employment under the employment agreement other than for "cause," death or "disability". The executive must give notice of the event alleged to constitute "good reason" within six months of its occurrence and we have 30 days upon receipt of the notice to cure the alleged "good reason" event.

LTIP Phantom Unit Awards

Mr. Boone has periodically held awards of phantom units as previously described in the section above titled "—Compensation Discussion and Analysis—Phantom Unit Awards," although as of December 31, 2018 none of the Partnership's named executive officers held outstanding phantom unit awards.

Director Compensation

All of our directors are named executive officers, and therefore their compensation is reflected in the Summary Compensation Table above. We currently do not pay any compensation to our directors for service on our board, other than what they receive as officers. However, our executive officers receive compensation for service on the board of Rhino GP LLC, the general partner of the Partnership, which is disclosed in the Summary Compensation Table above. We anticipate developing a board compensation policy that is consistent with that provided to board members of other companies within our industry, in order to attract qualified candidates to our board.

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

The following table sets forth certain information, as of March 20, 2019, with respect to the beneficial ownership of our common stock by (i) all of our directors, (ii) each of our executive officers named in the Summary Compensation Table, (iii) all of our directors and named executive officers as a group, and (iv) all persons known to us to be the beneficial owner of more than five percent (5%) of any class of our voting securities.

	Common Stock		Series A Preferred Stock		Total Votes	
Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class (1)	Amount and Nature of Beneficial Ownership	Percent of Class (1)	Aggregate No. of Votes (1)	% of Total Votes (1)
William L. Tuorto (2)(3)	8,013,119	45.4%	51,000	100.0%	29,823,593	75.6%
William King and Paulette King Trust 10925 US Highway 60 Canadian, TX 79014	1,361,429	7.7%	-	0.0%	1,361,429	3.4%
DWCF, Ltd. 3988 FM 2933 McKinney, TX 75071	1,191,440	6.7%	-	0.0%	1,191,440	3.0%
Brian Hughs (3)	909,810	5.2%	-	0.0%	909,810	2.3%
Richard A. Boone (4)	-	-%	-	0.0%	-	0.0%
All Officers and Directors as a Group	8,922,929	50.5%	51,000	100.0%	30,733,403	77.9%

(1) Based upon 18,579,293 shares of common stock issued and outstanding as of March 20, 2019, less 914,797 shares held by the Partnership, which are excluded because the Partnership is a consolidated subsidiary of the Company. Each share of common stock is entitled to one vote per share. As of March 20, 2019, there were 51,000 shares of Series A Preferred Stock issued and outstanding, which are entitled to 54% of the votes on any matter upon which shareholders are entitled to vote. Total votes are 40,389,767.

(2) Mr. Tuorto's ownership of common stock consists of 824,559 shares owned outright, 7,188,560 shares owned by E-Starts Money Co., a corporation owned by Mr. Tuorto, and 51,000 shares which he has the right to acquire upon the conversion of shares of Series A Preferred Stock owned by him.

(3) The address for Messrs. Tuorto and Hughs is 56 Broad Street, Suite 2, Charleston, SC 29401.

(4) The address for Mr. Boone is 424 Lewis Hargett Circle, Suite 250, Lexington, KY 40503.

The following table sets forth certain information, as of March 20, 2019, with respect to the beneficial ownership of equity interests in Rhino Resource Partners, LP, our consolidated subsidiary, by (i) all of our directors, (ii) each of our executive officers named in the Summary Compensation Table, and (iii) all of our directors and named executive officers as a group.

Name of Beneficial Owner	Amount of Nature of Beneficial Ownership (Common Units)	Percentage (1)
William L. Tuorto	106,172	0.8%
Richard A. Boone	68,521	0.5%
Brian Hughs	33,890	0.3%
All officers and directors as a group	208,583	1.6%

(1) Based on 13,098,353 common units outstanding.

Securities Authorized for Issuance under Equity Compensation Plans

The following table summarizes certain information as of December 31, 2018, with respect to compensation plans (including individual compensation arrangements) under which our common stock is authorized for issuance:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance
Royal 2015 Employee, Consultant and Advisor Stock Compensation Plan (1)	—	—	785,908
Royal 2015 Stock Option Plan (1)	—	—	1,000,000
Rhino Long-term Incentive Plan (2)	—	n/a(2)	12,996
	—	—	

(1) The Royal Energy Resources, Inc. 2015 Employee, Consultant and Advisor Stock Compensation Plan and the Royal Energy Resources 2015 Stock Option Plan (“Plans”) were adopted on July 31, 2015 and reserve 1,000,000 shares for awards under each Plan. The Company’s compensation committee is designated to administer the Plans at the direction of the board of directors, and if there is no compensation committee the Plans are administered by the board of directors.

(2) Adopted by board of directors of the Partnership in connection with its IPO. To date, only phantom and restricted and unrestricted units have been granted under the Long-Term Incentive Plan. For more information relating to the Partnership’s Long-Term Incentive Plan and the unit awards granted thereunder, please see Note 19 of the consolidated financial statements included elsewhere in this annual report.

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

Transactions Involving Royal Only

E-Starts Money Co. Loans

On March 6, 2015, we borrowed $203,593 from E-Starts pursuant to a demand promissory date, which bears interest at six percent per annum. We used the proceeds to repay all of our indebtedness at the time. On June 11, 2015, we borrowed an additional $200,000 from E-Starts Money Co. pursuant to a non-interest bearing demand promissory note. On September 22, 2016, we borrowed $50,000 from E-Starts pursuant to a non-interest bearing demand promissory note and on December 8, 2016, we borrowed an additional $50,000 from E-Starts pursuant to a non-interest bearing demand promissory note. On April 26, 2017, we borrowed $10,000 from E-Starts pursuant to a non-interest bearing demand promissory note. The total amount owed to E-Starts at December 31, 2018 and December 31, 2017 was $513,989, plus accrued interest.

Miscellaneous Amounts Due Related Parties

E-Starts, in addition to the four notes described above, advanced money to us for use in paying certain of our obligations, and is owed accrued interest on one of the notes described above. In addition, we have advanced funds to GS Energy, LLC and Gary and Ian Ganzer, the owners of GS Energy, LLC, from time to time. Ian Ganzer was an officer until September 13, 2016, and GS Energy, LLC is an affiliate of Mr. Ganzer. All amounts due to or from the Ganzers or GS Energy, LLC were released on July 1, 2017 in connection with an agreement under which we reconveyed Blue Grove Coal, LLC to the Ganzers. The details of the due to related party account are summarized as follows:

	December 31, 2018	December 31, 2017
	(thousands)	
Due to E-Starts Money Co		
Expense advances	$ -	$ -
Accrued interest	46	34
	46	34

Transactions Involving Rhino

Acquisition of Control of Rhino

In the first quarter of 2016, Royal acquired control of the Partnership from Wexford Capital LP and certain of its affiliates (collectively, “Wexford”) in two different closings for aggregate consideration of $4,500,000. In the closings, Royal acquired all of the membership interests of Rhino GP, LLC (“Rhino GP”), the Partnership’s general partner, 676,912 common units (which represented 40% of the outstanding common units at the time) and 945,526 subordinated units (which represented 76.5% of the subordinated units at the time). In connection with the transaction, all of the directors of Rhino GP affiliated with Wexford resigned, and Royal appointed new directors. The general partner owns the general partner interest in the Partnership as well as certain incentive distribution rights in the Partnership. The terms of the transactions and agreements under which we acquired control of the Partnership were determined by arms-length negotiations between us and Wexford, who were not affiliated entities.

Registration Rights

Under the Partnership’s partnership agreement, as amended and restated, it has agreed to register for resale under the Securities Act and applicable state securities laws any common units, subordinated units or other limited partner interests proposed to be sold by its general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of the general partner. The Partnership is obligated to pay all expenses incidental to the registration, excluding underwriting discounts.

Transactions with Partnership

The effect of the following transactions are eliminated in consolidation.

On December 5, 2017, we entered into a Coal Sales Fee Agency Agreement (the “Agency Agreement”) with the Partnership, under which we act as a non-exclusive agent to the Partnership to procure coal buyers for coal produced by the Partnership and its subsidiaries. Under the Agency Agreement, the Partnership is obligated to pay us $0.25 for every short ton of steam coal and $1.50 for every ton of metallurgical coal (except $0.50 per ton for one buyer) loaded and sold pursuant to a sales contract procured by us. The Agency Agreement provides that the Partnership’s obligation to pay fees in relation to coal sold to a buyer introduced by us will extent in perpetuity, unless the buyer does not purchase any coal from the Partnership for two consecutive years. The Agency Agreement further provides that we have the right, with the consent of the Partnership, to convert any fees due to us into common units of the Partnership at a price equal to seventy-five percent (75%) of the volume weighted average price of the common units for the ninety (90) trading days preceding the date of conversion. By its terms, the Agency Agreement did not become effective until the Partnership refinanced its indebtedness with PNC Bank, N.A., which occurred on December 27, 2017. In the year ended December 31, 2018, the Partnership paid us $521,293 in fees earned under the Agency Agreement, which included coal sold to buyers introduced by us prior to the effective date of the Agency Agreement. An extension of the Coal Sales Fee Agency Agreement was signed in December 2018 and extends the agreement until December 31, 2019.

On December 5, 2017, we entered into a Guaranty Fee and Indemnity Agreement (the “Guaranty Agreement”) with the Partnership, under which we act as a guarantor of the Partnership’s obligations under any surety bond issued for the benefit of the Partnership by Indemnity National Insurance Company (“INIC”). In consideration for the guaranty, the Partnership is obligated to pay us one percent (1%) of the face value of the surety bond per year. The Guaranty Agreement has a term of three years. The Guaranty Agreement provides that, until our liability under the guaranty to INIC is extinguished, the Partnership is obligated to issue us additional common units sufficient to ensure that our ownership of the Partnership’s common units does not fall below 10% of the issued and outstanding common units at the time. The Guaranty Agreement further provides that we have the right, with the consent of the Partnership, to convert any fees due to us into common units of the Partnership at a price equal to seventy-five percent (75%) of the volume weighted average price of the common units for the ninety (90) trading days preceding the date of conversion. By its terms, the Guaranty Agreement did not become effective until the Partnership refinanced its indebtedness with PNC Bank, N.A., which occurred on December 27, 2017. In the year ended December 31, 2017, the Partnership paid us two payments of $364,916.96 each, one of which represented amounts due under the Guaranty Agreement for 2017 and the other was for amounts that will be due under the Guaranty Agreement in 2018.

Review, Approval and Ratification of Related Party Transactions

The board of directors has responsibility for establishing and maintaining guidelines relating to any related party transactions between us and any of our officers or directors. We do not currently have any written guidelines for the board of directors which will set forth the requirements for review and approval of any related party transactions, but we plan to adopt such guidelines once we add independent board members.

The Partnership has a committee of independent directors that review and approve any transactions between the Partnership and a related party to the Partnership, including transactions between us and the Partnership.

Director Independence

Our common stock is currently quoted on the OTCQB. Since the OTCQB does not have its own rules for director independence, we use the definition of independence established by the NYSE Amex (formerly the American Stock Exchange). Under applicable NYSE Amex rules, a director will only qualify as an “independent director” if, in the opinion of our Board, that person does not have a relationship which would interfere with the exercise of independent judgment in carrying out the responsibilities of a director.

We periodically review the independence of each director. Pursuant to this review, our directors and officers, on an annual basis, are required to complete and forward to the Corporate Secretary a detailed questionnaire to determine if there are any transactions or relationships between any of the directors or officers (including immediate family and affiliates) and us. If any transactions or relationships exist, we then consider whether such transactions or relationships are inconsistent with a determination that the director is independent. As this time, we do not have any independent directors.

Conflicts Relating to Officers and Directors

To date, we do not believe that there are any conflicts of interest involving our officers or directors, other than as disclosed above. With respect to transactions involving real or apparent conflicts of interest, we have not adopted any formal policies or procedures. In the absence of any formal policies and procedures regarding conflicts, we intend to follow the provisions of Delaware corporate law regarding conflicts, which generally requires that: (i) the fact of the relationship or interest giving rise to the potential conflict be disclosed or known to the directors who authorize or approve the transaction prior to such authorization or approval, (ii) the transaction be approved by a majority of our disinterested outside directors, and (iii) the transaction be fair and reasonable to us at the time it is authorized or approved by our directors.

Item 14. Principal Accounting Fees and Services.

The following table presents fees for professional services provided by Brown Edwards & Company, L.L.P. for the years December 31, 2018 and 2017, respectively:

	December 31, 2018	December 31, 2017
	(in thousands)	
Audit fees	$ 472	$ 660
Audit-related fees	-	-
Tax fees	-	-
All other fees	-	-
Total	$ 472	$ 660

(1) *Audit Fees*. Audit services include work performed for the audit of our financial statements and the review of financial statements included in our quarterly reports, as well as work that is normally provided by the independent registered public accounting firm in connection with statutory and regulatory filings.
(2) *Audit-related services* . Audit-related services are for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and are not covered above under “audit services.”
(3) *Tax services* . Tax services include all services performed by the independent registered public accounting firm’s tax personnel for tax compliance, tax advice and tax planning.
(4) *Other services* . Other services are those services not described in the other categories.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements

See “Index to the Consolidated Financial Statements” set forth on Page 88.

(2) Financial Statement Schedules

All schedules are omitted because they are not applicable or the required information is presented in the financial statements or notes thereto.

EXHIBIT LIST

Exhibit Number	Description	Filer
3.1	Amended and Restated Certificate of Incorporation dated July 29, 2016 (incorporated by reference from the Current Report on Form 8-K (File No. 000-52547) filed on July 29, 2016)	Royal
3.2	Amended and Restated Bylaws dated July 29, 2016 (incorporated by reference from the Current Report on Form 8-K (File No. 000-52547) filed on July 29, 2016)	Royal
3.3	Certificate of Amendment to Certificate of Incorporation of Royal Energy Resources, Inc. dated March 13, 2017 (incorporated by reference from the Annual Report on Form 10-K (File No. 000-52547) filed on April 3, 2017)	Royal
3.4	Certificate of Limited Partnership of Rhino Resource Partners LP, incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (File No. 333-166550) filed on May 5, 2010	Rhino
3.5	Fourth Amended and Restated Agreement of Limited Partnership of Rhino Resource Partners LP, dated as of December 30, 2016 (incorporated by reference to Exhibit 10.7 to the Current Report on Form 8-K (File No. 000-52547) filed on January 6, 2017)	Royal
3.7	Amendment No. 1 to the Fourth Amended and Restated Agreement of Limited Partnership of Rhino Resource Partners LP, dated January 25, 2018 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-34892) filed on January 26, 2018)	Rhino
4.1	Registration Rights Agreement, dated as of March 21, 2016, by and between Rhino Resource Partners LP and Royal Energy Resources, Inc. (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-34892) filed on March 23, 2016)	Rhino
4.2	Warrant Agreement between Rhino Resource Partners, LP and certain investors (incorporated by reference to Exhibit 4.3 from the Annual Report on Form 10-K (File No. 000-52547) filed April 17, 2018)	Royal
4.3	Form of Warrant of Rhino Resource Partners, LP (incorporated by reference to Exhibit 4.4 from the Annual Report on Form 10-K (File No. 000-52547) filed April 17, 2018)	Royal
10.1	Financing Agreement dated as of December 27, 2017, by and among Rhino Resource Partners LP, as Parent, Rhino Energy LLC and each subsidiary of Rhino Energy listed as a borrower on the signature pages thereto, as Borrowers, Parent and each subsidiary of Parent listed as a guarantor on the signature pages thereto, as Guarantors, the lenders from time to time party thereto, as Lenders, Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent and CB Agent Services LLC, as Origination Agent (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K (File No. 001-34892), filed on December 28, 2017)	Rhino
10.2	Consent to Financing Agreement dated as of April 17, 2018, by and among Rhino Resource Partners LP, as Parent, Rhino Energy LLC and each subsidiary of Rhino Energy listed as a borrower on the signature pages thereto, as Borrowers, Parent and each subsidiary of Parent listed as a guarantor on the signature pages thereto, as Guarantors, the lenders from time to time party thereto, as Lenders, Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent and CB Agent Services LLC, as Origination Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-34982) filed on April 23, 2018)	Rhino

Exhibit Number	Description	Filer
10.3	Consent to Financing Agreement dated as of July 27, 2018, by and among Rhino Resource Partners LP, as Parent, Rhino Energy LLC and each subsidiary of Rhino Energy listed as a borrower on the signature pages thereto, as Borrowers, Parent and each subsidiary of Parent listed as a guarantor on the signature pages thereto, as Guarantors, the lenders from time to time party thereto, as Lenders, Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent and CB Agent Services LLC, as Origination Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-34982) filed on July 31, 2018)	Rhino
10.4	First Amendment to Financing Agreement dated as of November 8, 2018, by and among Rhino Resource Partners LP, as Parent, Rhino Energy LLC and each subsidiary of Rhino Energy listed as a borrower on the signature pages thereto, as Borrowers, Parent and each subsidiary of Parent listed as a guarantor on the signature pages thereto, as Guarantors, the lenders from time to time party thereto, as Lenders, Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent and CB Agent Services LLC, as Origination Agent (incorporated by reference to Exhibit 10.2 on Form 10-Q (File No. 001-34982) filed on November 9, 2018)	Rhino
10.5	Limited Waiver and Consent to Financing Agreement dated as of December 20, 2018, by and among Rhino Resource Partners LP, as Parent, Rhino Energy LLC and each subsidiary of Rhino Energy listed as a borrower on the signature pages thereto, as Borrowers, Parent and each subsidiary of Parent listed as a guarantor on the signature pages thereto, as Guarantors, the lenders from time to time party thereto, as Lenders, Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent and CB Agent Services LLC, as Origination Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-34982) filed on December 28, 2018)	Rhino
10.6	Second Amendment to Financing Agreement dated as of February 13, 2019, by and among Rhino Resource Partners LP, as Parent, Rhino Energy LLC and each subsidiary of Rhino Energy listed as a borrower on the signature pages thereto, as Borrowers, Parent and each subsidiary of Parent listed as a guarantor on the signature pages thereto, as Guarantors, the lenders from time to time party thereto, as Lenders, Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent and CB Agent Services LLC, as Origination Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-34982) filed on February 15, 2019)	Rhino
10.7	Secured Promissory Note dated May 31, 2017 between Royal Energy Resources, Inc. and Cedarview Opportunities Master Fund, LP. (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K (File No. 000-52547) filed August 8, 2017)	Royal
10.8	Pledge and Security Agreement dated May 31, 2017 between Royal Energy Resources, Inc. and Cedarview Opportunities Master Fund, LP. (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K (File No. 000-52547) filed August 8, 2017)	Royal
10.9	Amended and Restated Secured Promissory Note dated March 5, 2019 between Royal Energy Resources, Inc. and Cedarview Opportunities Master Fund, LP (LP. (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K (File No. 000-52547) filed March 11, 2019)	Royal

Exhibit Number	Description	Filer
10.10	Securities Purchase Agreement dated March 21, 2016 by and between Rhino Resource Partners LP and Royal Energy Resources, Inc. (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K (File No. 000-52547), filed on March 23, 2016)	Royal
10.11†	2015 Stock Option Plan of Royal Energy Resources, Inc. (incorporated by reference to Exhibit 10.1 the Form S-8 (File No. 333-206024) filed on July 31, 2015)	Royal
10.12†	2015 Employee, Consultant and Advisor Stock Compensation Plan of Royal Energy Resources, Inc. (incorporated by reference to Exhibit 10.2 the Form S-8 (File No. 333-206024) filed on July 31, 2015)	Royal
10.13†	Employment Agreement between Royal Energy Resources, Inc. and William L. Tuorto (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K (File No. 000-52547) filed November 30, 2015)	Royal
10.14†	Amendment to Employment Agreement between Royal Energy Resources, Inc. and William L. Tuorto dated January 31, 2018 (incorporated by reference to Exhibit 10.12 from the Annual Report on Form 10-K (File No. 000-52547) filed April 17, 2018)	Royal
10.15†	Employment Agreement between Royal Energy Resources, Inc. and Brian Hughs (incorporated by reference to Exhibit 10.7 to the Annual Report on Form 10-K (File No. 000-52547) filed November 30, 2015)	Royal
10.16†	Amendment to Employment Agreement between Royal Energy Resources, Inc. and Brian Hughs dated January 31, 2018 (incorporated by reference to Exhibit 10.14 from the Annual Report on Form 10-K (File No. 000-52547) filed April 17, 2018)	Royal
10.17†	Employment Agreement between Royal Energy Resources, Inc. and Richard A. Boone dated January 31, 2018 (incorporated by reference to Exhibit 10.15 from the Annual Report on Form 10-K (File No. 000-52547) filed April 17, 2018)	Royal
10.18†	Employment Agreement between Royal Energy Resources, Inc. and Wendell S. Morris dated January 31, 2018 (incorporated by reference to Exhibit 10.16 from the Annual Report on Form 10-K (File No. 000-52547) filed April 17, 2018)	Royal
10.19†	Employment Agreement Amendment between Richard A. Boone and Rhino GP LLC, effective January 1, 2018 (incorporated by reference to Exhibit 10.3 of the 2017 Annual Report on Form 10-K (File No. 001-34892), filed on March 26, 2018)	Rhino
10.20†	Employment Agreement between Rhino GP LLC and William L. Tuorto, effective December 30, 2016 (incorporated by reference to Exhibit 10.20 from the Annual Report on Form 10-K (File No. 000-52547) filed April 17, 2018)	Royal
10.23†	Amended and Restated Employment Agreement between Rhino GP LLC and Reford C. Hunt effective January 1, 2019 (incorporated by reference to Exhibit 10.6 from the Annual Report on Form 10-K (File No. 001-34892) filed March 25, 2019)	Rhino

Exhibit Number	Description	Filer
10.24†	Amended and Restated Employment Agreement between Rhino GP LLC and Wendell S. Morris effective January 1, 2019 (incorporated by reference to Exhibit 10.7 from the Annual Report on Form 10-K (File No. 001-34892) filed March 25, 2019)	Rhino
10.25†	Amended and Restated Employment Agreement between Rhino GP LLC and Brian T. Aug effective January 1, 2019 (incorporated by reference to Exhibit 10.8 from the Annual Report on Form 10-K (File No. 001-34892) filed March 25, 2019)	Rhino
10.26†	Rhino Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-34892) filed on October 1, 2010)	Rhino
10.27†	Form of Long-Term Incentive Plan Grant Agreement—Phantom Units with DERs (incorporated by reference to Exhibit 10.12 of Amendment No. 3 to the Registration Statement on Form S-1 (File No. 333-166550) filed on July 23, 2010)	Rhino
10.28	Guaranty Fee and Indemnity Agreement between Royal Energy Resources, Inc. and Rhino Resource Partners, LP dated December 5, 2017 (incorporated by reference to Exhibit 10.25 from the Annual Report on Form 10-K (File No. 000-52547) filed April 17, 2018)	Royal
10.29	Coal Sales Fee Agency Agreement between Royal Energy Resources, Inc. and Rhino Resource Partners, LP dated December 5, 2017 (incorporated by reference to Exhibit 10.27 from the Annual Report on Form 10-K (File No. 000-52547) filed April 17, 2018)	Royal
14.0*	Code of Ethics	Royal
21.1*	List of Subsidiaries of Royal Energy Resources, Inc.	Royal
23.3*	Consent of Brown, Edwards and Company L.L.P.	Royal
23.4*	Consent of Marshall Miller and Associates, Inc.	Royal
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241)	Royal
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241)	Royal
32.1*	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)	Royal
32.2*	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)	Royal
95.1*	Mine Health and Safety Disclosure pursuant to §1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act for the year ended December 31, 2017 and the three months ended December 31, 2017	Royal
101.INS*	XBRL Instance Document	Royal
101.SCH*	XBRL Taxonomy Extension Schema Document	Royal
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document	Royal
101.DEF*	XBRL Taxonomy Definition Linkbase Document	Royal
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document	Royal
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document	Royal

* Filed or furnished herewith, as applicable.

† Management contract or compensatory plan or arrangement required to be filed as an exhibit to this 10-K pursuant to Item 15(b).

** Schedules and similar attachments have been omitted pursuant to Item 601(b)(2) of Regulation S K. The registrant undertakes to furnish supplementally copies of any of the omitted schedules and exhibits upon request by the Securities and Exchange Commission.

Item 16. Form 10-K Summary.

Not applicable.

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.

ROYAL ENERGY RESOURCES, INC.

By: */s/ Richard A. Boone*
Richard A. Boone
Chief Executive Officer

Date: March 29, 2019

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

Signature	Title	Date
/s/ Richard A. Boone Richard A. Boone	Chief Executive Officer and Director (Principal Executive Officer)	March 29, 2019
/s/ Wendell S. Morris Wendell S. Morris	Chief Financial Officer (Principal Financial and Accounting Officer)	March 29, 2019
/s/ William L. Tuorto William L. Tuorto	Director	March 29, 2019
/s/ Brian Hughs Brian Hughs	Director	March 29, 2019

INDEX TO FINANCIAL STATEMENTS

ROYAL ENERGY RESOURCES, INC.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Stockholders of Royal Energy Resources, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Royal Energy Resources, Inc. and Subsidiaries ("the Company") as of December 31, 2018 and 2017, and the related consolidated statements of operations and comprehensive income (loss), stockholders' equity and cash flows for each of the years in the two-year period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements 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 years in the two-year period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Emphasis of Matters

As discussed in Note 2 to the consolidated financial statements, effective December 31, 2018, the Company adopted Accounting Standards Update 2016-01 – *Financial Instruments-Overall (Subtopic 825-10): Recognition and measurement of Financial Assets and Financial Liabilities* . This new standard changed the method of accounting for equity securities. Such securities are now reported at fair value, with unrealized gains and losses recognized in Unrealized (gain) loss on marketable securities, net, in the consolidated statements of operations and comprehensive income rather than as an element of other comprehensive income. The opening balance cumulative adjustment reclassified the Company's unrealized gain from Accumulated Other Comprehensive Income/Loss to Accumulated Earnings (Deficit).

As further discussed in Note 14 of the Notes to Consolidated Financial Statements, the Company has prepared the provision for federal and state income taxes, the related current amount payable and the net deferred income tax liability based on best estimates determined upon available information. The ultimate resolution of certain pending complex tax matters, the completion and filing of delinquent income tax returns and tax positions taken could have a material impact on income tax obligations as reflected in these financial statements. Management has concluded that estimates of possible changes to these amounts cannot be made at this time.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

CERTIFIED PUBLIC ACCOUNTANTS

We have served as the Company's auditor since 2016.

513 State Street
Bristol, Virginia
March 29, 2019

ROYAL ENERGY RESOURCES, INC. AND SUBSIDIARIES
Consolidated Balance Sheets
(in thousands)

	December 31, 2018	December 31, 2017
Assets		
CURRENT ASSETS		
Cash and cash equivalents	$ 6,629	$ 10,834
Restricted cash	-	7,116
Accounts receivable	15,475	20,386
Inventories	6,573	12,860
Investment in equity securities	1,872	11,165
Advance royalties, current portion	548	495
Prepaid expenses and other assets	2,768	2,703
Total current assets	33,865	65,559
PROPERTY, PLANT AND EQUIPMENT:		
At cost, including coal properties, mine development and construction costs	255,320	238,266
Less accumulated depreciation, depletion and amortization	(75,206)	(44,696)
Net property, plant and equipment	180,114	193,570
Advance royalties, net of current portion	8,026	7,901
Investment in unconsolidated affiliates	-	130
Other non-current assets	33,954	33,778
TOTAL ASSETS	$ 255,959	$ 300,938
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 14,112	$ 9,328
Accrued expenses and other	10,603	12,617
Accrued distributions	3,210	6,038
Notes payable - related party	514	514
Current portion of long-term debt	3,174	5,475
Current portion of asset retirement obligations	465	498
Related party advances and accrued interest payable	46	34
Total current liabilities	32,124	34,504
NON-CURRENT LIABILITIES:		
Long-term debt, net	23,932	31,073
Deferred tax liability, net	25,711	30,692
Asset retirement obligations, net of current portion	15,124	15,496
Other non-current liabilities	37,091	42,718
Total non-current liabilities	101,858	119,979
Total liabilities	133,982	154,483
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY		
Preferred stock: $0.00001 par value; authorized 5,000,000 shares; 51,000 issued and outstanding at December 31, 2018 and December 31, 2017	-	-
Common stock: $0.00001 par value; authorized 25,000,000 shares; 18,579,293 shares issued and 17,664,496 outstanding December 31, 2018 and 18,079,293 shares issued and 17,164,496 outstanding at December 31, 2017, respectively	1	1
Additional paid-in capital	48,139	46,315
Treasury stock (914,797 common stock shares)	(4,176)	(4,176)
Accumulated other comprehensive income	-	1,442
Accumulated earnings	65,946	78,670
Total stockholders' equity owned by common shareholders	109,910	122,252
Non-controlling interest	12,067	24,203
Total stockholders' equity	121,977	146,455
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 255,959	$ 300,938

See accompanying notes to consolidated financial statements.

ROYAL ENERGY RESOURCES, INC. AND SUBSIDIARIES
Consolidated Statements of Operations and Comprehensive Income (Loss)
Years ended December 31, 2018 and 2017
(in thousands)

	Year ended December 31, 2018	Year ended December 31, 2017
REVENUES:		
Coal sales	$ 244,269	$ 217,192
Other revenue	3,669	1,549
Total revenues	247,938	218,741
COSTS AND EXPENSES:		
Cost of operations (exclusive of depreciation, depletion and amortization shown separately below)	211,782	177,218
Freight and handling costs	9,084	1,837
Depreciation, depletion and amortization	31,457	40,437
Asset impairment and related charges	1,825	32,206
Selling, general and administrative expense (exclusive of depreciation, depletion and amortization shown separately above)	16,300	13,115
(Gain)/loss on sale/disposal of assets, net	(23)	39
Total costs and expenses	270,425	264,852
LOSS FROM OPERATIONS	(22,487)	(46,111)
INTEREST AND OTHER EXPENSE/(INCOME):		
Interest expense	8,975	4,059
Interest income	(68)	(86)
Other income, net	(20)	(525)
Unrealized loss on marketable securities	172	-
Gain on sale of marketable securities	(2,765)	-
Gain on bargain purchase	-	(168,410)
Equity in net income of unconsolidated affiliates, net	-	(36)
Total other expense (income)	6,294	(164,998)
NET INCOME/(LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAX	(28,781)	118,887
Income tax provision (benefit)	(5,370)	29,970
NET INCOME/(LOSS) FROM CONTINUING OPERATIONS	(23,411)	88,917
INCOME/(LOSS) FROM DISCONTINUED OPERATIONS	-	(1,718)
NET INCOME (LOSS) BEFORE NON-CONTROLLING INTEREST	(23,411)	87,199
Less net income/(loss) attributable to non-controlling interest	(12,455)	(18,088)
NET INCOME/(LOSS)	(10,956)	105,287
OTHER COMPREHENSIVE INCOME/(LOSS)		
Fair market value adjustment for available-for-sale investment, net of tax of $852	-	1,754
Less comprehensive earnings attributable to non-controlling interest	-	(1,186)
COMPREHENSIVE INCOME/(LOSS)	$ (10,956)	$ 105,855
Net Income/(Loss)	$ (10,956)	$ 105,287
Preferred Distribution on Subsidiary	(3,210)	(6,038)
Net Income/(Loss) available to Company’s Stockholders	$ (14,166)	$ 99,249
Net income (loss) per share, basic and diluted		
Continuing operations	$ (0.80)	$ 5.77
Discontinued operations	-	(0.10)
	$ (0.80)	$ 5.67
Weighted average shares outstanding, basic and diluted	17,622,829	17,138,778

See accompanying notes to consolidated financial statements.

Royal Energy Resources, Inc. and Subsidiaries
Consolidated Statements of Stockholders' Equity
Years ended December 31, 2018 and 2017
(in thousands, except shares)

	Preferred stock		Common stock		Additional Paid In	Non- Controlling	Accumulated Other Comprehensive	Treasury	Stock Subscription	Accumulated Earnings	
	Shares	**Amt.**	**Shares**	**Amt.**	**Capital**	**Interest**	**Income (Loss)**	**Stock**	**Receivable**	**(Deficit)**	**Total**
Balance December 31, 2016	51,000	$ -	17,212,278	$ 1	$ 47,295	$ 37,904	$ 874	$ -	$ (213)	$ (20,579)	$ 65,282
Common stock issued for:											
Cash	-	-	21,817	-	120	-	-	-	-	-	120
Services and payment of taxes with Rhino stock	-	-	-	-	-	250	-	-	-	-	250
Stock returned for Blue Grove interest	-	-	(10,000)	-	-	-	-	(50)	-	-	(50)
Ganzer employment agreement	-	-	(9,599)	-	-	-	-	-	-	-	-
Issuance of Rhino common unit warrants	-	-	-	-	-	1,264	-	-	-	-	1,264
Equity based compensation	-	-	-	-	-	260	-	-	-	-	260
Stock subscription receivable	-	-	(50,000)	-	(213)	-	-	-	213	-	-
Other	-	-	-	-	-	(90)	-	-	-	-	(90)
Mark-to-market investment, net of tax	-	-	-	-	-	1,186	568	-	-	-	1,754
Adjustments of NCI	-	-	-	-	(887)	(783)	-	-	-	-	(1,670)
Sale of Rhino units	-	-	-	-	-	2,300	-	-	-	-	2,300
Rhino note conversion (issued but not outstanding shares)	-	-	914,797	-	-	-	-	(4,126)	-	-	(4,126)
Rhino preferred distributions	-	-	-	-	-	-	-	-	-	(6,038)	(6,038)
Net (loss) income	-	-	-	-	-	(18,088)	-	-	-	105,287	87,199
Balance December 31, 2017	51,000	$ -	18,079,293	$ 1	$ 46,315	$ 24,203	$ 1,442	$ (4,176)	$ -	$ 78,670	$ 146,455
Net loss	-	-	-	-	-	(12,455)	-	-	-	(10,956)	(23,411)
Preferred Distribution	-	-	-	-	-	-	-	-	-	(3,210)	(3,210)
Impact from adoption of ASU 2016-01	-	-	-	-	-	-	(1,442)	-	-	1,442	-
Equity compensation	-	-	-	-	-	230	-	-	-	-	230
Rhino units as financing cost	-	-	-	-	-	89	-	-	-	-	89
Stock option granted	-	-	-	-	174	-	-	-	-	-	174
Stock compensation	-	-	500,000	-	1,650	-	-	-	-	-	1,650
Balance December 31, 2018	51,000	$ -	18,579,293	$ 1	$ 48,139	$ 12,067	$ -	$ (4,176)	$ -	$ 65,946	$ 121,977

See accompanying notes to consolidated financial statements.

ROYAL ENERGY RESOURCES, INC. AND SUBSIDIARIES
Consolidated Statements of Cash Flows
Years Ended December 31, 2018 and 2017
(in thousands)

	Year ended December 31, 2018	Year ended December 31, 2017
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (23,411)	$ 87,199
Adjustment to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	31,457	43,264
Accretion of asset retirement obligations	1,277	1,556
Deferred tax (benefit) provision	(4,977)	29,116
Amortization of advance royalties	667	1,116
Amortization of debt issuance costs	1,881	1,239
Amortization of common unit warrants	421	-
Asset impairment and related charges	1,825	32,206
Loss on retirement of advance royalties	113	136
Gain on bargain purchase	-	(168,410)
Loss (gain) on sale/disposal of assets, net	(23)	39
Gain on sale of marketable securities	(2,765)	-
Unrealized loss on marketable securities	172	-
Gain on deconsolidation	-	(50)
Equity-based compensation	1,880	330
Equity income of unconsolidated affiliates	-	(36)
Gain/loss on business disposal	-	(1,751)
Accrued interest expense - related party	12	12
Provision of bad debts	737	56
Change in assets and liabilities:		
Accounts receivable	4,174	(6,698)
Inventories	6,287	(4,810)
Advance royalties	(958)	(1,098)
Prepaid expenses and other assets	3,153	(3,022)
Accounts payable	4,583	(1,017)
Accrued expenses and other liabilities	(7,643)	5,908
Asset retirement obligations	(1,682)	(1,624)
Net cash provided by operations	17,180	13,661
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to property, plant and equipment	(24,405)	(20,078)
Proceeds from business disposal	-	890
Proceeds from sale of Rhino preferred and common units	-	300
Proceeds from sale of property, plant, and equipment	4,855	656
Proceeds from sale of investment	11,887	-
Net cash used in investing activities	(7,663)	(18,232)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from short term borrowing	5,000	-
Repayment on long term and other debt	(17,051)	-
Borrowings on line of credit	-	132,200
Repayments on line of credit	-	(142,240)
Payments on debt issuance costs	(1,225)	(4,915)
Loan proceeds	1,622	42,469
Proceeds of related party loans	-	85
Payments on related party loans	-	(75)
Proceeds from issuance of common stock	-	120
Deposit for worker's compensation and surety programs	(8,266)	-
Preferred distributions paid	(6,039)	-
Net cash provided by (used in) financing activities	(25,959)	27,644
Net increase (decrease) in cash and cash equivalents and restricted cash	(16,442)	23,073
Cash and cash equivalents and restricted cash, beginning of period	23,159	86
Cash and cash equivalents and restricted cash, end of period	$ 6,717	$ 23,159
Summary Statement of Financial Position:		
Cash and cash equivalents	$ 6,629	$ 10,834
Restricted cash- current portion	-	7,116
Restricted cash- noncurrent portion	88	5,209

Total	$	6,717	$	23,159
Supplemental cash flow information				
Cash paid for interest	$	6,330	$	3,252
Cash paid for income taxes		61		-
Non-cash investing and financing activities				
Property and equipment additions in accounts payable		1,200		1,000
Stock option for royalty rights		174		-
Rhino units provided to pay off a note payable		-		2,000
Rhino units provided as financing costs		89		-
Issuance of common stock in payment of accrued franchise taxes		-		180
Accrued preferred distributions charged to equity		3,210		6,038

See accompanying notes to consolidated financial statements.

ROYAL ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2018 and 2017

1. ORGANIZATION AND BASIS OF PRESENTATION

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Royal Energy Resources, Inc. ("Royal") and its wholly owned subsidiary Rhino GP LLC ("Rhino GP"), and majority owned subsidiary Rhino Resource Partners, LP ("Rhino")(the "Partnership") (OTCQB:RHNO), a Delaware limited partnership (collectively the "Company"). Rhino GP is the general partner of Rhino. All significant intercompany balances and transactions have been eliminated in consolidation.

Organization and nature of business

Royal is a Delaware corporation which was incorporated on March 22, 1999, under the name Webmarketing, Inc. On July 7, 2004, the Company revived its charter and changed its name to World Marketing, Inc. In December 2007 the Company changed its name to Royal Energy Resources, Inc. Since 2007, the Company pursued gold, silver, copper and rare earth metal mining concessions in Romania and mining leases in the United States. Commencing in January 2015, the Company began a series of transactions to sell all of its existing assets, undergo a change in ownership control and management and repurpose itself as a North American energy recovery company, planning to purchase a group of synergistic, long-lived energy assets, but taking advantage of favorable valuations for mergers and acquisitions in the current energy markets. On April 13, 2015, the Company executed an agreement for the first acquisition in furtherance of its change in principal operations.

Rhino was formed on April 19, 2010 to acquire Rhino Energy LLC (the "Operating Company"). The Operating Company and its wholly owned subsidiaries produce and market coal from surface and underground mines in Kentucky, Ohio, West Virginia and Utah. The majority of sales are made to domestic utilities and other coal-related organizations in the United States.

Royal Energy Resources, Inc. Acquisition of Rhino

On January 21, 2016, a definitive agreement ("Definitive Agreement") was completed between Royal and Wexford Capital whereby Royal acquired 676,912 issued and outstanding common units of Rhino from Wexford Capital for $3.5 million. The Definitive Agreement also included the committed acquisition by Royal within sixty days from the date of the Definitive Agreement of all of the issued and outstanding membership interests of the General Partner, as well as 945,525 issued and outstanding subordinated units of Rhino from Wexford Capital for $1.0 million.

On March 17, 2016, Royal completed the acquisition of all of the issued and outstanding membership interests of the General Partner as well as the 945,525 issued and outstanding subordinated units from Wexford Capital. Royal obtained control of, and a majority limited partner interest, in Rhino with the completion of this transaction.

On March 21, 2016, Royal and Rhino entered into a securities purchase agreement (the "Securities Purchase Agreement") pursuant to which Rhino issued 6,000,000 common units to Royal in a private placement at $1.50 per common unit for an aggregate purchase price of $9.0 million. Royal paid the Partnership $2.0 million in cash and delivered a promissory note payable to Rhino in the amount of $7.0 million (the "Rhino Promissory Note"). The promissory note was payable in three installments: (i) $3.0 million on July 31, 2016; (ii) $2.0 million on or before September 30, 2016 and (iii) $2.0 million on or before December 31, 2016. The payments were made in relation to the fifth amendment of Rhino's amended and restated credit agreement completed on May 13, 2016. On December 30, 2016, the Partnership modified the Securities Purchase Agreement with Royal for the final $2.0 million payment due on or before December 31, 2016 to extend the due date to December 31, 2018.

As a result of these transactions, Rhino became a majority owned subsidiary of Royal. See Note 3.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND GENERAL

Trade Receivables and Concentrations of Credit Risk. See Note 21 for discussion of major customers. The Company does not require collateral or other security on accounts receivable. The credit risk is controlled through credit approvals and monitoring procedures.

Cash, Cash Equivalents and Restricted Cash. The Company considers all highly liquid investments purchased with original maturities of three months or less to be cash equivalents. The Company early adopted ASU No. 2016-18, *Statement of Cash Flows-Restricted Cash* as of December 31, 2017 and as such its consolidated statement of cash flows for all historical periods reflect restricted cash combined with cash and cash equivalents. We did not have any other material impact of early adoption of this ASU.

Inventories. Inventories are stated at the lower of cost, based on a three month rolling average, or market. Inventories primarily consist of coal contained in stockpiles.

Advance Royalties. The Company is required, under certain royalty lease agreements, to make minimum royalty payments whether or not mining activity is being performed on the leased property. These minimum payments may be recoupable once mining begins on the leased property. The Company capitalizes the recoupable minimum royalty payments and amortizes the deferred costs on the units-of-production method once mining activities begin or expenses the deferred costs when the Company has ceased mining or has made a decision not to mine on such property.

Property, Plant and Equipment. Property, plant, and equipment, including coal properties, oil and natural gas properties, mine development costs and construction costs, are recorded at acquisition date fair value, which includes construction overhead and interest, where applicable. Expenditures for major renewals and betterments are capitalized, while expenditures for maintenance and repairs are expensed as incurred. Mining and other equipment and related facilities are depreciated using the straight-line method based upon the shorter of estimated useful lives of the assets or the estimated life of each mine. Coal properties are depleted using the units-of-production method, based on estimated proven and probable reserves. Mine development costs are amortized using the units-of-production method, based on estimated proven and probable reserves. The Company assumes zero salvage values for the majority of its property, plant and equipment when depreciation and amortization are calculated. Gains or losses arising from sales or retirements are included in current operations.

Stripping costs incurred in the production phase of a mine for the removal of overburden or waste materials for the purpose of obtaining access to coal that will be extracted are variable production costs that are included in the cost of inventory produced and extracted during the period the stripping costs are incurred. The Company defines a surface mine as a location where the Company utilizes operating assets necessary to extract coal, with the geographic boundary determined by property control, permit boundaries, and/or economic threshold limits. Multiple pits that share common infrastructure and processing equipment may be located within a single surface mine boundary, which can cover separate coal seams that typically are recovered incrementally as the overburden depth increases. In accordance with the accounting guidance for extractive mining activities, the Company defines a mine in production as one from which saleable minerals have begun to be extracted (produced) from an ore body, regardless of the level of production; however, the production phase does not commence with the removal of de minimis saleable mineral material that occurs in conjunction with the removal of overburden or waste material for the purpose of obtaining access to an ore body. The Company capitalizes only the development cost of the first pit at a mine site that may include multiple pits.

Asset Impairments for Coal Properties, Mine Development Costs and Other Coal Mining Equipment and Related Facilities. The Company follows the accounting guidance in Accounting Standards Codification ("ASC") 360, Property, Plant and Equipment, on the impairment or disposal of property, plant and equipment for its coal mining assets, which requires that projected future cash flows from use and disposition of assets be compared with the carrying amounts of those assets when potential impairment is indicated. When the sum of projected undiscounted cash flows is less than the carrying amount, impairment losses are recognized. In determining such impairment losses, the Company must determine the fair value for the coal mining assets in question in accordance with the applicable fair value accounting guidance. Once the fair value is determined, the appropriate impairment loss must be recorded as the difference between the carrying amount of the coal mining assets and their respective fair values. Also, in certain situations, expected mine lives are shortened because of changes to planned operations or changes in coal reserve estimates. When that occurs and it is determined that the mine's underlying costs are not recoverable in the future, reclamation and mine closing obligations are accelerated and the mine closing accrual is increased accordingly. To the extent it is determined that coal asset carrying values will not be recoverable during a shorter mine life, a provision for such impairment is recognized.

Debt Issuance Costs. Debt issuance costs reflect fees incurred to obtain financing and are amortized (included in interest expense) using the effective interest method over the life of the related debt. Debt issuance costs are presented as a direct deduction from long-term debt for the years ended December 31, 2018 and 2017.

Asset Retirement Obligations. The accounting guidance for asset retirement obligations addresses asset retirement obligations that result from the acquisition, construction or normal operation of long-lived assets. This guidance requires companies to recognize asset retirement obligations at fair value when the liability is incurred or acquired. Upon initial recognition of a liability, an amount equal to the liability is capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. The Company has recorded the asset retirement costs for its mining operations in coal properties.

The Company estimates its future cost requirements for reclamation of land where it has conducted surface and underground mining operations, based on its interpretation of the technical standards of regulations enacted by the U.S. Office of Surface Mining, as well as state regulations. These costs relate to reclaiming the pit and support acreage at surface mines and sealing portals at underground mines. Other reclamation costs are related to refuse and slurry ponds, as well as holding and related termination/exit costs.

The Company expenses contemporaneous reclamation which is performed prior to final mine closure. The establishment of the end of mine reclamation and closure liability is based upon permit requirements and requires significant estimates and assumptions, principally associated with regulatory requirements, costs and recoverable coal reserves. Annually, the Company reviews its end of mine reclamation and closure liability and makes necessary adjustments, including mine plan and permit changes and revisions to cost and production levels to optimize mining and reclamation efficiency. When a mine life is shortened due to a change in the mine plan, mine closing obligations are accelerated, the related accrual is increased and the related asset is reviewed for impairment, accordingly.

The adjustments to the liability from annual recosting reflect changes in expected timing, cash flow and the discount rate used in the present value calculation of the liability. Each respective year includes a range of discount rates that are dependent upon the timing of the cash flows of the specific obligations. The discount rates changed in each respective year due to changes in applicable market indicators that are used to arrive at an appropriate discount rate. Other recosting adjustments to the liability are made annually based on inflationary cost increases or decreases and changes in the expected operating periods of the mines. The related inflation rate utilized in the recosting adjustments was 2.3 % for 2018 and 2017.

Business Combinations. For purchase acquisitions accounted for as business combinations, the Company is required to record the assets acquired, including identified intangible assets and liabilities assumed at their fair value, which in many instances involves estimates based on third party valuations, such as appraisals, or internal valuations based on discounted cash flow analyses or other valuation techniques.

The Company determines the fair value of cash and cash equivalents, trade receivables, prepaid expenses, advanced royalties, deposits, accounts payable and accrued expenses at the acquired carrying value given the highly liquid and short-term nature of these assets and liabilities. The fair value of inventories and property, plant and equipment (inclusive of mineral interests) is determined based on a market approach. The market approach includes the development of an entity-wide value using discounted cash flows and allocating the entity-wide value back to the underlying assets based on observed market prices and historical cost values. The Company evaluates the acquired asset retirement obligations to determine the cost to fulfill the obligation and applies an appropriate discount rate to determine the fair value. The assumptions used in these fair value measurements are not observable in active markets and, thus represent Level 3 fair value measurements. The fair value of the long-term debt acquired is analyzed through comparison of similar debt instruments and interest rates in active markets, and thus the assumptions used for the long-term debt represent Level 2 fair value measurements.

Occasionally (e.g., distress sales), the Company's consideration transferred is less than the fair value of the identifiable net assets acquired. Such a transaction results in an economic gain to the Company and is referred to as a bargain purchase. Any such gain is recognized in earnings only after a thorough reassessment of all elements of the accounting for the acquisition.

Noncontrolling Interests. All of Rhino equity interests in its operating partnership not held by the Company are reflected as noncontrolling interests. In the consolidated statements of operations, the Company allocates net income (loss) attributable to noncontrolling interests to arrive at net income (loss) attributable to Royal.

For transactions that result in changes to the Company's ownership interest in its operating partnership, the carrying amount of noncontrolling interests is adjusted to reflect such changes. The difference between the fair value of the consideration received or paid and the amount by which the noncontrolling interests is adjusted is reflected as an adjustment to additional paid-in capital on the consolidated balance sheets.

The Company presents Rhino's preferred dividends as a component of the attribution of net income (loss) to the noncontrolling interest on the face of the consolidated statements of operation. The preferred dividends result in a decrease in consolidated net income attributable to Royal.

Revenue Recognition. The Company adopted ASU 2014-09, Topic 606 on January 1, 2018, using the modified retrospective method. The adoption of Topic 606 had no impact on revenue amounts recorded on the Royal financial statements (See Note 22 for additional discussion). Most of the Company's revenues are generated under coal sales contracts with electric utilities, coal brokers, domestic and non-U.S. steel producers, industrial companies or other coal-related organizations. Revenue is recognized and recorded when shipment or delivery to the customer has occurred, prices are fixed or determinable, the title or risk of loss has passed in accordance with the terms of the sales agreement and collectability is reasonably assured. Under the typical terms of these agreements, risk of loss transfers to the customers at the mine or port, when the coal is loaded on the rail, barge, truck or other transportation source that delivers coal to its destination. Advance payments received are deferred and recognized in revenue as coal is shipped and title has passed.

Freight and handling costs paid directly to third-party carriers and invoiced separately to coal customers are recorded as freight and handling costs and freight and handling revenues, respectively. Freight and handling costs billed to customers as part of the contractual per ton revenue of customer contracts is included in coal sales revenue.

Other revenues generally consist of coal royalty revenues, coal handling and processing revenues, rebates and rental income. With respect to other revenues recognized in situations unrelated to the shipment of coal, the Partnership carefully reviews the facts and circumstances of each transaction and does not recognize revenue until the following criteria are met: persuasive evidence of an arrangement exists, delivery has occurred or services have been rendered, the seller's price to the buyer is fixed or determinable and collectability is reasonably assured.

Equity-Based Compensation. The Company applies the provisions of ASC Topic 718 to account for any stock/unit awards granted to employees, directors or consultants. This guidance requires that all share-based payments to employees or directors, including grants of stock options, be recognized in the financial statements based on their fair value. Royal has granted stock awards to officers and consultants and Rhino GP has granted restricted units to directors and certain employees of Rhino GP and Rhino. The fair value of each stock grant, stock option and each restricted unit award was calculated using the closing price of Rhino's common units or Royal's share price on the date of grant.

Derivative Financial Instruments. On occasion, the Company has used diesel fuel contracts to manage the risk of fluctuations in the cost of diesel fuel. The Company's diesel fuel contracts have met the requirements for the normal purchase normal sale ("NPNS") exception prescribed by the accounting guidance on derivatives and hedging, based on management's intent and ability to take physical delivery of the diesel fuel. The Company had one diesel fuel contract as of December 31, 2018 to purchase approximately 1.0 million gallons of diesel fuel at fixed prices through December 31, 2019.

Investments in Joint Ventures. Investments in joint ventures are accounted for using the equity method or cost basis depending upon the level of ownership, the Company's ability to exercise significant influence over the operating and financial policies of the investee and whether the Company is determined to be the primary beneficiary of a variable interest entity. Equity investments are recorded at original cost and adjusted periodically to recognize the Company's proportionate share of the investees' net income or losses after the date of investment. Any losses from the Company's equity method investment are absorbed by the Company based upon its proportionate ownership percentage. If losses are incurred that exceed the Company's investment in the equity method entity, then the Company must continue to record its proportionate share of losses in excess of its investment. Investments are written down only when there is clear evidence that a decline in value that is other than temporary has occurred.

Income Taxes. The Company uses the asset and liability method of accounting for income taxes in accordance with ASC Topic 740 "Income Taxes." Under this method, income tax expense is recognized for the amount of: (i) taxes payable or refundable for the current year and (ii) deferred tax consequences of temporary differences resulting from matters that have been recognized in an entity's financial statements or tax returns. Deferred taxes and liabilities are measured using enacted tax rates or expected tax rates to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the results of operations in the period that includes the enactment date. A valuation allowance is provided to reduce the deferred tax assets reported if, based on the weight of the available positive and negative evidence, it is more likely than not some portion or all of the deferred tax assets will not be realized.

ASC Topic 740-10-30 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. ASC Topic 740-10-40 provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition.

The U.S. Tax Cuts and Jobs Act (Tax Act), which was enacted in December 2017, had a substantial impact on the Company's income tax expense and deferred tax assets and liabilities for the year ended December 31, 2017. See Note 14 for further detail.

The Company is subject to U.S. federal income tax and state income tax in several jurisdictions. The Company has filed federal but not all of its required state income tax returns for 2014, 2015, 2016 and 2017, and failed to timely file an application for a change in tax year when it changed its reporting year for external reporting purposes from August 31st to December 31st in 2015. In addition, management and third-party specialists have identified certain transactions which are highly complex from an income tax perspective and have not completed the necessary analysis to bring these matters to conclusion. In preparing the financial statements as of and for the year ended December 31, 2018, management has used its best estimates to compute the Company's provision for federal and state income taxes based on available information; however, the resolution of certain of the complex tax matters, the ultimate completion of returns for all open tax years and tax positions taken could materially impact management's estimates. Therefore, the ultimate tax obligations could be materially different from that reflected in the accompanying consolidated balance sheet at December 31, 2018 once these issues are resolved.

The tax years ended in 2015 through 2017 remain open for examination for U.S. federal income tax and tax years ended in 2014 through 2017 are open for state income tax examination upon filing.

Loss Contingencies. In accordance with the guidance on accounting for contingencies, the Company records loss contingencies at such time that an unfavorable outcome becomes probable and the amount can be reasonably estimated. When the reasonable estimate is a range, the recorded loss is the best estimate within the range. If no amount in the range is a better estimate than any other amount, the minimum amount of the range is recorded. The Company discloses information concerning loss contingencies for which an unfavorable outcome is probable. See Note 20, "Commitments and Contingencies," for a discussion of such matters.

Management's Use of Estimates. The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements as well as the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Recently Issued Accounting Standards. In January 2016, the FASB issued ASU 2016-01, *Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities ("ASU 2016-01").* ASU 2016-01 requires entities to measure equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) at fair value and recognize any changes in fair value in net income. An exception is available for equity investments without a readily determinable fair value, but provides a new measurement alternative where entities may choose to measure those investments at cost, less any impairment, plus or minus any changes resulting from observable price changes in transactions for the same issuer. ASU 2016-01 is effective for fiscal years beginning after December 15, 2017. Upon adoption during 2018, the Company recorded a $1.4 million reclassification from accumulated other comprehensive income to partners' accumulated earnings relating to securities with a readily determinable fair value.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* . ASU 2016-02 requires that lessees recognize all leases (other *than* leases with a term of twelve months or less) on the balance sheet as lease liabilities, based upon the present value of the lease payments, with corresponding right of use assets. The standard is effective for public companies with fiscal years beginning after December 31, 2018. ASU 2016-02 also makes targeted changes to other aspects of current guidance, including identifying a lease and lease classification criteria as well as the lessor accounting model, including guidance on separating components of a contract and consideration in the contract. The Company has established an implementation team and has implemented a new lease accounting information system. In July 2018, the FASB issued additional authoritative guidance providing companies with an optional prospective transition method to apply the provisions of this guidance. The Company will adopt the standard in the first quarter of 2019 and elect this transition method to apply the standard prospectively. The Company's adoption of this standard is expected to result in the recognition of between $13.0 million and $16.0 million of right-of-use assets and lease liabilities on the consolidated balance sheets.

In January 2017, the FASB issued ASU 2017-01, "Business Combinations (Topic 805)." ASU 2017-01 clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. The Company has adopted this standard in its consolidated financial statements, which has no current period impact but may impact future periods in which acquisitions are completed.

In July 2017, the FASB issued ASU 2017-11, "Earnings Per Share (Topic 260): Distinguishing Liabilities from Equity (Topic 480), I. Derivatives and Hedging (Topic 815): Accounting for Certain Financial Instruments with Down Round Features and II. Replacement of the Indefinite Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Noncontrolling Interests with a Scope Exception." Part I of ASU 2017-11 will result in freestanding equity-linked financial instruments, such as warrants, and conversion options in convertible debt or preferred stock to no longer be accounted for as a derivative liability at fair value as a result of the existence of a down round feature. For freestanding equity-classified financial instruments, the amendments require entities that present earnings per share (EPS) in accordance with Topic 260 to recognize the effect of the down round feature when it is triggered. That effect is treated as a dividend and as a reduction of income available to common shareholders in basic EPS. The amendments in Part II recharacterize the indefinite deferral of certain provisions of Topic 480 that now are presented as pending content in the Codification. The amendments in Part II do not require any transition guidance as the amendments do not have an accounting effect. The amendments in ASU 2017-11 will be effective on January 1, 2020, and the Part I amendments must be applied retrospectively. Early application is permitted. The Company early adopted ASU 2017-11, which did not have any material impact.

3. ACQUISITION

In March of 2016, the Company acquired a majority interest in Rhino at a price less than fair value of the net identifiable assets, and a $168.4 million gain on bargain purchase was recorded in 2017, upon completion of the acquisition accounting. The bargain purchase gain is reported as other income in the consolidated statements of operations. Prior to recognizing a bargain purchase, management reassessed whether all assets acquired and liabilities assumed had been correctly identified, and reviewed the key valuation assumptions and business combination accounting procedures for this acquisition. After careful consideration and review, management concluded that the recognition of a bargain purchase gain was appropriate for this acquisition.

4. DISCONTINUED OPERATIONS

ARQ Royalty Interest

On March 23, 2018, the Company and ARQ Gary Land LLC (ARQ) executed an option agreement related to a West Virginia mineral royalty interest controlled by the Company. The option allowed ARQ the option to purchase the Company's royalty stream for $1.8 million. ARQ did not exercise the option and the option agreement expired during the three months ended September 30, 2018. The Company has fully impaired the royalty interest during the fourth quarter of 2018 due to market conditions. The Company has recorded a $1.8 million asset impairment charge in the statements of operations and comprehensive income (loss) to reflect this impairment in 2018.

Sands Hill.

On November 7, 2017, the Company closed an agreement with a third party to transfer 100% of the membership interests and related assets and liabilities in Sands Hill Mining LLC to the third party in exchange for a future override royalty for any mineral sold, excluding coal, from Sands Hill Mining LLC after the closing date. The Company recognized a gain of $1.8 million from the sale of Sands Hill Mining LLC since the third party assumed the reclamation obligations associated with this operation. The disposition of Sands Hill Mining LLC resulted in the Partnership exiting its limestone sales business. The previous operating results of Sands Hill Mining LLC have been reclassified and reported on the (Gain)/loss from discontinued operations line on the Company's consolidated statements of operations and comprehensive income for the year ended December 31, 2017.

Sands Hill Mining LLC

Major components of net income from discontinued operations for Sands Hill Mining LLC for years ended December 31, 2018 and 2017 are summarized as follows:

	Year Ended December 31, 2018	Year Ended December 31, 2017
Major line items constituting income from discontinued operations for the Sands Hill Mining disposal:		
Coal sales	$ -	$ 1,280
Limestone sales	-	3,483
Other revenue	-	1,503
Total revenues	-	6,266
Cost of operations (exclusive of depreciation, depletion and amortization shown separately below)	-	6,479
Freight and handling	-	771
Depreciation, depletion and amortization	-	2,827
Selling, general and administrative (exclusive of depreciation, depletion and amortization shown separately above)	-	91
(Gain) on sale/disposal of assets, net	-	(1,751)
Interest income	-	-
Interest expense and other	-	-
Total costs, expenses and other	-	8,417
Income (loss) from discontinued operations before income taxes for the Sands Hill Mining disposal	-	(2,151)
Income tax benefit	-	(433)
Net income (loss) from discontinued operations	$ -	$ (1,718)

Cash Flows.

The depreciation, depletion and amortization amounts for Sands Hill Mining LLC for each period presented are listed in the previous table. The Company did not fund any material capital expenditures for Sands Hill Mining LLC for any period presented. Sands Hill Mining LLC did not have any material non-cash investing items for any period presented.

5. PREPAID EXPENSES AND OTHER CURRENT ASSETS

Prepaid expenses and other current assets as of December 31, 2018 and 2017, consisted of the following:

	December 31, 2018	December 31, 2017
	(in thousands)	
Other prepaid expenses	$ 973	$ 732
Prepaid insurance	1,397	1,445
Prepaid leases	92	92
Supply inventory	306	434
Total	$ 2,768	$ 2,703

6. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment, including coal properties and mine development and construction costs, as of December 31, 2018 and 2017, are summarized as follows:

	Useful Lives	December 31, 2018	December 31, 2017
Land and land improvements		$ 9,406	$ 10,104
Mining and other equipment and related facilities	2-20 Years	204,605	188,140
Mine development costs	1-15 Years	6,714	1,598
Coal properties	1-15 Years	31,396	33,197
Construction work in process		3,199	5,227
Total		255,320	238,266
Less accumulated depreciation, depletion and amortization		(75,206)	(44,696)
Net		$ 180,114	193,570

Depreciation expense for mining and other equipment and related facilities, depletion expense for coal and oil and natural gas properties, amortization expense for mine development costs and amortization expense for intangible assets for the years ended December 31, 2018 and 2017, are summarized as follows:

	December 31, 2018	2017
	(in thousands)	
Depreciation expense – mining and other equipment and related facilities	$ 30,474	$ 39,320
Depletion expense for coal properties	667	1,012
Amortization of mine development costs	248	72
Amortization of intangible assets	68	33
	$ 31,457	$ 40,437

During 2017, the Company revalued its Rhino assets acquired in 2016 (see Note 3) which caused a substantial increase in depreciation. The 2017 depreciation includes approximately $12.9 million relating to the change in depreciation estimate impact related to 2016.

On May 17, 2018, the Company entered into a sale leaseback agreement with Wintrust Commercial Finance for certain equipment previously owned by the Company. The Company received approximately $3.7 million of proceeds, of which $1.7 million was used to reduce debt. The lease agreement has a thirty-six month term. The Company recorded a loss of $0.2 million on the sale of the equipment which is included on the (Gain)/Loss on sale/disposal of assets-net line in the Company's consolidated statements of operations.

Asset Impairments-2018

We performed a comprehensive review of our coal mining operations as well as potential future development projects for the year ended December 31, 2018 to ascertain any potential impairment losses. We did not record any impairment losses for coal properties, mine development costs or coal mining equipment and related facilities for the year ended December 31, 2018. We did record an impairment loss for the ARQ royalty interest during the fourth quarter of 2018 (see Note 4).

Asset Impairments-2017

The Company performed a comprehensive review of current coal mining operations as well as potential future development projects for the year ended December 31, 2017 to ascertain any potential impairment losses. The Company engaged an independent third party to perform a fair market value appraisal on certain parcels of land in Mesa County, Colorado. The parcels appraised for $6.0 million compared to the carrying value of $6.8 million. The Company recorded an impairment loss of $0.8 million, which is recorded on the Asset impairment and related charges line of the consolidated statements of operations and comprehensive income. No other coal properties, mine development costs or other coal mining equipment and related facilities were impaired as of December 31, 2017.

The Company completed a comprehensive review of all assets beyond those related to Rhino and identified impairments in 2017. The Company holds a royalty from ARQ Gary Land, LLC, f/k/a Hendricks Gary Land, LLC ("ARQ")(net of royalties granted to a third party) of $1.075 on raw coal and coal refuse and $1.50 on processed or refined coal mined or removed from the Alpheus Coal Impoundment reclamation site in McDowell County, West Virginia under an agreement dated March 22, 2016. Mining had not commenced on the site as of December 31, 2017 or 2018. The ARQ royalty was determined to be impaired based upon facts and circumstances related to its carrying amount. The value of the ARQ royalty at December 31, 2017 was based on an option that we granted to ARQ to purchase the royalty (See Note 4). Accordingly, the Company recorded an asset impairment loss of $2.6 million in the fourth quarter of 2017 for the ARQ royalty.

Additionally, at December 31, 2017, management determined that its investment in Blaze Minerals was impaired and removed the entire investment and associated assets from the consolidated financial statements. Accordingly, the Company recorded an additional asset impairment loss of $7.0 million in the fourth quarter of 2017.

7. INTANGIBLE ASSETS

The Partnership and Rhino Resource Holdings LLC ("Rhino Holdings") executed an option agreement in December 2016 where the Partnership received a call option from Rhino Holdings to acquire substantially all of the outstanding common stock of Armstrong Energy. In exchange for Rhino Holdings granting the Partnership the call option, the Partnership issued 5.0 million common units to Rhino Holdings upon the execution of the option agreement. The Partnership valued the call option at $21.8 million based upon the closing price of the Partnership's publicly traded common units on the date the option agreement was executed. The Partnership has determined the value of the common units issued at December 30, 2016 of $21.8 million constituted an amount that would be applied to the potential acquisition of Armstrong Energy. On October 31, 2017, Armstrong Energy filed Chapter 11 petitions in the Eastern District of Missouri's United States Bankruptcy Court. On February 9, 2018, the U.S. Bankruptcy Court confirmed Armstrong Energy's Chapter 11 reorganization plan and as such the Partnership concluded that the call option was fully impaired. As such, the Partnership recorded an impairment charge of $21.8 million related to the call option, which has been recorded on the Asset impairment and related charges line of the consolidated statements of operations for the year ended December 31, 2017.

8. FAIR VALUE

The Company determines the fair value of assets and liabilities based on the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants. The fair values are based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. The fair value hierarchy is based on whether the inputs to valuation techniques are observable or unobservable. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the Company's assumptions of what market participants would use.

The fair value hierarchy includes three levels of inputs that may be used to measure fair value as described below:

Level One - Quoted prices for identical instruments in active markets.

Level Two - The fair value of the assets and liabilities included in Level 2 are based on standard industry income approach models that use significant observable inputs.

Level Three - Unobservable inputs significant to the fair value measurement supported by little or no market activity.

In those cases when the inputs used to measure fair value meet the definition of more than one level of the fair value hierarchy, the lowest level input that is significant to the fair value measurement in its totality determines the applicable level in the fair value hierarchy.

The book values of cash and cash equivalents, accounts receivable and accounts payable are considered to be representative of their respective fair values because of the immediate short-term maturity of these financial instruments. The fair value of the Partnership's financing agreement was determined based upon a market approach and approximates the carrying value at December 31, 2018. The fair value of the Partnership's financing agreement is a Level 2 measurement.

As of December 31, 2018 and December 31, 2017, the Company had a recurring fair value measurement relating to its investment in Mammoth, Inc. The Company acquired 568,794 shares of Mammoth Energy Services, Inc. (NASDAQ: TUSK)("Mammoth Inc.") through a series of transactions in years prior to 2018. During 2018, the Company sold 464,694 shares for net consideration of approximately $11.9 million. As of December 31, 2018, the Company owned 104,100 shares of Mammoth Inc. The Company's shares of Mammoth, Inc. are classified as an investment on the Company's consolidated balance sheets. Based on the availability of a quoted price, the recurring fair value measurement of the Mammoth, Inc. shares is a Level 1 measurement.

For the year ended December 31, 2017, the Company had a nonrecurring fair value measurement related to an asset impairment. The Company engaged an independent third party to perform a fair market value appraisal on certain parcels of land that it owns in Mesa County, Colorado. Based on the availability of an independent fair market value appraisal, the nonrecurring fair value measurement of the impairment is a Level 2 measurement.

For the year ended December 31, 2017, the Company had a nonrecurring fair value measurement related to the Common Unit Warrants (see Note 12 for discussion of the Common Unit Warrants). The Company calculated the fair value of the Common Unit Warrants using a Black-Scholes model with inputs that include the Common Unit Warrants' strike price, the term of the agreement, historical volatility of the Partnership's common units and the risk free interest rate. The nonrecurring fair value measurement for the Common Unit Warrants for the year ended December 31, 2017 was a Level 3 measurement.

For the year ended December 31, 2018, the Company had a nonrecurring fair value measurement related to a stock option (see Note 16). The Company calculated the fair value of the stock option using a Black-Scholes model with inputs that include the stock options' strike price, the term of the agreement, historical volatility of the Company's common shares and the risk free interest rate. The nonrecurring fair value measurement for the stock grant for the year ended December 31, 2018 was a Level 2 measurement.

For the year ended December 31, 2018, the Company had a nonrecurring fair value measurement related to a stock grant (see Note 19). The Company calculated the fair value of the stock grant using the Company's stock price at date of settlement. The nonrecurring fair value measurement for the stock grant for the year ended December 31, 2018 was a Level 1 measurement.

9. OTHER NON-CURRENT ASSETS

Other non-current assets as of December 31, 2018 and 2017 consisted of the following:

	December 31, 2018	December 31, 2017
	(in thousands)	
Deposits-workers compensation and surety programs	$ 8,266	$ -
Deposits and other	1,250	423
Non-current receivable	24,192	27,806
Deferred expenses	158	340
Restricted cash	88	5,209
	$ 33,954	$ 33,778

Non-current receivable .

As of December 31, 2018 and 2017, the non-current receivable balance of $24.2 and $27.8 million respectively, consisted of the amount due from workers' compensation and black lung insurance providers for potential claims that are the primary responsibility of Rhino, but are covered under Rhino's insurance policies. See Note 15 for discussion of the offsetting balances that are also recorded in other non-current workers' compensation liabilities.

10. ACCRUED EXPENSES AND OTHER CURRENT LIABILITIES

Accrued expenses and other current liabilities as of December 31, 2018 and 2017 consisted of the following:

	December 31, 2018	December 31, 2017
	(in thousands)	
Payroll, bonus and vacation expense	2,151	2,888
Non-income taxes	2,317	3,130
Royalty expenses	1,669	2,410
Accrued interest	152	162
Health claims	868	871
Workers' compensation & pneumoconiosis	1,900	1,750
Income taxes (Note 20)	134	584
Other	1,412	822
	$ 10,603	$ 12,617

11. NOTES PAYABLE – RELATED PARTY

Related party notes payable consist of the following at December 31, 2018 and 2017.

	December 31, 2018	December 31, 2017
	(in thousands)	
Demand note payable dated March 6, 2015; owed E-Starts Money Co., a related party; interest at 6% per annum	$ 204	$ 204
Demand note payable dated June 11, 2015; owed E-Starts Money Co., a related party; non-interest bearing	200	200
Demand note payable dated September 22, 2016; owed E-Starts Money Co., a related party; non-interest bearing	50	50
Demand note payable dated December 8, 2016; owed E-Starts Money Co., a related party; non-interest bearing	50	50
Demand note payable dated April 26, 2017; owed E-Starts Money Co., a related party; non-interest bearing	10	10
	$ 514	$ 514

The related party notes payable have accrued interest of $46 thousand at December 31, 2018 and $34 thousand at December 31, 2017. Related party interest expense amounted to $12 thousand for both years ended December 31, 2018 and 2017.

12. DEBT

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

	December 31, 2018	December 31, 2017
	(in thousands)	
Note payable- Financing Agreement	$ 29,048	$ 40,000
Note payable- other debt	522	-
Note payable to Cedarview	2,500	2,500
Net unamortized debt issuance costs	(4,121)	(4,688)
Net unamortized original issue discount	(843)	(1,264)
Total	27,106	36,548
Current portion	(3,174)	(5,475)
Long-term debt	$ 23,932	$ 31,073

Financing Agreement

On December 27, 2017, Rhino Energy LLC (“Rhino Energy”), a wholly-owned subsidiary of the Partnership, certain of Rhino Energy’s subsidiaries identified as Borrowers (together with Rhino Energy, the “Borrowers”), the Partnership and certain other Rhino Energy subsidiaries identified as Guarantors (together with the Partnership, the “Guarantors”), entered into a Financing Agreement (the “Financing Agreement”) with Cortland Capital Market Services LLC, as Collateral Agent and Administrative agent, CB Agent Services LLC, as Origination Agent and the parties identified as Lenders therein (the “Lenders”), pursuant to which Lenders have agreed to provide Borrowers with a multi-draw term loan in the aggregate principal amount of $80 million, subject to the terms and conditions set forth in the Financing Agreement. The total principal amount is divided into a $40 million commitment, the conditions of which were satisfied at the execution of the Financing Agreement (the “Effective Date Term Loan Commitment”) and an additional $35 million commitment that is contingent upon the satisfaction of certain conditions precedent specified in the Financing Agreement (“Delayed Draw Term Loan Commitment”). Loans made pursuant to the Financing Agreement are secured by substantially all of the Borrowers’ and Guarantors’ assets. The Financing Agreement terminates on December 27, 2020.

Loans made pursuant to the Financing Agreement will, at Rhino Energy’s option, either be “Reference Rate Loans” or “LIBOR Rate Loans.” Reference Rate Loans bear interest at the greatest of (a) 4.25% per annum, (b) the Federal Funds Rate plus 0.50% per annum, (c) the LIBOR Rate (calculated on a one-month basis) plus 1.00% per annum or (d) the Prime Rate (as published in the Wall Street Journal) or if no such rate is published, the interest rate published by the Federal Reserve Board as the “bank prime loan” rate or similar rate quoted therein, in each case, plus an applicable margin of 9.00% per annum (or 12.00% per annum if Rhino Energy has elected to capitalize an interest payment pursuant to the PIK Option, as described below). LIBOR Rate Loans bear interest at the greater of (x) the LIBOR for such interest period divided by 100% minus the maximum percentage prescribed by the Federal Reserve for determining the reserve requirements in effect with respect to eurocurrency liabilities for any Lender, if any, and (y) 1.00%, in each case, plus 10.00% per annum (or 13.00% per annum if the Borrowers have elected to capitalize an interest payment pursuant to the PIK Option). Interest payments are due on a monthly basis for Reference Rate Loans and one-, two- or three-month periods, at Rhino Energy’s option, for LIBOR Rate Loans. If there is no event of default occurring or continuing, Rhino Energy may elect to defer payment on interest accruing at 6.00% per annum by capitalizing and adding such interest payment to the principal amount of the applicable term loan (the “PIK Option”).

Commencing December 31, 2018, the principal for each loan made under the Financing Agreement was payable on a quarterly basis in an amount equal to $375,000 per quarter, with all remaining unpaid principal and accrued and unpaid interest due on December 27, 2020. In addition, the Borrowers must make certain prepayments over the term of any loans outstanding, including: (i) the payment of 25% of Excess Cash Flow (as that term is defined in the Financing Agreement) of the Partnership and its subsidiaries for each fiscal year, commencing with respect to the year ending December 31, 2019, (ii) subject to certain exceptions, the payment of 100% of the net cash proceeds from the dispositions of certain assets, the incurrence of certain indebtedness or receipts of cash outside of the ordinary course of business, and (iii) the payment of the excess of the outstanding principal amount of term loans outstanding over the amount of the Collateral Coverage Amount (as that term is defined in the Financing Agreement). In addition, the Lenders are entitled to certain fees, including 1.50% per annum of the unused Delayed Draw Term Loan Commitment for as long as such commitment exists, (ii) for the 12-month period following the execution of the Financing Agreement, a make-whole amount equal to the interest and unused Delayed Draw Term Loan Commitment fees that would have been payable but for the occurrence of certain events, including among others, bankruptcy proceedings or the termination of the Financing Agreement by Rhino Energy, and (iii) audit and collateral monitoring fees and origination and exit fees.

The Financing Agreement requires the Borrowers and Guarantor to comply with several affirmative covenants at any time loans are outstanding, including, among others: (i) the requirement to deliver monthly, quarterly and annual financial statements, (ii) the requirement to periodically deliver certificates indicating, among other things, (a) compliance with terms of the Financing Agreement and ancillary loan documents, (b) inventory, accounts payable, sales and production numbers, (c) the calculation of the Collateral Coverage Amount (as that term is defined in the Financing Agreement), (d) projections for the Partnership and its subsidiaries and (e) coal reserve amounts; (ii) the requirement to notify the Administrative Agent of certain events, including events of default under the Financing Agreement, dispositions, entry into material contracts, (iii) the requirement to maintain insurance, obtain permits, and comply with environmental and reclamation laws (iv) the requirement to sell up to $5.0 million of shares in Mammoth Energy Securities, Inc. and use the net proceeds therefrom to prepay outstanding term loans and (v) establish and maintain cash management services and establish a cash management account and deliver a control agreement with respect to such account to the Collateral Agent. The Financing Agreement also contains negative covenants that restrict the Borrowers and Guarantors ability to, among other things: (i) incur liens or additional indebtedness or make investments or restricted payments, (ii) liquidate or merge with another entity, or dispose of assets, (iii) change the nature of their respective businesses; (iii) make capital expenditures in excess, or, with respect to maintenance capital expenditures, lower than, specified amounts, (iv) incur restrictions on the payment of dividends, (v) prepay or modify the terms of other indebtedness, (vi) permit the Collateral Coverage Amount to be less than the outstanding principal amount of the loans outstanding under the Financing Agreement or (vii) permit the trailing six month Fixed Charge Coverage Ratio of the Partnership and its subsidiaries to be less than 1.20 to 1.00 commencing with the six-month period ended June 30, 2018.

The Financing Agreement contains customary events of default, following which the Collateral Agent may, at the request of lenders, terminate or reduce all commitments and accelerate the maturity of all outstanding loans to become due and payable immediately together with accrued and unpaid interest thereon and exercise any such other rights as specified under the Financing Agreement and ancillary loan documents.

On April 17, 2018, the Partnership amended the Financing Agreement to allow for certain activities including a sale leaseback of certain pieces of equipment, the extension of the due date for lease consents required under the Financing Agreement to June 30, 2018 and the distribution to holders of the Series A preferred units of $6.0 million (accrued in the consolidated financial statements at December 31, 2017). Additionally, the amendments provided that the Partnership could sell additional shares of Mammoth Energy Services Inc. stock and retain 50% of the proceeds with the other 50% used to reduce debt. The Partnership reduced its outstanding debt by $3.4 million with proceeds from the sale of Mammoth Energy Services Inc. stock in the second quarter of 2018.

On July 27, 2018, the Partnership entered into a consent with its Lenders related to the Financing Agreement. The consent included the Lender's agreement to make a $5 million loan from the Delayed Draw Term Loan Commitment; which was repaid in full by October 26, 2018 pursuant to the terms of the consent. The consent also included a waiver of the requirements relating to the use of proceeds of any sale of the shares of Mammoth Inc. set forth in the consent to the Financing Agreement, dated as of April 17, 2018, and also waived any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended June 30, 2018.

On November 8, 2018, the Partnership entered into a consent with its Lenders related to the Financing Agreement. The consent includes the lenders agreement to waive any Event of Default that arose or would otherwise arise under the Financing Agreement for failing to comply with the Fixed Charge Coverage Ratio for the six months ended September 30, 2018.

On December 20, 2018, the Partnership, entered into a limited waiver and consent (the "Waiver") to the Financing Agreement. The Waiver relates to the sales by the Partnership of certain real property in Western Colorado, the net proceeds of which are required to be used to reduce the Partnership's debt under the Financing Agreement. As of the date of the Waiver, the Partnership had sold 9 individual lots in smaller transactions. On December 31, 2018, the Partnership used the sale proceeds of approximately $379,000 to reduce the debt. Rather than transmitting net proceeds with respect to each individual transaction, the Partnership and Lenders agreed in principle to delay repayment until an aggregate payment could be made at the end of 2018. The Waiver (i) contains a ratification by the Lenders of the sale of the individual lots to date and waives the associated technical defaults under the Financing Agreement for not making immediate payments of net proceeds therefrom, (ii) permits the sale of certain specified additional lots and (iii) subject to Lender consent, permits the sale of other lots on a going forward basis. The net proceeds of future sales will be held by the Partnership until a later date to be determined by the Lenders.

On February 13, 2019, the Partnership entered into a second amendment to the Financing Agreement. Please refer to Note 24 (Subsequent Events) of the consolidated financial statements.

At December 31, 2018, $29.0 million was outstanding under the Financing Agreement at a variable interest rate of Libor plus 10.00% (12.53% at December 31, 2018).

Common Unit Warrants

The Partnership entered into a warrant agreement with certain parties that are also parties to the Financing Agreement discussed above. The warrant agreement included the issuance of a total of 683,888 warrants for common units ("Common Unit Warrants") of the Partnership at an exercise price of $1.95 per unit, which was the closing price of the Partnership's units on the OTC market as of December 27, 2017. The Common Unit Warrants have a five year expiration date. The Common Unit Warrants and the Rhino common units after exercise are both transferable, subject to applicable US securities laws. The Common Unit Warrant exercise price is $1.95 per unit, but the price per unit will be reduced by future common unit distributions and other further adjustments in price included in the warrant agreement for transactions that are dilutive to the amount of Rhino's common units outstanding. The warrant agreement includes a provision for a cashless exercise whereby the warrant holders can receive a net number of common units. Per the warrant agreement, the warrants are detached from the Financing Agreement and fully transferable. The Partnership analyzed the Common Unit Warrants in accordance with the applicable accounting literature and concluded the Common Unit Warrants should be classified as equity. The Partnership allocated the $40.0 million proceeds from the Financing Agreement between the Common Unit Warrants and the Financing Agreement based upon their relative fair values. The allocation based upon relative fair values resulted in approximately $1.3 million being recorded for the Common Unit Warrants in the Partner's Capital equity section and a corresponding reduction in Long-term debt, net on the Company's consolidated balance sheets.

Letter of Credit Facility – PNC Bank

On December 27, 2017, the Partnership entered into a master letter of credit facility, security agreement and reimbursement agreement (the "LoC Facility Agreement") with PNC Bank, National Association ("PNC"), pursuant to which PNC agreed to provide the Partnership with a facility for the issuance of standby letters of credit used in the ordinary course of its business (the "LoC Facility"). The LoC Facility Agreement provided that the Partnership pay a quarterly fee at a rate equal to 5% per annum calculated based on the daily average of letters of credit outstanding under the LoC Facility, as well as administrative costs incurred by PNC and a $100,000 closing fee. The LoC Facility Agreement provided that the Partnership reimburse PNC for any drawing under a letter of credit by a specified beneficiary as soon as possible after payment was made. The Partnership's obligations under the LoC Facility Agreement were secured by a first lien security interest on a cash collateral account that was required to contain no less than 105% of the face value of the outstanding letters of credit. In the event the amount in such cash collateral account was insufficient to satisfy the Partnership's reimbursement obligations, the amount outstanding would bear interest at a rate per annum equal to the Base Rate (as that term was defined in the LoC Facility Agreement) plus 2.0%. The Partnership was to indemnify PNC for any losses which PNC may have incurred as a result of the issuance of a letter of credit or PNC's failure to honor any drawing under a letter of credit, subject in each case to certain exceptions. The Partnership provided cash collateral to its counterparties during the third quarter of 2018 and as of September 30, 2018, the LoC Facility was terminated. The Partnership had no outstanding letters of credit at December 31, 2018.

Cedarview

On June 12, 2017, the Company entered into a Secured Promissory Note dated May 31, 2017 with Cedarview Opportunities Master Fund, L.P. (the "Lender"), under which the Company borrowed $2,500,000 from the Lender. The loan bears non-default interest at the rate of 14%, and default interest at the rate of 17% per annum. The Company and the Lender simultaneously entered into a Pledge and Security Agreement dated May 31, 2017, under which the Company pledged 5,000,000 Common Units in the Partnership as collateral for the loan. The loan is payable through quarterly payments of interest only until May 31, 2019, when the loan matures, at which time all principal and interest is due and payable. The Company deposited $350,000 of the loan proceeds into an escrow account, from which interest payments for the first year will be paid. After the first year, the Company is obligated to maintain at least one quarter of interest on the loan in the escrow account at all times. In consideration for the Lender's agreement to make the loan, the Company has transferred 25,000 Common Units of Rhino to the Lender as a fee. The Company intended to use the proceeds to repay in full all loans made to the Company by E-Starts Money Co. in the principal amount of $578,593, and the balance for general corporate overhead, as well as costs associated with potential acquisitions of mineral resource companies, including legal and engineering due diligence, deposits, and down payments. See Note 24 for updated terms of this note which impact the current and long-term presentation of this note at December 31, 2018.

Weston Energy LLC

The Company entered into a short-term note payable with Weston Energy LLC ("Weston") dated December 30, 2016 and due January 15, 2017 with interest at 8% per annum. On January 27, 2017, the Company sold 100,000 of its Series A preferred units to Weston and the other 100,000 Series A preferred units to another third party. The proceeds were used to repay the loan from Weston in the amount of $2.0 million.

The Company did not capitalize any interest costs during the years ended December 31, 2018 and 2017.

Principal payments on long-term debt (excluding unamortized debt issuance costs and unamortized warrant costs) due subsequent to December 31, 2018 are as follows:

		(in thousands)
2019	$	3,174
2020		28,896
Total principal payments	$	32,070

13. ASSET RETIREMENT OBLIGATIONS

The changes in asset retirement obligations for the year ended December 31, 2018 and 2017 are as follows:

	Year ended December 31, 2018	Year ended December 31, 2017
Balance at beginning of year, including current portion	$ 15,994	$ 21,720
Revaluation (net of disposal)	-	(5,267)
Accretion expense	1,277	1,556
Adjustments to the liability from annual recosting and other	(1,383)	(1,695)
Disposal (1)	-	(260)
Liabilities settled	(299)	(60)
Balance at end of period	15,589	15,994
Less current portion	(465)	(498)
Non-current portion	$ 15,124	$ 15,496

(1) The ($0.3) million adjustment for the year ended December 31, 2017 relates to the sale of the Sands Hill Mining entity as discussed in Note 4.

14. INCOME TAXES

The income tax provision (benefit) consists of the following:

	Year Ended December 31, 2018	Year Ended December 31, 2017
Federal:		
Current	$ (345)	$ 345
Deferred	(2,940)	24,898
State and local:		
Current	(47)	76
Deferred	(2,038)	4,651
Income tax contingency- see below		
Income tax expense	$ (5,370)	$ 29,970

The expected tax expense based on the statutory rate is reconciled with the actual expense as follows:

	Year Ended December 31, 2018	Year Ended December 31, 2017
U.S. federal statutory rate	$ (6,044)	$ 41,610
State income tax, net of federal benefit	(1,647)	3,083
Impact of tax legislation	-	(17,367)
Change in valuation allowance	(58)	(3,063)
Loss (income) allocated to noncontrolling interest	2,616	5,983
Other, net	(237)	(276)
Income tax contingency- see below		
Income tax expense	$ (5,370)	$ 29,970

The 2017 Tax Act was enacted on December 22, 2017. The 2017 Tax Act includes a number of changes in existing tax law impacting businesses, including a permanent reduction in the U.S. federal statutory rate from 35% to 21%, effective on January 1, 2018. Under U.S. GAAP, changes in tax rates and tax law are accounted for in the period of enactment and deferred tax assets and liabilities are measured at the enacted tax rate. The Company has reflected the impact of the 2017 Tax Act on its income taxes in the tables contained in this note. The adjustment described above is mainly due to the remeasurement of deferred income taxes resulting from the federal income tax rate change from 35% to 21%. During 2018 the Company completed its analysis of the Act as provided by SAB 118. The Company has not recorded any adjustments related to the Act during 2018 that would materially change the amounts recorded at December 31, 2017.

A valuation allowance was recorded by the Company at the end of 2016 for the net deferred tax asset after the Company considered carryback potential, tax planning strategies and the projection of future taxable income. The change in valuation allowance shown in the rate reconciliation is due, in part, to impairments and net operating losses as of the end of 2016 being fully reserved but recognized in 2017 after the recording of the bargain purchase gain and the taxable differences resulting therefrom. Additionally, a valuation allowance was recorded for capital losses and an impairment which occurred in 2017. The valuation allowance related to the capital loss was reversed in 2018.

Deferred tax assets and liabilities consists of the effects of temporary differences attributable to the following:

	Year Ended December 31, 2018	Year Ended December 31, 2017
Loss and credit carryforwards including AMT	$ 6,021	$ 1,204
Asset impairment	6,467	6,307
Accrued expenses and other	26	96
Investment in public limited partnership	(36,561)	(36,488)
Valuation allowance	(1,664)	(1,811)
Net deferred tax liabilities	$ (25,711)	$ (30,692)

A reconciliation of the changes in the valuation allowance is as follows:

	Year Ended December 31, 2018	Year Ended December 31, 2017
Beginning balance	$ 1,811	7,415
Current year addition	54	2,830
Current year reduction	(126)	(7,416)
Tax rate change	(75)	(1,018)
Ending balance	$ 1,664	$ 1,811

The Company has loss carryforwards for U.S. federal income tax purposes of $20.8 million, $2.8 million of which that will expire from 2034 to 2036 and the balance has no expiration. Additionally, the Company has $10.2 million of loss carryforwards for state income tax purposes, $2.5 million of which that expire from 2035 to 2036 and the balance has no expiration. The alternative minimum tax credit carryforward for 2017 has been recorded as a deferred tax asset as it is fully refundable and can be utilized to offset regular tax during the years 2018 through 2021.

The Company has not recorded a reserve for uncertain tax positions for federal or state income taxes. See Income Tax Contingency below.

Income Tax Contingency

The Company has filed federal but not all of its required state income tax returns for 2014, 2015, 2016 and 2017, and failed to timely file an application for a change in tax year when it changed its reporting year for external reporting purposes from August 31st to December 31st in 2015. In addition, management and third-party specialists have identified certain transactions which are highly complex from an income tax perspective and have not completed the necessary analysis to bring these matters to conclusion. In preparing the financial statements as of and for the year ended December 31, 2018, management has used its best estimates to compute the Company’s provision for federal and state income taxes based on available information; however, the resolution of certain of the complex tax matters, the ultimate completion of returns for all open tax years and tax positions taken could materially impact management’s estimates. Therefore, the ultimate tax obligations could be materially different from that reflected in the accompanying consolidated balance sheet at December 31, 2018 once these issues are resolved.

15. OTHER NON-CURRENT LIABILITIES

Workers' Compensation and Black Lung

Certain of the Company's subsidiaries are liable under federal and state laws to pay workers' compensation and coal workers' black lung benefits to eligible employees, former employees and their dependents. The Company currently utilizes an insurance program and state workers' compensation fund participation to secure its on-going obligations depending on the location of the operation. Premium expense for workers' compensation benefits is recognized in the period in which the related insurance coverage is provided.

The Company's black lung benefit liability is calculated using the service cost method that considers the calculation of the actuarial present value of the estimated black lung obligation. The Company's actuarial calculations using the service cost method for its black lung benefit liability are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and interest rates. The Company's liability for traumatic workers' compensation injury claims is the estimated present value of current workers' compensation benefits, based on actuarial estimates, which are based on numerous assumptions including claim development patterns, mortality, medical costs and interest rates. The discount rate used to calculate the estimated present value of future obligations for black lung was 4.0% and 3.5%, for December 31, 2018 and 2017, respectively and for workers' compensation the discount rate was 3.4% and 3.0% at December 31, 2018 and 2017, respectively.

The uninsured black lung and workers' compensation expenses for the year ended December 31, 2018 and 2017 are as follows:

	Year ended December 31, 2018	Year ended December 31, 2017
Black lung benefits:		
Service cost	$ (296)	$ 1,771
Interest cost	391	344
Actuarial loss/(gain)	(893)	924
Total black lung	(798)	3,039
Workers' compensation expense	3,912	3,231
Total expense	$ 3,114	$ 6,270

The changes in the black lung benefit liability for the year ended December 31, 2018 and 2017 are as follows:

	Year ended December 31, 2018	Year ended December 31, 2017
Benefit obligations at beginning of year	$ 11,446	$ 8,782
Service cost	(296)	1,771
Interest cost	391	344
Actuarial loss (gain)	(893)	924
Benefits and expenses paid	(554)	(375)
Benefit obligations at end of year	$ 10,094	$ 11,446

The classification of the amounts recognized for the workers' compensation and black lung benefits liability as of December 31, 2018 and December 31, 2017 are as follows:

	December 31, 2018	December 31, 2017
	(in thousands)	
Black lung claims	$ 10,094	$ 11,446
Insured black lung and workers' compensation claims	24,191	27,806
Workers' compensation claims	4,706	5,216
Total obligations	38,991	44,468
Less current portion	(1,900)	(1,750)
Non-current obligations	$ 37,091	$ 42,718

The balance for insured black lung and workers' compensation claims as of December 31, 2018 and 2017 consisted of $24.2 million and $27.8 million respectively. This is a primary obligation of the Company, but is also due from the Company's insurance providers and is included in Note 9 as non-current receivables. The Company presents this amount on a gross asset and liability basis since a right of setoff does not exist per the accounting guidance in ASC Topic 210. This presentation has no impact on the results of operations or cash flows.

16. STOCKHOLDERS' EQUITY

At December 31, 2018 and 2017, the authorized capital stock of the Company consists of 25,000,000 shares of Common Stock, par value $0.00001 per share, and 5,000,000 shares of Preferred Stock, par value $0.00001 per share.

Royal Series A preferred stock

The Company's Board is authorized, without further stockholder approval, to issue Preferred Stock in one or more series from time to time and fix or alter the designations, relative rights, priorities, preferences, qualifications, limitations and restrictions of the shares of each series.

The Board has authorized one series of Preferred Stock, which is known as the "Series A Preferred Stock," for 100,000 shares. The certificate of designation of the Series A Preferred Stock provides: the holders of Series A Preferred Stock shall be entitled to receive dividends when, as and if declared by the Board of Directors of the Company; participates with common stock upon liquidation; convertible into one share of common stock; and has voting rights such that the Series A Preferred Stock shall have an aggregate voting right for 54% of the total shares entitled to vote.

At December 31, 2018 and 2017, 51,000 shares of Series A Preferred Stock were issued and outstanding.

Common Stock Transactions

On January 30, 2018, Ronald Phillips resigned as president of the Company. Mr. Phillips remained a consultant to the Company through May 30, 2018. As part of Mr. Phillips severance arrangement, he was paid $100,000 and received 400,000 shares of Company restricted common shares and 100,000 shares of Company common registered shares. The shares were valued based on the Company's stock price at the date of the severance agreement settlement for a total fair value of $1,650,000, which is reflected as stock compensation expense and additional paid in capital in the accompanying consolidated financial statements.

In November 2017, the Company entered an overriding royalty agreement with a third party regarding a coal transloading facility on the Ohio River. The Company originally committed to issue $0.4 million of Company common stock as consideration for this royalty stream. The Company never issued the stock. On August 21, 2018, the royalty agreement was amended to remove the stock transfer requirement through issuance of a stock option. The Company granted the counterparty a 10-year stock option to 100,000 shares at $4.00 per share. The Company determined through a Black Scholes model that the fair value of the option was $174,000 through the following key assumptions: stock price $2.01, $4.00 strike price per share, risk free rate 2.85% and volatility 100%. The Company is amortizing the cost of the option over the estimated life of the royalty stream (3 years) retroactive to inception.

Disposition of Rhino Common Units

On January 18, 2017, the Company entered into a Securities Purchase Agreement with a third party, pursuant to which the Company sold the third party 83,334 Rhino common units at $3.00 per unit for total consideration of $250,000 (allocated to non-controlling interest).

On May 4, 2017, the Company entered into a Securities Purchase Agreement with a third party, pursuant to which the Company sold the third party 100,000 Rhino common units at $3.00 per unit for total consideration of $300,000 (allocated to non-controlling interest).

Rhino Series A preferred stock

During the year ended December 31, 2018, the Partnership paid $6.0 million in preferred distributions earned for the year ended December 31, 2017 to holders of the Series A preferred units. The Partnership also accrued $3.2 million for preferred distributions as of December 31, 2018.

At December 31, 2018 and 2017, 51,000 shares of Series A Preferred Stock were issued and outstanding.

17. RELATED PARTY TRANSACTIONS

On March 6, 2015, the Company borrowed $203,593 from E-Starts Money Co. (“E-Starts”) pursuant to a 6% demand promissory note. The proceeds were used to repay all of the Company’s indebtedness at the time. E-Starts is owned by William L. Tuorto, the Company’s Chairman and Chief Executive Officer. Since the initial loan, the Company has borrowed additional amounts from E-Starts, the proceeds of which were used to pay Company expenses. The total amount owed to E-Starts at both December 31, 2018 and 2017 was $513,989 and $513,989, respectively, plus accrued interest. See Note 11 for detail of all outstanding notes.

In 2015 and 2016, the Company advanced Ian Ganzer and GS Energy, LLC certain amounts. Ian Ganzer was the Company’s chief operating officer at the time, a position which Mr. Ganzer resigned in September 2016. GS Energy, LLC is owned by Ian and Gary Ganzer and is a creditor of Blue Grove Coal, LLC, which at the time was a subsidiary of the Company. All amounts owed by Mr. Ganzer and GS Energy, LLC were settled as of July 1, 2017, pursuant to an agreement under which the Company reconveyed Blue Grove Coal, LLC to the Ganzers.

The following table reflects additional related party transactions for the years ended December 31, 2018 and 2017:

Related Party	Description	2018	2017
		(in thousands)	
Cox Holsted	Professional services	$ 40	$ 60
Mammoth Energy Partners LP	Investment in unconsolidated affiliate	-	40
Mammoth Energy Services, Inc.	Proceeds from sale of shares	11,887	-
Sturgeon Acquisitions LLC	Equity in net income of unconsolidated affiliate	-	(4)
Weston Energy LLC	Preferred distribution accrual	3,210	6,038

18. EMPLOYEE BENEFITS

401(k) Plans

The Company sponsors defined contribution savings plans for all employees. Under one defined contribution savings plan, the Operating Company matches voluntary contributions of participants up to a maximum contribution based upon a percentage of a participant’s salary with an additional matching contribution possible at the Operating Company’s discretion. The expense under these plans for the period owned by the Company is included in cost of operations and selling, general and administrative expense in the consolidated statements of operations and was as follows:

	Year ended December 31, 2018	Year ended December 31, 2017
401(k) plan expense	$ 1,742	$ 1,453

19. EQUITY-BASED COMPENSATION

Stock option plan

The Royal Energy Resources, Inc. 2015 Stock Option Plan and the Royal Energy Resources, Inc. 2015 Employee, Consultant and Advisor Stock Compensation Plan ("Plans") were approved by the Company's board on July 31, 2015. Each Plan reserves 1,000,000 shares for awards under each Plan. The Company's Board of Directors is designated to administer the Plan. No options are outstanding under the Plans at December 31, 2018 and 2017. The Company issued 100,000 and 0 shares under the Employee, Consultant and Advisor Stock Compensation Plan during years ended December 31, 2018 and 2017, respectively. As of December 31, 2018 and 2017, there are 1,000,000 shares available under the Stock Option Plan and 785,098 shares available under the Employee, Consultant and Advisor Stock Compensation Plan. The shares issued under the Employee, Consultant and Advisor Stock Compensation Plan were expensed at their market value on the date of issuance.

In October 2010, the general partner established the Rhino Long-Term Incentive Plan (the "Plan" or "LTIP"). The Plan is intended to promote the interests of the Partnership by providing to employees, consultants and directors of the general partner, the Partnership or affiliates of either, incentive compensation awards to encourage superior performance. The LTIP provides for grants of restricted units, unit options, unit appreciation rights, phantom units, unit awards, and other unit-based awards.

As of December 31, 2018 and 2017, the general partner had granted restricted units and unit awards to its directors. The Partnership did not have any unrecognized compensation expense of any non-vested LTIP awards as of December 31, 2018 and 2017.

Partners' Capital

On September 1, 2017, Royal elected to convert certain obligations to the Partnership totaling $4.1 million to shares of Royal common stock. Royal issued 914,797 shares of its common stock to the Partnership at a conversion price of $4.51 per share. Per the guidance in ASC 505, the Company recorded the $4.1 million conversion of the Weston Promissory Note and Rhino Promissory Note as treasury stock.

20. COMMITMENTS AND CONTINGENCIES

Coal Sales Contracts and Contingencies

As of December 31, 2018, the Company had commitments under sales contracts to deliver annually scheduled base quantities of coal as follows:

Year	Tons (in thousands)	Number of customers
2019	3,699	18
2020	1,979	6
2021	352	2

Some of the contracts have sales price adjustment provisions, subject to certain limitations and adjustments, based on a variety of factors and indices.

Purchase Commitment

As of December 31, 2018, the Company had a commitment to purchase approximately 1.0 million gallons of diesel fuel at a fixed price from January 2019 through December 2019 for approximately $2.2 million.

Purchased Coal Expenses

The Company incurs purchased coal expense from time to time related to coal purchase contracts. In addition, the Company incurs expense from time to time related to coal purchased on the over-the-counter market ("OTC"). Purchase coal expense from coal purchase contracts and expense from OTC purchases for the years ended December 31, 2018 and 2017 was as follows:

	Year Ended December 31,	
	2018	2017
	(in thousands)	
Purchased coal expense	$ 31	$ 377
OTC expense	-	-

Leases

The Company leases various mining, transportation and other equipment under operating leases. The Company also leases coal reserves under agreements that call for royalties to be paid as the coal is mined. Lease and royalty expense for the years ended December 31, 2018 and 2017 were as follows:

	Year ended December 31, 2018	Year ended December 31, 2017
Lease expense	$ 3,917	$ 3,752
Royalty expense	$ 13,607	$ 14,274

Approximate future minimum lease and royalty payments (not including advance royalties already paid and recorded as assets in the accompanying consolidated balance sheets) are as follows:

Years Ending December 31,	Royalties	Leases
	(in thousands)	
2019	$ 1,580	$ 3,924
2020	1,568	3,867
2021	1,568	3,044
2022	1,568	1,702
2023	1,568	700
Thereafter	7,842	1,730
Total minimum royalty and lease payments	$ 15,694	$ 14,967

Environmental Matters

Based upon current knowledge, the Company believes that it is in compliance with environmental laws and regulations as currently promulgated. However, the exact nature of environmental control problems, if any, which the Company may encounter in the future cannot be predicted, primarily because of the increasing number, complexity and changing character of environmental requirements that may be enacted by federal and state authorities.

Legal Matters

The Company is involved in various legal proceedings arising in the ordinary course of business due to claims from various third parties, as well as potential citations and fines from the Mine Safety and Health Administration, potential claims from land or lease owners and potential property damage claims from third parties. The Company is not party to any other pending litigation that is probable to have a material adverse effect on the financial condition, results of operations or cash flows of the Company. Management is also not aware of any significant legal, regulatory or governmental proceedings against or contemplated to be brought against the Company.

Guarantees/Indemnifications and Financial Instruments with Off-Balance Sheet Risk

In the normal course of business, the Company is a party to certain guarantees and financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. No liabilities related to these arrangements are reflected in the consolidated balance sheets. The Company had no outstanding letters of credit at December 31, 2018. The Company had outstanding surety bonds with third parties of $42.6 million as of December 31, 2018 to secure reclamation and other performance commitments, which are secured by $3.0 million in cash collateral on deposit with the Partnership's surety bond provider. As of December 31, 2018, we had approximately $42.6 million in surety bonds outstanding to secure the performance of our reclamation obligations. Of the $42.6 million, approximately $0.4 million relates to surety bonds for Deane Mining, LLC and approximately $3.4 million relates to surety bonds for Sands Hill Mining, LLC, which in each case have not been transferred or replaced by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC as was agreed to by the parties as part of the transactions. We can provide no assurances that a surety company will underwrite the surety bonds of the purchasers of these entities, nor are we aware of the actual amount of reclamation at any given time. Further, if there was a claim under these surety bonds prior to the transfer or replacement of such bonds by the buyers of Deane Mining, LLC or Sands Hill Mining, LLC, then we may be responsible to the surety company for any amounts it pays in respect of such claim. While the buyers are required to indemnify us for damages, including reclamation liabilities, pursuant the agreements governing the sales of these entities, we may not be successful in obtaining any indemnity or any amounts received may be inadequate.

The Financing Agreement is fully and unconditionally, jointly and severally guaranteed by Rhino and substantially all of its wholly owned subsidiaries. Borrowings under the financing agreement are collateralized by the unsecured assets of the Partnership and substantially all of its wholly owned subsidiaries. See Note 12, for a more complete discussion of the Company's debt obligations.

Income Tax

The Company has filed federal but not all of its required state income tax returns for 2014, 2015, 2016 and 2017, and failed to timely file an application for a change in tax year when it changed its reporting year for external reporting purposes from August 31st to December 31st in 2015. In addition, management and third-party specialists have identified certain transactions which are highly complex from an income tax perspective and have not completed the necessary analysis to bring these matters to conclusion. In preparing the financial statements as of and for the year ended December 31, 2018, management has used its best estimates to compute the Company's provision for federal and state income taxes based on available information; however, the resolution of certain of the complex tax matters, the ultimate completion of returns for all open tax years and tax positions taken could materially impact management's estimates. Therefore, the ultimate tax obligations could be materially different from that reflected in the accompanying consolidated balance sheet at December 31, 2018 once these issues are resolved.

21. MAJOR CUSTOMERS

The Company had revenues or receivables from the following major customers that in each period equaled or exceeded 10% of revenues or receivables:

	Year ended December 31, 2018 Receivables	Year ended December 31, 2018 Sales	Year ended December 31, 2017 Receivables	Year ended December 31, 2017 Sales
Revenues				
Javelin Global	$ 4,347	$ 52,777	$ 2,470	$ 15,090
LGE/KU	467	13,480	1,483	40,217
Integrity Coal	937	24,089	2,238	24,234
Dominion Energy	n/a	19,045	1,232	22,087
Big Rivers	863	20,342	-	21,716
PacifiCorp Energy	960	12,343	1,717	16,518

22. REVENUES

The Company adopted ASC Topic 606 on January 1, 2018, using the modified retrospective method. The adoption of Topic 606 has no impact on revenue amounts recorded on the Company's financial statements. The new disclosures required by ASC Topic 606, as applicable, are presented below. The majority of the Company's revenues are generated under coal sales contracts. Coal sales accounted for approximately 99% of the Company's total revenues for the years ended December 31, 2018 and 2017. Other revenues generally consist of coal royalty revenues, coal handling and processing revenues, rebates and rental income, which accounted for approximately 1% of the Company's total revenues for the years ended December 31, 2018 and 2017.

The majority of the Company's coal sales contracts have a single performance obligation (shipment or delivery of coal according to terms of the sales agreement) and as such, the Company is not required to allocate the contract's transaction price to multiple performance obligations. All of the Company's coal sales revenue is recognized when shipment or delivery to the customer has occurred, prices are fixed or determinable and the title or risk of loss has passed in accordance with the terms of the coal sales agreement. With respect to other revenues recognized in situations unrelated to the shipment of coal, the Company carefully reviews the facts and circumstances of each transaction and does not recognize revenue until the following criteria are met: persuasive evidence of an arrangement exists, delivery has occurred or services have been rendered, the seller's price to the buyer is fixed or determinable and collectability is reasonably assured.

The following table disaggregates revenue by type for the years ended December 31, 2018 and 2017:

	Years Ended December 31, 2018	Years Ended December 31, 2017
Coal Sales:		
Steam coal	$ 157,254	$ 153,159
Met coal	87,015	64,033
Other revenues	3,669	1,549
Total	$ 247,938	$ 218,741

23. SEGMENTS

The Company has to identify the level at which the Company's most senior executive decision-maker makes regular reviews of sales and operating income. These levels are defined as segments. The Company's most senior executive decision-maker is the company's CEO. The regular internal reporting of income to the CEO, which fulfills the criteria to constitute a segment, is done for the coal group as a whole, and we therefore report the total coal group as the company's only primary segment.

The Company operates as a single primary reportable segment relating to its coal investments. The Company has some general corporate assets that it breaks out separately as unallocated corporate assets in the segment disclosure. All of the Company's revenues relate to the coal segment.

A reconciliation of the Company's consolidated assets to the total of the coal segment assets is provided below as of December 31, 2018 and 2017:

Segment assets (1)	2018	2017
Primary	$ 213,504	237,740
Corporate, unallocated	42,455	63,198
Total assets	$ 255,959	300,938

(1) Segment assets include accounts receivable, due from affiliates, prepaid and other current assets, inventory, intangible assets and property, plant and equipment — net; the remaining assets are unallocated corporate assets.

24. SUBSEQUENT EVENTS

Effective February 13, 2019, Rhino Energy (the “Operating Company”), the Partnership, certain of Rhino Energy’s subsidiaries, identified as Borrowers (together with the Operating Company, the “Borrowers”), the Partnership and certain other Rhino Energy subsidiaries identified as Guarantors (together with the Partnership, the “Guarantors”), entered into a second amendment (the “Amendment”) to the Financing Agreement originally executed on December 27, 2017 with Cortland Capital Market Services LLC, as Collateral Agent and Administrative Agent, CB Agent Services LLC, as Origination Agent and the parties identified as Lenders therein (the “Lenders”). The Amendment provides the Lender’s consent for the Partnership to pay a one-time cash distribution on February 14, 2019 to the Series A Preferred Unitholders an amount not to exceed approximately $3.2 million. The Amendment allows the Partnership to sell its remaining shares of Mammoth Energy Services, Inc. and utilize the proceeds for payment of the one-time cash distribution to the Series A Preferred Unitholders and waives the requirement to use such proceeds to prepay the outstanding principal amount outstanding under the Financing Agreement.

The Amendment also waives any Event of Default that has or would otherwise arise under Section 9.01(c) of the Financing Agreement solely by reason of the Borrowers failing to comply with the Fixed Charge Coverage Ratio covenant in Section 7.03(b) of the Financing Agreement for the fiscal quarter ending December 31, 2018. The Amendment includes an amendment fee of approximately $0.6 million payable by the Partnership on May 13, 2019 and an exit fee equal to 1% of the principal amount of the term loans made under the Financing Agreement that is payable on the earliest of (w) the final maturity date of the Financing Agreement, (x) the termination date of the Financing Agreement, (y) the acceleration of the obligations under the Financing Agreement for any reason, including, without limitation, acceleration in accordance with Section 9.01 of the Financing Agreement, including as a result of the commencement of an insolvency proceeding and (z) the date of any refinancing of the term loan under the Financing Agreement. The Amendment amends the definition of the Make-Whole Amount under the Financing Agreement to extend the date of the Make-Whole Amount period to December 31, 2019.

On March 5, 2019, the Company modified the terms of the Cedarview note (see Note 12), to modify the maturity date with $1.0 million of the note balance due by May 31, 2019 with the remaining balance of $1.5 million and associated accrued interest due May 31, 2020. The Company paid a $45,000 loan extension fee to execute this agreement. All other terms of the note remain the same.

Royal Energy Resources, Inc.

Code of Financial and Business Ethics for Directors, Officers, and Employees

Royal Energy Resources, Inc. (the "Company") is committed to conducting business according to the highest ethical standards and in accordance with a code of business conduct which all directors, officers, and employees of the Company (each, a "Team Member" and collectively, the "Team Members") understand and appreciate as being part of the core values of the Company. This document (this "Code") summarizes the basic principles of honest and ethical behavior and conduct that we share as Team Members, including:

1. ethical handling of actual or apparent conflicts of interest between personal and professional relationships;
2. full, fair, accurate, timely, and understandable disclosure in the periodic reports required to be filed with the Securities and Exchange Commission by the Company and in other public communications that the Company makes;
3. compliance with applicable laws and governmental rules and regulations;
4. prompt internal reporting to an appropriate person or persons identified herein of violations of this Code; and,
5. accountability for adherence to this Code.

We are committed to ethical and legally compliant operations. Where you have any doubt whether a situation or action is ethical or legal, raise the issue with your supervisor or the General Counsel of the Company.

It is the responsibility of each Team Member to report, in accordance with the Company's Accounting Complaints Policy, improper or questionable accounting or auditing practices whenever such practices come to his or her attention. None of the Company's funds or assets shall be used for any unlawful or improper purpose.

Each director, officer and employee shall receive a copy of this Code and sign a certification acknowledging receipt of this Code.

CERTIFICATION

I have read and understand the Code of Financial and Business Ethics (the "Code") of Royal Energy Resources, Inc. I agree that I will comply with the policies and procedures set forth in the Code.

____________________ Job Title: ____________________

Signature

____________________ Location: ____________________

Type or Print Name

Date: ____________________

Exhibit 21.1

Subsidiaries of Royal Energy Resources, Inc.

Entity	Jurisdiction of Organization	Ownership Percentage
Rhino Resource Partners, LP	Delaware	*
Royal Ventures, LLC	Delaware	100%

* As of March 29, 2019, Royal Energy Resources, Inc. owns 100% of the general partner interest, 50.9% of the common units and 85.8% of the subordinated units, and 0% of the Series A Preferred Units.

Subsidiaries of Rhino Resource Partners, LP**

Entity	Jurisdiction of Organization
Rhino Energy LLC	Delaware
CAM Mining LLC	Delaware
Rhino Northern Holdings LLC	Delaware
Hopedale Mining LLC	Delaware
Castle Valley Mining LLC	Delaware
Pennyrile Energy LLC	Delaware

** 100% owned by Rhino Resource Partners, LP

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Royal Energy Resources, Inc.:

We consent to the incorporation by reference in Registration Statement No. 333-206024 on Form S-8 of Royal Energy Resources, Inc. of our report dated March 29, 2019, with respect to the consolidated balance sheets of Royal Energy Resources, Inc. and Subsidiaries as of December 31, 2018 and 2017, and the related consolidated statements of operations and comprehensive income (loss), stockholders' equity, and cash flows for each of the years in the two-year period ended December 31, 2018, appearing in this Annual Report on Form 10-K of Royal Energy Resources, Inc. for the year ended December 31, 2018.

CERTIFIED PUBLIC ACCOUNTANTS

513 State Street
Bristol, Virginia
March 29, 2019

Exhibit 23.4

CONSENT OF MARSHALL MILLER & ASSOCIATES, INC.

As mining and geological consultants, we hereby consent to the use by Royal Energy Resources, Inc. (the "Company") in connection with its Annual Report on Form 10-K for the year ended December 31, 2018 (the "Form 10-K"), and any amendments thereto, and to the incorporation by reference in the Company's Registration Statement on Form S-8 (No. 333-206024), and in the Company's Registration Statement on Form S-3 (File No. 333-213031) of information contained in our report dated January 17, 2019 in the Form 10-K. We also consent to the reference to Marshall Miller & Associates, Inc. in those filings and any amendments thereto.

By:	*/s/ Justin S. Douthat*
	Marshall Miller & Associates, Inc.
Name:	Justin S. Douthat
Title:	Vice President, Manager of Engineering
Dated:	March 29, 2019

By:	*/s/ J. Scott Nelson*
	Marshall Miller & Associates, Inc.
Name:	J. Scott Nelson
Title:	Senior Principal
Dated:	March 29, 2019

Exhibit 31.1

Certifications

I, Richard A. Boone, certify that:

1. I have reviewed this annual report on Form 10-K of Royal Energy Resources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 29, 2019

/s/ Richard A. Boone

Richard A. Boone
Chief Executive Officer

Exhibit 31.2

Certifications

I, Wendell S. Morris, certify that:

1. I have reviewed this annual report on Form 10-K of Royal Energy Resources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 29, 2019

/s/ Wendell S. Morris

Wendell S. Morris
Chief Financial Officer

Exhibit 32.1

**Certification of Chief Executive Officer Pursuant To
18 U.S.C. Section 1350, as Adopted Pursuant To
Section 906 of the Sarbanes-Oxley Act of 2002**

In connection with the Annual Report on Form 10-K of Royal Energy Resources, Inc. (the “Company”) for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Richard A. Boone, as Chief Executive Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

By:	*/s/ Richard A. Boone*
Name:	Richard A. Boone
Title:	*Chief Executive Officer*

Date: March 29, 2019

Exhibit 32.2

Certification of Chief Financial Officer Pursuant To
18 U.S.C. Section 1350, as Adopted Pursuant To
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report on Form 10-K of Royal Energy Resources, Inc. (the "Company") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Wendell S. Morris, as Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Wendell S. Morris

Wendell S. Morris
Chief Financial Officer

Date: March 29, 2019

Exhibit 95.1

Federal Mine Safety and Health Act Information

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Federal Mine Safety and Health Act of 1977 (the “Mine Act”). The following disclosures respond to that legislation.

Whenever MSHA believes that a violation of the Mine Act, any health or safety standard, or any regulation has occurred, it may issue a citation that describes the violation and fixes a time within which the operator must abate the violation. In these situations, MSHA typically proposes a civil penalty, or fine, as a result of the violation, that the operator is ordered to pay. In evaluating the information below regarding mine safety and health, investors should take into account factors such as: (a) the number of citations and orders will vary depending on the size of a coal mine, (b) the number of citations issued will vary from inspector to inspector and mine to mine, and (c) citations and orders can be contested and appealed, and during that process are often reduced in severity and amount, and are sometimes dismissed.

Responding to the Dodd-Frank Act legislation, we report that, for the year ended December 31, 2018, none of our subsidiaries received written notice from MSHA of (a) a violation under section 110(b)(2) of the Mine Act for failure to make reasonable efforts to eliminate a known violation of a mandatory safety or health standard that substantially proximately caused, or reasonably could have been expected to cause, death or serious bodily injury, (b) a pattern of violations of mandatory health or safety standards under section 104(e) of the Mine Act, or (c) a violation under section 107(a) of the Mine Act for alleged conditions or practices that could reasonably be expected to cause death or serious physical harm. In addition, none of our subsidiaries suffered any mining related fatalities during the year ended December 31, 2018.

The following table sets out information required by the Dodd-Frank Act for the year ended December 31, 2018. The mine data retrieval system maintained by MSHA may show information that is different than what is provided herein. Any such difference may be attributed to the need to update that information on MSHA’s system and/or other factors. The table also displays pending legal actions before the Federal Mine Safety and Health Review Commission (the “Commission”) that were initiated during the year ended December 31, 2018 as well as total pending legal actions that were pending before the Commission as of December 31, 2018, which includes the legal proceedings before the Commission as well as all contests of citations and penalty assessments which are not before an administrative law judge. All of these pending legal actions constitute challenges by us of citations issued by MSHA. Since none of our subsidiaries received notice from MSHA of a pattern of violations of mandatory health or safety standards under section 104(e) of the Mine Act, the column that would normally display this information in the table below has been omitted for ease of presentation.

For the year ended December 31, 2018

Company	Mine [1]	MSHA ID	104(a)S & S [2]	104 (b) [3]	104 (d) [4]	107 (a) [5]	110 (b)(2) [6]	Proposed Assessments [7]	Pending Legal Proceedings [8]	Legal Proceedings Initiated	Legal Proceedings Resolved
Hopedale Mining LLC	Hopedale Mine	33-00968	24	0	0	0	0	$ 31,624	0	0	0
	Nelms Plant	33-04187	2	0	0	0	0	$ 1,665	0	0	0
CAM/Deane Mining LLC	Mine #28	15-18911	23	0	0	0	0	$ 49,420	1	1	0
	Three Mile Mine #1	15-17659	0	0	0	0	0	$ 0	0	0	0
	Right Fork-Rob Fork Contour	15-18977	7	0	0	0	0	$ 2,908	0	0	0
	Grapevine South	46-08930	10	0	0	0	0	$ 12,957	2	2	9
	Remining No. 3	46-09345	19	1	0	0	0	$ 35,262	2	4	2
	Rob Fork Processing	15-14468	16	0	3	0	0	$ 14,962	0	2	2
	Jamboree Loadout	15-12896	2	0	0	0	0	$ 1,067	0	0	0
	CAM Highwall Miner	46-09545	1					$ 1,117			
	Mill Creek Prep Plant	15-16577	0	0	0	0	0	$ -	0	0	0
	Tug Fork Plant	46-08626	3	0	0	0	0	$ 3,149	0	0	0
	Rhino Trucking	Q569	0	0	0	0	0	$ -	0	0	0
	Rhino Reclamation Services	R134	0	0	0	0	0	$ -	0	0	0
	Rhino Services	S359	0	0	0	0	0	$ -	0	0	0
Rhino Eastern LLC	Eagle #1	4608758	0	0	0	0	0	$ -	0	0	0
	Eagle #3	4609427	0	0	0	0	0	$ -	0	0	0
Pennyrile Energy LLC	Riveredge Mine	15-19424	73	0	0	0	0	$ 175,541	1	1	6
	Riveredge Surface Ops	15-19749	12	0	0	0	0	$ 4,102	0	0	0
McClane Canyon Mining LLC	McClane Canyon Mine	05-03013	0	0	0	0	0	$ -	0	0	0
Castle Valley Mining LLC	Castle Valley Mine #3	42-02263	2	0	0	0	0	$ 4,627	0	0	0
	Castle Valley Mine #4	42-02335	10	0	0	0	0	$ 23,595	2	2	0
	Bear Canyon Loading Facility	42-02395	4	0	0	0	0	$ 8,201	1	1	2
Total			208	1	3	0	0	$ 370,197	9	13	21

[1] The foregoing table does not include the following: (i) facilities which have been idle or closed unless they received a citation or order issued by MSHA; and (ii) permitted mining sites where we have not begun operations and therefore have not received any citations.

[2] Mine Act section 104(a) citations shown above are for alleged violations of health or safety standards that could significantly and substantially contribute to a serious injury if left unabated.

[3] Mine Act section 104(b) orders are for alleged failures to totally abate a citation within the period of time specified in the citation. These orders result in an order of immediate withdrawal from the area of the mine affected by the condition until MSHA determines that the violation has been abated.

[4] Mine Act section 104(d) citations and orders are for an alleged unwarrantable failure (i.e. aggravated conduct constituting more than ordinary negligence) to comply with a mandatory mining health or safety standard or regulation. These types of violations could significantly and substantially contribute to a serious injury; however, the conditions do not cause imminent danger.

[5] Mine Act section 107(a) orders are for alleged conditions or practices which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated and result in orders of immediate withdrawal from the area of the mine affected by the condition.

[6] The total number of flagrant violations issued under section 110(b)(2) of the Mine Act.

[7] Total dollar value of MSHA assessments proposed during the year ended December 31, 2018.

[8] Any pending legal action before the Federal Mine Safety and Health Review Commission (the "Commission") involving a coal mine owned and operated by us. The number of legal actions pending as of December 31, 2018 that fall into each of the following categories is as follows:

(a) Contests of citations and orders: 9

(b) Contests of proposed penalties: 0

(c) Complaints for compensation under Section 111 of the Mine Act: 0

(d) Complaints of discharge, discrimination or interference under Section 105 of the Mine Act: 0

(e) Applications for temporary relief under Section 105(b)(2) of the Mine Act: 0

(f) Appeals of judges' decisions or orders to the Commission: 0