CNX Coal Resources LP
Form 10-K
February 08, 2017

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

FORM 10-K

(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 001-14901

CNX Coal Resources LP
(Exact name of registrant as specified in its charter)

Delaware	47-3445032
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1000 CONSOL Energy Drive
Canonsburg, PA 15317-6506
(724) 485-4000
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

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

Title of Each Class	Name of Each Exchange On Which Registered
Common Units representing limited partner interests	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No x
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o
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. (check one):

Large accelerated filer o Accelerated filer o Non-accelerated filer x Smaller Reporting Company o

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

The aggregate value of the common units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $97,349,982 as of June 30, 2016, the last business day of the registrant's most recently completed second fiscal quarter, based on the reported closing price of the common units as reported on The New York Stock Exchange on such date.

CNX Coal Resources LP had 11,717,235 common units, 11,611,067 subordinated units, 3,956,496 Class A Preferred Units and a 1.7% general partner interest outstanding at January 31, 2017.

DOCUMENTS INCORPORATED BY REFERENCE:

None

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PART I

Significant Relationships and Other Important Definitions Referenced in this Annual Report

- “Class A Preferred Units” means the convertible preferred units representing limited partner interests in CNX Coal Resources LP designated as “Class A Preferred Units.” The Partnership issued 3,956,496 Class A Preferred Units to CONSOL Energy on September 30, 2016. Key terms of the Class A Preferred Units include the following:
Distributions: Distributions on each outstanding Class A Preferred Unit will be cumulative, and will accumulate at 11% per annum (the “Class A Preferred Unit Distribution Rate”) for each calendar quarter beginning with the quarter ending December 31, 2016 until such time as the Partnership pays the full cumulative Class A Preferred Unit distribution in respect of such Class A Preferred Unit with respect to such calendar quarter or such Class A Preferred Unit is converted in accordance with the Partnership Agreement (as defined herein), whether or not such Class A Preferred distributions have been declared. Subject to certain exceptions, a holder of Class A Preferred Units (currently, CONSOL Energy) will be entitled to receive Class A Preferred distributions out of any assets of the Partnership legally available for the payment of distributions at the Class A Preferred Unit Distribution Rate when, as, and if declared by the Board of Directors of CNX Coal Resources GP LLC to be paid by the Partnership in accordance with the Partnership Agreement, will be paid quarterly, in arrears, at the election of the Partnership either in additional Class A Preferred Units or in cash;
Voting: Holders of Class A Preferred Units will have such voting rights as if their Class A Preferred Units were converted, on a one-for-one basis, into common units and will vote together with the holders of common units as a single class. Holders of Class A Preferred Units will be entitled to vote as a separate class on any matter that adversely affects the rights, privileges or preferences of the Class A Preferred Units in any material respect or as required by applicable law or regulation;
Conversion at the Election of the Holder: Class A Units are convertible, at the election of the holder, into common units on a one-for-one basis (i) at any time after September 30, 2017, (ii) with respect to the Partnership’s dissolution or liquidation and (iii) with respect to certain change of control events as described in the Partnership Agreement;
Conversion at the Election of the Partnership: All, but not less than all, of the outstanding Class A Preferred Units are convertible, at the election of the Partnership, into common units on a one-for-one basis, on or after September 30, 2019; provided, that (i) no “Class A Preferred Unit Payment Default,” arising from the Partnership’s failure to pay in full any Class A Preferred Unit distribution, has occurred and is continuing; (ii) the volume-weighted average trading price of the common units over the 15-day trading period ending on the trading day immediately prior to the date of the conversion notice is equal to or greater than 140% of the issue price of the Class A Preferred Units; and (iii) the average trading volume is at least 35,000 common units (subject to customary anti-dilution adjustments) with respect to any 20 trading days within the 30-trading day period ending on the trading day immediately prior to the date of the conversion notice;
Restrictions on Transfer: Prior to September 30, 2017, other than transfers to affiliates, CONSOL Energy may not transfer any Class A Preferred Units without the approval of the Partnership;

- “CNX Coal Resources LP,” our "Partnership,” “we,” “our,” “us” and similar terms, when used in a historical context, refer to CNX Coal Resources LP, a Delaware limited partnership, and its subsidiaries;

- “CNX Operating” refers to CNX Operating LLC, a Delaware limited liability company and a direct, wholly-owned subsidiary of the Partnership;

- “CNX Thermal Holdings” refers to CNX Thermal Holdings LLC, a Delaware limited liability company and a direct, wholly-owned subsidiary of CNX Operating; subsequent to the PA Mining Acquisition, CNX Thermal Holdings owns a 25% undivided interest in the assets, liabilities, revenues and expenses comprising the Pennsylvania Mining Complex;

- the “common units” refer to the limited partner interests in CNX Coal Resources LP. The holders of common units are entitled to participate in partnership distributions and are entitled to exercise the rights or privileges of limited partners under the Partnership Agreement. The common units are listed on the New York Stock Exchange, under the symbol “CNXC”;

- "Concurrent Private Placement” refers to the issuance (concurrent with the IPO) of 5,000,000 common units to Greenlight Capital pursuant to a common unit purchase agreement;

- “CONSOL Energy” and our “sponsor” refer to CONSOL Energy Inc., a Delaware corporation and the parent of our general partner, and its subsidiaries other than our general partner, us and our subsidiaries;

- “CPCC” refers to CONSOL Pennsylvania Coal Company LLC, a Delaware limited liability company and a wholly-owned subsidiary of CONSOL Energy;

- “Conrhein” refers to Conrhein Coal Company, a Pennsylvania general partnership and a wholly-owned subsidiary of CONSOL Energy;

- our “general partner” refers to CNX Coal Resources GP LLC, a Delaware limited liability company and our general partner;

- “Greenlight Capital” refers to certain funds managed by Greenlight Capital, Inc. and its affiliates;

- "IPO" refers to the completion of the Partnership's initial public offering on July 7, 2015;

- “omnibus agreement” refers to the Omnibus Agreement dated July 7, 2015, as replaced as the Amended and Restated Agreement of Limited Partnership of the Partnership dated as of September 30, 2016;

- "PA Mining Acquisition" refers to a transaction which closed on September 30, 2016, where the Partnership and its wholly owned subsidiary, CNX Thermal, entered into a Contribution Agreement with CONSOL Energy, CPCC and Conrhein, under which CNX Thermal Holdings acquired an undivided 6.25% of the contributing parties’ right, title and interest in and to the Pennsylvania Mining Complex (which represents an aggregate 5% undivided interest in and to the Pennsylvania Mining Complex);

- the “Partnership Agreement” refers to the First Amended and Restated Agreement of Limited Partnership of the Partnership, as replaced by the Second Amended and Restated Agreement of Limited Partnership of the Partnership dated as of September 30, 2016;

- the “Pennsylvania Mining Complex” refers to the coal mines, coal reserves and related assets and operations, located primarily in southwestern Pennsylvania, owned 80% by CONSOL Energy and 20% by CNX Thermal Holdings, prior to the PA Mining Acquisition; and subsequent to the PA Mining Acquisition, owned 75% by CONSOL Energy, and its subsidiaries and 25% by CNX Thermal Holdings; and

- the “preferred units” refer to any limited partnership interests, other than the common units and subordinated units, issued in accordance with the Partnership Agreement that, as determined by our general partner, have special voting rights to which our common units are not entitled. As of the date of this Annual Report on Form 10-K, the only outstanding preferred units are the Class A Preferred Units.

FORWARD-LOOKING STATEMENTS

We are including the following cautionary statement in this Annual Report on Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of us. With the exception of historical matters, the matters discussed in this Annual Report on Form 10-K are forward-looking statements (as defined in Section 21E of the Exchange Act) that involve risks and uncertainties that could cause actual results to differ materially from projected results. Accordingly, investors should not place undue reliance on forward-looking statements as a prediction of actual results. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future production, revenues, income and capital spending. When we use the words "believe," "intend," "expect," "may," "should," "anticipate," "could," "estimate," "plan," "predict," "project," or their negatives, or other expressions, the statements which include those words are usually forward-looking statements. When we describe strategy that involves risks or uncertainties, we are making forward-looking statements. The forward-looking statements in this Annual Report on Form 10-K speak only as of the date of this Annual Report on Form 10-K; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- changes in coal prices or the costs of mining or transporting coal;
- uncertainty in estimating economically recoverable coal reserves and replacement of reserves;
- our ability to develop our existing coal reserves and successfully execute our mining plans;
- changes in general economic conditions, both domestically and globally;
- competitive conditions within the coal industry;
- changes in the consumption patterns of coal-fired power plants and steelmakers and other factors affecting the demand for coal by coal-fired power plants and steelmakers;
- the availability and price of coal to the consumer compared to the price of alternative and competing fuels;
- competition from the same and alternative energy sources;
- energy efficiency and technology trends;
- our ability to successfully implement our business plan;
- the price and availability of debt and equity financing;
- operating hazards and other risks incidental to coal mining;
- major equipment failures and difficulties in obtaining equipment, parts and raw materials;
- availability, reliability and costs of transporting coal;
- adverse or abnormal geologic conditions, which may be unforeseen;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- labor availability, relations and other workforce factors;
- defaults by our sponsor under our operating agreement and employee services agreement;
- changes in availability and cost of capital;
- changes in our tax status;
- delays in the receipt of, failure to receive or revocation of necessary governmental permits;
- defects in title or loss of any leasehold interests with respect to our properties;
- the effect of existing and future laws and government regulations, including the enforcement and interpretation of environmental laws thereof;

- the effect of new or expanded greenhouse gas regulations;
- the effects of litigation; and
- other factors discussed in this 2016 Form 10-K under “Risk Factors,” as updated by any subsequent Forms 10-Q, which are on file at the Securities and Exchange Commission.

ITEM 1. BUSINESS

General

We are a growth-oriented master limited partnership formed by CONSOL Energy to manage and further develop all of its active coal operations in Pennsylvania. At December 31, 2016, our assets include a 25% undivided interest in, and operational control over, CONSOL Energy's Pennsylvania Mining Complex, which consists of three underground mines and related infrastructure that produce high-Btu bituminous thermal coal that is sold primarily to electric utilities in the eastern United States, our core market. We are a leading producer of high-Btu thermal coal in the Northern Appalachian Basin and the eastern United States due to our ability to efficiently produce and deliver large volumes of high-quality coal at competitive prices, the strategic location of our mines, the industry experience of our management team and our relationship with CONSOL Energy.

The Pennsylvania Mining Complex, which includes the Bailey Mine, the Enlow Fork Mine and the Harvey Mine, has extensive high-quality coal reserves. We mine our reserves from the Pittsburgh No. 8 Coal Seam, which is a large contiguous formation of uniform, high-Btu thermal coal that is ideal for high productivity, low-cost longwall operations. As of December 31, 2016, the Partnership's portion of the Pennsylvania Mining Complex included 191,678 thousand tons of proven and probable coal reserves with an average gross heat content of approximately 12,970 British thermal units ("Btu") per pound and approximately 3.7 pounds sulfur dioxide per million British thermal units ("lb SO2/mmBtu"). Based on our current production capacity, these reserves are sufficient to support approximately 27 years of production. In addition, our reserves currently exhibit thermoplastic behavior suitable for cokemaking and contain an average of approximately 39%-40% volatile matter (on a dry basis), which enables us, if market dynamics are favorable, to capture greater margins from selling our coal as a crossover product in the high-vol metallurgical market to cokemakers and steel manufacturers who utilize modern cokemaking technologies.

The design of the Pennsylvania Mining Complex is optimized to produce large quantities of coal on a cost-efficient basis. We are able to sustain high production volumes at comparatively low operating costs due to, among other things, the technologically advanced longwall mining systems, logistics infrastructure and safety. All of our mines utilize longwall mining, which is a highly automated underground mining technique that produces large volumes of coal at lower costs compared to other underground mining methods. Generally, we operate five longwalls and 15-17 continuous mining sections at the Pennsylvania Mining Complex. The current production capacity of the Partnership's portion of the Pennsylvania Mining Complex's five longwalls is 7,125 thousand tons of coal per year. The preparation plant is connected via conveyor belts to each of our mines, to clean and process up to 8,200 tons of coal per hour. Our onsite logistics infrastructure at the preparation plant includes a dual-batch train loadout facility capable of loading up to 9,000 tons of coal per hour and 19.3 miles of track linked to separate Class I rail lines owned by Norfolk Southern and CSX, which enables us to simultaneously accommodate multiple unit trains and significantly increases our efficiency in meeting our customers' transportation needs. Our ability to accommodate multiple unit trains allows for the seamless transition of locomotives from empty inbound trains to fully loaded outbound trains at our facility.

On July 1, 2015, the Partnership's common units began trading on the New York Stock Exchange under the ticker symbol “CNXC”. On July 7, 2015, the Partnership completed the issuance of common units under the IPO, a private placement with Greenlight Capital, and entered into a $400,000 thousand senior secured revolving credit facility. In connection with the IPO CONSOL Energy contributed a 20% undivided interest in the assets, liabilities, revenues and expenses comprising the Pennsylvania Mining Complex.

On September 30, 2016, the Partnership acquired an additional 5% of the Pennsylvania Mining Complex, from CONSOL Energy and its affiliates, for $21,500 thousand in cash and the issuance of 3,956,496 Class A Preferred Units with a value of $67,300 thousand. All information (except distributable cash flow, which reflects the ownership percentage at the time) included within this filing has been recast to reflect the Partnership's current 25% interest in the assets, liabilities, revenues and expenses comprising the Pennsylvania Mining Complex.

Our primary strategy for growing our business and increasing distributions to our unitholders is to make acquisitions that increase our distributable cash flow. The primary component of our growth strategy is based upon our expectation of future divestitures by our sponsor to us of portions of its retained 75% undivided interest in the Pennsylvania Mining Complex. We have a right of first offer pursuant to our omnibus agreement to purchase part or all of the remaining undivided interest in the Pennsylvania Mining Complex retained by our sponsor for so long as our sponsor controls our general partner. CONSOL Energy has stated its desire to divest its retained interest in the Pennsylvania Mining Complex, however the timing and magnitude of such divestitures are dependent upon many market factors.

Organization Structure

The following simplified diagram depicts our organizational structure as of December 31, 2016:

Our Relationship with CONSOL Energy

One of our principal strengths is our relationship with CONSOL Energy. CONSOL Energy is a producer of coal and natural gas headquartered in Canonsburg, Pennsylvania. CONSOL Energy has been mining coal, primarily in the Appalachian Basin, since 1864. CONSOL Energy deploys an organic growth strategy focused on efficiently developing its resource base. CONSOL Energy's premium coal grades are sold to electricity generators, steel makers, coke producers and industrial consumers, both domestically and internationally. In addition, CONSOL Energy is one of the largest independent natural gas exploration, development and production companies with operations focused on the major shale formations of the Appalachian Basin, including the Marcellus Shale. CONSOL Energy is listed on the NYSE under the symbol "CNX" and had a market capitalization of approximately $4.2 billion as of December 31, 2016.

Our Rights of First Offer

CONSOL Energy granted to us a right of first offer to acquire its retained 75% undivided interest in the Pennsylvania Mining Complex for so long as its affiliates control our general partner. In addition, at December 31, 2016, we also have a right of first offer to acquire two other assets, which will expire in July 2020. CONSOL Energy is under no obligation to sell those assets and we are under no obligation to purchase those assets from CONSOL Energy.

Our Assets

CNX Thermal Holdings, owns a 25% undivided interest in the Pennsylvania Mining Complex. CNX Thermal Holdings entered into an operating agreement with CPCC and Conrhein under which CNX Thermal Holdings is named as operator and assumes management and control over the day-to-day operations of the Pennsylvania Mining Complex for the life of the mines. We are managed by the directors and executive officers of our general partner. As a result, the directors and executive officers of our general partner have the ultimate responsibility for managing and conducting all of our and our subsidiaries' operations, including with respect to CNX Thermal Holdings' rights and obligations under the operating agreement. Based on our current production capacity utilizing five longwall mining systems, our recoverable reserves are sufficient to support approximately 27 years of production.

CONSOL Energy owns a 75% undivided interest in the Pennsylvania Mining Complex, as well as 100% of our general partner and, indirectly through our general partner, our 1.7% general partner interest and incentive distribution rights. In addition, CONSOL Energy owns a 60.1% limited partner interest in us.

Our Operations

Bailey Mine

The Bailey Mine is located in Enon, Pennsylvania. As of December 31, 2016, the Partnership's portion of the Bailey Mine's assigned and accessible reserve base contained an aggregate of 64,921 thousand tons of clean recoverable proven and probable coal. While operating two longwalls, the typical production capacity of our portion of the Bailey Mine is 2,875 thousand tons (11,500 thousand 100% basis) of coal per year. For the years ended December 31, 2016, 2015 and 2014, our portion of the Bailey Mine produced 3,014 thousand tons, 2,547 thousand tons and 3,081 thousand tons of coal, respectively.

Enlow Fork Mine

The Enlow Fork Mine is located directly north of the Bailey Mine. As of December 31, 2016, the Partnership's portion of the Enlow Fork Mine's assigned and accessible reserve base contained an aggregate of 76,629 thousand tons of clean recoverable proven and probable coal. While operating two longwalls, the typical production capacity of our portion of the Enlow Fork Mine is 2,875 thousand tons (11,500 thousand 100% basis) of coal per year. For the years ended December 31, 2016, 2015 and 2014, our portion of the Enlow Fork Mine produced 2,409 thousand tons, 2,250 thousand tons and 2,639 thousand tons of coal, respectively.

Harvey Mine

The Harvey Mine is located directly east of the Bailey and Enlow Fork Mines. As of December 31, 2016, the Partnership's portion of the Harvey Mine's assigned and accessible reserve base contained an aggregate of 50,128 thousand tons of clean recoverable proven and probable coal. While operating one longwall, the typical production capacity of our portion of the Harvey Mine is 1,375 thousand tons (5,500 thousand 100% basis) of coal per year. For the year ended December 31, 2016, 2015 and 2014, our portion of the Harvey Mine produced 743 thousand tons, 901 thousand tons and 796 thousand tons of coal, respectively. Longwall production commenced in March 2014.

Coal Capital

In 2017, the Partnership expects to invest $30-$36 million in maintenance capital expenditures. the Partnership is not expecting to invest in expansion projects in 2017, however, the Partnership continually evaluates potential acquisitions.

Our Customers and Contracts

We sell coal to an established customer base through opportunities as a result of strong business relationships or through a formalized bidding process. We refer to the contracts under which coal produced from the Pennsylvania Mining Complex is sold and which a wholly-owned subsidiary of CONSOL Energy administers under the contract agency agreement at our direction as "our contracts". Our total sold position for 2017 is 6.4 million tons or 98% of the estimated total sales volumes based on the midpoint of our guidance range. In addition to a strong 2017 sold position, we have a solid position of approximately 66% sold for 2018, based on 6.5 million tons of total sales. With our planned coal production in 2017 largely sold out, our focus now has shifted to maximizing realizations for any additional production and booking additional sales for contract years 2018 and 2019. We are currently active in negotiations with several customers to expand our crossover metallurgical coal portfolio, and we continue to pursue select domestic customers that fit with our long-term market strategy.

The sales commitments under contract are our expected sales tons and can fluctuate up or down due to provisions contained within our contracts. The contractual time commitments for customers to nominate future purchase volumes under our contracts are typically sufficient to allow us to balance our sales commitments with prospective production capacity or incremental sales volume. In addition, the commitments can change because of reopener provisions contained in certain of these long-term contracts. For the year ended December 31, 2016 and 2015, approximately 80% and 75%, respectively, of all the coal produced from the Pennsylvania Mining Complex was sold under contracts with terms of one year or more.

The provisions of our contracts are the results of both bidding procedures and extensive negotiations with each customer. As a result, the provisions of our contracts vary significantly in many respects, including, among other factors, price adjustment features, price and contract reopener terms, force majeure provisions, coal qualities and quantities. Our contracts typically stipulate procedures for transportation of coal, quality control, sampling and weighing. Most contain provisions requiring us to deliver coal within stated ranges for specific coal characteristics such as heat, sulfur, ash, moisture, grindability, volatility and other qualities. Failure to meet these specifications can result in economic penalties, rejection or suspension of shipments or termination of the contracts. Although the volume to be delivered pursuant to a long-term contract is stipulated, the customers often have the option to vary the volume within specified limits.

Substantially all of our multi-year sales contracts contain base prices, subject only to pre-established adjustment mechanisms based primarily on (i) variances in the quality characteristics of coal delivered to the customer beyond threshold quality characteristics specified in the applicable sales contract, (ii) the actual calorific value of coal delivered to the customer, and/or (iii) changes in electric power prices in the markets in which our customers operate, as adjusted for any factors set forth in the applicable contract. The electric power price-related adjustments, if any, result only in positive monthly adjustments to the contracted base price that we receive for our coal. Price reopener provisions are present in several of our multi-year sales contracts. These price reopener provisions may automatically set a new price prospectively based on prevailing market price or, in some instances, require the parties to agree on a new price, sometimes within a specified range of prices. In a limited number of agreements, failure of the parties to agree on a price under a price reopener provision can lead to termination of the contract. Under some of our contracts, we have the right to match lower prices offered to our customers by other suppliers. Some of the long-term contracts also permit the contract to be reopened for renegotiation of terms and conditions other than pricing terms, and where a mutually acceptable agreement on terms and conditions cannot be concluded, either party may have the option to terminate the contract.

Of our 2016 sales tons, approximately 75% were sold to U.S. electric generators, 22% were priced on export markets and 3% were sold to other domestic customers. We derive a significant portion of our revenues from two customers: Duke Energy Corporation (“Duke Energy”) and GenOn Energy, Inc. (“GenOn Energy”) from each of whom we derived at least 10% of our total coal sales revenues for the year ended December 31, 2016. As of December 31, 2016, we had approximately nine sales agreements with these customers that expire at various times between 2017 and 2018.

Transportation Logistics and Infrastructure

We have developed a transportation and logistics network with dual rail transportation options that we believe provides us with operational and marketing flexibility, reduces the cost to deliver coal to our core market and allows us to realize higher netback prices. Most of our coal is sold free on board ("FOB") at the Pennsylvania Mining Complex, which means that our customers bear the transportation costs from the mining complex, and essentially all of our coal transported to our domestic customers or to an export terminal facility originates by rail. We believe our proximity to our core markets, dual rail transportation options, rail-to-barge access and customized on-site logistics infrastructure contribute to lower overall delivered costs for power plants in the eastern United States as a result of shorter transportation distances, access to diversified rail route options, higher rail car utilization, more efficient use of locomotive power and more predictable movement of product between mine and destination. In addition, we have favorable access to international coal markets through coal export terminals located on the U.S. east coast.

Seasonality

Our business has historically experienced limited variability in its results due to the effect of seasonal changes. Demand for coal-fired power can increase due to unusually hot or cold weather as power consumers use more air conditioning or heating, respectively. Conversely, mild weather can result in weaker demand for our coal. Adverse weather conditions, such as blizzards or floods, can impact our ability to transport coal over our overland conveyor systems and to transport our coal by rail.

Competition

The coal industry is highly competitive, with numerous producers selling into all markets that use coal. There are numerous large and small producers in all coal producing basins of the United States, and we compete with many of these producers.

The most important factors on which we compete are coal price, coal quality and characteristics, transportation costs and reliability of supply. Demand for coal and the prices that we will be able to obtain for our coal are closely linked to coal consumption patterns of the domestic electric generation industry and foreign coal consumers. These coal consumption patterns are influenced by many factors that are beyond our 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, quality, price and availability of competing sources of fuel.

Laws and Regulations

Overview

Our coal mining operations are subject to various federal, state and local environmental, health and safety regulations. Regulations relating to our operations require us to obtain permits and other licenses; reclaim and restore our properties after mining operations have been completed; store, transport and dispose of materials used or generated by our operations; manage surface subsidence from underground mining; control water and air emissions; protect wetlands and endangered plant and wildlife; and to ensure employee health and safety. Furthermore, the electric power generation industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for our coal. Compliance with these laws has substantially increased the cost of coal mining, and the possibility exists that new legislation
or regulations may be adopted which would have a significant impact on our coal mining operations or our customers' ability to use our coal and may require us or our customers to change their operations significantly or incur substantial costs.

The following is a summary of the more significant existing environmental and worker health and safety laws and regulations to which we and our customers' business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations and financial position.

Environmental Laws

Air Emissions. The Clean Air Act ("CAA") and corresponding state and local laws and regulations affect all aspects of coal mining operations, both directly and indirectly. The CAA directly impacts our coal mining and processing operations by requiring us to obtain pre-approval for the construction or modification of certain facilities or to use specific equipment, technologies or best management practices to control emissions.

The CAA also indirectly and more significantly affects the U.S. coal industry by extensively regulating the air emissions of coal-fired electric power generating plants operated by our customers. Coal contains impurities, such as sulfur, mercury and other constituents, many of which are released into the air when coal is burned. Carbon dioxide ("CO_2"), a regulated greenhouse gas ("GHG"), is also emitted when coal is burned. Environmental regulations governing emissions from coal-fired electric generating plants increase the costs to operate and could affect demand for coal as a fuel source and affect the volume of our sales. Moreover, additional environmental regulations increase the likelihood that existing coal-fired electric generating plants will be decommissioned, including plants to which the Partnership sells coal to, and reduce the likelihood that new coal-fired plants will be built in the future.

In early 2012, the United States Environmental Protection Agency ("EPA") promulgated or finalized several rules for New Source Performance Standards ("NSPS") for coal- and oil- fired power plants which also have a negative effect on coal-generating facilities. The Utility Maximum Control Technology ("UMACT") rule requires more stringent NSPS for particulate matter ("PM"), Sulfur dioxide "SO_2") and nitrogen oxides ("NO_X") and the Mercury and Air Toxics Standards ("MATS") rule requires new mercury and air toxic standards. In November 2012, the EPA published a notice of reconsideration of certain aspects of the UMACT and MATS rules. Following reconsideration in April 2013 and again in April 2014, the EPA promulgated final UMACT and MATS rules in November 2014 at which point the standards became applicable to new power plants. The final rules have higher emission limits, but the standards are still stringent and compliance with the rules is expensive.

The CAA requires the EPA to set National Ambient Air Quality Standards ("NAAQS") for certain pollutants and the CAA identifies two types of NAAQS. Primary standards provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. On October 1, 2015, the EPA finalized the NAAQS for ozone pollution and reduced the limit to 70 parts per billion (ppb) from the previous 75 ppb standard. The final rule could have a large impact on both the oil and gas and coal mining industries as states would be required to update their permitting standards to meet these potentially unachievable limits. Six states have now filed a petition for review in the D.C. Circuit of Appeals.

On July 6, 2011, the EPA finalized a rule known as the Cross-State Air Pollution Rule ("CSAPR"). CSAPR regulates cross-border emissions of criteria air pollutants such as SO_2 and NO_X, as well as byproducts, fine particulate matter ("$PM_{2.5}$") and ozone by requiring states to limit emissions from sources that "contribute significantly" to noncompliance with air quality standards for the criteria air pollutants. If the ambient levels of criteria air pollutants are above the thresholds set by the EPA, a region is considered to be in "nonattainment" for that pollutant and the EPA applies more stringent control standards for sources of air emissions located in the region. In April 2014, the Supreme Court reversed a decision of the D.C. Circuit Court of Appeals that vacated the rule. Following remand and briefing the D.C. Circuit Court, in October 2014, granted a motion to lift a stay of the rule and allow the EPA to modify the CSAPR compliance deadline by three-years, setting the stage for issuance of the proposed rule. Implementation of CSAPR Phase 1 began in 2015, with Phase 2 scheduled to begin in 2017. On September 7, 2016, the EPA finalized an update to the CSAPR for the 2008 ozone NAAQS by issuing the final CSAPR Update. Starting in May 2017, this rule will reduce summertime (May - September) NO_X emissions from power plants in 22 states in the eastern United States.

On March 27, 2012, the EPA published its proposed NSPS for CO_2 emissions from new coal-powered electric generating units. The proposed rule would have applied to new power plants and to existing plants that make major modifications. If the rule had been adopted as proposed, only new coal-fired power plants with CO_2 capture and storage ("CCS") could have met the proposed emission limits. Commercial scale CCS is not likely to be available in the near future, and if available, it may make coal-fired electric generation units uneconomical compared to new gas-fired electric generation units. On January 8, 2014, the EPA re-proposed NSPS for CO_2 for new fossil fuel fired power plants and rescinded the rules that were proposed on April 12, 2012.

On September 20, 2013, the EPA issued a new proposal to control carbon emissions from new power plants. Under the Clean Power Plan ("CPP") proposal, the EPA would establish separate NSPS for CO_2 emissions for natural gas-fired turbines and coal-fired units. The proposed “Carbon Pollution Standard for New Power Plants” replaces the earlier proposal released by the EPA in 2012. On August 3, 2015, the EPA finalized the Carbon Pollution Standards to cut carbon emissions from new, modified and reconstructed power plants, which would have become effective on October 23, 2015. On June 2, 2014, the EPA proposed additional CPP legislation to cut carbon emissions from existing power plants. Under this proposed rule, the EPA would create emission guidelines for states to follow in developing plans to address GHG emissions from existing fossil fuel-fired electric generating units. Specifically, the EPA is proposing state-specific rate-based goals for CO_2 emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. On August 3, 2015, the EPA finalized the CPP Rule to cut carbon pollution from existing power plants, which would have become effective on December 22, 2015.

States, industry, organizations, and private entities have filed multiple petitions for review of the CPP in the D.C. Circuit of Appeals and requested that the Court stay implementation of the CPP because they will suffer “irreparable harm.” Petitioners also argued that the Final Rule violates the CAA because energy generating units are already subject to hazardous air pollutant limits under Section 112 of the CAA. On November 3, 2015, twenty-three states were involved in filing a Petition for Review in the U.S. Court of Appeals in Washington, D.C., challenging EPA’s Section 111(b) Rule-also called the “NSPS”-which regulates new coal-fired power plants. On February 9, 2016, the U.S. Supreme Court granted a stay, halting implementation of the EPA’s CPP pending the resolution of legal challenges to the program in court.

Clean Water Act. The federal Clean Water Act ("CWA") and corresponding state laws affect our coal operations by regulating discharges into surface waters. Permits requiring regular monitoring and compliance with effluent limitations and reporting requirements govern the discharge of pollutants into regulated waters. The CWA and corresponding state laws include requirements for: improvement of designated "impaired waters" (i.e., not meeting state water quality standards) through the use of effluent limitations; anti-degradation regulations which protect state designated "high quality/exceptional use" streams by restricting or prohibiting discharges; requirements to treat discharges from coal mining properties for non-traditional pollutants, such as chlorides, selenium and dissolved solids; requirements to minimize impacts and compensate for unavoidable impacts resulting from discharges of fill materials to regulated streams and wetlands; and requirements to dispose of produced wastes and other oil and gas wastes at approved disposal facilities. In addition, the Spill Prevention, Control and Countermeasure ("SPCC") requirements of the CWA apply to all CONSOL Energy operations that use or produce fluids and require the implementation of plans to address any spills and the installation of secondary containment around all storage tanks. These requirements may cause us to incur significant additional costs that could adversely affect our operating results, financial condition and cash flows.

However, on June 29, 2015, the EPA issued a final rule effective August 28, 2015, clarifying which waterways are subject to federal jurisdiction under the Clean Water Act, which would impose additional permitting obligations on our operations. On August 27, 2015, the District Court for the District of North Dakota blocked implementation of the rule in 13 states. On October 9, 2015, the U.S. Circuit Court of Appeals for the Sixth Circuit blocked implementation of the rule nationwide. On January 19, 2017 the U.S. Supreme Court agreed to consider whether jurisdiction rests with the federal district or appellate courts to decide this matter.

In order to obtain a permit for surface coal mining activities, including valley fills associated with steep slope mining, an operator must obtain a permit for the discharge of fill material from the ACOE and a discharge permit from the state regulatory authority under the state counterpart to the CWA. Beginning in early 2009, the EPA took a number of initiatives that have resulted in delays and obstruction of the issuance of such permits for surface mining operations in the Appalachian states, including Pennsylvania where the Pennsylvania Mining Complex is located. Increased oversight of delegated state programmatic authority, coupled with individual permit review and additional requirements imposed by the EPA, has resulted in delays in the review and issuance of permits for surface coal mining operations, including applications for surface facilities for underground mines, such as applications for coal refuse disposal areas.

Resource Conservation and Recovery Act. The federal Resource Conservation and Recovery Act ("RCRA") and corresponding state laws and regulations affect coal mining by imposing requirements for the treatment, storage and disposal of hazardous wastes. Facilities at which hazardous wastes have been treated, stored or disposed of are subject to corrective action orders issued by the EPA that could adversely affect our results, financial condition and cash flows. In 2010, the EPA proposed options for the regulation of Coal Combustion Residuals ("CCRs") from the electric power sector as either hazardous waste or non-hazardous waste. On December 19, 2014, the EPA announced the first national regulations for the disposal of CCRs from electric utilities and independent power producers under RCRA. On April 17, 2015, the EPA finalized these regulations under the solid waste provisions (Subtitle D) of RCRA and not the hazardous waste provisions (Subtitle C) which became effective on October 19, 2015. The EPA affirms in the preamble to the final rule that “this rule does not apply to CCR placed in active or abandoned underground or surface mines.” Instead, “the U.S. Department of Interior ("DOI") and the EPA will address the management of CCR in mine fills in a separate regulatory action(s).” On November 3, 2015, the EPA published the final rule Effluent Limitations Guidelines and Standards ("ELG"), revising the regulations for the Steam Electric Power Generating category which became effective on January 4, 2016. The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades. The combined effect of the CCR and ELG regulations has forced power generating companies to close existing ash ponds and will likely force the closure of certain older existing coal burning power plants that cannot comply with the new standards.

Surface Mining Control and Reclamation Act. The federal Surface Mining Control and Reclamation Act ("SMCRA") establishes minimum national operational and reclamation standards for all surface mines as well as most aspects of underground mines. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and following completion of mining activities. Permits for all mining operations must be obtained from the U.S. Office of Surface Mining ("OSM") or, where state regulatory agencies have adopted federally approved state programs under SMCRA, the appropriate state regulatory authority. States that operate federally approved state programs may impose standards which are more stringent than the requirements of SMCRA and OSM's regulations and in many instances have done so. The Pennsylvania Mining Complex is located in states which have achieved primary jurisdiction for enforcement of SMCRA through approved state programs. In addition, SMCRA imposes a reclamation fee on all current mining operations, the proceeds of which are deposited in the Abandoned Mine Reclamation Fund, which is used to restore unreclaimed and abandoned mine lands mined before 1977. The current per ton fee is $0.28 per ton for surface mined coal and $0.12 per ton for underground mined coal. These fees are currently scheduled to be in effect until September 30, 2021.

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining and to satisfy other miscellaneous obligations. These bonds are provided by CONSOL Energy and are typically renewable on a yearly basis. Surety bond costs have increased while the market terms of surety bonds have generally become less favorable. It is possible that surety-bond issuers may refuse to renew bonds or may demand additional collateral. Any failure by CONSOL Energy or us to maintain, or our inability to acquire, surety bonds that are required by state and federal laws would have a material adverse effect on our ability to produce coal, which could adversely affect our business, financial condition, liquidity, results of operations and cash flows.

Excess Spoil, Coal Mine Waste, Diversions, and Buffer Zones for Perennial and Intermittent Streams. The OSM has issued final amendments to regulations concerning stream buffer zones, stream channel diversions, excess spoil, and coal mine waste to comply with an order issued by the U.S. District Court for the District of Columbia on February 20, 2014, which vacated the stream buffer zone rule that was published December 12, 2008. On July 27, 2015, OSM published the proposed Stream Protection Rule ("SPR"). After much debate and thousands of comments, the final SPR was published by OSM in the Federal Register on December 20, 2016. The final SPR requires the restoration of the physical form, hydrologic function, and ecological function of the segment of a perennial or intermittent stream that a permittee mines through. Additionally, it requires that the post-mining surface configuration of the reclaimed mine site include a drainage pattern, including ephemeral streams, similar to the pre-mining drainage pattern, with exceptions for stability, topographical changes, fish and wildlife habitat, etc. The rule also, requires the establishment of a 100-foot-wide streamside vegetative corridor of native species (including riparian species, when appropriate) along each bank of any restored or permanently-diverted perennial, intermittent, or ephemeral stream. The congressional majority have vowed to block the SPR through a Congressional Review Act resolution. The Congressional Review Act is a law that allows Congress to overturn rules issued by federal agencies. Once a rule is finalized, Congress has a limited period of time to pass a joint resolution of disapproval preventing it from taking effect. The president-elect has also vowed to overturn the SPR. It remains to be seen if the SPR will be enforced. Many believe the SPR to be an overreach of jurisdiction by the OSM, particularly into areas under the legal jurisdiction of other federal agencies, particularly the EPA, the Corps of Engineers, and the U.S. Fish and Wildlife Service, as well as delegated state programs or state laws (e.g., Clean Water Act authority, PA Clean Streams Law, etc.).

Health and Safety Laws

Mine Safety. Legislative and regulatory changes have required us to purchase additional safety equipment, construct stronger seals to isolate mined out areas, and engage in additional training. We have also experienced more aggressive inspection protocols, and with new regulations the volume of civil penalties have increased. The actions taken thus far by federal and state governments include requiring:

- the caching of additional supplies of self-contained self-rescuer ("SCSR") devices underground;
- the purchase and installation of electronic communication and personal tracking devices underground;
- the purchase and installation of proximity detection devices on continuous miner machines;
- the placement of refuge chambers, which are structures designed to provide refuge for groups of miners during a mine emergency when evacuation from the mine is not possible, which will provide breathable air for 96 hours;
- the purchase of new fire resistant conveyor belting underground;
- additional training and testing that creates the need to hire additional employees;
- more stringent rock dusting requirements; and
- the purchase of personal dust monitors for collecting respirable dust samples from certain miners.

On October 2, 2015, the Mine Safety and Health Administration ("MSHA") published proposed rules for underground coal mining operations concerning proximity detection systems for 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. On January 15, 2015, MSHA published a final rule requiring underground coal mine operations to equip continuous mining machines, except full-face continuous mining machines, with proximity detection systems. The proximity detection system strengthens protection for miners by reducing the potential of pinning, crushing and striking hazards that result in accidents involving life-threatening injuries and death. The final rule became effective March 15, 2015 and included a phased in schedule for newly manufactured and in-service equipment.

In 2010, MSHA rolled out the "End Black Lung, Act Now" initiative. As a result, MSHA implemented a new final rule on August 1, 2014 to lower miners' exposure to respirable coal mine dust including using the new Personal Dust Monitor technology. This final rule was implemented in three phases. The first phase began on August 1, 2014 and utilized the current gravimetric sampling device to take full shift dust samples from the current designated occupations and areas. It also required additional record keeping and immediate corrective action in the event of overexposure. The second phase began on February 1, 2016 and required additional sampling for designated and other occupations using the new continuous personal dust monitor

("CPDM") technology, which provides real time dust exposure information to the miner. CPDM equipment was purchased and was placed into service which was required to meet compliance with the new rule. Dust Coordinators and Dust Technicians were hired in order to meet the staffing demand to manage compliance with the new rule. The final phase of the rule went into effect on August 1, 2016. The current respirable dust standard was reduced from 2.0 to 1.5mg/m3 for designated occupations and from 1.0 to 0.5mg/m3 for Part 90 Miners.

Black Lung Legislation. Under federal black lung benefits legislation, each coal mine operator is required to make payments of black lung benefits or contributions to:

- current and former coal miners totally disabled from black lung disease;
- certain survivors of miners who have died from black lung disease; and
- a trust fund for the payment of benefits and medical expenses to claimants whose last mine employment was before January 1, 1970, where no responsible coal mine operator has been identified for claims (where a miner's last coal employment was after December 31, 1969), or where the responsible coal mine operator has defaulted on the payment of such benefits. The trust fund is funded by an excise tax on U.S. production of up to $1.10 per ton for deep mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

The Patient Protection and Affordable Care Act ("PPACA") made two changes to the Federal Black Lung Benefits Act. First, it provided changes to the legal criteria used to assess and award claims by creating a legal presumption that miners are entitled to benefits if they have worked at least 15 years in underground coal mines, or in similar conditions, and suffer from a totally disabling lung disease. To rebut this presumption, a coal company would have to prove that a miner did not have black lung or that the disease was not caused by the miner's work. Second, it changed the law so black lung benefits will continue to be paid to dependent survivors when the miner passes away, regardless of the cause of the miner's death. The changes have increased the cost to us of complying with the Federal Black Lung Benefits Act. In addition to the federal legislation, we are also liable under various state statutes for our portion of black lung claims.

Employees

Neither we nor our subsidiaries have any employees. Our general partner has the sole responsibility for providing the employees and other personnel necessary to conduct our operations. The directors and executive officers of our general partner manage our and our subsidiaries' operations and activities. The executive officers of our general partner are employed and compensated by CONSOL Energy or its affiliates, other than the general partner. Under our omnibus agreement with CONSOL Energy, we reimburse CONSOL Energy for compensation-related expenses (including salary, bonus, incentive compensation and other amounts) attributable to the portion of an executive's compensation that is allocable to our general partner. Pursuant to the operating agreement with CONSOL Energy, CNX Thermal Holdings, a wholly-owned subsidiary, manages and controls the day-to-day operations of the Pennsylvania Mining Complex. Under our employee services agreement with CONSOL Energy, CONSOL Energy employees continue to mine, process and market coal from the Pennsylvania Mining Complex, subject to our direction and control under the operating agreement. All of the field-level employees required to conduct and support our operations are employed by CONSOL Energy or its subsidiaries and are subject to the employee services agreement that we entered into with CONSOL Energy. As of December 31, 2016, CONSOL Energy employed approximately 1,600 people who provide direct support to our operations pursuant to the employee services agreement. None of the employees who provide direct support to our operations are represented by a labor union or collective bargaining agreement.

Jumpstart Our Business Startups Act ("JOBS Act")

Under the JOBS Act, for as long as the Partnership remains an "emerging growth company" as defined in the JOBS Act, we may take advantage of certain exemptions from the SEC's reporting requirements that are applicable to other public companies that are not emerging growth companies, including not being required to provide an auditor's attestation report on management's assessment of the effectiveness of its system of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and seeking unitholder approval of any golden parachute payments not previously approved. We may take advantage of these reporting exemptions until we are no longer an emerging growth company.

The Partnership will remain an emerging growth company for up to five years, although we will lose that status sooner if:

- we have more than $1 billion of revenues in a fiscal year;
- limited partner interests held by non-affiliates have a market value of more than $700 million (large accelerated filer); or

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- we issue more than $1 billion of non-convertible debt over a three-year period.

The JOBS Act also provides that an emerging growth company can delay adopting new or revised accounting standards until such time as those standards apply to private companies. The Partnership has irrevocably elected to “opt out” of this exemption and, therefore, will be subject to the same new or revised accounting standards as other public companies that are not emerging growth companies.

Available Information

CNX Coal Resources LP maintains a website at www.cnxlp.com. CNX Coal Resources LP makes available, free of charge, on this website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the 1934 Act), as soon as reasonably practicable after such reports are available, electronically filed with, or furnished to the SEC, and are also available at the SEC's website www.sec.gov. Apart from SEC filings, we also use our website to publish information which may be important to investors.

ITEM 1A. RISK FACTORS

Risks Related to Our Business

We may not generate sufficient distributable cash flow to support the payment of the minimum quarterly distribution to our common and subordinated unitholders.

In order to support the payment of the minimum quarterly distribution of $0.5125 per unit common and subordinated per quarter, or $2.05 per common and subordinated unit on an annualized basis, we must generate distributable cash flow of approximately $12.1 million per quarter, or approximately $48.6 million per year, based on the number of common units and subordinated units and the general partner interest outstanding (without taking into account the conversion of any preferred units).

Distributions on Class A Preferred Units may be payable either in additional Class A Preferred Units ("PIK Units") or in cash. To be able to pay the Class A Preferred Unit distribution in cash, we must generate additional cash flow of approximately $1.9 million per quarter, or approximately $7.4 million per year, based on the number of Class A Preferred Units outstanding as of December 31, 2016. We may not generate sufficient distributable cash flow to support the payment of the minimum cash quarterly distributions to our holders of preferred units.

The amount of available cash (as defined in the Partnership Agreement. See Item 5 - “Definition of Available Cash”) that we can distribute on our common units (and, as permitted under our Partnership Agreement, on our Class A Preferred Units) principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of coal we are able to produce from our mines and the efficiency of our mining, preparation and transportation of coal, which could be adversely affected by, among other things, operating difficulties, unfavorable geologic conditions, inclement or hazardous weather conditions and natural disasters or other force majeure events;
- the levels of our operating expenses, general and administrative expenses and capital expenditures;
- the fees and expenses of our general partner and its affiliates (including our sponsor) that we are required to reimburse;
- the amount of cash reserves established by our general partner;
- restrictions on distributions contained in our debt agreements;
- our ability to borrow under our debt agreements and/or to access the capital markets to fund our capital expenditures and operating expenditures and to pay distributions;

- our debt service requirements and other liabilities;
- the loss of, or significant reduction in, purchases by our largest customers;
- the level and timing of our capital expenditures;
- fluctuations in our working capital needs;
- the cost of acquisitions, if any; and
- other business risks affecting our cash levels.

In addition, the actual amount of distributable cash flow that we generate will also depend on other factors, some of which are beyond our control, including:

- overall domestic and global economic and industry conditions, including the market price of, supply of and demand for domestic and foreign coal;
- the consumption pattern of industrial consumers, electricity generators and residential users;
- the price and availability of alternative fuels for electricity generation, especially natural gas;
- competition from other coal suppliers;
- the impact of domestic and foreign governmental laws and regulations, including environmental and climate change regulations and regulations affecting the coal mining industry and coal-fired power plants, and delays in the receipt of, failure to receive, failure to maintain or revocation of necessary governmental permits;
- the costs associated with our compliance with domestic and foreign governmental laws and regulations, including environmental and climate change regulations;
- technological advances affecting energy consumption;
- the costs, availability and capacity of transportation infrastructure;
- the cost and availability of skilled labor (including miners), the effects of new or expanded health and safety regulations and work stoppages and other labor difficulties; and
- changes in tax laws.

Our growth strategy primarily depends on us acquiring additional undivided interests in the Pennsylvania Mining Complex from our sponsor.

Our primary strategy for growing our business and increasing distributions to our unitholders is to make acquisitions that increase our distributable cash flow. The primary component of our growth strategy is based upon our expectation of future divestitures by our sponsor to us of portions of its currently retained 75% undivided interest in the Pennsylvania Mining Complex. We have a right of first offer pursuant to our omnibus agreement to purchase part or all of the undivided interest in the Pennsylvania Mining Complex retained by our sponsor for so long as CONSOL Energy controls our general partner. However, our sponsor is under no obligation to sell us additional undivided interests in the Pennsylvania Mining Complex and we are under no obligation to purchase additional undivided interests in the Pennsylvania Mining Complex from our sponsor. We may never purchase additional undivided interests in the Pennsylvania Mining Complex for several reasons, including the following:

- our sponsor may choose not to sell any portion of its undivided interests in the Pennsylvania Mining Complex;
- we may not make offers to buy any additional interests in the Pennsylvania Mining Complex;
- we and our sponsor may be unable to agree to terms acceptable to both parties;
- we may be unable to obtain financing to purchase additional undivided interests in the Pennsylvania Mining Complex on acceptable terms or at all; or
- we may be prohibited by the terms of our debt agreements (including our revolving credit facility) or other contracts from purchasing additional undivided interests in the Pennsylvania Mining Complex, and our sponsor may be prohibited by the terms of its debt agreements or other contracts from selling all or any portion of it. If we or our sponsor must seek waivers of such provisions or refinance debt governed by such provisions in order to consummate a sale of our sponsor's undivided interests in the Pennsylvania Mining Complex, we or our sponsor may be unable to do so in a timely manner or at all.

We can provide no assurance that we will be able to successfully consummate any future acquisition of all or any portion of CONSOL Energy's retained 75% undivided interest in the Pennsylvania Mining Complex. In addition, our right of first offer will terminate upon the date that CONSOL Energy no longer controls our general partner. Our general partner may not transfer all or any part of its general partner interest to another person prior to June 30, 2025, without the approval of the holders of at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates (subject to certain exceptions included in the Partnership Agreement). For additional information regarding our right of first offer and its terms and conditions, please read: Item 13 - Omnibus Agreement - Right of first offer.

Furthermore, if our sponsor reduces its ownership interest in us, it may be less willing to sell to us additional undivided interests in the Pennsylvania Mining Complex. Except for our right of first offer, there are no restrictions on our sponsor’s ability to transfer the assets covered by our right of first offer to a third party. If we do not acquire all or a significant portion of CONSOL Energy's retained 75% undivided interest in the Pennsylvania Mining Complex, our ability to grow our business and increase our cash distributions to our unitholders may be significantly limited.

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

Coal is economically recoverable when the price at which coal can be sold exceeds the costs and expenses of mining and selling the coal. Forecasts of our future performance are based on, among other things, estimates of our recoverable coal reserves. We base our reserve information on geologic data, coal ownership information and current and proposed mine plans. These estimates are periodically updated to reflect past coal production, new drilling information and other geologic or mining data. There are numerous uncertainties inherent in estimating quantities and qualities of coal and costs to mine recoverable reserves, including many factors beyond our control. As a result, estimates of economically recoverable coal reserves are by their nature uncertain. Some of the factors and assumptions which impact economically recoverable coal reserve estimates include:

- geological and mining conditions;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations and taxes by governmental agencies;
- our ability to obtain, maintain and renew all required permits;
- future improvements in mining technology;
- assumptions related to future prices; and
- future operating costs, including the cost of materials, and capital expenditures.

Each of the factors that impacts reserve estimation may vary considerably from the assumptions used in estimating the reserves. For these reasons, estimates of coal reserves may vary substantially. Actual production, revenues and expenditures with respect to our coal reserves will likely vary from estimates, and these variances may be material. As a result, our estimates may not accurately reflect our actual coal reserves.

Our inability to acquire additional coal reserves that are economically recoverable may have a material adverse effect on our future profitability.

Our profitability depends substantially on our ability to mine, in a cost-effective manner, coal reserves that possess the quality characteristics our customers desire. Because our reserves decline as we mine our coal, our future profitability depends upon our ability to acquire additional coal reserves that are economically recoverable to replace the reserves we produce. If we fail to acquire or develop sufficient additional reserves over the long term to replace the reserves depleted by our production, our existing reserves will eventually be depleted.

Deterioration in the global economic conditions in any of the industries in which our customers operate, a worldwide financial downturn, or negative credit market conditions could have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to make cash distributions.

Economic conditions in a number of industries in which our customers operate, such as electric power generation and steelmaking, substantially deteriorated in recent years and reduced the demand for coal. The general economic challenges for some of our customers continued in 2016 and the outlook is uncertain. In addition, liquidity is essential to our Partnership and developing our assets. Renewed or continued weakness in the economic conditions of any of the industries served by our customers could have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to make cash distributions. For example:

- demand for electricity in the United States is impacted by levels of industrial activity, which if weakened would negatively impact our revenues, margins and profitability;
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demand for metallurgical coal depends on steel demand in the United States and globally, which if weakened would negatively impact the revenues, margins and profitability of our metallurgical coal business including our ability to sell our thermal coal as higher-priced high volatile metallurgical coal;

- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables; and
- our ability to access the capital markets may be restricted at a time when we intend to raise capital for our business, including for exploration and/or development of coal reserves, or for strategic acquisitions of assets, including from our sponsor.

Decreases in demand for electricity and changes in coal consumption patterns of U.S. electric power generators could adversely affect our business.

Our business is closely linked to domestic demand for electricity, and any changes in coal consumption by U.S. electric power generators would likely impact our business over the long term. According to the EIA, in 2016, the domestic electric power sector accounted for approximately 92% of total U.S. coal consumption. In 2016, the Pennsylvania Mining Complex sold approximately 76% of its coal to U.S. electric power generators, and we have multi-year contracts in place with these electric power generators for a significant portion of our future production. The amount of coal consumed by the electric power generation industry is affected by, among other things:

- general economic conditions, particularly those affecting industrial electric power demand, such as a downturn in the U.S. economy and financial markets;
- overall demand for electricity;
- indirect competition from alternative fuel sources for power generation, such as natural gas, fuel oil, nuclear, hydroelectric, wind and solar power, and the location, availability, quality and price of those alternative fuel sources;
- environmental and other governmental regulations, including those impacting coal-fired power plants; and
- energy conservation efforts and related governmental policies.

For example, the relatively recent low price of natural gas has resulted, in some instances, in domestic electric power generators increasing natural gas consumption while decreasing coal consumption. Federal and state mandates for increased use of electricity derived from renewable energy sources could affect demand for our coal. Such mandates, combined with other incentives to use renewable energy sources, such as tax credits, could make alternative fuel sources more competitive with coal. A decrease in coal consumption by the electric power generation industry could adversely affect the price of coal, which could have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to make cash distributions.

According to the EIA, although electricity demand fell in only three years between 1950 and 2007, it declined in five of the eight years between 2008 and 2015. The largest drop in electricity demand occurred in 2009, primarily as the result of the steep economic downturn from late 2007 through 2009, which led to a large drop in electricity sales in the industrial sector. Other factors, such as efficiency improvements associated with new appliance standards in the buildings sectors and overall improvement in the efficiency of technologies powered by electricity, have slowed electricity demand growth and may contribute to slower growth in the future, even as the U.S. economy continues its recovery. Further decreases in the demand for electricity, such as decreases that could be caused by a worsening of current economic conditions, a prolonged economic recession or other similar events, could have a material adverse effect on the demand for coal and on our business over the long term.

Changes in the coal industry that affect our customers, such as those caused by decreased electricity demand and increased competition, could also adversely affect our business. Indirect competition from natural gas-fired plants that are relatively less expensive to construct and less difficult to permit has the most potential to displace a significant amount of coal-fired electric power generation in the near term, particularly from older, less efficient coal-fired powered generators. For example, according to the EIA, installed U.S. natural gas-fired net summer generating capacity increased by about 7 gigawatt from 2014-2015, while installed coal-fired net summer generating capacity decreased by about 19 gigawatt over the same period. In addition, uncertainty caused by federal and state regulations could cause coal customers to be uncertain of their coal requirements in future years, which could adversely affect our ability to sell coal to our customers under multi-year sales contracts.

Prices for coal are volatile and can fluctuate widely based upon a number of factors beyond our control, including oversupply relative to the demand available for our coal, weather and the price and availability of alternative fuels. A substantial or extended decline in the prices we receive for our coal could adversely affect our business, results of operations, financial condition, cash flows and ability to make cash distributions to our unitholders.

Our financial results are significantly affected by the prices we receive for our coal and depend, in part, on the margins that we receive on sales of our coal. Our margins reflect the price we receive for our coal over our cost of producing and transporting our coal. Prices and quantities under our multi-year sales contracts are generally based on expectations of future coal prices at the time the contract is entered into, renewed, extended or re-opened. The expectation of future prices for coal depends upon many factors beyond our control, including the following:

- the market price for coal;
- overall domestic and global economic conditions, including the supply of and demand for domestic and foreign coal;

- changes in the consumption pattern of electricity generators, industrial consumers, electricity generators and residential end-users of electricity;
- weather conditions in our markets which affect the demand for thermal coal;
- competition from other coal suppliers;
- the price and availability of alternative fuels and sources for electricity generation, especially natural gas and renewable energy sources;
- technological advances affecting energy consumption;
- the costs, availability and capacity of transportation infrastructure; and
- the impact of domestic and foreign governmental laws and regulations, including environmental and climate change regulations and regulations affecting the coal mining industry and coal-fired power plants, and delays in the receipt of, failure to receive, failure to maintain or revocation of necessary governmental permits.

The coal industry also faces concerns with respect to oversupply from time to time. For example, the unusually warm 2015-16 winter left utilities with large coal stockpiles and depressed the demand for thermal coal. Also, China, a key participant in the seaborne market, has experienced highly volatile swings in seaborne coal demand which can adversely affect the supply/demand balance. Our average sales price per ton sold in 2016 declined 23% from 2015 due to imbalanced supply and demand. A substantial or extended decline in the prices we receive for our coal could adversely affect our business, results of operations, financial condition, cash flows and ability to make cash distributions to our unitholders.

Competition within the coal industry may adversely affect our ability to sell coal. Increased competition or a loss of our competitive position could adversely affect our sales of, or our prices for, our coal, which could impair our profitability. In addition, foreign currency fluctuations could adversely affect the competitiveness of our coal abroad.

We compete with other producers primarily on the basis of price, coal quality, transportation costs and reliability of delivery. We compete with coal producers in various regions of the United States and with some foreign coal producers for domestic sales primarily to electric power generators. We also compete with both domestic and foreign coal producers for sales in international markets. Demand for our coal by our principal customers is affected by the delivered price of competing coals, other fuel supplies and alternative generating sources, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric, wind and solar power.

We sell coal to foreign electricity generators and to the more specialized metallurgical coal market, both of which are significantly affected by international demand and competition. Competition from other producers may or may not adversely affect us in the future. The coal industry has experienced consolidation in recent years, including consolidation among some of our major competitors. As a result, a substantial portion of coal production is from companies that have significantly greater resources than we do. Current or further consolidation in the coal industry or current or future bankruptcy proceedings of coal competitors may or may not adversely affect us. In addition, increases in coal prices could encourage existing producers to expand capacity or could encourage new producers to enter the market. If overcapacity results, the prices of and demand for our coal could significantly decline, which could have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to make cash distributions.

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

Our business involves many hazards and operating risks, some of which may not be fully covered by insurance. The occurrence of a significant accident or other event that is not fully insured could curtail our operations and have a material adverse effect on our results of operations, financial condition, cash flows and ability to make cash distributions to our unitholders.

Our mining operations, including our transportation infrastructure, are subject to many hazards and operating risks. In particular, underground mining and related processing activities present inherent risks of injury to persons and damage to property and equipment. Our mines are subject to a number of operating risks that could disrupt operations, decrease production and increase the cost of mining for varying lengths of time, thereby adversely affecting our operating results. In addition, if coal production declines, we may not be able to produce sufficient amounts of coal to deliver under our multi-year sales contracts. Our inability to satisfy contractual obligations could result in our customers initiating claims against us. The operating risks that may have a significant impact on our coal operations include:

- variations in thickness of the layer, or seam, of coal;
- adverse geologic conditions, including amounts of rock and other natural materials intruding into the coal seam, that could affect the stability of the roof and the side walls of the mine;
- environmental hazards;
- mining and processing equipment failures and unexpected maintenance problems;
- fires or explosions, including as a result of methane, coal, coal dust or other explosive materials, and/or other accidents;
- inclement or hazardous weather conditions and natural disasters or other force majeure events;
- seismic activities, ground failures, rock bursts or structural cave-ins or slides;
- delays in moving our longwall equipment;
- railroad derailments;
- security breaches or terroristic acts; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- personal injury or loss of life;
- damage to and destruction of property, natural resources and equipment, including our coal properties and our coal production or transportation facilities;
- pollution and other environmental damage to our properties or the properties of others;
- potential legal liability and monetary losses;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

In addition, the total cost of coal sold and overall coal production may be adversely affected by various factors. For example, unit costs were negatively impacted in 2016 due to adverse geological conditions at the Enlow Fork mine, primarily related to sandstone intrusions, which reduced its coal production. Although we, through CONSOL Energy, maintain insurance for a number of risks and hazards, we may not be insured or fully insured against the losses or liabilities that could arise from a significant accident in our coal operations. We or CONSOL Energy may elect not to obtain insurance for any or all of these risks if we or CONSOL Energy believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. Moreover, a significant mine accident could potentially cause a mine shutdown. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to make cash distributions.

In addition, if any of the foregoing changes, conditions or events occurs and is not excusable as a force majeure event, any resulting failure on our part to deliver coal to the purchaser under our contracts could result in economic penalties, suspension or cancellation of shipments or ultimately termination of the agreement, any of which could have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to make cash distributions.

All of our mines are part of a single mining complex and are exclusively located in the Northern Appalachian Basin, making us vulnerable to risks associated with operating in a single geographic area.

All of our operations are conducted at a single mining complex located in the Northern Appalachian Basin in southwestern Pennsylvania. The geographic concentration of our operations at the Pennsylvania Mining Complex may disproportionately expose us to disruptions in our operations if the region experiences adverse conditions or events, including severe weather, transportation capacity constraints, constraints on the availability of required equipment, facilities, personnel or services, significant governmental regulation or natural disasters. If any of these factors were to impact the Northern Appalachian Basin more than other coal producing regions, our business, financial condition, results of operations and ability to make cash distributions will be adversely affected relative to other mining companies that have a more geographically diversified asset portfolio.

The availability and reliability of transportation facilities and fluctuations in transportation costs could affect the demand for our coal or impair our ability to supply coal to our customers.

Transportation logistics play an important role in allowing us to supply coal to our customers. Any significant delays, interruptions or other limitations on the ability to transport our coal could negatively affect our operations. Currently, all of our coal is transported from the Pennsylvania Mining Complex by rail. Delays and interruptions of rail services because of accidents, infrastructure damage, lack of rail or port capacity, weather related problems, governmental regulation, terrorism, strikes, lock-outs, third-party actions or other events could temporarily impair our ability to supply coal to customers and adversely affect our profitability. In addition, transportation costs represent a significant portion of the delivered cost of coal and, as a result, the cost of delivery is a critical factor in a customer's purchasing decision. Increases in transportation costs, including increases resulting from emission control requirements and fluctuations in the price of locomotive diesel fuel and
demurrage, could make our coal less competitive, which could have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to make cash distributions.

Any significant downtime of our major pieces of mining equipment, including our preparation plant, could impair our ability to supply coal to our customers and materially and adversely affect our results of operations.

We depend on several major pieces of mining equipment to produce and transport our coal, including, but not limited to, longwall mining systems, continuous mining units, our preparation plant and related facilities, conveyors and transloading facilities. If any of these pieces of equipment or facilities suffered major damage or were destroyed by fire, abnormal wear, flooding, incorrect operation or otherwise, we may be unable to replace or repair them in a timely manner or at a reasonable cost, which would impact our ability to produce and transport coal and materially and adversely affect our business, results of operations, financial condition, cash flows and ability to make cash distributions to our unitholders.

All of the coal from our mines is processed at a single preparation plant and loaded on to rail cars using a single train loadout facility. If either of our preparation plant or train loadout facility suffers extended downtime, including from major damage, or is destroyed, our ability to process and deliver coal to our customers would be materially impacted, which would materially adversely affect our business, results of operations, financial condition, cash flows and ability to make cash distributions to our unitholders.

If our customers do not extend existing contracts or do not enter into new multi-year sales contracts on favorable terms, our profitability could be adversely affected.

During the year ended December 31, 2016, approximately 65% of the coal we produced was sold under multi-year sales contracts. If a substantial portion of our contracts are modified or terminated (or if force majeure is exercised) and we are unable to replace the contracts (or if new contracts are priced at lower levels), our profitability would be adversely affected. In addition, if customers refuse to accept shipments of our coal for which they have existing contractual obligation, our revenues will decrease and we may have to reduce production at our mines until our customer's contractual obligations are honored.

The profitability of our multi-year sales contracts depends on a variety of factors, which vary from contract to contract and fluctuate during the contract term, including our production costs and other factors. Price changes, if any, provided in multi-year sales contracts may not reflect our cost increases and, therefore, increases in our costs may reduce our profit margins. In addition, during periods of declining market prices, provisions in our multi-year sales contracts for adjustment or renegotiation of prices and other provisions may increase our exposure to short-term coal price and electric power price volatility. As a result, we may not be able to obtain multi-year agreements at favorable prices compared to either market conditions, as they may change from time to time, or our cost structure, which may reduce our profitability.

The loss of, or significant reduction in, purchases by our largest customers could adversely affect our business, financial condition, results of operations, cash flows and ability to make cash distributions.

We derive a significant portion of our revenues from two customers: Duke Energy Corporation ("Duke Energy") and GenOn Energy, Inc. ("GenOn Energy"), from each of whom we derived at least 10% of our total coal sales revenues for the year ended December 31, 2016. There are inherent risks whenever a significant percentage of total revenues are concentrated with a limited number of customers. Revenues from our largest customers may fluctuate from time to time based on numerous factors, including market conditions, which may be outside of our control. As of December 31, 2016, we had approximately nine sales agreements with these customers that expire at various times between 2017 and 2018. If any of our largest customers experience declining revenues due to market, economic or competitive conditions, we could be pressured to reduce the prices that we charge for our coal, which could have an adverse effect on our margins, profitability, cash flows and financial position. In addition, if any of our largest customers were to significantly reduce their purchases of coal from us, including by failing to buy and pay for coal they committed to purchase in sales contracts, our business, financial condition, results of operations, cash flows and ability to make cash distributions could be adversely affected.

Certain provisions in our multi-year sales 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 reopener” and other similar provisions in our multi-year sales contracts may reduce the protection from short-term coal price volatility traditionally provided by such contracts. Price reopener provisions are present in several of our multi-year sales contracts. These price reopener provisions may automatically set a new price based on prevailing market price or, in some instances, require the parties to agree on a new price, sometimes within a specified range of prices. In a limited number of agreements, failure of the parties to agree on a price under a price reopener provision can lead to termination of the contract. Any adjustment or renegotiations leading to a significantly lower contract price could adversely affect our profitability.

Most of our sales agreements contain provisions requiring us to deliver coal within certain ranges for specific coal quality characteristics such as heat content, sulfur, ash, moisture, volatile matter, grindability, ash fusion temperature, and size consist. Failure to meet these conditions could result in penalties or rejection of the coal at the election of the customer. Our sales contracts also typically contain force majeure provisions allowing for the suspension of performance by either party for the duration of specified events. Force majeure events include, but are not limited to, floods, earthquakes, storms, fire, faults in the coal seam or other geologic conditions, other natural catastrophes, wars, terrorist acts, civil disturbances or disobedience, strikes, railroad transportation delays caused by a force majeure event and actions or restraints by court order and governmental authority or arbitration award. Depending on the language of the contract, some contracts may terminate upon continuance of an event of force majeure that extends for a period greater than three to twelve months.

Our ability to collect payments from our customers could be impaired if their creditworthiness declines or if they fail to honor their contracts with us.

Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. Many utilities have sold their power plants to non-regulated affiliates or third parties that may be less creditworthy, thereby increasing the risk we bear with respect to payment default. These new power plant owners may have credit ratings that are below investment grade. In addition, some of our customers have been adversely affected by the current economic downturn, which may impact their ability to fulfill their contractual obligations. Competition with other coal suppliers could force us to extend credit to customers and on terms that could increase the risk we bear with respect to payment default. We also have a contract to supply coal to an energy trading and brokering customer under which that customer sells coal to end users. If the creditworthiness of our energy trading and brokering customer declines, we may not be able to collect payment for all coal sold and delivered to this customer. In addition, if customers refuse to accept shipments of our coal for which they have an existing contractual obligation, our revenues will decrease and we may have to reduce production at our mines until our customers’ contractual obligations are honored. Our inability to collect payment from counterparties to our sales contracts may materially adversely affect our business, financial condition, results of operations, cash flows and ability to make cash distributions.

To maintain and grow our business, we will be required to make substantial capital expenditures. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to make cash distributions may be diminished or our financial leverage could increase.

In order to maintain and grow our business, we will need to make substantial capital expenditures to fund our share of capital expenditures associated with our mines. Maintaining and expanding mines and infrastructure is capital intensive. Specifically, the exploration, permitting and development of coal reserves, mining costs, the maintenance of machinery and equipment and compliance with applicable laws and regulations require substantial capital expenditures. While a significant amount of the capital expenditures required to build out our mining infrastructure has been spent, we must continue to invest capital to maintain or to increase our production. Decisions to increase our production levels could also affect our capital needs. Our production levels may decrease or may not be able or generate sufficient cash flow, or that we will have access to sufficient financing to continue our production, exploration, permitting and development activities at or above our present levels, and we may be required to defer all or a portion of our capital expenditures. If we do not make sufficient or effective capital expenditures, we will be unable to maintain and grow our business and, as a result, we may be unable to maintain or raise the level of our future cash distributions over the long term. To fund our capital expenditures, we will be required to use cash from our operations, incur debt or sell additional units or other equity securities. Using cash from our operations will reduce cash available for distribution to our unitholders. Our ability to obtain bank financing or our ability to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering and the covenants in our existing debt agreements, as well as by general economic conditions, contingencies and uncertainties that are beyond our control. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant unitholder dilution and would increase the aggregate amount of cash required to maintain the then current distribution rate, which could materially decrease our ability to pay distributions at the then prevailing distribution rate. While we have historically received funding from our sponsor, none of our sponsor, our general partner or any of their respective affiliates is committed to providing any direct or indirect financial support to fund our growth.

We may not be able to obtain equipment, parts and raw materials in a timely manner, in sufficient quantities or at reasonable costs to support our coal mining operations.

Coal mining consumes large quantities of commodities including steel, copper, rubber products and liquid fuels and requires the use of capital equipment. Some commodities, such as steel, are needed to comply with roof control plans required by regulation. The prices we pay for commodities and capital equipment are strongly impacted by the global market. A rapid or significant increase in the costs of commodities or capital equipment we use in our operations could impact our mining operations costs because we may have a limited ability to negotiate lower prices and, in some cases, may not have a ready substitute. We use equipment in our coal mining and transportation operations such as continuous mining units, conveyors, shuttle cars, rail cars, locomotives, roof bolters, shearers and shields. We procure this equipment from a concentrated group of suppliers, and obtaining this equipment often involves long lead times. Occasionally, demand for such equipment by mining companies can be high and some types of equipment may be in short supply. Delays in receiving or shortages of this equipment, as well as the raw materials used in the manufacturing of supplies and mining equipment, which, in some cases, do not have ready substitutes, or the cancellation of our supply contracts under which we obtain equipment and other consumables, could limit our ability to obtain these supplies or equipment. In addition, if any of our suppliers experiences an adverse event, or decides to no longer do business with us, we may be unable to obtain sufficient equipment and raw materials in a timely manner or at a reasonable price to allow us to meet our production goals and our revenues may be adversely impacted. We use considerable quantities of steel in the mining process. If the price of steel or other materials increases substantially or if the value of the U.S. dollar declines relative to foreign currencies with respect to certain imported supplies or other products, our operating expenses could increase. Any of the foregoing events could materially and adversely impact our business, financial condition, results of operations, cash flows and ability to make cash distributions.

We may be unsuccessful in integrating the operations of any future acquisitions, including acquisitions involving new lines of business, with our existing operations, and in realizing all or any part of the anticipated benefits of any such acquisitions.

From time to time, we may evaluate and acquire assets and businesses that we believe complement our existing assets and business. The assets and businesses we acquire may be dissimilar from our existing lines of business. Acquisitions may require substantial capital or the incurrence of substantial indebtedness. Our capitalization and results of operations may change significantly as a result of future acquisitions. Acquisitions and business expansions, including the acquisition of assets on which we have a right of first offer, involve numerous risks, including the following:

- difficulties in the integration of the assets and operations of the acquired businesses;
- inefficiencies and difficulties that arise because of unfamiliarity with new assets and the businesses associated with them and new geographic areas;
- the possibility that we have insufficient expertise to engage in such activities profitably or without incurring inappropriate amounts of risk; and
- the diversion of management's attention from other operations.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. Entry into certain lines of business may subject us to new laws and regulations with which we are not familiar, and may lead to increased litigation and regulatory risk. Also, following an acquisition, we may discover previously unknown liabilities associated with the acquired business or assets for which we have no recourse under applicable indemnification provisions. If a new business generates insufficient revenue or if we are unable to efficiently manage our expanded operations, our results of operations may be adversely affected.

Restrictions in our revolving credit facility and our level of indebtedness could adversely affect our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

Our revolving credit facility limits our ability to, among other things:

• incur or guarantee additional debt;

- redeem or repurchase units or make distributions under certain circumstances;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

Our revolving credit facility contains covenants requiring us to maintain certain financial ratios. For example, we are obligated to maintain at the end of each fiscal quarter (i) an interest coverage ratio of at least 3.0 to 1.0 and (ii) a maximum leverage ratio of no greater than 3.5 to 1.0 (or 4.00 to 1.00 for two fiscal quarters after consummation of a material acquisition). Our ability to meet those financial ratios can be affected by events beyond our control, and we cannot assure that we will meet any such ratios.

The restrictions in our revolving credit facility and our level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in planning for and responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend upon, among other things, our 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 our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, investments or capital expenditures, selling assets or issuing equity. We may not be able to effect any of these actions on satisfactory terms or at all.

In addition, a failure to comply with the provisions of our revolving credit facility could result in a default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment. Please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Capital Resources and Liquidity.”

Increases in interest rates could adversely affect our business.

We will have exposure to increases in interest rates. Based on our current debt level of $201,000 thousand as of December 31, 2016, comprised of funds drawn on our revolving credit facility, an increase of one percentage point in the interest rate will result in an increase in annual interest expense of $2,010 thousand. As a result, our results of operations, cash flows and financial condition and our ability to make cash distributions to our unitholders, could be materially adversely affected by significant increases in interest rates.

The amount of distributable cash flow that we have available for distribution to our unitholders depends primarily on our cash flow and not solely on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of distributable cash flow that we have available for distribution depends primarily upon our cash flow and not solely on our profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record a net loss for financial accounting purposes; and conversely, we might determine not to make cash distributions during periods when we record net income for financial accounting purposes.

Our mines are located in areas containing oil and natural gas shale plays, which may require us to coordinate our operations with oil and natural gas drillers.

All of our coal reserves are in areas containing shale oil and natural gas plays, including the Marcellus Shale, which are currently the subject of substantial exploration for oil and natural gas, particularly by horizontal drilling. If we have received a permit for our mining activities, then while we will have to coordinate our mining with such oil and natural gas drillers, our mining activities will have priority over any oil and natural gas drillers with respect to the land covered by our permit. For reserves outside of our permits, we engage in discussions with drilling companies on potential areas on which they can drill that may have a minimal effect on our mine plan. If a well is in the path of our mining for coal on land that has not yet been permitted for our mining activities, we may not be able to mine through the well unless we purchase it. Although in the past we have purchased vertical wells, the cost of purchasing a producing horizontal well could be substantially greater than that of a vertical well. Horizontal wells with multiple laterals extending from the well pad may access larger oil and natural gas reserves than a vertical well, which would typically result in a higher cost to acquire. The cost associated with purchasing oil and natural gas wells that are in the path of our coal mining activities may make mining through those wells uneconomical, thereby effectively causing a loss of significant portions of our coal reserves, which could materially and adversely affect our business, financial condition, results of operations, cash flows and ability to make cash distributions.

We do not have any officers or employees and rely on officers of our general partner and employees of our sponsor.

We are managed and operated by the board of directors and executive officers of our general partner. Our general partner has no field-level employees that conduct mining operations and relies on the employees of our sponsor to conduct mining activities. Our sponsor conducts businesses and activities of its own in which we have no economic interest. As a result, there could be material competition for the time and effort of the officers and employees who provide services to both our general partner and to our sponsor. If our general partner and the officers and employees of our sponsor do not devote sufficient attention to the management and operation of our business and activities, our business, financial condition, results of operations, cash flows and ability to make cash distributions could be materially adversely affected.

We operate our mines with a work force that is employed exclusively by our sponsor. While none of our sponsor’s employees who conduct mining operations at the Pennsylvania Mining Complex are currently members of unions, our business could be adversely affected by union activities.

None of our sponsor’s employees who conduct mining operations at the Pennsylvania Mining Complex are represented by a labor union or covered under a collective bargaining agreement, although many employers in our industry have employees who belong to a union. It is possible that our sponsor’s employees who conduct mining operations at the Pennsylvania Mining Complex may join or seek recognition to form a labor union, or our sponsor may be required to become a labor agreement signatory. If some or all of the employees who conduct mining operations at the Pennsylvania Mining Complex were to become unionized, it could adversely affect productivity, increase labor costs and increase the risk of work stoppages at our mines. If a work stoppage were to occur, it could interfere with operations at the Pennsylvania Mining Complex and have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to make cash distributions. In addition, the mere fact that a portion of our sponsor’s labor force could be unionized may harm our reputation in the eyes of some investors and thereby negatively affect our common unit price.

We are a holding company with no independent operations or assets. Distributions to our unitholders are dependent on cash flow generated by our subsidiaries.

We have a holding company structure, meaning the sole source of our earnings and cash flow consists exclusively of the earnings of and cash distributions from our direct and indirect subsidiaries. All of our operations are conducted, and all of our assets are owned, by our direct and indirect subsidiaries. Consequently, our cash flow and our ability to meet our obligations or to pay cash distributions to our unitholders will depend upon the cash flows of our subsidiaries and the payment of funds by our subsidiaries to us in the form of distributions or otherwise. The ability of our subsidiaries to make any payments to us will depend on their earnings, the terms of their indebtedness and legal restrictions applicable to them. In particular, the terms of our revolving credit facility place limitations on the ability of our subsidiaries to pay distributions to us, and thus on our ability to pay distributions to our unitholders. In the event that we do not receive distributions from our subsidiaries, we may be unable to make cash distributions to our unitholders.

Terrorist attacks or cyber-incidents could result in information theft, data corruption, operational disruption and/or financial loss.

We have become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications and services, to operate our businesses, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of coal reserves, as well as other activities related to our businesses. Strategic targets, such as energy-related assets, may be at greater risk of future terrorist or cyber-attacks than other targets in the United States. Deliberate attacks on, or security breaches in, our systems or infrastructure, or the systems or infrastructure of third parties, or cloud-based applications could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery, difficulty in completing and settling transactions, challenges in maintaining our books and records, environmental damage, communication interruptions, other operational disruptions and third-party liability. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to make cash distributions. Further, as cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents.

Environmental regulations introduce uncertainty that could adversely impact the market for coal with potential short and long-term liabilities.

The Federal Endangered Species Act (ESA) and similar state laws protect species threatened with extinction. Protection of endangered and threatened species may cause us to modify mining plans, or develop and implement species-specific protection and enhancement plans to avoid or minimize impacts to endangered species or their habitats. A number of species indigenous to the areas where we operate are protected under the ESA. Based on species that have been identified and the current application of endangered species laws and regulations, we do not believe that there are any species protected under the ESA or state laws that would materially and adversely affect our ability to mine coal from our properties. However, In April 2015, the U.S. Fish and Wildlife Service announced a Section 4(d) threatened listing final rule for the Northern Long-Eared Bat throughout our operations area. This listing will establish habitat protection for the species but will not prevent the cause of the decline in the population of the Long-Eared bat, which is due to a disease commonly referred to as White Nose Syndrome. This listing could lead to significant timing and critical path hurdles, ultimately limiting the ability to clear timber for construction activities.

The Partnership's coal business must obtain permits with associated mitigation from the Army Corps of Engineers (ACOE) for impacts to streams and wetlands that are unavoidable. In 2013, the EPA issued a draft report entitled "Connectivity of Streams and Wetlands to Downstream Waters", which affects a proposed rulemaking known as the WOTUS rule that would expand the scope of the Clean Water Act (CWA) to include previously non-jurisdictional streams, wetlands, and waters, making these areas jurisdictional inter-coastal waters of the U.S. On June 29, 2015 the EPA published the final WOTUS Rule which becomes effective on August 28, 2015. This rule making will likely cause states that have jurisdiction over their own waters to make regulatory changes to their already robust regulatory programs, add unwarranted delays to the permitting process and extend review times even further for regulatory agencies already under resourced, and lead to additional mitigation cost and severely limit the Partnership’s ability to avoid regulated jurisdictional waters.

Risks Related to Environmental, Health, Safety and Other Regulations

Regulation of greenhouse gas emissions as well as uncertainty concerning such regulation could adversely impact the market for coal, increase our operating costs, and reduce the value of our coal assets.

Climate change continues to attract considerable public and scientific attention with widespread concern about the impacts of human activity on such changes, especially the emission of greenhouse gases (“GHGs”). The mining and combustion of fossil fuels, like the coal that we produce, results in the emission of GHGs, including from end-users like coal-fired power plants. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. For example, while federal climate change legislation is unlikely in the next several years, several states have already adopted measures requiring GHG emissions to be reduced within state boundaries, including cap-and-trade programs and the imposition of renewable energy portfolio standards.

Internationally, the Kyoto Protocol, which set binding emission targets for developed countries (but was never ratified by the United States) was nominally extended past its expiration date of December 2012 with a requirement for a new legal construct to be put into place by 2015. In December 2015, the United Nations Climate Change Conference was held and an agreement reached between the participating countries, including the United States, to limit global warming to less than 2 degrees Celsius compared to pre-industrial levels. This agreement, known as the Paris Agreement, calls for zero net anthropogenic greenhouse gas emissions to be reached in the second half of the 21st century. To become effective, at least 55 countries, representing at least 55 percent of global greenhouse gas emissions, must sign the agreement in New York between April 22, 2016, and April 21, 2017, and adopt it within their own legal systems through ratification, acceptance, approval or accession. In addition, in November 2014, President Obama announced that the United States would seek to cut net greenhouse gas emissions 26-28 percent below 2005 levels by 2025 in return for China's commitment to seek to peak emissions around 2030, with concurrent increases in renewable energy.

Following a U.S. Supreme Court decision effectively mandating that the EPA regulate GHGs from cars and trucks under the Clean Air Act ("CAA"), the EPA began to regulate GHG emissions from power plants. On September 30, 2013, the EPA re-proposed New Source Performance Standards ("NSPS") for carbon dioxide ("CO2") for new fossil fuel fired power plants, and on June 2, 2014, re-proposed NSPS for existing and modified power plants, which rescinded the rules that were originally proposed in 2012. In addition, on June 2, 2014, the EPA announced the Clean Power Plan, which proposed to limit CO_2 emissions from existing power plants through state-specific rate-based goals. On August 3, 2015, EPA finalized the Clean Power Plan which became effective December 22, 2015. States, industry and labor organizations filed at least 17 petitions for review on the rule in the D.C. Circuit Court of Appeals.

Adoption of comprehensive legislation or regulation focusing on GHG emission reductions for the United States or other countries where we sell coal, or the inability of utilities to obtain financing in connection with coal-fired plants, may make it more costly to operate coal-fired electric power generation plants and make coal less attractive for electric utility power plants in the future. Apart from actual regulation, uncertainty over the extent of regulation of GHG emissions may inhibit utilities from investing in the building of new coal-fired plants to replace older plants or investing in the upgrading of existing coal-fired plants. Any reduction in the amount of coal consumed by electric power generators as a result of actual or potential regulation of greenhouse gas emissions could decrease demand for our coal, thereby reducing our revenues and materially and adversely affecting our business and results of operations. We or our customers may also have to invest in carbon dioxide
capture and storage technologies in order to burn coal and comply with future GHG emission standards.

In addition, coalbed methane must be expelled from our underground coal mines for mining safety reasons. Coalbed methane has a greater GHG effect than carbon dioxide. CNX Gas Corporation’s gas operations capture coalbed methane from our underground coal mines, although some coalbed methane is vented into the atmosphere when the coal is mined. In June 2010, Earth Justice petitioned the EPA to make a finding that emissions from coal mines endangered public health and welfare, and to list them as a stationary source subject to further regulation of emissions. On April 30, 2013, the EPA denied the petition. Judicial challenges seeking to force the EPA to list coal mines as a stationary source have likewise been unsuccessful to-date. If in the future the agency were to make an endangerment finding, we may have to further reduce our methane emissions, install additional air pollution controls, pay higher taxes, incur costs to purchase credits that permit us to continue operations as they now exist at our underground coal mines or perhaps curtail coal production.

Apart from governmental regulation, investment banks both domestically and internationally have announced that they have adopted climate change guidelines for lenders. The guidelines require the evaluation of carbon risks in the financing of electric power generation plants which may make it more difficult for utilities to obtain financing for coal-fired plants.

In addition, there have also been efforts in recent years to promote the divestiture by the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, of fossil fuel equities and also pressure applied to lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. The impact of such efforts may adversely affect the demand for and price of securities issued by us, and impact our access to the capital and financial markets.

The characteristics of coal may make it costly for electric power generators and other coal users to comply with various environmental standards regarding the emissions of impurities released when coal is burned, which could cause utilities to replace coal-fired power plants with plants utilizing alternative fuels. In addition, various incentives have been proposed to encourage the generation of electricity from renewable energy sources. A reduction in the use of coal for electric power generation could decrease the volume of our coal sales and adversely affect our results of operations.

Coal contains impurities, including sulfur, mercury, chlorine and other elements or compounds, many of which are released into the air when coal is burned. Complying with regulations to address these emissions can be costly for electric power generators. For example, in order to meet the CAA limits for sulfur dioxide emissions from electric power plants, coal users need to install costly pollution control devices, use sulfur dioxide emission allowances (some of which they may purchase), or switch to other fuels. Recent EPA rulemakings requiring additional reductions in permissible emission levels of impurities by coal-fired plants will likely make it more costly to operate coal-fired electric power plants and may make coal a less attractive fuel alternative for electric power generation in the future. Examples include (i) implementation of Phase I of the Cross-State Air Pollution Rule (“CSAPR”) that began in May 2015, with implementation of Phase 2 planned to begin in 2017; (ii) the issuance by the EPA on December 3, 2015, of the proposed CSAPR Update Rule to require reductions of seasonal nitrogen oxides ("NOX") emissions from power plants in 23 or the original 28 proposed Eastern states to address interstate ozone air quality impacts for downwind states; (iii) the October 1, 2015, promulgation by EPA for a revised National Ambient Air Quality Standard ("NAAQS") for ozone pollution which further lowered the standard and resulted in more air quality non-attainment counties across the U.S.; and (iv) promulgation of the Mercury and Air Toxics Standards, known as the MATS rule, which included reduced emissions limits for particulate matter ("PM"), mercury, sulfur dioxide ("SO2") and NOX. Although the U.S. Supreme Court issued a ruling on June 29, 2015, holding that the EPA should have considered compliance costs when developing the MATS rule, a number of coal-fired power plants, particularly smaller and older plants, already have retired or announced that they will retire rather than retrofit to meet the obligations of the MATS rules. Prior to the U.S. Supreme Court’s ruling, the MATS rules, in combination with other environmental regulations and economic factors, resulted in the retirement of more than 20 GW of domestic coal-fired generating capacity prior to 2015 and has led to the announcement of more than 40 GW of additional domestic coal-fired generating capacity for the period from 2015 through 2019.

On October 14, 2014, the EPA Clean Water Act Section 316(b) rulemaking went into effect which requires new and existing power plants, including coal and natural gas-fired plants to reduce fish mortality caused by their cooling water intake structures through either the installation of technologies or the reduction of intake velocity.

Apart from actual and potential regulation of emissions and solid wastes from coal-fired plants, state and federal mandates for increased use of electricity from renewable energy sources could have an impact on the market for our coal. Several states have enacted legislative mandates requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power. There have been numerous proposals to establish a similar uniform, national standard although none of these proposals have been enacted to date.

Possible advances in technologies and incentives, such as tax credits, to enhance the economics of renewable energy sources could make these sources more competitive with coal. Any reductions in the amount of coal consumed by electric power generators as a result of current or new standards for the emission of impurities or incentives to switch to alternative fuels or renewable energy sources could reduce the demand for our coal, thereby reducing our revenues and adversely affecting our business and results of operations.

Existing and future government laws, regulations and other legal requirements relating to protection of the environment, and others that govern our business may increase our costs of doing business and may restrict our coal operations.

We are subject to laws, regulations and other legal requirements enacted by federal, state and local authorities relating to protection of the environment. These include those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and wastes, the cleanup of contaminated sites, threatened and endangered plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the installation of various safety equipment in our mines, remediation of impacts of surface subsidence from underground mining, and work practices related to employee health and safety. Complying with these requirements, including the terms of our permits, has had, and will continue to have, a significant effect on our costs of operations. In addition, there is the possibility that we could incur substantial costs as a result of violations under environmental laws, or in connection with the investigation and remediation of environmental contamination. Any additional laws, regulations and other legal requirements enacted or adopted by federal, state and local authorities, or new interpretations of existing legal requirements by regulatory bodies relating to the protection of the environment could further affect our costs of operations.

One such proposed regulation was issued by the Office of Surface Mining on July 27, 2015, to amend regulations concerning stream buffer zones, stream channel diversions, excess spoil and coal mine waste. As drafted, this proposed rule would extend the impacts of mining to include surrounding areas of the entire coal reserve previously not included in assessments submitted as part of the permit application. The proposed rule would also prohibit mining in or through a perennial, intermittent or ephemeral stream, even if impacts were temporary, and require a 100 foot buffer zone on either side of a stream. As drafted, this proposed rule has the potential to impact the profitability of our longwall coal mines.

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

Our operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time. Drainage flowing from or caused by mining activities can be acidic with elevated levels of dissolved metals, a condition referred to as “acid mine drainage.” We could become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and clean-up of soil, surface water, groundwater, and other media. Such claims may arise, for example, 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. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or for the entire share.

We maintain coal refuse areas and slurry impoundments at the Pennsylvania Mining Complex. Such areas and impoundments are subject to extensive regulation. Structural failure of a slurry impoundment or coal refuse area could result in extensive damage to the environment and natural resources, such as bodies of water that the coal slurry reaches, as well as liability for related personal injuries and property damages, and injuries to wildlife. Some of our impoundments overlie mined out areas, which can pose a heightened risk of failure and of damages arising out of failure. If one of our impoundments were to fail, we could be subject to claims for the resulting environmental contamination and associated liability, as well as for fines and penalties. Our coal refuse areas and slurry impoundments are designed, constructed, and inspected by our company and by regulatory authorities according to stringent environmental and safety standards.

We must obtain, maintain, and renew governmental permits and approvals which if we cannot obtain in a timely manner could reduce our production, cash flow and results of operations.

Our coal production is dependent on our ability to obtain various federal and state permits and approvals to mine our coal reserves. The permitting rules, and the interpretations of these rules, are complex, change frequently, and are often subject to discretionary interpretations by regulators. The EPA also has the authority to veto permits issued by the U.S. Army Corps of Engineers under the Clean Water Act's Section 404 program that prohibits the discharge of dredged or fill material into regulated waters without a permit. In addition, the public, including non-governmental organizations and individuals, have certain statutory rights to comment upon and otherwise impact the permitting process, including through court intervention. The pace with which the government issues permits needed for new operations and for on-going operations to continue mining has slowed significantly and negatively impacted expected production. These delays or denials of mining permits could reduce our production, cash flow and results of operations. In 2005, the Pennsylvania Department of Environmental Protection ("PADEP") issued a technical guidance document that imposes standards in the material mining permits that we hold, including potentially costly stream mitigation and monitoring requirements and alterations to our longwall mining plans. In addition, we may be required to alter our mine plans, which could result in a reduction in our accessible reserves in the affected mines.

Our mines are subject to stringent federal and state safety regulations that increase our cost of doing business at active operations and may place restrictions on our methods of operation. In addition, government inspectors under certain circumstances have the ability to order our operations to be shutdown based on safety considerations.

The Coal Mine Safety and Health Act and Mine Improvement and New Emergency Response Act impose stringent health and safety standards on mining operations. Regulations that have been adopted under the Act are comprehensive and affect numerous aspects of mining operations, including training of mine personnel, mining procedures, the equipment used in emergency procedures, and other matters. Pennsylvania has a similar program for mine safety and health regulation and enforcement. The various requirements mandated by law or regulation can place restrictions on our methods of operations, and potentially lead to fees and civil penalties for the violation of such requirements, creating a significant effect on operating costs and productivity. In addition, government inspectors under certain circumstances, have the ability to order our operation to be shutdown based on safety considerations. If an incident were to occur at one of our mines, it could be shut down for an extended period of time and our reputation with our customers could be materially damaged.

We have reclamation and mine closing obligations. If the assumptions underlying our accruals are inaccurate, we could be required to expend greater amounts than anticipated.

The Surface Mining Control and Reclamation Act establishes operational, reclamation and closure standards for our mining operations. We accrue for the costs of current mine disturbance and of final mine closure, including the cost of treating mine water discharge where necessary. The amounts recorded are dependent upon a number of variables, including the estimated future closure costs, estimated proven reserves, assumptions involving profit margins, inflation rates, and the assumed credit-adjusted risk-free interest rates. If these accruals are insufficient or our liability in a particular year is greater than currently anticipated, our future operating results could be adversely affected.

We are also required to post bonds for the cost of coal mine reclamation, which is being expanded in Pennsylvania to cover all coal mine bonding, further increasing the amount of surety bonds we must seek in order to permit our mining activities. If our creditworthiness declines, states may seek to require us to post letters of credit or cash collateral to secure those obligations, or we may be unable to obtain surety bonds, in which case we would be required to post letters of credit. Additionally, the sureties that post bonds on our behalf may require us to post security in order to secure the obligations underlying these bonds. Posting letters of credit in place of surety bonds or posting security to support these surety bonds would have an adverse effect on our liquidity.

Risks Inherent in an Investment in Us

Our general partner and its affiliates, including our sponsor, have conflicts of interest with us and limited fiduciary duties to us and our unitholders, and they may favor their own interests to our detriment and that of our unitholders. Additionally, we have no control over the business decisions and operations of our sponsor, and our sponsor is under no obligation to adopt a business strategy that favors us.

Our sponsor, CONSOL Energy, owns 3,956,496 Class A Preferred Units representing limited partnership interests, which convert on a one-for-one basis into common units, 1,050,000 common units and 11,611,067 subordinated units, representing a 60.1% limited partner interest. In addition, our general partner owns a 1.7% general partner interest in us and all of our incentive distribution rights. Our sponsor also continues to own a 75% undivided interest in the Pennsylvania Mining Complex.

Although our general partner has a duty to manage us in a manner that is in the best interests of our Partnership and our unitholders, the directors and officers of our general partner also have a duty to manage our general partner in a manner that is in the best interests of our sponsor. Conflicts of interest may arise between our sponsor and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interests, our general partner may favor its own interests and the interests of its affiliates, including our sponsor, over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our Partnership Agreement nor any other agreement requires our sponsor to pursue a business strategy that favors us or utilizes our assets, which could involve decisions by our sponsor to pursue and grow particular markets or undertake acquisition opportunities for itself. Our sponsor's directors and officers have a fiduciary duty to make these decisions in the best interests of our sponsor;
- our general partner is allowed to take into account the interests of parties other than us, such as our sponsor, in resolving conflicts of interest;
- our sponsor may be constrained by the terms of its debt instruments from taking actions, or refraining from taking actions, that may be in our best interests;
- our Partnership Agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limiting our general partner's liabilities and restricting the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty under Delaware law;
- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- our general partner will determine the amount and timing of, among other things, cash expenditures, borrowings and repayments of indebtedness, the issuance of additional partnership interests, the creation, increase or reduction in cash reserves in any quarter and asset purchases and sales, each of which can affect the amount of cash that is available for distribution to unitholders;
- our general partner will determine the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of available cash from operating surplus that is distributed to our unitholders and to our general partner, the amount of adjusted operating surplus generated in any given period and the ability of the subordinated units to convert into common units;
- our general partner will determine which costs and expenses incurred by it are reimbursable by us;
- our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period;
- our Partnership Agreement permits us to distribute up to $50.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated units or to our general partner in respect of the general partner interest or the incentive distribution rights;
- our Partnership Agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations;
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- our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates at a price not less than the then-current market price if it and its affiliates own more than 80% of our common units;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates, including obligations under our operating agreement and employee services agreement;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our general partner, or any transferee holding incentive distribution rights, may elect to cause us to issue common units and general partner interests to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of the conflicts committee of the board of directors of our general partner, which we refer to as our conflicts committee, or our common unitholders. This election could result in lower distributions to our common unitholders in certain situations.

Neither our Partnership Agreement nor our omnibus agreement prohibit our sponsor or any other affiliates of our general partner from owning assets or engaging in businesses that compete directly or indirectly with us. Under the terms of our Partnership Agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to our general partner or any of its affiliates, including our sponsor. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. Consequently, our sponsor and other affiliates of our general partner may acquire, construct or dispose of additional coal assets in the future without any obligation to offer us the opportunity to purchase any of those assets. As a result, competition from our sponsor and other affiliates of our general partner could materially and adversely impact our results of operations and distributable cash flow. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders.

Our Partnership Agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

Our Partnership Agreement requires that we distribute all of our available cash (which is defined in the Partnership Agreement) to our unitholders. As a result, we expect to rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. Therefore, to the extent we are unable to finance our growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we will distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional partnership interests in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional partnership interests may increase the risk that we will be unable to maintain or increase our per unit distribution level. Under the Partnership Agreement, the holders of the Class A Preferred Units are entitled to vote as a separate class on any matter that adversely affects the rights, privileges or preferences of Class A Preferred Units in any material respect, which would include the issuance of additional partnership interests that would change the seniority rights of the Class A Preferred Units as to the payment of distributions. There are no other limitations in our Partnership Agreement on our ability to issue additional partnership interests, including partnership interests ranking senior to our common units as to distributions or in liquidation or that have special voting rights and other rights, and our unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such additional partnership interests. The incurrence of additional commercial bank borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may reduce the amount of cash that we have available to distribute to our unitholders.

While our Partnership Agreement requires us to distribute all of our available cash, our Partnership Agreement, including the provisions requiring us to make cash distributions, may be amended.

While our Partnership Agreement requires us to distribute all of our available cash, our Partnership Agreement, including the provisions requiring us to make cash distributions, may be amended. During the subordination period, our Partnership Agreement may not be amended without the approval of our public common unitholders, except in a limited number of circumstances when our general partner can amend our Partnership Agreement without any unitholder approval.

However, after the subordination period has ended, our Partnership Agreement may be amended with the consent of our general partner and the approval of a majority of the outstanding common units, including Class A Preferred Units (voting together with the common units) and common units owned by our general partner and its affiliates. Our sponsor owns an aggregate of approximately 9.0% of our outstanding common units, all of our subordinated units and all of our preferred units.

Our Partnership Agreement replaces our general partner's fiduciary duties to holders of our units with contractual standards governing its duties.

Delaware law provides that a Delaware limited partnership may, in its Partnership Agreement, expand, restrict or eliminate the fiduciary duties otherwise owed by the general partner to limited partners and the partnership, provided that the Partnership Agreement may not eliminate the implied contractual covenant of good faith and fair dealing. This implied covenant is a judicial doctrine utilized by Delaware courts in connection with interpreting ambiguities in Partnership Agreements and other contracts, and does not form the basis of any separate or independent fiduciary duty in addition to the express contractual duties set forth in our Partnership Agreement. Under the implied contractual covenant of good faith and fair dealing, a court will enforce the reasonable expectations of the partners where the language in the Partnership Agreement does not provide for a clear course of action.

As permitted by Delaware law, our Partnership Agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our Partnership Agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and affiliates of our general partner;
- whether to exercise its limited call right;
- how to exercise its voting rights with respect to any units it owns;
- whether to exercise its registration rights;
- whether to sell or otherwise dispose of units or other partnership interests that it owns;
- whether to elect to reset target distribution levels;
- whether to consent to any merger, consolidation or conversion of the Partnership or amendment to our Partnership Agreement; and
- whether to refer or not to refer any potential conflict of interest to the conflicts committee for special approval or to seek or not to seek unitholder approval.

By purchasing a unit, a unitholder is treated as having consented to the provisions in our Partnership Agreement, including the provisions discussed above.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that counterparties to such agreements have recourse only against our assets and not against our general partner or its assets or any affiliate of our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our Partnership Agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner’s duties, even if we could have obtained terms that are more favorable without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Our Partnership Agreement restricts the remedies available to holders of our common units, preferred units and subordinated units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our Partnership Agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our Partnership Agreement provides that:

- whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the determination or the decision to take or decline to take such action was in the best interests of our Partnership, and will not be subject to any other or different standard imposed by our Partnership Agreement, Delaware law, or any other law, rule or regulation, or at equity;
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- our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith;
- our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and nonappealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in intentional fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- our general partner will not be in breach of its obligations under our Partnership Agreement or its duties to us or our limited partners if a transaction with an affiliate or the resolution of a conflict of interest is approved in accordance with, or otherwise meets the standards set forth in, our Partnership Agreement.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, our Partnership Agreement provides that any determination by our general partner must be made in good faith, and that our general partner, our conflicts committee and the board of directors of our general partner are entitled to a presumption that they acted in good faith. In any proceeding brought by or on behalf of any limited partner or the Partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Cost and expense reimbursements, which will be determined by our general partner in its sole discretion, and fees due to our general partner and its affiliates for services provided will be substantial and will reduce our distributable cash flow.

Under our Partnership Agreement, we are required to reimburse our general partner and its affiliates for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner and its affiliates in connection with managing and operating our business and affairs (including expenses allocated to our general partner by its affiliates). Except to the extent specified under our omnibus agreement and the other agreements described under “Certain Relationships and Related Party Transactions—Agreements Governing the Transactions,” our general partner determines the amount of these expenses. Under the terms of the omnibus agreement we will be required to reimburse our sponsor for the provision of certain administrative support services to us. Under our employee services
agreement, we will be required to reimburse our sponsor for all direct third-party and allocated costs and expenses actually incurred by our sponsor in providing operational services. Our general partner and its affiliates also may provide us other services for which we will be charged fees as determined by our general partner. The costs and expenses for which we will reimburse our general partner and its affiliates may include reimbursements for salary, bonus, incentive compensation and other amounts paid to affiliates of our general partner for the costs incurred in providing services for us or on our behalf and expenses allocated to our general partner by its affiliates. The costs and expenses for which we are required to reimburse our general partner and its affiliates are not subject to any caps or other limits under our Partnership Agreement. The total amount of such reimbursed expenses was $4.5 million for the year ended December 31, 2016. Payments to our general partner and its affiliates may be substantial and may reduce the amount of cash we have available to distribute to unitholders.

Unitholders have very limited voting rights and, even if they are dissatisfied, they will have limited ability to remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management’s decisions regarding our business. For example, unlike holders of stock in a public corporation, unitholders will not have “say-on-pay” advisory voting rights. Unitholders did not elect our general partner or the board of directors of our general partner and will have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis. Through its direct ownership of our general partner, our sponsor has the right to appoint the entire board of directors of our general partner, including our independent directors. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which our common units will trade could be
diminished because of the absence or reduction of a takeover premium in the trading price.

Our general partner may not be removed unless such removal is both (i) for cause and (ii) approved by a vote of the holders of at least 66.67% of the outstanding units, including any units owned by our general partner and its affiliates, voting together as a single class. “Cause” is narrowly defined under our Partnership Agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable to us or any limited partner for intentional fraud or willful misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business. Our sponsor owns 61.1% of our total outstanding common units, subordinated units and preferred units on an aggregate basis. This will give our sponsor the ability to prevent the removal of our general partner.

Furthermore, unitholders' voting rights are further restricted by the Partnership Agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our Partnership Agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

The restrictions in our Partnership Agreement applicable to holders of 20% or more of any class of our outstanding partnership interests do not apply to Greenlight Capital.

Unitholders' voting rights are restricted by the Partnership Agreement provision providing that any units held by a person or group that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons or groups who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. In connection with the Concurrent Private Placement, our general partner waived this provision with respect to Greenlight Capital. As a result of this waiver, the common units purchased by Greenlight Capital in the Concurrent Private Placement are generally considered to be outstanding under our Partnership Agreement and will be entitled to vote on any matter on which the common unitholders are otherwise entitled to vote. Greenlight Capital owns 47.3% of our outstanding common units.

Our general partner interest or the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest in us to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in our Partnership Agreement on the ability of our sponsor to transfer its membership interest in our general partner to a third party after June 30, 2025 without the consent of the unitholders. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices.

The incentive distribution rights of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its incentive distribution rights to a third party at any time without the consent of our unitholders. If our general partner transfers its incentive distribution rights to a third party but retains its general partner interest, our general partner may not have the same incentive to grow our Partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of its incentive distribution rights. For example, a transfer of incentive distribution rights by our general partner could reduce the likelihood that our sponsor, which owns our general partner, will sell or contribute additional assets to us, as our sponsor would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

On or after September 30, 2017, our sponsor may convert its Class A Preferred Units into common units or transfer its Class A Preferred Units to a third party.

On September 30, 2016, we issued 3,956,496 Class A Preferred Units to our sponsor, CONSOL Energy. Under the terms of the Partnership Agreement, the holder of the Class A Preferred Units has the same voting rights as it would have if all of its Class A Preferred Units were converted, on a one-for-one basis, into common units and will vote together with the holders of the common units as a single class. Additionally, Class A Preferred Unit holders will be entitled to vote as a separate class on any matter that adversely affects the rights, privileges or preferences of the Class A Preferred Units in any material respect or as required by applicable law. Prior to September 30, 2017, CONSOL Energy may not transfer any Class A Preferred Units, other than transfers to affiliates, without our approval. On and after September 30, 2017, CONSOL Energy may transfer any of its Class A Preferred Units to a third party. If CONSOL Energy transfers any of its Class A Preferred Units to a third party, the transferees would vote together with the holders of the common units. A transfer of the Class A Preferred Units would further dilute CONSOL Energy's interest in the Partnership and may reduce the likelihood that CONSOL Energy will continue to sell or contribute assets to us, which in turn could negatively impact our ability to grow our asset base and materially and adversely impact our results of operations and distributable cash flow.

We may issue an unlimited number of additional partnership interests without unitholder approval, which would dilute our then-existing unitholders' proportionate ownership interests in us. In addition, the general partner has the right to cause additional Class A Preferred Units to be issued to our sponsor in lieu of cash payment of accrued distributions.

At any time, we may issue an unlimited number of general partner interests or limited partner interests of any type without the approval of our unitholders and our unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such general partner interests or limited partner interests. Further, there are no limitations in our Partnership Agreement on our ability to issue equity securities that rank equal or senior to our common units as to distributions or in liquidation or that have special voting rights and other rights. In addition the general partner has the right to elect to pay any Class A Preferred Unit distribution in additional Class A Preferred Units.

The issuance by us of additional common units, Class A Preferred Units or other equity securities of equal or senior rank will have the following effects:

- our then-existing unitholders' proportionate ownership interests in us will decrease;
- the amount of cash we have available to distribute on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and

- the market price of our common units may decline.

The issuance by us of additional general partner interests may have the following effects, among others, if such general partner interests are issued to a person who is not an affiliate of our sponsor:

- management of our business may no longer reside solely with our current general partner; and
- affiliates of the newly admitted general partner may compete with us, and neither that general partner nor such affiliates will have any obligation to present business opportunities to us except with respect to rights of first offer contained in our omnibus agreement.

Our sponsor and Greenlight Capital may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

Our sponsor holds 1,050,000 common units, 11,611,067 subordinated units and 3,956,496 Class A Preferred Units. All of the subordinated units will convert into common units at the end of the subordination period and the Class A Preferred Units will be convertible on a one-for-one basis at any time after September 30, 2017, or potentially earlier upon the occurrence of certain events. In addition, Greenlight Capital holds 5,488,438 common units, per public filings. We also agreed to provide our sponsor and Greenlight Capital with certain registration rights under applicable securities laws. The sale of these units described above in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner’s discretion in establishing cash reserves may reduce the amount of cash we have available to distribute to unitholders.

Our Partnership Agreement requires our general partner to deduct from operating surplus the cash reserves that it determines are necessary to fund our future operating expenditures. In addition, the Partnership Agreement permits the general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party, or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash we have available to distribute to unitholders.

Affiliates of our general partner, including, but not limited to, our sponsor, may compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us except with respect to rights of first offer contained in our omnibus agreement.

Neither our Partnership Agreement nor our omnibus agreement will prohibit our sponsor or any other affiliates of our general partner from owning assets or engaging in businesses that compete directly or indirectly with us. Under the terms of our Partnership Agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to our general partner or any of its affiliates, including our sponsor. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. Consequently, our sponsor and other affiliates of our general partner may acquire, construct or dispose of additional coal assets in the future without any obligation to offer us the opportunity to purchase any of those assets. Moreover, except for the obligations set forth in the omnibus agreement, neither our sponsor nor any of its affiliates have a contractual obligation to present us the opportunity to purchase additional assets from it, and we are unable to predict whether or when such an opportunity may be presented to us. As a result, competition from our sponsor and other affiliates of our general partner could materially and adversely impact our results of operations and distributable cash flow.

Our general partner has a limited call right that may require you to sell your common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of our then-outstanding common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, common unit holders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. They may also incur a tax liability upon a sale of their units. Our general partner and its affiliates own approximately 9.0% of our common units (excluding any common units purchased by the directors, director nominees and executive officers of our general partner, directors of our sponsor and certain other individuals as selected by our sponsor under our directed unit program). At the end of the subordination period and upon the conversion of the preferred units, our general partner and its affiliates will own approximately 61.1% of our outstanding common units (excluding any common units purchased by the directors, director nominee and executive officers of our general partner, directors of our sponsor and certain other individuals as selected by our sponsor under our directed unit program) and therefore would not be able to exercise the call right at that time.

Unitholders may have to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the “Delaware Act”), we may not make a distribution to the common unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Transferees of common units are liable for the obligations of the transferor to make contributions to the Partnership that are known to the transferee at the time of the transfer and for unknown obligations if the liabilities could be determined from our Partnership Agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the Partnership are not counted for purposes of determining whether a distribution is permitted.

Our general partner, or any transferee holding incentive distribution rights, may elect to cause us to issue common units and general partner interests to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of our conflicts committee or our common unitholders. The exercise of this election could result in lower distributions to our common unitholders in certain situations.

Our general partner has the right, at any time when there are no subordinated units outstanding and it has received distributions on its incentive distribution rights at the highest level to which it is entitled (48%, in addition to distributions paid on its 1.7% general partner interest) for each of the prior four consecutive fiscal quarters and the amount of such distribution did not exceed the adjusted operating surplus for such quarter, to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution, and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

If our general partner elects to reset the target distribution levels, it will be entitled to receive a number of common units and a general partner interest. The number of common units to be issued to our general partner will be equal to that number of common units that would have entitled their holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the incentive distribution rights in such two quarters. Our general partner will also be issued an additional general partner interest necessary to maintain our general partner’s interest in us at the level that existed immediately prior to the reset election. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It is possible, however, that our general partner could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions it receives related to its incentive distribution rights and may, therefore, desire to be issued common units rather than retain the right to receive distributions based on the initial target distribution levels. This risk could be elevated if our incentive distribution rights have been transferred to a third party. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that they would have otherwise received had we not issued new common units and general partner interests in connection with resetting the target distribution levels. Additionally, our general partner has the right to transfer all or any portion of our incentive distribution rights at any time, and such transferee shall have the same rights as the general partner relative to resetting target distributions if our general partner concurs that the tests for resetting target distributions have been fulfilled.

Units held by persons who our general partner determines are not “eligible holders” at the time of any requested certification in the future may be subject to redemption.

As a result of certain laws and regulations to which we are or may in the future become subject, we may require owners of our common units to certify that they are both U.S. citizens and subject to U.S. federal income taxation on our income. Units held by persons who our general partner determines are not “eligible holders” at the time of any requested certification in the future may be subject to redemption. “Eligible holders” are limited partners whose (or whose owners’) (i) U.S. federal income tax status or lack of proof of U.S. federal income tax status does not have and is not reasonably likely to have, as determined by our general partner, a material adverse effect on the maximum applicable rates that can be charged to customers by us or our subsidiaries and (ii) nationality, citizenship or other related status does not create and is not reasonably likely to create, as determined by our general partner, a substantial risk of cancellation or forfeiture of any property in which we have an interest. The aggregate redemption price for redeemable interests will be an amount equal to the current market price (the date of determination of which will be the date fixed for redemption) of limited partner interests of the class to be so redeemed multiplied by the number of limited partner interests of each such class included among the redeemable interests. For these purposes, the “current market price” means, as of any date for any class of limited partner interests, the average of the daily closing prices per limited partner interest of such class for the 20 consecutive trading days immediately prior to such date. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner. The units held by any person the general partner determines is not an eligible holder will not be entitled to voting rights.

Our Partnership Agreement designates the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders, which limits our unitholders’ ability to choose the judicial forum for disputes with us or our general partner’s directors, officers or other employees.

Our Partnership Agreement provides that, with certain limited exceptions, the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court located in the State of Delaware with subject matter jurisdiction) shall be the exclusive forum for any claims, suits, actions or proceedings (i) arising out of or relating in any way to our Partnership Agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our Partnership Agreement or the duties, obligations or liabilities among our partners, or obligations or liabilities of our partners to us, or the rights or powers of, or restrictions on, our partners or us), (ii) brought in a derivative manner on our behalf, (iii) asserting a claim of breach of a duty owed by any of our, or our general partner’s, directors, officers, or other employees, or owed by our general partner, to us or our partners, (iv) asserting a claim against us arising pursuant to any provision of the Delaware Act or (v) asserting a claim against us governed by the internal affairs doctrine. In addition, our Partnership Agreement provides that each limited partner irrevocably waives the right to trial by jury in any such claim, suit, action or proceeding. By purchasing a common unit, a limited partner is irrevocably consenting to these limitations and provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other court) in connection with any such claims, suits, actions or proceedings. These provisions may have the effect of discouraging lawsuits against us and our general partner’s directors and officers.

The NYSE does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

Our common units are listed on the NYSE. Because we are a publicly traded limited partnership, the NYSE does not require us to have a majority of independent directors on our general partner’s board of directors or to establish a compensation committee or a nominating and corporate governance committee. Additionally, any future issuance of additional common units or other securities, including to affiliates, are not subject to the NYSE’s shareholder approval rules that apply to a corporation. Accordingly, unitholders do not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

Tax Risks

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes. If the Internal Revenue Service (the “IRS”) were to treat us as a corporation for U.S. federal income tax purposes, which would subject us to entity-level taxation, or if we were otherwise subjected to a material amount of additional entity-level taxation, then our distributable cash flow to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for U.S. federal income tax purposes. We have not requested a ruling from the IRS on this or any other tax matter affecting us. Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for U.S. federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to a unitholder. In addition, changes in current state law may subject us to additional entity-level taxation by individual states. Because of state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, Pennsylvania may assess a partnership level tax if the partnership is found to have underreported income by more than $1,000,000 in any tax year. Imposition of any such taxes may substantially reduce our distributable cash flow. Therefore, if we were treated as a corporation for U.S. federal income tax purposes, or otherwise subjected to a material amount of entity-level taxation, there would be a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our units.

Our Partnership Agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution levels may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our 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, including us, or an investment in our units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, members of Congress and the President propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships, including the elimination of the qualifying income exception upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. However, it is possible that a change in law could affect us, and any such changes could negatively impact the value of an investment in our units.

Our unitholders’ allocated share of our income will be taxable to them for U.S. federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder will be treated as a partner to whom we will allocate taxable income that could be different in amount than the cash we distribute, a unitholder’s allocable share of our taxable income will be taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes, on its share of our taxable income even if it receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

If the IRS contests the U.S. federal income tax positions we take, the market for our units may be adversely impacted and the cost of any IRS contest will reduce our distributable cash flow to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes or any other matter affecting us. We intend to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his or her share of our income, gains, losses, and deductions for our preceding taxable year. In preparing this information, we will take various accounting and reporting positions. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this report or from the positions we take, and the IRS’s positions may ultimately be sustained in an audit of our U.S. federal income tax information returns. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel’s conclusions or the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of our counsel’s conclusions or the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on the market for our units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our distributable cash flow. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year’s tax liability, and possibly may result in an audit of his or her return. Any audit to a unitholder’s return could result in adjustments not related to our returns, as well as those related to our returns.

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

If our unitholders sell units, they will recognize a gain or loss for U.S. federal income tax purposes equal to the difference between the amount realized and their tax basis in those units. Because distributions in excess of their allocable share of our net taxable income decrease their tax basis in their units, the amount, if any, of such prior excess distributions with respect to the units a unitholder sells will, in effect, become taxable income to the unitholder 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. Furthermore, a substantial portion of the amount realized on any sale of units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation and depletion recapture. In addition, because the amount realized includes a unitholder’s share of our nonrecourse liabilities, a unitholder that sells units may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our units that may result in adverse tax consequences to them.

Investment in our units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and each non-U.S. person will be required to file U.S. federal income tax returns and pay tax on its share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our units.

We will treat each purchaser of units as having the same tax benefits without regard to the actual units purchased. The IRS may challenge this treatment, which could adversely affect the value of our units.

Because we cannot match transferors and transferees of units and because of other reasons, we adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations, promulgated under the Internal Revenue Code of 1986 (the "Code") referred to as "Treasury Regulations." A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a unitholder. Our tax counsel is unable to opine as to the validity of such filing positions. It also could affect the timing of these tax benefits or the amount of gain from a sale of units and could have a negative impact on the value of our units or result in audit adjustments to your tax returns.

We will prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We will prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our tax counsel is unable to opine as to the validity of this method. The U.S. Treasury Department issued regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the regulations do not specifically authorize the use of the proration method we adopted. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to effect a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for U.S. federal income tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to effect a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for U.S. federal income tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gains, losses or deductions with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their units.

We will adopt 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, and such a challenge could adversely affect the value of our units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, in certain circumstances, including when we issue additional units, we must determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our units as a means to measure the fair market value of our 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 amount, character and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of units and could have a negative impact on the value of the units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our Partnership for U.S. federal income tax purposes.

We will be considered to have technically terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for U.S. federal income tax purposes, but instead we would be treated as a new partnership for U.S. federal income tax purposes. If treated as a new partnership, we must make new tax elections, including a new election under Section 754 of the Code, and we could be subject to penalties if we are unable to determine that a termination occurred. Moreover, a termination may either accelerate the application of, or subject us to, any tax legislation enacted before the termination that would not otherwise have been applied to us as a continuing as opposed to terminating partnership. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

The elimination of any U.S. federal income tax preferences currently available with respect to coal exploration and development could negatively impact the value of our units.

The passage of any legislation or any other similar changes in U.S. federal income tax laws could eliminate or defer certain tax deductions that are currently available with respect to coal exploration and development could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units.

As a result of investing in our units, unitholders may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to U.S. federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or control property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We conduct business in Pennsylvania and West Virginia, which currently impose a personal income tax on individuals. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal income tax.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Coal Reserves

The estimates of our proven and probable reserves are calculated internally using the face positions of the Pennsylvania Mining Complex’s longwall mines as of December 31, 2016. The December 31, 2016 reserve estimates were computed using the same techniques and assumptions as in prior years. These estimates are based on geologic data, coal ownership information and current and proposed mine plans. Our proven and probable coal reserves are reported as “recoverable coal reserves,” which is the portion of the coal that could be economically and legally extracted or produced at the time of the reserve determination, taking into account mining recovery and preparation plant yield. These estimates are periodically updated to reflect past coal production, new drilling information and other geologic or mining data. Acquisitions or dispositions of coal properties will also change these estimates. Changes in mining methods may increase or decrease the recovery basis for a coal seam, as will changes in preparation plant processes. The ability to update or modify the estimates of our coal reserves is restricted to the engineering group and all modifications are documented.

“Reserves” are defined by SEC Industry Guide 7 as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. Industry Guide 7 divides reserves between “proven (measured) reserves” and “probable (indicated) reserves,” which are defined as follows:

- “Proven (Measured) Reserves.” Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; and grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

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

Spacing of points of observation for confidence levels in our reserve calculations is based on guidelines in U.S. Geological Survey Circular 891 (Coal Resource Classification System of the U.S. Geological Survey). Our estimates for proven reserves have the highest degree of geologic assurance. Because of the well-known continuity of the Pittsburgh No. 8 Coal Seam, estimates for proven reserves are based on points of observation that are equal to or less than 3,000 feet, and estimates for probable reserves are computed from points of observation that are between 3,000 feet and 7,920 feet apart.

Our estimates of proven and probable reserves do not rely on isolated points of observation. Small pods of reserves based on a single observation point are not considered; continuity between observation points over a large area is necessary for proven or probable reserves.

Our proven and probable coal reserves fall within the range of commercially marketed coal grades in the United States. The marketability of coal depends on its value-in-use for a particular application, and this is affected by coal quality, including sulfur content, ash content and heating value. Modern power plant boiler design aspects can compensate for coal quality differences that occur. As a result, all of our coal can be marketed for the electric power generation industry. In addition, our reserves currently exhibit thermoplastic behavior suitable for cokemaking and contain an average of approximately 39%-40% volatile matter (on a dry basis), which enables us, if market dynamics are favorable, to capture greater margins from selling our coal in the metallurgical market to cokemakers and steel manufacturers who utilize modern cokemaking technologies. The addition of this crossover market adds additional assurance that our proven and probable coal reserves are commercially marketable. For the years ended December 31, 2016, 2015 and 2014, our portion of the Pennsylvania Mining Complex sold approximately 0.5 million tons, 0.3 million tons and 0.3 million tons of coal, respectively, in the metallurgical market.

The amount of coal we assign to a mining complex generally is sufficient to support mining through the duration of the applicable current mining permit. Under federal law, we must renew our mining permits every five years. All assigned reserves have their required permits or governmental approvals, or there is a high probability that these approvals will be secured.

In addition, mines may have access to additional reserves that have not yet been assigned. We refer to these reserves as accessible. Accessible reserves are proven and probable reserves that can be accessed by an existing mine, utilizing the existing infrastructure of the complex to mine and to process the coal in this area. Mining an accessible reserve does not require additional capital spending beyond that required to extend or to continue the normal progression of the mine, such as the sinking of airshafts or the construction of portal facilities.

Some reserves may be accessible by more than one mine because of the proximity of our mines to one another. In the table below, the accessible reserves indicated for a mine are based on our review of current mining plans and reflect our best judgment as to which mine is most likely to utilize the reserve. Assigned and accessible coal reserves are proven and probable reserves which are either owned or leased. The leases have terms extending up to 30 years and generally provide for renewal through the anticipated life of the associated mine. These renewals are exercisable by the payment of minimum royalties. Under current mining plans, assigned reserves reported will be mined out within the period of existing leases or within the time
period of probable lease renewal periods.

The following table sets forth additional information regarding the recoverable coal reserves at the Pennsylvania Mining Complex as of December 31, 2016 (tons in thousands):

Mine	Reserve Class	Average Seam Thickness (feet)	As Received Heat Value (1) (Btu/lb)		As Received lb SO2 / mmBtu	Recoverable Reserves (2)(3)		
			Typical	Range		Owned (%)	Leased (%)	Total (tons)
Bailey:	Assigned	7.5	12,950	12,860 - 13,030	3.8	43%	57 %	22,257
	Accessible	7.5	12,910	12,700 - 13,170	4.2	78%	22 %	42,664
Enlow Fork:	Assigned	7.8	12,980	12,820 - 13,190	4.2	81%	19 %	7,800
	Accessible	7.6	13,040	12,780 - 13,180	3.4	76%	24 %	68,829
Harvey:	Assigned	6.3	13,040	12,920 - 13,160	2.8	86%	14 %	5,107
	Accessible	7.6	12,900	12,840 - 13,130	3.6	99%	1 %	45,021
Total								191,678

(1) The heat values (gross calorific values) shown for Assigned Operating reserves are on as-received basis and are based on the 2016 actual quality and five-year forecasted quality for each mine/reserve, assuming that the coal is washed to an extent consistent with normal full-capacity operation of each mine's/complex's preparation plant. Actual quality is based on laboratory analysis of samples collected from coal shipments delivered in 2016. Forecasted quality is derived from exploration sample analysis results, which have been adjusted to account for anticipated moisture and for the effects of mining and coal preparation. The heat values (gross calorific values) shown for Accessible Reserves are on an as-received basis (dry values obtained from drill hole analyses, adjusted for moisture), and are prorated by the associated Assigned Operating product values to account for similar mining and processing methods.

(2) Recoverable reserves are calculated based on proposed mine plans in the area in which mineable coal exists, coal seam thickness and average density determined by laboratory testing of drill core samples. This calculation is adjusted to account for coal that will not be recovered during mining and for losses that occur if the coal is processed after mining. Reserve tons are reported on an as-received basis, based on the anticipated product moisture. Reserves are reported only for those coal seams that are controlled by ownership or leases.

(3) Economic viability of the reported proven and probable coal reserves is established through a life of mine plan for each mine operation, pursuant to SEC Industry Guide 7. Economic viability is determined by providing a net value on a cash-forward looking basis which is based on historical performance, with forward adjustments based on planned changes in production volumes, in fixed and variable proportion of costs and forecasted fluctuation in costs of supplies, energy costs and wages. Coal sales prices are forecasted based on management’s internal market analysis throughout each mine’s life of mine plan. Based on these calculations, we concluded that the reported reserve tons produce a positive economic impact over each
mine’s life. Our mines operate in the Pittsburgh No. 8 Coal Seam and have historically generated positive net income and positive cash flow which demonstrates the economic viability of the coal reserves. The Pittsburgh No. 8 Coal Seam is typically consistent in geological formation, including seam thickness, coal quality and other characteristics. Therefore, our mines are expected to continue to produce positive economic results using mining technologies currently employed. The reported coal reserves do not exceed the quantities that we estimate could be extracted economically at average prices received and costs incurred as discussed in “Management’s Discussion and Analysis of Financial Condition and Results of Operations.” The historical three-year average realized prices received for production at these locations was $53.96 per ton.

ITEM 3. LEGAL PROCEEDINGS

Our operations are subject to a variety of risks and disputes normally incidental to our business. As a result, we may, at any given time, be a defendant in various legal proceedings and litigation arising in the ordinary course of business. However, we are not currently subject to any material litigation. Refer to paragraph one and two of Note 18 "Commitments and Contingent Liabilities," in the Notes to Audited Consolidated Financial Statements in Item 8 of this Form 10-K, Incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

The information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in exhibit 95 to this annual report.

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

The Partnership's common units have been listed on the New York Stock Exchange (NYSE) under the symbol "CNXC" since July 1, 2015. Prior to that, the Partnership's equity securities were not listed on any exchange or traded on any public trading market. The following table sets forth the range of high and low sales prices per common unit as reported on the New York Stock Exchange and the cash distributions declared on the common units from the closing of the IPO through December 31, 2016:

Period	High Price	Low Price	Distribution per Limited Partner Unit
Third Quarter 2015 (a)	$17.34	$10.68	$0.4791 (b)
Fourth Quarter 2015	$13.71	$8.25	$0.5125
First Quarter 2016	$9.39	$5.98	$0.5125
Second Quarter 2016	$10.29	$6.70	$0.5125 (c)
Third Quarter 2016	$16.72	$8.80	$0.5125
Fourth Quarter 2016	$22.30	$15.15	$0.5125

(a) Since July 1, 2015, the commencement date of trading.
(b) The third quarter 2015 distribution was prorated from the closing date of the IPO based upon a minimum quarterly distribution of $0.5125 per unit per quarter.
(c) The partnership elected not to pay a distribution to holders of subordinated units for the second quarter 2016. The second quarter 2016 distribution paid to common unit holders was $0.5125 per unit.

Transfer Agent and Registrar The transfer agent and registrar for our common units is Computershare Trust Company, N.A.

Unitholders Profile Pursuant to the records of the transfer agent, as of January 16, 2017, the number of registered holders of our common units was approximately nine. The Fourth Quarter 2016 cash distribution of $0.5125 per common and subordinated unit and $0.4678 per Class A preferred unit was declared on January 30, 2017 to holders of record as of February 9, 1017 and will be paid on February 15, 2017.

Equity Compensation Plan Information Please read "Item 12 - Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters - Securities Authorized for Issuance Under Equity Compensation Plans."

Market Repurchases

The Partnership did not repurchase any of its common units during the year ended December 31, 2016.

Distributions of Available Cash

General

Our Partnership Agreement requires that, within 45 days after the end of each quarter we distribute all of our available cash to unitholders of record on the applicable record date.

Definition of Available Cash

Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

- less, the amount of cash reserves established by our general partner to:

provide for the proper conduct of our business (including reserves for our future capital expenditures, future acquisitions and anticipated future debt service requirements);

comply with applicable law or any loan agreement, security agreement, mortgage, debt instrument or other agreement or obligation to which we or any of our subsidiaries is a party or by which we or such subsidiary is bound or we or such subsidiary's assets are subject; or
provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for distributions pursuant to this bullet point if the effect of such reserves will prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for the current quarter);

- plus, if our general partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

The purpose and effect of the last bullet point above is to allow our general partner, if it so decides, to use cash from working capital borrowings made after the end of the quarter but on or before the date of determination of available cash for that quarter to pay distributions to unitholders. Under our Partnership Agreement, working capital borrowings are generally borrowings incurred under a credit facility, commercial paper facility or similar financing arrangement that are used solely for working capital purposes or to pay distributions to our partners and with the intent of the borrower to repay such borrowings within twelve months with funds other than from additional working capital borrowings.

Intent to Distribute the Minimum Quarterly Distribution and Pay the Preferred Distribution

Under the Partnership's current cash distribution policy, the Partnership intends to make a minimum quarterly distribution to the holders of common units and subordinated units of $0.5125 per unit per quarter, or $2.05 per unit on an annualized basis, to the extent the Partnership has sufficient available cash after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our general partner. However, there is no guarantee that the Partnership will pay the minimum quarterly distribution on those units in any quarter. The amount of distributions paid under the Partnership's cash distribution policy and the decision to make any distribution will be determined by our general partner, taking into consideration the terms of the Partnership Agreement. Please read Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

The Partnership intends to make a minimum quarterly distribution to the holders of the Class A Preferred Units of $0.4678 per unit per quarter, or $1.8712 per unit on an annualized basis, to the extent the Partnership has sufficient available cash after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our general partner. Under the Partnership Agreement, the Partnership can make distributions on the Class A Preferred Units in cash or in PIK Units, and there is no guarantee that the Partnership will pay the preferred quarterly distribution on the Class A Preferred Units in cash in any quarter. The amount of distributions paid under the Partnership's cash distribution policy and the decision to make any distribution will be determined by our general partner, taking into consideration the terms of the Partnership Agreement. Please read Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

General Partner Interest and Incentive Distribution Rights

Initially, our general partner was entitled to 2% of all quarterly distributions from inception that we made prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner's initial 2% general partner interest in these distributions was reduced as a result of issuing additional limited partner interests in the form of Class A Preferred Units and our general partner did not contribute a proportionate amount of capital to maintain a 2% general partner interest. This resulted in our general partner now having a 1.7% general partner interest.

Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 48%, of the available cash we distribute from operating surplus in excess of $0.5894 per unit per quarter. The maximum distribution of 48% does not include any distributions that our general partner or its affiliates may receive on common units, subordinated units or the general partner interest that they own.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected historical financial data, representing the Partnership's 25% undivided interest in Pennsylvania Mining Complex, of CNX Coal Resources LP and its Predecessor for the periods indicated. The selected historical financial data of our Predecessor as of and for the years ended December 31, 2014 and 2013 are derived from the audited financial statements of our Predecessor. The following table should be read together with, and is qualified in its entirety by reference to, the historical financial statements and the accompanying notes included in this Form 10-K. The table should also be read together with “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

	For the Years Ended December 31,			
	2016	2015	2014	2013
CONSOLIDATED STATEMENTS OF OPERATIONS:	(Dollars in thousands, except per unit data)			
Coal revenue	$266,395	$ 322,261	$404,247	$339,334
Freight revenue	11,603	3,809	4,192	4,445
Other revenues and income	3,119	941	9,660	1,515
Total Revenue and Other Income	281,117	327,011	418,099	345,294
Operating and Other Costs	183,001	193,961	239,863	209,776
Depreciation, Depletion and Amortization	41,994	44,136	43,337	32,291
Freight Expense	11,603	3,809	4,192	4,445
Selling, General and Administrative Expenses	9,949	10,931	17,149	15,778
Interest Expense	8,719	9,636	8,683	2,616
Total Costs	255,266	262,473	313,224	264,906
Net Income	$25,851	$ 64,538	$104,875	$80,388
Limited Partner Interest in Net Income	$19,487	$ 22,888	N/A	N/A
Net Income per Limited Partner Unit - Basic (1)	$0.84	$ 0.99	N/A	N/A
Net Income per Limited Partner Unit - Diluted (1)	$0.83	$ 0.99	N/A	N/A
Limited Partner Units Outstanding - Basic	23,225,142	23,222,134	N/A	N/A
Limited Partner Units Outstanding - Diluted	23,402,897	23,223,045	N/A	N/A

	As of December 31,		
	2016	2015	2014
CONSOLIDATED BALANCE SHEETS:	(in thousands)		
Working Capital (2)	$(16,060)	$(15,266)	$(68,242)
Total Assets	$504,296	$525,944	$523,510
Long Term Debt (3)	$197,989	$181,070	$201,451
Total Liabilities	$277,726	$254,141	$310,227
Total Partners' Capital and Parent Net Investment	$226,570	$271,803	$213,283

	For the Years Ended December 31,			
	2016	2015	2014	2013
OTHER FINANCIAL DATA:	(in thousands, except per ton amounts)			
Net Cash Provided by Operating Activities	$73,098	$76,908	$142,636	$118,020
Net Cash Used in Investing Activities	$(34,181)	$(34,002)	$(66,030)	$(84,535)
Net Cash Used in Financing Activities	$(35,666)	$(36,376)	$(76,606)	$(33,486)
Actual Maintenance Capital Expenditures	12,704	34,073	39,847	61,524
Tons Sold	6,151	5,719	6,533	5,308
Tons Produced	6,166	5,698	6,516	5,359
Coal Sales Per Ton Sold (4)	$43.31	$56.36	$61.88	$63.93
Cost Per Ton Sold (5)	$34.35	$41.78	$42.61	$44.53
Adjusted EBITDA (6)	$77,749	$115,964	$157,340	$121,219
Estimated Maintenance Capital Expenditures (7)	$28,964	$29,708	$30,042	$29,573

(1) Diluted earnings per unit (“EPU”) gives effect to all dilutive potential common units outstanding during the period using the treasury stock method.

(2) Working capital is impacted by current maturities of long term debt and capital lease obligations. For information regarding long-term debt, please read “Item 8. Financial Statements and Supplementary Data—Note 9 Revolving Credit Facility” of this Annual Report on Form 10-K.

(3) Long-term debt excludes the current portions of debt and capital lease obligations.

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

(5) Cost per ton sold is based on the total of operating expenses divided by tons sold.

(6) We define adjusted EBITDA as (i) net income (loss) before net interest expense, depreciation, depletion and amortization, as adjusted for (ii) material nonrecurring and other items which may not reflect the trend of our future results. The Generally Accepted Accounting Principles ("GAAP") measure most directly comparable to adjusted EBITDA is net income. Adjusted EBITDA is used as a supplemental financial measure by management and by external users of our financial statements, such as investors, industry analysts, lenders and ratings agencies, to assess:

• our operating performance as compared to the operating performance of other companies in the coal industry, without regard to financing methods, historical cost basis or capital structure;

• the ability of our assets to generate sufficient cash flow to make distributions to our partners;

• our ability to incur and service debt and fund capital expenditures; and

• the viability of acquisitions and other capital expenditure projects and the returns on investment of various investment opportunities.

The non-GAAP financial measures should not be considered an alternative to total costs, net income, operating cash flow, or any other measure of financial performance or liquidity presented in accordance with GAAP. These measures exclude some, but not all, items that affect net income or net cash, and these measures may vary from those of other companies. As a result, the items presented below may not be comparable to similarly titled measures of other companies.

(7) Our estimated maintenance capital expenditures, as defined under the terms of our Partnership Agreement, are those forecasted average capital expenditures required to maintain, over the long-term, the operating capacity of our capital assets. These do not reflect the actual cash capital incurred in the period presented.

The following table presents a reconciliation of adjusted EBITDA to net income, the most directly comparable GAAP financial measure, on a historical basis for each of the periods indicated.

	Years Ended December 31,		
	2016	2015	2014
Net Income	$25,851	$64,538	$104,875
Interest Expense	8,719	9,636	8,683
Depreciation, Depletion and Amortization	41,994	44,136	43,337
OPEB Plan Change	—	(5,339)	—
OPEB Transition Payment	—	—	4,124
Backstop Loan Fees	—	1,895	—
Coal Contract Buyout	—	—	(7,500)
Litigation Settlement	—	—	(1,069)
Bailey Belt Repairs	—	—	689
Stock/Unit Based Compensation	1,185	1,098	4,201
Adjusted EBITDA	$77,749	$115,964	$157,340

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

We are a growth-oriented master limited partnership formed by CONSOL Energy in 2015 to manage and further develop all of its thermal coal operations in Pennsylvania. Our primary strategy for growing our business and increasing distributions to our unitholders is to make acquisitions that increase our distributable cash flow. The primary component of our growth strategy is based upon our expectation of future divestitures by our sponsor to us of portions of its retained 75% undivided interest in the Pennsylvania Mining Complex. We have a right of first offer pursuant to our omnibus agreement to purchase the undivided interest in the Pennsylvania Mining Complex retained by our sponsor. At December 31, 2016, our assets include a 25% undivided interest in, and operational control over, CONSOL Energy's Pennsylvania Mining Complex, which consists of three underground mines and related infrastructure that produce high-Btu bituminous thermal coal that is sold primarily to electric utilities in the eastern United States, our core market. We believe that our ability to efficiently produce and deliver large volumes of high-quality coal at competitive prices, the strategic location of our mines, the industry experience of our management team and our relationship with CONSOL Energy position us as a leading producer of high-Btu thermal coal in the Northern Appalachian Basin and the eastern United States.

The Pennsylvania Mining Complex, which includes the Bailey Mine, the Enlow Fork Mine and the Harvey Mine, has extensive high-quality coal reserves. We mine our reserves from the Pittsburgh No. 8 Coal Seam, which is a large contiguous formation of uniform, high-Btu thermal coal that is ideal for high productivity, low-cost longwall operations. As of December 31, 2016, the Partnership's portion of the Pennsylvania Mining Complex included 191.7 million tons of proven and probable coal reserves with an average gross heat content of approximately 12,970 Btu per pound and approximately 3.7 pounds sulfur dioxide per million British thermal units ("lb SO_2/mmBtu"). Based on our current production capacity, these reserves are sufficient to support approximately 27 years of production. In addition, our reserves currently exhibit thermoplastic behavior suitable for cokemaking and contain an average of approximately 39%-40% volatile matter (on a dry basis), which enables us, if market dynamics are favorable, to capture greater margins from selling our coal as a crossover product in the high-vol metallurgical market to cokemakers and steel manufacturers who utilize modern cokemaking technologies.

On September 30, 2016, the Partnership and its wholly owned subsidiary, CNX Thermal Holdings, entered into a Contribution Agreement (the "Contribution Agreement") with CONSOL Energy, CPCC and Conrhein and together with CPCC, (the "Contributing Parties"), under which CNX Thermal Holdings acquired an undivided 6.25% of the Contributing Parties' right, title and interest in and to the Pennsylvania Mining Complex (which represents an aggregate 5% undivided interest in and to the Pennsylvania Mining Complex). The PA Mining Acquisition was a transaction between entities under common control; therefore, the partnership recorded the assets and liabilities of the acquired 5% of Pennsylvania Mining Complex at their carrying amounts to CONSOL Energy on the date of the transaction. The difference between CONSOL Energy's net carrying amount and the total consideration paid to CONSOL Energy was recorded as a capital transaction with CONSOL Energy, which resulted in a reduction in partners' capital. The Partnership recast its historical consolidated financial statements to retrospectively reflect the additional 5% (a total 25%) interest in Pennsylvania Mining Complex as if the business was owned for all periods presented; however, the consolidated financial statements are not necessarily indicative of the results of operations that would have occurred if the Partnership had owned it during the periods reported.

How We Evaluate Our Operations

Our management team uses a variety of financial and operating metrics to analyze our performance. These metrics are significant factors in assessing our operating results and profitability. The metrics include: (i) coal production, sales volumes and average sales price; (ii) cost of coal sold, a non-GAAP financial measure; (iii) average cash margin per ton, an operating ratio derived from non-GAAP financial measures, (iv) adjusted EBITDA, a non-GAAP financial measure; and (v) distributable cash flow, a non-GAAP financial measure.

Cost of coal sold, average cash margin per ton, adjusted EBITDA and distributable cash flow normalize the volatility contained within GAAP measures, by adjusting certain non-operating or non-cash transactions. These metrics are used as supplemental financial measures by management and by external users of our financial statements, such as investors, industry analysts, lenders and ratings agencies, to assess:

• our operating performance as compared to the operating performance of other companies in the coal industry, without regard to financing methods, historical cost basis or capital structure;

• the ability of our assets to generate sufficient cash flow to make distributions to our partners;

• our ability to incur and service debt and fund capital expenditures;

• the viability of acquisitions and other capital expenditure projects and the returns on investment of various investment opportunities; and

• the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

The non-GAAP financial measures should not be considered an alternative to total costs, net income, operating cash flow, or any other measure of financial performance or liquidity presented in accordance with GAAP. These measures exclude some, but not all, items that affect net income or net cash, and these measures may vary from those of other companies. As a result, the items presented below may not be comparable to similarly titled measures of other companies.

Reconciliation of Non-GAAP Financial Measures

We evaluate our cost of coal sales on a cost per ton basis. Our cost of coal sold per ton represents our costs of coal sold divided by the tons of coal we sell. We define cost of coal sold as operating and other production costs related to produced tons sold, along with changes in coal inventory, both in volumes and carrying values. The cost of coal sold per ton includes items such as direct operating costs, royalty and production taxes, direct administration, and depreciation, depletion and amortization costs. Our costs exclude any indirect costs such as general and administrative costs and other costs not directly attributable to the production of coal. The GAAP measure most directly comparable to cost of coal sold is total costs.

We define average cash margin per ton as average coal revenue per ton, net of average cost of coal sold per ton, less depreciation, depletion and amortization.

We define adjusted EBITDA as (i) net income (loss) before net interest expense, depreciation, depletion and amortization, as adjusted for (ii) certain non-cash items, such as long-term incentive awards including phantom units under the CNX Coal Resources LP 2015 Long-Term Incentive Plan ("Unit Based Compensation"). The GAAP measure most directly comparable to adjusted EBITDA is net income.

We define distributable cash flow as (i) net income (loss) before net interest expense, depreciation, depletion and amortization, as adjusted for (ii) certain non-cash items, such as unit based compensation, less net cash interest paid and estimated maintenance capital expenditures, which is defined as those forecasted average capital expenditures required to maintain, over the long-term, the operating capacity of our capital assets. These estimated capital expenditures do not reflect the actual cash capital incurred in the period presented. Distributable cash flow will not reflect changes in working capital balances. The GAAP measures most directly comparable to distributable cash flow are net income and net cash provided by operating activities.

The following table presents a reconciliation of cost of coal sold to total costs, the most directly comparable GAAP financial measure, on a historical basis for each of the periods indicated (in thousands).

	Years Ended December 31,		
	2016	2015	2014
Total Costs	$255,266	$262,473	$313,224
Freight Expense	(11,603)	(3,809)	(4,192)
Selling, General and Administrative Expenses	(9,949)	(10,931)	(17,149)
Interest Expense	(8,719)	(9,636)	(8,683)
Other Costs (Non-Production)	(10,330)	3,263	(2,801)

Depreciation, Depletion and Amortization (Non-Production)	(3,400)	(2,461)	(2,006)
Cost of Coal Sold	$211,265	$238,899	$278,393

The following table presents a reconciliation of average cash margin per ton for each of the periods indicated (in thousands, except for per ton information).

	Years Ended December 31,		
	2016	2015	2014
Total Coal Revenue	$266,395	$322,261	$404,247
Operating and Other Costs	183,001	193,961	239,863
Depreciation, Depletion and Amortization	41,994	44,136	43,337
Less: Other Costs (Non-Production)	(10,330)	3,263	(2,801)
Less: Depreciation, Depletion and Amortization (Non-Production)	(3,400)	(2,461)	(2,006)
Total Cost of Coal Sold	$211,265	$238,899	$278,393
Total Tons Sold	6,151	5,719	6,533
Average Sales Price Per Ton Sold	$43.31	$56.36	$61.88
Average Cost Per Ton Sold	34.35	41.78	42.61
Average Margin Per Ton Sold	8.96	14.58	19.27
Add: Total Depreciation, Depletion and Amortization Costs Per Ton Sold	6.26	7.31	6.34
Average Cash Margin Per Ton Sold	$15.22	$21.89	$25.61

The following table presents a reconciliation of adjusted EBITDA to net income, the most directly comparable GAAP financial measure, on a historical basis for each of the periods indicated. The table also presents a reconciliation of distributable cash flow to net income and operating cash flows, the most directly comparable GAAP financial measures, on a historical basis for each of the periods indicated (in thousands).

	Years Ended December 31,		
	2016	2015	2014
Net Income	$25,851	$64,538	$104,875
Interest Expense	8,719	9,636	8,683
Depreciation, Depletion and Amortization	41,994	44,136	43,337
OPEB Plan Change	—	(5,339)	—
OPEB Transition Payment	—	—	4,124
Backstop Loan Fees	—	1,895	—
Coal Contract Buyout	—	—	(7,500)
Litigation Settlement	—	—	(1,069)
Bailey Belt Repairs	—	—	689
Stock/Unit Based Compensation	1,185	1,098	4,201
Adjusted EBITDA	$77,749	$115,964	$157,340
Less:			
Cash Interest	8,049	7,896	9,538
PA Mining Acquisition Adjusted EBITDA[1]	10,272	23,366	31,468
Distributions to Preferred Units	1,851	—	—
Estimated Maintenance Capital Expenditures	28,964	29,708	30,042
Expansion Capital Expenditures	21,500	—	39,653
Add:			
Borrowings to Fund Expansion Capital Expenditures	21,500	—	39,653
Distributable Cash Flow	$28,613	$54,994	$86,292
Net Cash Provided by Operating Activities	$73,098	$76,908	$142,636
Less: Interest Expense, Net	8,719	9,636	8,683
Less: Other, Including Working Capital	(13,370)	(48,692)	(23,387)
Adjusted EBITDA	$77,749	$115,964	$157,340
Less:			
Cash Interest	8,049	7,896	9,538
PA Mining Acquisition Adjusted EBITDA[1]	10,272	23,366	31,468
Distributions to Preferred Units	1,851	—	—
Estimated Maintenance Capital Expenditures	28,964	29,708	30,042
Expansion Capital Expenditures	21,500	—	39,653
Add:			
Borrowings to Fund Expansion Capital Expenditures	21,500	—	39,653
Distributable Cash Flow	$28,613	$54,994	$86,292

[1]PA Mining Acquisition Adjusted EBITDA relates to the amount of Adjusted EBITDA acquired with the PA Mining Acquisition included in the recasted Adjusted EBITDA amounts. It is backed out to derive distributable cash flows reflecting the ownership percentage for all periods presented.

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Results of Operations

Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015

Total net income was $25,851 for the year ended December 31, 2016 compared to $64,538 for the year ended December 31, 2015. Our results of operations for each of these periods are presented in the table below. Variances are discussed following the table.

	For the Years Ended December 31,		
	2016	2015	Variance
Revenue:	(in thousands)		
Coal Revenue	$266,395	$322,261	$(55,866)
Freight Revenue	11,603	3,809	7,794
Other Income	3,119	941	2,178
Total Revenue and Other Income	281,117	327,011	(45,894)
Cost of Coal Sold:			
Operating Costs	172,671	197,224	(24,553)
Depreciation, Depletion and Amortization	38,594	41,675	(3,081)
Total Cost of Coal Sold	211,265	238,899	(27,634)
Other Costs:			
Other Costs	10,330	(3,263)	13,593
Depreciation, Depletion and Amortization	3,400	2,461	939
Total Other Costs	13,730	(802)	14,532
Freight Expense	11,603	3,809	7,794
Selling, General and Administrative Expenses	9,949	10,931	(982)
Interest Expense	8,719	9,636	(917)
Total Costs	255,266	262,473	(7,207)
Net Income	$25,851	$64,538	$(38,687)
Adjusted EBITDA	$77,749	$115,964	$(38,215)
Distributable Cash Flow	$28,613	$54,994	$(26,381)

Coal Production Rates

The table below presents total tons produced from the Pennsylvania Mining Complex on our 25% undivided interest for the periods indicated:

	Years Ended December 31,		
Mine	2016	2015	Variance
	(in thousands)		
Bailey	3,014	2,547	467
Enlow Fork	2,409	2,250	159
Harvey	743	901	(158)
Total	6,166	5,698	468

Coal production was 6,166 tons for the year ended December 31, 2016 compared to 5,698 tons for the year ended December 31, 2015. The 468 increase was attributable to improved domestic and export demand in the second half of 2016, offset partially by a decrease in production at the Harvey Mine due to the temporary idling of one longwall for 90 days.

Coal Operations

Coal revenue and cost components on a per unit basis for the years ended December 31, 2016 and 2015 were as indicated in the table below. Our operations also include various costs such as selling, general and administrative, freight and other costs not included in our unit cost analysis because these costs are not directly associated with coal production.

	For the Years Ended December 31,		
	2016	2015	Variance
Total Tons Sold (in thousands)	6,151	5,719	432
Average Sales Price Per Ton Sold	$43.31	$56.36	$(13.05)
Operating Costs Per Ton Sold (Cash Cost)	$28.09	$34.47	$(6.38)
Depreciation, Depletion and Amortization Per Ton Sold (Non-Cash Cost)	6.26	7.31	(1.05)
Total Costs Per Ton Sold	$34.35	$41.78	$(7.43)
Average Margin Per Ton Sold	$8.96	$14.58	$(5.62)
Add: Depreciation, Depletion and Amortization Costs Per Ton Sold	6.26	7.31	(1.05)
Average Cash Margin Per Ton Sold (1)	$15.22	$21.89	$(6.67)

(1) Average cash margin per ton is an operating ratio derived from non-GAAP measures.

Revenue and Other Income

Coal revenue was $266,395 for the year ended December 31, 2016 compared to $322,261 for the year ended December 31, 2015. The $55,866 decrease was attributable to a $13.05 per ton lower average sales price, offset by a 432 ton increase in tons sold. The higher sales volumes and lower average coal sales price per ton sold in the 2016 period were primarily the result of the overall decline in the domestic and global thermal coal markets, particularly in the first half of 2016. This was related to higher customer inventories and lower gas prices after mild 2015 weather. The average realized price per ton declined by 23% compared to the prior year as some of the high priced coal contracts rolled off and were replaced by lower priced sales. The increased sales volumes reflect the improvement in coal demand throughout the second half of 2016, both domestic and international.

Freight revenue, which is completely offset by freight expense, is the amount billed to customers based on the weight of coal shipped and negotiated freight rates for rail transportation. Freight revenue was $11,603 for the year ended December 31, 2016 compared to $3,809 for the year ended December 31, 2015. The $7,794 increase in freight revenue was due to increased shipments to customers where we were contractually obligated to provide transportation services.

Other income is comprised of income generated by the Partnership not in the ordinary course of business. Other income was $3,119 for the year ended December 31, 2016 compared to $941 for the year ended December 31, 2015. The $2,178 increase was primarily attributable to a customer's partial coal contract buyout and sales of coal purchased from third parties and resold to end users in the 2016 period.

Cost of Coal Sold

Cost of coal sold is comprised of operating costs related to produced tons sold, along with changes in coal inventory, both in volumes and carrying values. The cost of coal sold per ton includes items such as direct operating costs, royalties and production taxes, direct administration expenses, and depreciation, depletion, and amortization costs. Total cost of coal sold was $211,265 for the year ended December 31, 2016, or $27,634 lower than the $238,899 for the year ended December 31, 2015. Total costs per ton sold were $34.35 per ton for the year ended December 31, 2016 compared to $41.78 per ton for the year ended December 31, 2015. The decrease in the cost of coal sold was driven by the idling of one longwall for approximately 90 days in the first quarter of 2016, reduction of staffing levels, vendor concessions and the realignment of employee benefits. Productivity for the year ended December 31, 2016, as measured by tons per employee-hour, also improved by 17% compared to the year-ago period, despite the reduced average number of longwalls in operation over the 2016 period.

Total Other Costs

Total other costs is comprised of various costs that are not allocated to each individual mine and therefore are not included in unit costs. Total other costs increased $14,532 for the year ended December 31, 2016 compared to the year ended December 31, 2015. The increase in other costs was primarily attributable to a net periodic benefit credit of $7,341 related to the OPEB plan remeasurement for the year ended December 31, 2015 compared to the year ended December 31, 2016, where no benefit credits were recorded, as the Partnership had no further OPEB obligation in connection with the completion of the IPO. The increase was also attributable to $4,518 of costs related to temporarily idling one of the longwalls at the Pennsylvania Mining Complex for approximately 90 days in the first quarter of 2016 due to market conditions. The remaining variance was related to costs to purchase coal from third parties for blending purposes and discretionary 401(k) contributions in the 2016 period which we are required to reimburse under the omnibus agreement.

Selling, General and Administrative Expense

Selling, general, and administrative expenses decreased $982 in the period-to-period comparison primarily due to reduced staffing levels and the realignment of employee benefits in 2016 compared to 2015.

Interest Expense

Interest expense, net of amounts capitalized, for the year ended December 31, 2016 was $8,719, which primarily relates to obligations under our revolving credit facility. For the year ended December 31, 2015, $9,636 of interest expense was incurred primarily on several related party long-term notes with CONSOL Financial Inc. ("CFI"), a wholly owned subsidiary of CONSOL Energy (see Note 9 - Revolving Credit Facility and Note 19 - Related Party in Item 8 of this Form 10-K for additional information), which were excluded from the Partnership's assets and liabilities at the time of the IPO. Also, interest expense related to the revolving credit facility was $3,928 for the year ended December 31, 2015.

Adjusted EBITDA

Adjusted EBITDA was $77,749 for the year ended December 31, 2016 compared to $115,964 for the year ended December 31, 2015. The $38,215 decrease was a result of a $13.05 per ton decrease in the average sales price, offset in part, by a $6.38 per ton improvement in the cash cost of coal sold resulting in a $41,028 decrease in Adjusted

EBITDA. Additional decreases to Adjusted EBITDA were due to cash costs of $3,300 related to idling one of the longwalls at the Pennsylvania Mining Complex for approximately 90 days in the first quarter of 2016, and $2,271 related to a CONSOL Energy discretionary 401(k) contribution. These decreases in Adjusted EBITDA were offset by $9,457 related to increased sales tons. The remaining variance was due to various transactions through out both periods, none of which were individually material.

Distributable Cash Flow

Distributable cash flow was $28,613 for the year ended December 31, 2016 compared to $54,994 for the year ended December 31, 2015. The $26,381 decrease was primarily attributed to a $38,215 decrease in Adjusted EBITDA as discussed above, offset in part, by $13,094 decrease in the PA Mining Acquisition Adjusted EBITDA. The remaining variance was due to various other transactions in both periods, none of which are individually material.

Years Ended December 31, 2015 Compared to the Years Ended December 31, 2014

Total net income was $64,538 for the year ended December 31, 2015 compared to $104,875 for the year ended December 31, 2014. Our results of operations for each of these periods are presented in the table below. Variances are discussed following the table.

	For the Years Ended December 31,		
	2015	2014	Variance
Revenue:	(in thousands)		
Coal Revenue	$322,261	$404,247	$(81,986)
Freight Revenue	3,809	4,192	(383)
Other Income	941	9,660	(8,719)
Total Revenue and Other Income	327,011	418,099	(91,088)
Cost of Coal Sold:			
Operating Costs	197,224	237,062	(39,838)
Depreciation, Depletion and Amortization	41,675	41,331	344
Total Cost of Coal Sold	238,899	278,393	(39,494)
Other Costs:			
Other Costs	(3,263)	2,801	(6,064)
Depreciation, Depletion and Amortization	2,461	2,006	455
Total Other Costs	(802)	4,807	(5,609)
Freight Expense	3,809	4,192	(383)
Selling, General, and Administrative Expenses	10,931	17,149	(6,218)
Interest Expense	9,636	8,683	953
Total Costs	262,473	313,224	(50,751)
Net Income	$64,538	$104,875	$(40,337)
Adjusted EBITDA	$115,964	$157,340	$(41,376)
Distributable Cash Flow	$54,994	$86,292	$(31,298)

Coal Production Rates

The table below presents total tons produced from the Pennsylvania Mining Complex on our 25% undivided interest for the periods indicated:

Mine	Years Ended December 31, 2015	2014	Variance
	(in thousands)		
Bailey	2,547	3,081	(534)
Enlow Fork	2,250	2,639	(389)
Harvey	901	796	105
Total	5,698	6,516	(818)

Coal production was 5,698 tons for the year ended December 31, 2015 compared to 6,516 tons for the year ended December 31, 2014. The 818 decrease in tons was attributable to reduced production to adjust to contracted sales commitments. The production at the Harvey Mine increased as a result of the commencement of longwall mining operations in March 2014.

Coal Operations

Coal revenue and cost components on a per unit basis for the years ended December 31, 2015 and December 31, 2014 were as indicated in the table below. Our operations also include various costs such as selling, general and administrative, freight and other costs not included in our unit cost analysis because these costs are not directly associated with coal production.

	For the Years Ended December 31, 2015	2014	Variance
Total Tons Sold (in thousands)	5,719	6,533	(814)
Average Sales Price Per Ton Sold	$56.36	$61.88	$ (5.52)
Operating Costs Per Ton Sold (Cash Cost)	$34.47	$36.27	$ (1.80)
Depreciation, Depletion and Amortization Per Ton Sold (Non-Cash Cost)	7.31	6.34	0.97
Total Costs Per Ton Sold	$41.78	$42.61	$ (0.83)
Average Margin Per Ton Sold	$14.58	$19.27	$ (4.69)
Add: Depreciation, Depletion and Amortization Costs Per Ton Sold	7.31	6.34	0.97
Average Cash Margin Per Ton Sold (1)	$21.89	$25.61	$ (3.72)

(1) Average cash margin per ton is an operating ratio derived from non-GAAP measures.

Revenue and Other Income

Coal revenue was $322,261 for the year ended December 31, 2015 compared to $404,247 for the year ended December 31, 2014. The $81,986 decrease was attributable to $5.52 per ton lower average sales price and an 814 decrease in tons sold. The lower average coal sales price per ton in the 2015 period was primarily the result of the overall decline in the domestic thermal and global coal markets. Due to a weak domestic thermal spot market, 1,384 tons were sold on the export market for the year ended December 31, 2015 as compared to 835 tons for the year ended December 31, 2014, which negatively impacted the average sales price per ton sold in the year-to-year comparison.

Freight revenue, which is completely offset in freight expense, is the amount billed to customers based on the weight of coal shipped and negotiated freight rates for rail transportation. Freight revenue was $3,809 for the year ended

December 31, 2015 compared to $4,192 for the year ended December 31, 2014. The $383 decrease in freight revenue was due to decreased shipments to customers where we were contractually obligated to provide transportation services.

Other income is comprised of income generated by the Partnership not in the ordinary course of business. Other income was $941 for the year ended December 31, 2015 compared to $9,660 for the year ended December 31, 2014. The $8,719 decrease was due to a $7,500 coal customer contract buyout in the 2014 period and $1,220 of various transactions in both periods, none of which were individually material.

Cost of Coal Sold

Cost of coal sold is comprised of operating costs related to produced tons sold, along with changes in coal inventory, both in volumes and carrying values. The costs of coal sold per ton include items such as direct operating costs, royalties and production taxes, direct administration expenses, and depreciation, depletion, and amortization costs. Total cost of coal sold was $238,899 for the year ended December 31, 2015, or $39,494 lower than the $278,393 for the year ended December 31, 2014. Total costs per ton sold were $41.78 per ton for the year ended December 31, 2015 compared to $42.61 per ton for the year ended December 31, 2014. The decrease in the cost of coal sold was driven by a reduced workforce, approximately 90,000 less feet of coal mined with continuous mining units, improved operational efficiencies, reduction of Pennsylvania stream subsidence expense and other ongoing cost reduction efforts as a result of reducing production for 2015 to match the contracted sales commitments of the Partnership. There was also a decrease in unit costs due to Other Post-Retirement Benefit ("OPEB") liabilities being retained by CONSOL Energy, in conjunction with the IPO.

Total Other Costs

Total other costs is comprised of various costs that are not allocated to each individual mine and therefore not included in unit costs. Total other costs decreased $5,609 for the year ended December 31, 2015 compared to the year ended December 31, 2014. The decrease was primarily attributable to the remeasurement of the OPEB plans to reflect a plan amendment for salary and hourly workers that occurred on May 31, 2015. OPEB was excluded from the Partnership at the time of the IPO.

Selling, General and Administrative Expense

Upon the closing of the IPO, the Partnership entered into a service arrangement for CONSOL Energy to provide certain selling, general and administrative services. These services are paid monthly based on agreed upon rates. In addition, the Partnership incurred various costs as a result of being a publicly traded entity for the year ended December 31, 2015. For the year ended December 31, 2014, CONSOL Energy allocated selling, general and administrative expenses based upon the level of operating activity of its underlying business units. These expenses include CONSOL Energy's stock based compensation and short-term incentive compensation program, as well as costs that are directly related to our operations along with a portion of costs that are allocated to us based on a percent of total labor costs. The amount of selling, general and administrative expenses incurred was $10,931 for the year ended December 31, 2015 compared to $17,149 for the year ended December 31, 2014. The $6,218 decrease was primarily attributable to lower short-term incentive compensation payouts.

Interest Expense

Interest expense was $9,636 for the year ended December 31, 2015, which includes interest on the revolving credit facility that we entered into in connection with the completion of the IPO and interest expense incurred on the CONSOL Financial Inc. ("CFI"), a wholly owned subsidiary of CONSOL Energy, loan which was excluded from the Partnership at the time of the IPO. Interest expense, was $8,683 for the year ended December 31, 2014, which includes interest expense incurred on the CFI loan. The $953 increase in the year-to-year comparison was primarily due to lower capitalized interest as a result of the commencement of longwall mining operations at the Harvey Mine in March 2014.

Adjusted EBITDA

Adjusted EBITDA was $115,964 for the year ended December 31, 2015 compared to $157,340 for the year ended December 31, 2014. The $41,376 decrease was attributed to 814 less tons sold and a $3.72 per ton decrease in the average cash margin per ton sold. The $3.72 per ton decrease in the average cash margin per ton which was primarily a result of the $5.52 per ton coal sales price decrease offset, in part, against a $1.80 per ton improvement in the cash costs of coal sold, which resulted in a $21,275 decrease to Adjusted EBITDA. The remaining decrease in Adjusted EBITDA of $20,101 is primarily due to 814 less tons sold during 2015.

Distributable Cash Flow

Distributable cash flow was $54,994 for the year ended December 31, 2015 compared to $86,292 for the year ended December 31, 2014. The $31,298 decrease was primarily attributed to a $41,376 decrease in Adjusted EBITDA as discussed above, offset in part, by a reduction in cash interest paid for the year ended December 31, 2015 of $7,896 compared to $9,538 for the year ended December 31, 2014. The remaining variance was due to various other transactions in both periods, none of which are individually material.

Capital Resources and Liquidity

Liquidity and Financing Arrangements

Historically, our principal sources of liquidity have been cash from operations and, prior to our IPO, funding from CONSOL Energy. We do not currently have any commitment from CONSOL Energy, our general partner or any of their respective affiliates to fund our cash flow deficits or provide other direct or indirect financial assistance to us. We expect our ongoing sources of liquidity to include cash generated from operations, borrowings under our revolving credit facility and, if necessary, the issuance of additional equity or debt securities. We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements and our long-term capital expenditure requirements and to make quarterly cash distributions as declared by the board of directors of our general partner.

Our Partnership Agreement requires that we distribute all of our available cash (as defined in the Partnership Agreement - see Item 5 - “Definition of Available Cash”) to our unitholders. As a result, we expect to rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures, if any.

On January 30, 2017, the Board of Directors of our general partner declared a cash distribution to the Partnership's unitholders for the fourth quarter of 2016 of $0.5125 per common and subordinated unit and $0.4678 per Class A Preferred Unit. The cash distribution will be paid on February 15, 2017 to the unitholders of record at the close of business on February 9, 2017.

Revolving Credit Facility

Obligations under our $400,000 senior secured revolving credit facility, with certain lenders and PNC Bank N.A., as administrative agent, are guaranteed by our subsidiaries (the “guarantor subsidiaries”) and are secured by substantially all of our and our subsidiaries’ assets pursuant to a security agreement and various mortgages. CONSOL Energy is not a guarantor of our obligations under our revolving credit facility.

The unused portion of our revolving credit facility will be subject to a commitment fee of 0.50% per annum. Interest on outstanding indebtedness under our revolving credit facility accrues, at our option, at a rate based on either:

- The highest of (i) PNC Bank N.A.’s prime rate, (ii) the federal funds open rate plus 0.50%, and (iii) the one-month LIBOR rate plus 1.0%, in each case, plus a margin ranging from 1.50% to 2.50% depending on the total leverage ratio; or

- the LIBOR rate plus a margin ranging from 2.50% to 3.50% depending on the total leverage ratio.

As of December 31, 2016, the revolving credit facility had $201,000 of borrowings outstanding, leaving $199,000 of unused capacity. Interest on outstanding borrowings under the revolving credit facility at December 31, 2016 was accrued at 3.99% based on a LIBOR rate of 0.74%, plus a margin of 3.25%.

Our revolving credit facility matures on July 7, 2020, and requires compliance with conditions precedent that must be satisfied prior to any borrowing as well as ongoing compliance with certain affirmative and negative covenants.

Affirmative covenants include, among others, requirements relating to: (i) the preservation of existence; (ii) the payment of obligations, including taxes; (iii) the maintenance of properties and equipment, insurance and books and records; (iv) compliance with laws and material contracts; (v) use of proceeds; (vi) the subordination of intercompany loans; (vii) compliance with anti-terrorism, anti-money laundering, anti-corruption and sanctions laws; and (viii) collateral.

Negative covenants include, among others, restrictions on our and our guarantor subsidiaries' ability to: (i) create, incur, assume or suffer to exist indebtedness; (ii) create or permit to exist liens on their properties; (iii) make or pay any dividends or distributions; provided that we will be able to make cash distributions of available cash to partners so long as no event of default is continuing or would result therefrom; (iv) merge with or into another person, liquidate or dissolve, acquire all or substantially all of the assets of any going concern or going line of business or acquire all or a substantial portion of another person's assets; (v) make particular investments and loans; provided that we will be able to increase our ownership percentage of our undivided interest in the Pennsylvania Mining Complex and make investments in the Pennsylvania Mining Complex in accordance with our ratable ownership; (vi) sell, transfer, convey, assign or dispose of our assets or properties other than in the ordinary course of business and other select instances; (vii) deal with any affiliate except in the ordinary course of business on terms no less favorable to us than we would otherwise receive in an arm's length transaction; (viii) amend organizational documents or any documentation governing certain material debt; and (ix) amend, waive or grant a consent under any material contract. In addition, we are obligated to maintain at the end of each fiscal quarter (x) a minimum interest coverage ratio of at least 3.00 to 1.00 and (y) a maximum total leverage ratio of no greater than 3.50 to 1.00 (or 4.00 to 1.00 for two fiscal quarters after consummation of a material acquisition). At December 31, 2016, the interest coverage ratio was 9.48 to 1.00 and the total leverage ratio was 2.48 to 1.00.

Our revolving credit facility also contains events of default, including, but not limited to, cross-default to certain other debt, breaches of representations and warranties, change of control events and breaches of covenants.

Cash Flows

	For the Years Ended December 31,		
	2016	2015	Variance
	(in thousands)		
Cash flows provided by operating activities	$73,098	$76,908	$(3,810)
Cash used in investing activities	$(34,181)	$(34,002)	$(179)
Cash used in financing activities	$(35,666)	$(36,376)	$710

Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015:

Cash flows provided by operating activities decreased $3,810 in the year ended December 31, 2016 compared to the year ended December 31, 2015 primarily due to the decrease of $38,687 in net income in the period-to-period comparison, offset by a $35,683 increase in operating cash flow from changes in working capital in the period-to-period comparison. The increase in operating cash flow from changes in working capital was related to an increase accounts receivable of $19,389 during the year ended December 31, 2015 and a $14,254 change in other operating liabilities in the period-to-period comparison. The change in other operating liabilities primarily related to a decrease in subsidence liabilities during the year ended December 31, 2015. Prior to the IPO, accounts receivable were sold to CONSOL Financial Inc, which resulted in no trade receivables as of July 7, 2015. The remaining variance relates to various transactions throughout both periods, none of which are individually material.

Net cash used in investing activities increased $179 in the year ended December 31, 2016 compared to the year ended December 31, 2015 primarily as a result of increased capital expenditures of $131 and decreased proceeds from sale of assets of $48. The increase in capital expenditures is due to the following items:

	For the Years Ended December 31,		
	2016	2015	Variance
	(in thousands)		
Pennsylvania Mining Complex Acquisition	$21,500	$—	$21,500
Building and infrastructure	8,358	14,679	(6,321)
Equipment purchases and rebuilds	2,734	11,963	(9,229)
Refuse storage area	591	3,268	(2,677)
Water treatment systems	223	3,257	(3,034)
Other	798	906	(108)
Total capital expenditures	$34,204	$34,073	$131

Net cash used in financing activities decreased $710 in the year ended December 31, 2016 compared to the year ended December 31, 2015. The decrease is a result of the 2015 IPO, which resulted in a net cash inflow of $5,648, which was net proceeds from the issuance of common units of $148,359 plus $200,000 borrowings on the revolver, less $342,711 distribution of the proceeds to CONSOL Energy. The decrease is also attributable to an increase in cash distributions of $31,281 in the period to period comparison, as 2016 included four quarters of payments versus only one quarter in 2015. These decreases in cash used in financing were offset against $31,000 difference in the revolver activity in the period to period comparison, which was comprised of $16,000 in borrowing in 2016 versus $15,000 in post IPO payments in 2015. The remaining variance is primarily due to changes in pre-IPO and pre-PA Mining Acquisition related party activity in the period to period comparison.

Off-Balance Sheet Arrangements

We do not maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources which are not disclosed in the Notes to the Audited Consolidated Financial Statements of this Form 10-K.

Critical Accounting Policies

Critical accounting policies are those that are important to our financial condition and require management's most difficult, subjective or complex judgments. Different amounts would be reported under different operating conditions or under alternative assumptions. We have evaluated the accounting policies used in the preparation of the accompanying financial statements and related notes thereto and believe those policies are reasonable and appropriate.

We apply those accounting policies that we believe best reflect the underlying business and economic events, consistent with GAAP. Our more critical accounting policies include those related to the following items, but refer to Note 1 (Description of Business, Basis of Presentation and Recent Accounting Pronouncements) of the audited consolidated financial statements included elsewhere in this report for a complete listing of our accounting policies.

Worker's Compensation and Coal Workers' Pneumoconiosis ("CWP")

Liabilities and expenses for worker's compensation and CWP are determined using actuarial methodologies and incorporate significant assumptions, including the interest rate used to discount the future estimated liability, health care cost trend rates and mortality rates.

The interest rate used to discount future estimated liabilities is determined using a company-specific yield curve model (above median) developed with the assistance of an external actuary. The Partnership specific yield curve uses a subset of the expanded bond universe to determine the Partnership specific discount rate. Bonds used in the yield curves are rated AA by Moody's or Standard & Poor's as of the measurement date. The yield curve model parallels the plans' projected cash flows.

The estimated liabilities recognized at December 31, 2016 and the benefit payments made for the year end December 31, 2016 were as follows (in thousands):

Plan	Estimated Liability as of December 31, 2016	Benefit Payments for the year ended December 31, 2016
Workers' Compensation	$ 4,385	$ 1,553
CWP	$ 2,113	$ 53

Contingencies

The Partnership, from time to time, is subject to various lawsuits and claims with respect to such matters as personal injury, wrongful death, damage to property, exposure to hazardous substances, governmental regulations (including environmental remediation), employment and contract disputes, and other claims and actions, arising out of the normal course of business. Liabilities are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Estimates are developed through consultation with legal counsel involved in the defense and are based upon an analysis of potential results, assuming a combination of litigation and settlement strategies. Legal fees associated with defending these various lawsuits and claims are expensed when incurred.

Asset Retirement Obligations

The Surface Mining Control and Reclamation Act established operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Accounting for asset retirement obligations requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the long-lived asset. Asset retirement obligations are primarily related to the closure of the mines and gas wells and the reclamation of land upon exhaustion of coal reserves. Changes in the variables used to calculate the liabilities can have a significant effect on the mine closing and reclamation liabilities. We accrue for the costs of current mine disturbance and final mine and gas well closure, including the cost of treating mine water discharge where necessary. Estimates of our total reclamation, mine-closing and gas well closing liabilities, which are based upon permit requirements and our engineering expertise related to these requirements, including the current portion, were $9,937 at December 31, 2016 and $10,412 at December 31, 2015. These liabilities are reviewed annually, or when events and circumstances indicate an adjustment is necessary, by management and engineers. The estimated liability can significantly change if actual costs vary from assumptions or if governmental regulations change significantly.

Coal Reserve Values

There are numerous uncertainties inherent in estimating quantities and values of economically recoverable coal reserves, including many factors beyond our control. As a result, estimates of economically recoverable coal reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our staff. Some of the factors and assumptions which impact economically recoverable reserve estimates include:

- geological conditions;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations and taxes by governmental agencies;
- assumptions governing future prices; and
- future operating costs.

Each of these factors may in fact vary considerably from the assumptions used in estimating reserves. For these reasons, estimates of the economically recoverable quantities of coal attributable to a particular group of properties, and classifications of these reserves based on risk of recovery and estimates of future net cash flows, may vary substantially. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and these variances may be material.

Significant Contractual Obligations

The following is a summary of our significant contractual obligations at December 31, 2016 (in thousands).

	Payments due by Year				
	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
Long-term debt	$—	$—	$201,000	$—	$201,000
Interest on long-term debt	7,035	14,070	4,232	—	25,337
Capital (finance) lease obligations	88	126	19	—	233
Interest on capital (finance) lease obligations	4	8	2	—	14
Operating lease obligations	13,276	19,768	10,325	5,174	48,543
Long-term liabilities—employee related (a)	1,564	3,070	3,367	9,979	17,980
Other long-term liabilities (b)	42,693	1,051	1,214	2,764	47,722
Total contractual obligations	$64,660	$38,093	$220,159	$17,917	$340,829

(a) Long-term liabilities—employee related include liabilities for work-related injuries and illnesses.

(b) Other long-term liabilities include mine reclamation and closure and other long-term liability costs.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In addition to the risks inherent in operations, we are exposed to financial, market, political and economic risks. The following discussion provides additional detail regarding our exposure to the risks related to changes in commodity prices, interest rates and foreign exchange rates.

Commodity Price Risk

We are exposed to market price fluctuations in the normal course of selling coal. We sell coal in the spot market and under both short-term and multi-year contracts that may contain base prices subject to pre-established price adjustments that reflect (i) variances in the quality characteristics of coal delivered to the customer beyond threshold quality characteristics specified in the applicable sales contract, (ii) the actual calorific value of coal delivered to the customer, and/or (iii) changes in electric power prices in the markets in which our customers operate, as adjusted for any factors set forth in the applicable contract.

Interest Rate Risk

Based on our current debt level of $201,000 thousand, comprised of funds drawn on our revolving credit facility, an increase of one percentage point in the interest rate will result in an increase in annual interest expense of $2,010 thousand. As a result, our results of operations, cash flows and financial condition and our ability to make cash distributions to our unitholders could be materially adversely affected by significant increases in interest rates.

Foreign Exchange Rate Risk

All of our transactions are denominated in U.S. dollars. As a result, we do not have material direct exposure to fluctuations in foreign currency exchange rates from the sale of our coal under sales contracts. However, because coal is sold internationally in U.S. dollars, general economic conditions in foreign markets and changes in foreign currency exchange rates may provide our foreign competitors with a competitive advantage. If our competitors’ currencies decline against the U.S. dollar or against our foreign customers’ local currencies, those competitors may be able to offer lower prices for coal to our customers. Furthermore, if the currencies of our overseas customers were to significantly decline in value in comparison to the U.S. dollar, those customers may seek decreased prices for the coal we sell to them. Consequently, currency fluctuations could adversely affect the competitiveness of our coal in international markets.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors of CNX Coal Resources GP LLC and Unitholders of CNX Coal Resources LP

We have audited the accompanying consolidated balance sheets of CNX Coal Resources LP (including its Predecessor as defined in Note 1) as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, partners' capital and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Partnership's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of CNX Coal Resources LP at December 31, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Pittsburgh, Pennsylvania
February 8, 2017

CNX COAL RESOURCES LP
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands, except per unit data)

	For the Years Ended December 31,		
	2016	2015	2014
Coal Revenue	$266,395	$ 322,261	$404,247
Freight Revenue	11,603	3,809	4,192
Other Income	3,119	941	9,660
Total Revenue and Other Income	281,117	327,011	418,099
Operating and Other Costs [1]	183,001	193,961	239,863
Depreciation, Depletion and Amortization	41,994	44,136	43,337
Freight Expense	11,603	3,809	4,192
Selling, General and Administrative Expenses [2]	9,949	10,931	17,149
Interest Expense [3]	8,719	9,636	8,683
Total Costs	255,266	262,473	313,224
Net Income	$25,851	$ 64,538	$104,875
Less: Net Income Attributable to CONSOL Energy, Pre-IPO and Pre-PA Mining Acquisition	3,995	41,182	N/A
Net Income Attributable to General and Limited Partner Ownership Interest in CNX Coal Resources	$21,856	$ 23,356	N/A
Less: General Partner Interest in Net Income	399	468	N/A
Less: Net Income Allocable to Preferred Units	1,851	—	N/A
Limited Partner Interest in Net Income	$19,606	$ 22,888	N/A
Less: Effect of Subordinated Distribution Suspension	119	—	N/A
Net Income Allocable to Limited Partner Units	$19,487	$ 22,888	N/A
Net Income per Limited Partner Unit - Basic	$0.84	$ 0.99	N/A
Net Income per Limited Partner Unit - Diluted	$0.83	$ 0.99	N/A
Limited Partner Units Outstanding - Basic	23,225,142	23,222,134	N/A
Limited Partner Units Outstanding - Diluted	23,402,897	23,223,045	N/A
Cash Distributions Declared per Unit [4]			
Common Unit	$2.0500	$ 0.9916	N/A
Subordinated Unit	$1.5375	$ 0.9916	N/A

[1] Related Party of $4,251, $6,793 and $17,557 for the years ended December 31, 2016, 2015, and 2014, respectively.
[2] Related Party of $3,826, $8,926 and $11,384 for the years ended December 31, 2016, 2015, and 2014, respectively.
[3] Related Party of $0, $6,050 and $11,918 for the years ended December 31, 2016, 2015, and 2014, respectively.
[4] Represents the cash distribution declared related to the period presented. See Note 21 - Subsequent Events.

The accompanying notes are an integral part of these consolidated financial statements.

CNX COAL RESOURCES LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)

	For the Years Ended December 31,		
	2016	2015	2014
Net Income	$25,851	$64,538	$104,875
Actuarially Determined Long-Term Liability Adjustments:			
Amortization of prior service credits	—	(8,701)	(2,332)
Recognized net actuarial (gain) loss	(93)	1,245	546
Curtailment Gain	—	—	(2,553)
OPEB Plan amendments	—	4,714	35,469
Other comprehensive income before reclassifications	911	902	10,669
Total Actuarially Determined Long-Term Liability Adjustments	818	(1,840)	41,799
Other Comprehensive Income (Loss)	818	(1,840)	41,799
Comprehensive Income	$26,669	$62,698	$146,674

The accompanying notes are an integral part of these consolidated financial statements.

CNX COAL RESOURCES LP
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2016	December 31, 2015
ASSETS		
Current Assets:		
Cash	$ 9,785	$ 6,534
Trade Receivables	23,418	19,398
Other Receivables	515	471
Inventories	11,491	12,238
Prepaid Expenses	3,512	5,089
Total Current Assets	48,721	43,730
Property, Plant and Equipment:		
Property, Plant and Equipment	876,690	865,527
Less—Accumulated Depreciation, Depletion and Amortization	442,178	400,911
Total Property, Plant and Equipment—Net	434,512	464,616
Other Assets:		
Other	21,063	17,598
Total Other Assets	21,063	17,598
TOTAL ASSETS	$ 504,296	$ 525,944

The accompanying notes are an integral part of these consolidated financial statements.

CNX COAL RESOURCES LP
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts Payable	$ 18,797	$ 17,405
Accounts Payable—Related Party	1,666	4,310
Other Accrued Liabilities	44,318	37,281
Total Current Liabilities	64,781	58,996
Long-Term Debt:		
Revolver, Net of Debt Issuance and Financing Fees	197,843	180,946
Capital Lease Obligations	146	124
Total Long-Term Debt	197,989	181,070
Other Liabilities:		
Pneumoconiosis Benefits	2,057	1,934
Workers’ Compensation	3,090	2,929
Asset Retirement Obligations	9,346	8,499
Other	463	713
Total Other Liabilities	14,956	14,075
TOTAL LIABILITIES	277,726	254,141
Partners' Capital:		
Class A Preferred Units (3,956,496 Units Outstanding at December 31, 2016; No Units Outstanding at December 31, 2015)	69,151	—
Common Units (11,618,456 Units Outstanding at December 31, 2016; 11,611,067 Units Outstanding at December 31, 2015)	140,967	154,309
Subordinated Units (11,611,067 Units Outstanding at December 31, 2016 and December 31, 2015)	(7,631)	6,188
General Partner Interest	12,274	13,081
Parent Net Investment	—	87,234
Accumulated Other Comprehensive Income	11,809	10,991
Total Partners' Capital	226,570	271,803
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 504,296	$ 525,944

The accompanying notes are an integral part of these consolidated financial statements.

CNX COAL RESOURCES LP
CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
(Dollars in thousands)

			Limited Partners				
	Parent Net Investment	Class A Preferred Units	Common	Subordinated	General Partner	Accumulated Other Comprehensive Income	Total
Balance at December 31, 2013	$ 152,361		$—	$ —	$—	$ (2,590)	$ 149,771
Net Income	104,875		—	—	—		104,875
Other Comprehensive Income			—	—	—	41,799	41,799
Net Working Capital Advances to the Partnership	(83,162)		—	—	—		(83,162)
Balance at December 31, 2014	$ 174,074	$ —	$—	$ —	$—	$ 39,209	$ 213,283
Net Income Attributable to January 1, 2015 to July 6, 2015	34,134	—	—	—	—	—	34,134
Other Comprehensive Loss	—	—	—	—	—	(1,840)	(1,840)
Net Working Capital Advances to the Partnership	(26,981)	—	—	—	—	—	(26,981)
Assets and Liabilities Contributed/Distributed	258,276	—	—	—	—	(26,378)	231,898
Deemed Distribution to Partnership	(355,887)	—	28,450	314,597	12,840	—	—
Net Working Capital Advances to the Partnership	(3,430)				—		(3,430)
Issuance of Common Units to Public, Net of Offering Costs	—	—	148,359	—	—	—	148,359
Distribution of IPO Proceeds	—	—	(28,421)	(314,290)	—	—	(342,711)
Net Income Attributable to the Partnership	7,048	—	11,444	11,444	468	—	30,404
Unitholder Distributions	—	—	(5,563)	(5,563)	(227)		(11,353)
Unit Based Compensation	—	—	40	—	—	—	40
Balance at December 31, 2015	$ 87,234	$ —	$ 154,309	$ 6,188	$ 13,081	$ 10,991	$ 271,803
Issuance of Class A Preferred Units	—	67,300	—	—	—	—	67,300
Net Income	3,995	1,851	9,806	9,800	399	—	25,851
Other Comprehensive Income	—	—	—	—	—	818	818
Net Working Capital Advances to the Partnership	(8,953)	—	—	—	—	—	(8,953)
Net Asset Acquired in Pennsylvania Mining Complex	(82,276)	—	—	—	—	—	(82,276)
Purchase Price in Excess of Net Assets Acquired	—	—	(522)	(5,767)	(235)	—	(6,524)
Unitholder Distributions	—	—	(23,811)	(17,852)	(971)	—	(42,634)
Unit Based Compensation	—	—	1,185			—	1,185
Balance at December 31, 2016	$ —	$ 69,151	$ 140,967	$ (7,631)	$ 12,274	$ 11,809	$ 226,570

The accompanying notes are an integral part of these consolidated financial statements.

CNX COAL RESOURCES LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)

	For the Years Ended December 31,		
	2016	2015	2014
Cash Flows from Operating Activities:			
Net Income	$25,851	$64,538	$104,875
Adjustments to Reconcile Net Income to Net Cash Provided By Operating Activities:			
Depreciation, Depletion and Amortization	41,994	44,136	43,337
(Gain) Loss on Sale of Assets	9	(61)	(185)
Unit Based Compensation	1,185	40	—
Other Adjustments to Net Income	898	777	286
Changes in Operating Assets:			
Accounts and Notes Receivable	(4,064)	(19,389)	(331)
Inventories	747	1,061	366
Prepaid Expenses	1,577	(186)	(254)
Changes in Other Assets	(3,465)	(3,246)	(1,593)
Changes in Operating Liabilities:			
Accounts Payable	1,968	(416)	(2,275)
Accounts Payable—Related Party	(2,644)	3,430	—
Other Operating Liabilities	7,010	(7,244)	1,243
Changes in Other Liabilities	2,032	(6,532)	(2,833)
Net Cash Provided by Operating Activities	73,098	76,908	142,636
Cash Flows from Investing Activities:			
Capital Expenditures	(12,704)	(34,073)	(85,076)
PA Mining Acquisition	(21,500)	—	—
Proceeds from Sales of Assets	23	71	19,046
Net Cash Used in Investing Activities	(34,181)	(34,002)	(66,030)
Cash Flows from Financing Activities:			
Payments on Miscellaneous Borrowings	(79)	(53)	(24)
Payments on Related Party Long-Term Notes	—	(10,951)	(2,311)
Proceeds from Related Party Long-Term Notes	—	16,990	14,214
Proceeds from Revolver, Net of Payments	16,000	185,000	—
Proceeds from Issuance of Common Units, Net of Offering Costs	—	148,359	—
Distribution of Proceeds	—	(342,711)	—
Payments for Unitholder Distributions	(42,634)	(11,353)	—
Debt Issuance and Financing Fees	—	(4,329)	—
Net Change in Parent Advances	(8,953)	(17,328)	(88,485)
Net Cash Used In Financing Activities	(35,666)	(36,376)	(76,606)
Net Increase in Cash	3,251	6,530	—
Cash at Beginning of Period	6,534	4	4
Cash at End of Period	$9,785	$6,534	$4

The accompanying notes are an integral part of these consolidated financial statements.

CNX COAL RESOURCES LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands)
NOTE 1—SIGNIFICANT ACCOUNTING POLICIES

A summary of the significant accounting policies is included below. These, together with the other notes to the consolidated financial statements, are an integral part of the Consolidated Financial Statements.

Basis of Consolidation and Presentation:

On September 30, 2016, the Partnership and its wholly owned subsidiary, CNX Thermal Holdings, entered into a Contribution Agreement (the “Contribution Agreement”) with CONSOL Energy, CPCC and Conrhein and together with CPCC, (the “Contributing Parties”), under which CNX Thermal Holdings acquired an undivided 6.25% of the Contributing Parties’ right, title and interest in and to the Pennsylvania Mining Complex (which represents an aggregate 5% undivided interest in and to the Pennsylvania Mining Complex)("PA Mining Acquisition"). The PA Mining Acquisition was a transaction between entities under common control; therefore, the partnership recorded the assets and liabilities of the acquired 5% of Pennsylvania Mining Complex at their carrying amounts to CONSOL Energy on the date of the transaction. The difference between CONSOL Energy’s net carrying amount and the total consideration paid to CONSOL Energy was recorded as a capital transaction with CONSOL Energy, which resulted in a reduction in partners’ capital. Because this transaction is between entities under common control, the Partnership recast its historical consolidated financial statements to retrospectively reflect the additional 5% interest in Pennsylvania Mining Complex as if the business was owned for all periods presented; however, the consolidated financial statements are not necessarily indicative of the results of operations that would have occurred if the Partnership had owned it during the periods reported.

For the years ended December 31, 2016 and 2015, the Consolidated Financial Statements include the accounts of CNX Operating and CNX Thermal Holdings, wholly-owned and controlled subsidiaries.

For the year ended December 31, 2014, these audited Consolidated Financial Statements were prepared from separate records maintained by CONSOL Energy, CPCC and Conrhein and may not necessarily be indicative of the conditions that would have existed, or the results of operations, if CPCC and Conrhein had been operated as unaffiliated entities. These Audited Consolidated Financial Statements represent the combination of two separate legal entities wholly owned by CONSOL Energy, the net assets of the Partnership have been presented as a Parent Net Investment. Parent Net Investment is primarily comprised of the Partnership’s undivided interest in (i) CONSOL Energy’s initial investment in CPCC and Conrhein (and any subsequent adjustments thereto); (ii) the accumulated net earnings; (iii) net transfers to or from CONSOL Energy, including those related to cash management functions performed by CONSOL Energy; (iv) non-cash changes in financing arrangements, including the conversion of certain related party liabilities into Parent Net Investment; and (v) corporate cost allocations. Transactions between the Partnership and CONSOL Energy or CONSOL Energy’s other subsidiaries have been identified in the financial statements as transactions between related parties and are discussed in Note 19 - Related Party.

Jumpstart Our Business Startups Act ("JOBS Act"):

Under the JOBS Act, for as long as the Partnership remains an “emerging growth company” as defined in the JOBS Act, we may take advantage of certain exemptions from the SEC's reporting requirements that are applicable to other public companies that are not emerging growth companies, including not being required to provide an auditor’s attestation report on management’s assessment of the effectiveness of its system of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and seeking unitholder approval of any golden parachute payments not previously approved. We may take advantage of these reporting exemptions until we are no longer an emerging growth company.

The Partnership will remain an emerging growth company for up to five years, although we will lose that status sooner if:

- we have more than $1 billion of revenues in a fiscal year;
- limited partner interests held by non-affiliates have a market value of more than $700 million (large accelerated filer); or
- we issue more than $1 billion of non-convertible debt over a three-year period.

The JOBS Act also provides that an emerging growth company can delay adopting new or revised accounting standards until such time as those standards apply to private companies. The Partnership has irrevocably elected to “opt out” of this exemption and, therefore, will be subject to the same new or revised accounting standards as other public companies that are not emerging growth companies.

Use of Estimates:

The preparation of 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, liabilities, revenues and expenses, as well as various disclosures. Actual results could differ from those estimates. The most significant estimates included in the preparation of the consolidated financial statements are related to coal workers’ pneumoconiosis, workers’ compensation, asset retirement obligations, contingencies, and coal reserve values.

Cash:

Cash includes cash on hand and on deposit with banking institutions.

Accounts Receivable:

Accounts receivable are recorded at the invoiced amount and do not bear interest. We reserve for specific accounts receivable when it is probable that all or a part of an outstanding balance will not be collected, such as customer bankruptcies. Collectability is determined based on terms of sale, credit status of customers and various other circumstances. We regularly review collectability and establish or adjust the allowance as necessary using the specific identification method. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. There were no reserves for uncollectible trade amounts in the periods presented.

Inventories:

Inventories are stated at the lower of cost or market. The cost of coal inventories is determined by the first-in, first-out (FIFO) method. Coal inventory costs include labor, supplies, equipment costs, depreciation, depletion and amortization, operating overhead and other related costs. The cost of supplies inventory is determined by the average cost method and includes operating and maintenance supplies to be used in our coal operations.

Property, Plant and Equipment:

Property, plant and equipment is recorded at cost upon acquisition. Expenditures which extend the useful lives of existing plant and equipment are capitalized. Interest costs applicable to major asset additions are capitalized during the construction period. Costs of additional mine facilities required to maintain production after a mine reaches the production stage, generally referred to as “receding face costs,” are expensed as incurred; however, the costs of additional airshafts and new portals are capitalized. Planned major maintenance costs which do not extend the useful lives of existing plant and equipment are expensed as incurred.

Coal exploration costs are expensed as incurred. Coal exploration costs include those incurred to ascertain existence, location, extent or quality of ore or minerals before beginning the development stage of the mine.

Costs of developing new underground mines and certain underground expansion projects are capitalized. Underground development costs, which are costs incurred to make the mineral physically accessible, include costs to prepare property for shafts, driving main entries for ventilation, haulage, personnel, construction of airshafts, roof protection and other facilities.

Airshafts and capitalized mine development associated with a coal reserve are amortized on a units-of production basis as the coal is produced so that each ton of coal is assigned a portion of the unamortized costs. We employ this method to match costs with the related revenues realized in a particular period. Rates are updated when revisions to coal reserve estimates are made. Coal reserve estimates are reviewed when information becomes available that indicates a reserve change is needed, or at a minimum once a year. Any material effect from changes in estimates is disclosed in the period the change occurs. Amortization of development cost begins when the development phase is complete and the production phase begins. At an underground mine, the end of the development phase and the beginning of the production phase takes place when construction of the mine for economic extraction is substantially complete. Coal extracted during the development phase is incidental to the mine’s production capacity and is not considered to shift the mine into the production phase.

Coal reserves are either owned in fee or controlled by lease. The duration of the leases vary; however, the lease terms generally are extended automatically to the exhaustion of economically recoverable reserves, as long as active mining continues. Coal interests held by lease provide the same rights as fee ownership for mineral extraction and are legally considered real property interests.

Advance mining royalties are advance payments made to lessors under terms of mineral lease agreements that are recoupable against future production using the units-of-production method. Depletion of leased coal interests is computed using the units-of-production method over proven and probable coal reserves.

Advance mining royalties and leased coal interests are evaluated periodically, or at a minimum once a year, for impairment issues or whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Any revisions are accounted for prospectively as changes in accounting estimates.

When properties are retired or otherwise disposed, the related cost and accumulated depreciation are removed from the respective accounts and any profit or loss on disposition is recognized in Gain (Loss) on Sale of Assets in the Consolidated Statements of Operations.

Depreciation of plant and equipment is calculated on the straight-line method over their estimated useful lives or lease terms generally as follows:

	Years
Buildings and improvements	10 to 45
Machinery and equipment	3 to 25
Leasehold improvements	Life of Lease

Costs to obtain coal lands are capitalized based on the cost at acquisition and are amortized using the units-of-production method over all estimated proven and probable reserve tons assigned and accessible to the mine. Proven and probable coal reserves are calculated on a clean coal ton equivalent, which excludes non-recoverable coal reserves and anticipated preparation plant processing refuse. Rates are updated when revisions to coal reserve estimates are made. Coal reserve estimates are reviewed when events and circumstances indicate a reserve change is needed, or at a minimum once a year. Amortization of coal interests begins when the coal reserve is produced. At an underground mine, a ton is considered produced once it reaches the surface area of the mine. Any material effect from changes in estimates is disclosed in the period the change occurs.

Impairment of Long-lived Assets:

Impairment of long-lived assets is recorded when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying value. The carrying value of the assets is then reduced to its estimated fair value which is usually measured based on an estimate of future discounted cash flows. There were no impairment losses recognized during the years ended December 31, 2016, 2015 and 2014.

Pension:

The personnel who operate CPCC and Conrhein's assets are employees of CPCC and participate in certain defined benefit retirement plans administered by CONSOL Energy through December 31, 2015. Effective December 31, 2015, CONSOL Energy's qualified defined benefit retirement plans were frozen. CONSOL Energy directly charges the Partnership for its portion of the service costs associated with these employees that participate in the salary retirement pension plans. The Partnership's share of those costs is reflected in Operating and Other Costs in the accompanying Consolidated Statements of Operations.

On September 30, 2014, the qualified pension plan was remeasured to reflect an announced plan amendment that would reduce future accruals of pension benefits as of January 1, 2015. The plan amendment called for a hard freeze of the qualified defined benefit pension plan on January 1, 2015 for employees who were under age 40 or had less than ten years of service as of September 30, 2014. Employees who were age 40 or over and had at least 10 years of service would continue in the defined benefit pension plan unchanged. On August 31, 2015, the qualified pension plan was remeasured to reflect another announced plan amendment that reduced future accruals of pension benefits as of January 1, 2016. The plan amendment called for a hard freeze of the qualified defined benefit pension plan on January 1, 2016 for all remaining participants in the plan and eliminated CONSOL Energy contributing an additional 3% of eligible compensation into the 401(k) accounts.

Pneumoconiosis Benefits and Workers' Compensation:

The Partnership is required by federal and state statutes to provide our portion of benefits to certain current and former totally disabled employees or their dependents for awards related to coal workers' pneumoconiosis ("CWP"). The Partnership is also required by various state statutes to provide our portion of workers' compensation benefits for employees who sustain employment related physical injuries or some types of occupational disease. Workers' compensation benefits include compensation for their disability, medical costs, and on some occasions, the cost of rehabilitation. The provisions for our portion of estimated benefits are determined on an actuarial basis for the Partnership's dedicated contract labor provided under a service agreement with CONSOL Energy.

Asset Retirement Obligations:

Mine closing reclamation costs, perpetual water care costs and other costs associated with dismantling and removing facilities are accrued using the accounting treatment prescribed by the Asset Retirement and Environmental Obligations Topic of the FASB Accounting Standards Codification. This topic requires the fair value of an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the long-lived asset. Depreciation of the capitalized asset retirement cost is generally determined on a units-of-production basis. Accretion of the asset retirement obligation is recognized over time and generally will escalate over the life of the producing asset, typically as production declines. Accretion is included in Depreciation, Depletion and Amortization on the Consolidated Statements of Operations. Asset retirement obligations primarily relate to the closure of mines which includes treatment of water and the reclamation of land upon exhaustion of coal reserves.

Accrued mine closing costs, perpetual care costs and reclamation costs and other costs of dismantling and removing facilities are regularly reviewed by management and are revised for changes in future estimated costs and regulatory requirements.

Subsidence:

Subsidence occurs when there is damage of the ground surface due to the removal of underlying coal. Areas affected may include, although not limited to, streams, property, roads, pipelines and other land and surface structures. Total estimated subsidence claims are recognized in the period when the related coal has been extracted and are included in Operating and Other Costs on the Consolidated Statements of Operations and Other Accrued Liabilities on the Consolidated Balance Sheets. On occasion we prepay the estimated damages prior to undermining the property, in return for release of liability. Prepayments are included as assets and either recognized as Prepaid Expenses or in Other Assets on the Consolidated Balance Sheets, if the payment is made less than or greater than one year, respectively, prior to undermining the property.

Income Taxes:

The Partnership's assets and liabilities are comprised of a 25% undivided interest in the Pennsylvania Mining Complex which assets and liabilities are held by CPCC and Conrhein. The Partnership does not share in the separate income tax consequences attributable to the owners of CPCC and Conrhein. Accordingly, no provision for federal or state income taxes has been recorded. As of December 31, 2016 and 2015, the Partnership had no liability reported for unrecognized tax benefits and had not incurred interest and penalties related to income taxes. The Partnership's operations are treated as a partnership for federal and state income tax purposes, with each partner being separately taxed on its share of taxable income. Therefore, the Partnership has excluded income taxes from these financial statements.

Revenue Recognition:

Revenues are recognized when title passes to the customers. For domestic coal sales, this generally occurs when coal is loaded at the mine preparation facility. For export coal sales, revenue recognition generally occurs when coal is loaded onto marine vessels at terminal locations.

Freight Revenue and Expense:

Shipping and handling costs invoiced to coal customers and paid to third-party carriers are recorded as Freight Revenue and Freight Expense, respectively.

Royalty Recognition:

Royalty expenses for coal rights are included in Royalties and Production Taxes on the Consolidated Statements of Operations when the related revenue for the coal sale is recognized.

Contingencies:

The Partnership, from time to time, is subject to various lawsuits and claims with respect to such matters as personal injury, wrongful death, damage to property, exposure to hazardous substances, governmental regulations (including environmental remediation), employment and contract disputes, and other claims and actions, arising out of the normal course of business. Liabilities are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Estimates are developed through consultation with legal counsel involved in the defense and are based upon an analysis of potential results, assuming a combination of litigation and settlement strategies. Legal fees associated with defending these various lawsuits and claims are expensed when incurred.

Reclassifications:

The PA Mining Acquisition was accounted for as a transaction under common control, which resulted in the prior periods being recasted to reflect the as if the Partnership owned 25% of PA Mining Complex for all periods presented. Certain amounts have been reclassified to conform with the current reporting classifications with no effect on previously reported recasted net income or partners' capital.

Recent Accounting Pronouncements:

In January 2017, the FASB issued Update 2017-01 - Business Combinations (Topic 805). This update 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. For public business entities, the amendments in this update are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. The adoption of this new guidance will not have a material impact on the Partnership's financial statements.

In December 2016, the FASB issued Update 2016-19 - Technical Corrections and Improvements. This Update seeks to provide simplification, minor improvements, and guidance clarification to Topics in the Accounting Standards Codification. The changes are not expected to affect current accounting practice and are effective immediately. The adoption of this new guidance will not have a material impact on the Partnership's financial statements.

In May 2014, the FASB issued Accounting Standards Update ("ASU") 2014-09 "Revenue from Contracts with Customers (Topic 606)", which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. The objective of the amendments in this update is to improve financial reporting by creating common revenue recognition guidance for U.S. GAAP and International Financial Reporting Standards ("IFRS"). The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services and should disclose sufficient information, both qualitative and quantitative, to enable users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The following updates to Topic 606 were made during 2016:

- In March 2016, the FASB updated Topic 606 by issuing ASU 2016-08 "Principal versus Agent Considerations (Reporting Revenue Gross versus Net)," which clarifies how an entity determines whether it is a principal or an agent for goods or services promised to a customer as well as the nature of the goods or services promised to their customers.

- In April 2016, the FASB issued Update 2016-10 - Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing, which seeks to address implementation issues in the areas of identifying performance obligations and licensing.
- In May 2016, the FASB issued Update 2016-12 - Revenue from Contracts with Customers (Topic 606): Narrow Scope Improvements and Practical Expedients. The update, which was issued in response to feedback received by the FASB-IASB joint revenue recognition transition resource group (TRG), seeks to address implementation issues in the areas of collectibility, presentation of sales taxes, noncash consideration, and completed contracts and contract modifications at transition.
- In December 2016, the FASB issued Updated 2016-20 - Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers. This update applies technical corrections or improvements specific to Update 2014-09. The technical corrections seek to address implementation issues in the areas of loan guarantee fees,

contract costs - impairment testing, contract costs - interaction of impairment testing with guidance in other topics, provisions for losses on construction-type and production-type contracts, the scope of Topic 606, disclosure of remaining performance obligations, disclosure of prior-period performance obligations, contract modifications example, contract asset versus receivable, refund liability, advertising costs, fixed-odds wagering contracts in the casino industry, and cost capitalization for advisers to private and public funds.

The new standards are effective for annual reporting periods beginning after December 15, 2017, with the option to adopt as early as annual reporting periods beginning after December 15, 2016. Management continues to evaluate the impacts that these standards will have on the Partnership's financial statements, specifically as it relates to contracts that contain positive electric power price related adjustments. The Partnership anticipates using the modified retrospective approach at adoption as it relates to ASU 2014-09.

In August 2016, the FASB issued Update 2016-15 - Statement of Cash Flows (Topic 230) - Classification of Certain Cash Receipts and Cash Payments. This update seeks to reduce the existing diversity in practice of the presentation and classification of specific cash flow issues. For public business entities, the amendments in this update are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Management is currently evaluating the impact this guidance may have on the Partnership's financial statements.

In March 2016, the FASB issued Update 2016-09 - Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. The update simplifies several aspects of the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. In addition to those simplifications, the amendments eliminate the guidance in Topic 718 that was indefinitely deferred shortly after the issuance of FASB Statement No. 123 (revised 2004), Share-Based Payment. For public business entities, the amendments in this update are effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. Early application of the amendments in this update is permitted for all entities. The adoption of this new guidance will not have a material impact on the Partnership's financial statements.

In February 2016, the FASB issued Update 2016-02 - Leases (Topic 842). This update is intended to improve financial reporting about leasing transactions. This update will require lessees to recognize all leases with terms greater than 12 months on their balance sheet as lease liabilities with a corresponding right-of-use asset. This update maintains the dual model for lease accounting, requiring leases to be classified as either operating or finance, with lease classification determined in a manner similar to existing lease guidance. The basic principle is that leases of all types convey the right to direct the use and obtain substantially all the economic benefits of an identified asset, meaning they create an asset and liability for lessees. Lessees will classify leases as either finance leases (comparable to current capital leases) or operating leases (comparable to current operating leases). Costs for a finance lease will be split between amortization and interest expense, with a single lease expense reported for operating leases. This update also will require both qualitative and quantitative disclosures to help investors and other financial statement users better understand the amount, timing, and uncertainty of cash flows arising from leases. For public business entities, the amendments in this update are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application of the amendments in this update is permitted for all entities. Management is currently evaluating the impact this guidance may have on the Partnership's financial statements.

In July 2015, the FASB issued Update 2015-11 - Inventory (Topic 330): Simplifying the Measurement of Inventory. The Board is issuing this Update as part of its Simplification Initiative. The amendments in this Update do not apply to inventory that is measured using last-in, first-out (LIFO) or the retail inventory method. The amendments apply to all other inventory, which includes inventory that is measured using first-in, first-out (FIFO) or average cost. Topic 330, Inventory, currently requires an entity to measure inventory at the lower of cost or market, where market could be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. In accordance with this Update, an entity should now measure inventory within the scope of this Update at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. Subsequent measurement is unchanged for inventory measured using LIFO or the retail inventory method. Other than the change in the subsequent measurement guidance from the lower of cost or market to the lower of cost and net realizable value for inventory within the scope of this Update, there are no other substantive changes to the guidance on measurement of inventory. For public business entities, the amendments in this Update are effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The amendments in this Update should be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. The adoption of this new guidance will not have a material impact on the Partnership's financial statements.

NOTE 2—ACQUISITIONS AND DISPOSITIONS:

INITIAL PUBLIC AND PRIVATE PLACEMENT OFFERING:

On July 1, 2015, the Partnership's common units began trading on the New York Stock Exchange under the ticker symbol "CNXC". On July 7, 2015, the following transactions occurred in conjunction with the Partnership completing the IPO.

CONSOL Energy

In connection with the IPO, the Partnership issued 1,050,000 common units (including 188,933 common units issued upon the expiration of the underwriters' option to purchase additional common units), and 11,611,067 subordinated units to CONSOL Energy, representing a 53.4% limited partner interest in us, and issued a 2.0% general partner interest in us and all of our incentive distribution rights to our general partner. In connection with these issuances of common and subordinated units and other ownership interests, we relied upon the "private placement" exemption from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act"), provided by Section 4(a)(2) thereof and, accordingly, the common and subordinated units and other ownership interests issued to CONSOL Energy were not registered under the Securities Act. The Partnership also entered into an operating agreement, employee services agreement, contract agency agreement, terminal and throughput agreement, cooperation and safety agreement, water supply and services agreement, omnibus agreement and contribution agreement with CONSOL Energy.

Concurrent Private Placement

In connection with the IPO, Greenlight Capital and certain of its affiliates entered into a common unit purchase agreement with us to purchase 5,000,000 common units at a price per unit equal to $15.00 equating to $75,000 in gross proceeds. In connection with our issuance and sale of common units pursuant to the Concurrent Private Placement, we relied upon the "private placement" exemption from the Securities Act, provided by Section 4(a)(2) thereof and, accordingly, the common units issued to Greenlight Capital were not registered under the Securities Act. We distributed all of the proceeds from the Concurrent Private Placement to CONSOL Energy.

Initial Public Offering

As part of the IPO, we sold 5,000,000 common units to the public at a price per unit equal to $15.00 ($14.10 per unit net of underwriting discount) equating to gross proceeds of $75,000. After the deduction of the underwriting discount and structuring fees of $5,500 and offering expenses of approximately $4,052, the net proceeds contributed to the Partnership were approximately $65,448. We granted the underwriters a 30-day option to purchase up to 750,000 common units from us at the IPO price, less the underwriter discount, if the underwriters sold more than 5,000,000 common units. The underwriters partially exercised this option and sold an additional 561,067 common units to the public at $15.00 ($14.10 per unit net of underwriting discount) equating to additional net proceeds of $7,911. We distributed $70,711 of net proceeds from the IPO to CONSOL Energy. The remaining 188,933 common units that the underwriters did not exercise under their option, were issued to CONSOL Energy.

Revolving Credit Facility

In connection with the IPO, we entered into a $400,000 senior secured revolving credit facility with certain lenders and PNC Bank, National Association, as administrative agent ("PNC Bank N.A."). Obligations under our revolving credit facility are guaranteed by our subsidiaries (the"guarantor subsidiaries") and are secured by substantially all of our and our subsidiaries' assets pursuant to a security agreement and various mortgages. CONSOL Energy is not a guarantor of our revolving credit facility.

Borrowings under our revolving credit facility may be used by us to fund cash distributions, make capital expenditures, pay fees and expenses related to our revolving credit facility and for general partnership purposes. In connection with the completion of the IPO and our entry into our revolving credit facility, we made an initial draw of $200,000 and paid $3,000 in origination fees with net proceeds of $197,000 which were distributed to CONSOL Energy.

Use of Proceeds

In connection with the IPO, we used the net proceeds from the IPO, the proceeds from the Concurrent Private Placement and net borrowings under our revolving credit facility to make a distribution of $342,711, including $4,352 of offering and structure fees, to CONSOL Energy. The Partnership retained cash of $7,000. Based on the IPO price of $15.00 per common unit, the aggregate value of the common units and subordinated units that were issued to CONSOL Energy in connection with the completion of the IPO was approximately $189,916.

OTHER ACCQUISITIONS:

On September 30, 2016, the Partnership and its wholly owned subsidiary, CNX Thermal Holdings, entered into a Contribution Agreement with CONSOL Energy, CPCC and Conrhein and together with CPCC, under which CNX Thermal Holdings acquired an undivided 6.25% of the Contributing Parties' right, title and interest in and to the Pennsylvania Mining Complex (which represents an aggregate 5% undivided interest in and to the Pennsylvania Mining Complex), in exchange for (i) cash consideration in the amount of $21,500 and (ii) the Partnership's issuance of 3,956,496 Class A Preferred Units representing limited partner interests in the Partnership at an issue price of $17.01 per Class A Preferred Unit (the "Class A Preferred Unit Issue Price"), or an aggregate $67,300 in equity consideration. The Class A Preferred Unit Issue Price was calculated as the volume-weighted average trading price of the Partnership's common units over the trailing 15-day trading period ending on September 29, 2016 (or $14.79), plus a 15% premium. The PA Mining Acquisition was consummated on September 30, 2016. Our general partner elected not to contribute capital to retain their 2% interest. As of December 31, 2016 our general partner's ownership interest in the partnership was 1.7%. Following the PA Mining Acquisition and including interests it held previously, CNX Thermal holds an aggregate 25% undivided interest in and to the Pennsylvania Mining Complex.

The PA Mining Acquisition was a transaction between entities under common control; therefore, the Partnership recorded the assets and liabilities of the acquired 5% undivided interest in the Pennsylvania Mining Complex at their carrying amounts to CONSOL Energy on the date of the transaction. The difference between CONSOL Energy's net carrying amount and the total consideration paid to CONSOL Energy was recorded as a capital transaction with CONSOL Energy, which resulted in a reduction in partners' capital. The $67,300 in preferred equity consideration was a non-cash transaction, which impacted the investing and financing activities of the Partnership, by $6,524 of excess consideration paid over the net carrying amount and $60,776 of carrying amount paid from equity consideration.

In March 2014, CPCC completed a sale-leaseback of longwall shields for the Harvey Mine. Cash proceeds for the sale offset the basis of $18,839; therefore, no gain or loss was recognized on the sale. The five-year lease has been accounted for as an operating lease.

NOTE 3—NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER INTEREST:

The Partnership allocates net income among our general partner and limited partners using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income to our limited partners and our general partner in accordance with the terms of our Partnership Agreement. We also allocate any earnings in excess of distributions to our limited partners and our general partner in accordance with the terms of our Partnership Agreement. We allocate any distributions in excess of earnings for the period to our general partner and our limited partners based on their respective proportionate ownership interests in us, after taking into account distributions to be paid with respect to the incentive distribution rights, as set forth in the Partnership Agreement. Net income attributable to the PA Mining Acquisition for periods prior to September 30, 2016 was not allocated to the limited partners for purposes of calculating net income per limited partner unit.

Diluted net income per limited partner unit reflects the potential dilution that could occur if securities or agreements to issue common units, such as awards under the long-term incentive plan or convertible preferred units, were exercised, settled or converted into common units. If certain conditions are met, preferred units can be converted by election of the holder, partnership, or by change in control. When it is determined that potential common units resulting from an award subject to performance or market conditions should be included in the diluted net income per limited partner unit calculation, the impact is reflected by applying the treasury stock method. For the calculation of diluted net income per limited partner unit, the effect of conversion of the 3,956,496 Class A Preferred Units is antidilutive and is excluded from the calculation for the year ended December 31, 2016. No preferred units were available for the year ended December 31, 2015.

The following table illustrates the Partnership's calculation of net income per unit for common and subordinated partner units (in thousands, except for per unit information):

	For the Year Ended December 31, 2016	For the Year Ended December 31, 2015
Net Income Attributable to General and Limited Partner Ownership Interest in CNX Coal Resources	$ 25,851	$ 64,538
Less: Net (Loss) Income Attributable to CONSOL Energy, Pre-IPO	—	34,134
Less: Net Income Attributable to CONSOL Energy, Pre-PA Mining Acquisition	3,995	7,048
Less: General Partner Interest in Net Income	399	468
Less: Net Income Allocable to Class A Preferred Units	1,851	—
Less: Effect of Subordinated Distribution Suspension	119	—
Net Income Allocable to Limited Partner Units	$ 19,487	$ 22,888
Limited Partner Interest in Net Income - Common Units	$ 9,806	$ 11,444
Effect of Subordinated Distribution Suspension - Common Units	2,917	—
Net Income Allocable to Common Units	$ 12,723	$ 11,444
Limited Partner Interest in Net Income - Subordinated Units	$ 9,800	$ 11,444
Effect of Subordinated Distribution Suspension - Subordinated Units	(3,036)	—
Net Income Allocable to Subordinated Units	$ 6,764	$ 11,444
Weighted Average Limited Partner Units Outstanding - Basic		
Common Units	11,614,075	11,611,067
Subordinated Units	11,611,067	11,611,067
Total	23,225,142	23,222,134
Weighted Average Limited Partner Units Outstanding - Diluted		
Common Units	11,791,830	11,611,978
Subordinated Units	11,611,067	11,611,067
Total	23,402,897	23,223,045
Net Income Per Limited Partner Unit - Basic		
Common Units	$ 1.10	$ 0.99
Subordinated Units	$ 0.58	$ 0.99
Net Income Per Limited Partner Unit -Diluted		
Common Units	$ 1.08	$ 0.99
Subordinated Units	$ 0.58	$ 0.99

NOTE 4—OTHER INCOME:

	For the Years Ended December 31,		
	2016	2015	2014
Coal contract buyout	$1,572	$—	$7,500
Purchased coal sales	1,439	—	—
Right of way sales	31	608	364
Litigation	—	—	1,069
Gain (loss) on sale of assets	(9)	61	185
Other	86	272	542
Total Miscellaneous Other Income	$3,119	$941	$9,660

NOTE 5—INTEREST EXPENSE:

	For the Years Ended December 31,		
	2016	2015	2014
Interest on notes - related party	$—	$6,050	$11,918
Revolver interest	9,022	3,928	—
Capitalized interest	(315)	(348)	(3,236)
Interest on other payables, net	12	6	1
Total Interest Expense	$8,719	$9,636	$8,683

NOTE 6—INVENTORIES:

	December 31, 2016	December 31, 2015
Coal	$ 1,950	$ 1,165
Supplies	9,541	11,073
Total Inventories	$ 11,491	$ 12,238

NOTE 7—PROPERTY, PLANT AND EQUIPMENT:

	December 31, 2016	December 31, 2015
Coal and other plant and equipment	$ 576,917	$ 571,044
Coal properties and surface lands	121,241	120,912
Airshafts	92,938	87,967
Mine development	81,538	81,538
Coal advance mining royalties	4,056	4,066
Total property, plant and equipment	876,690	865,527
Less: Accumulated depreciation, depletion and amortization	442,178	400,911
Total Net Property, Plant and Equipment	$ 434,512	$ 464,616

As of December 31, 2016 and 2015, property, plant and equipment includes gross assets under capital lease of $631 and $481, respectively. Accumulated amortization for capital leases was $398 and $296 at December 31, 2016 and 2015, respectively.

Amortization expense for assets under capital leases approximated $78, $53, and $29 for the years ended December 31, 2016, 2015, and 2014, respectively, and is included in Depreciation, Depletion and Amortization in the accompanying Consolidated Statements of Operations.

NOTE 8—OTHER ACCRUED LIABILITIES:

	December 31, 2016	December 31, 2015
Subsidence liability	$ 26,887	$ 22,403
Accrued payroll and benefits	4,052	3,552
Litigation	2,507	2,138
Accrued other taxes	2,504	807
Equipment lease rental	2,442	2,442
Other	3,683	2,287
Current portion of long-term liabilities:		
Workers' compensation	1,380	1,431
Asset retirement obligations	591	1,913
Long-term disability	128	204
Capital leases	88	61
Pneumoconiosis benefits	56	43
Total Other Accrued Liabilities	$ 44,318	$ 37,281

NOTE 9—REVOLVING CREDIT FACILITY:

	December 31, 2016	December 31, 2015
Revolver, carrying amount	$ 201,000	$ 185,000
Less: Debt issuance and financing fees	3,157	4,054
Revolver, net	$ 197,843	$ 180,946

Revolving Credit Facility

Obligations under our $400,000 senior secured revolving credit facility with certain lenders and PNC Bank N.A, as administrative agent, are guaranteed by our subsidiaries and are secured by substantially all of our and our subsidiaries' assets pursuant to a security agreement and various mortgages. CONSOL Energy is not a guarantor of our obligations under our revolving credit facility.

The unused portion of our revolving credit facility will be subject to a commitment fee of 0.50% per annum. Interest on outstanding indebtedness under our revolving credit facility accrues, at our option, at a rate based on either:

- The highest of (i) PNC Bank N.A.'s prime rate, (ii) the federal funds open rate plus 0.50%, and (iii) the one-month LIBOR rate plus 1.0%, in each case, plus a margin ranging from 1.50% to 2.50% depending on the total leverage ratio; or

- the LIBOR rate plus a margin ranging from 2.50% to 3.50% depending on the total leverage ratio.

As of December 31, 2016, the revolving credit facility had $201,000 of borrowings outstanding, leaving $199,000 of unused capacity. At December 31, 2015, the revolving credit facility had $185,000 of borrowings outstanding, leaving $215,000 unused capacity. Interest on outstanding borrowings under the revolving credit facility as of December 31, 2016 was accrued at 3.99% based on a LIBOR rate of 0.74%, plus a margin of 3.25%. Interest on outstanding borrowings under the revolving credit facility at December 31, 2015 was 3.17% based on a LIBOR rate of 0.42%, plus a margin of 2.75%.

Our revolving credit facility matures on July 7, 2020 and requires compliance with conditions precedent that must be satisfied prior to any borrowing as well as ongoing compliance with certain affirmative and negative covenants. The revolving credit facility requires that the Partnership maintain a minimum interest coverage ratio of at least 3.00 to 1.00, which is calculated as the ratio of trailing 12 months Adjusted EBITDA, as defined in the credit agreement, to cash interest expense of the Partnership, measured quarterly. The Partnership must also maintain a maximum total leverage ratio not greater than 3.50 to 1.00, (or 4.00 to 1.00 for two fiscal quarters after consummation of a material acquisition) which is calculated as the ratio of total consolidated indebtedness to trailing 12 months Adjusted EBITDA, as defined in the credit agreement, measured quarterly. At December 31, 2016, interest coverage ratio was 9.48 to 1.00 and the maximum total leverage ratio was 2.48 to 1.00.

NOTE 10—LEASES:

We use various leased facilities and equipment in our operations. Future minimum lease payments under capital and operating leases, together with the present value of the net minimum capital lease payments as of December 31, 2016 are as follows:

	Capital Leases	Operating Leases
2017	$ 92	$ 13,276
2018	82	12,291
2019	52	7,477
2020	21	5,272
2021	—	5,053
Thereafter	—	5,174
Total minimum lease payments	$ 247	$ 48,543
Less amount representing interest	13	
Present value of minimum lease payments	234	
Less amount due in one year	88	
Total Long-Term Capital Lease Obligations	$ 146	

Rental expense related to operating leases approximated $14,578, $13,490 and $12,508 during the years ended December 31, 2016, 2015 and 2014, respectively.

NOTE 11—FAIR VALUE OF FINANCIAL INSTRUMENTS:

The Partnership 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 (including LIBOR-based discount rates), while unobservable inputs reflect the Partnership's own 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, including LIBOR-based discount rates.

Level Three - Unobservable inputs significant to the fair value measurement supported by little or no market activity. The significant unobservable inputs used in the fair value measurement of the Partnership's third party guarantees are the credit risk of the third party and the third party surety bond markets.

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 following methods and assumptions were used to estimate the fair value for which the fair value option was not elected:

Long-term debt: The fair value of long-term debt is measured using unadjusted quoted market prices or estimated using discounted cash flow analyses. The discounted cash flow analyses are based on current market rates for instruments with similar cash flows.

The carrying amounts and fair values of financial instruments for which the fair value option was not elected are as follows:

	December 31, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Revolver	$201,000	$201,000	$185,000	$185,000

The Partnership’s debt obligations are valued through reference to the applicable underlying benchmark rate and, as a result, constitute Level 2 fair value measurements.

NOTE 12—ASSET RETIREMENT OBLIGATIONS:

	December 31, 2016	December 31, 2015
Balance at beginning of period	$ 10,412	$ 11,389
Accretion expense	727	875
Payments	(149)	(995)
Revisions in estimated cash flows	(1,053)	(857)
Balance at end of period	$ 9,937	$ 10,412

NOTE 13— OTHER POST-EMPLOYMENT BENEFIT PLANS:

Prior to the IPO, the Partnership was contractually obligated for a portion of the medical and life insurance benefits to retired employees of CONSOL Pennsylvania Coal Company LLC (the “OPEB Plans”). In conjunction with the IPO, on July 7, 2015 the OPEB liability and related accumulated other comprehensive income was retained by CONSOL Energy, and the Partnership has no OPEB obligation as of such date. As of December 31, 2015, there was no benefit obligation or related accumulated other comprehensive income included in the Partnership's financial statements. For the year ended and as of December 31, 2016, there were no amounts included in the Partnership's financial statements.

The reconciliation of changes in the benefit obligation, plan assets and funded status of these plans at December 31, 2015, is as follows:

	Other Postretirement Benefits at December 31, 2015
Change in benefit obligation:	
Benefit obligation at beginning of period	$ 8,524
Service cost	—
Interest cost	58
Actuarial gain	(477)
Plan amendments	(4,713)
Plan transfer	(3,134)
Participant contributions	43
Benefits and other payments	(301)
Benefit obligation at end of period	$ —
Change in plan assets:	
Company contributions	$ 258
Participant contributions	43
Benefits and other payments	(301)
Fair value of plan assets at end of period	$ —

The components of net periodic benefit costs are as follows:

	Other Postretirement Benefits For the Years Ended December 31, 2015	2014
Service cost	$—	$927
Interest cost	58	1,760
Amortization of prior service credits	(8,703)	(2,332)
Recognized net actuarial loss	1,304	801
Curtailment gain	—	(2,553)
Net periodic benefit cost	$(7,341)	$(1,397)

NOTE 14—COAL WORKERS' PNEUMOCONIOSIS (CWP) AND WORKERS' COMPENSATION:

The Partnership is contractually obligated for our portion of medical and disability benefits to CPCC employees and their dependents resulting from occurrences of coal workers' pneumoconiosis disease. Conrhein has no current or former employees. The Partnership is also responsible under various state statutes for our portion of pneumoconiosis benefits. The calculation of our portion of the actuarial present value of the estimated pneumoconiosis obligation is based on an annual actuarial study by external actuaries and uses assumptions regarding disability incidence, medical costs, indemnity levels, mortality, death benefits, dependents and interest rates which are derived from actual experience and outside sources. Actuarial gains or losses can result from differences in incident rates and severity of claims filed as compared to original assumptions.

The Partnership is also contractually responsible to compensate individuals who sustain employment related physical injuries or some types of occupational diseases and, on some occasions, for our portion of costs of their rehabilitation. Workers' compensation laws will also compensate survivors of workers who suffer employment related deaths. Workers' compensation laws are administered by state agencies with each state having its own set of rules and regulations regarding compensation that is owed to an employee that is injured in the course of employment. The Partnership primarily provides for our portion of these claims through a self-insurance program. The Partnership recognizes an actuarial present value for our portion of the estimated workers' compensation obligation calculated by independent actuaries. The calculation is based on claims filed and an estimate of claims incurred but not yet reported as well as various assumptions. The assumptions include discount rate, future healthcare trend rate, benefit duration and recurrence of injuries. Actuarial gains associated with workers' compensation have resulted from discount rate changes, several years of favorable claims experience, various favorable state legislation changes and overall lower incident rates than our assumptions.

	CWP		Workers' Compensation	
	December 31,		December 31,	
	2016	2015	2016	2015
Change in benefit obligation:				
Benefit obligation at beginning of period	$1,977	$1,592	$4,291	$4,128
State administrative fees and insurance bond premiums	—	—	207	425
Service cost	803	255	1,299	1,656
Interest cost	72	65	132	146
Actuarial loss (gain)	(686)	102	9	(82)
Benefits and fees paid	(53)	(37)	(1,553)	(1,982)
Benefit obligation at end of period	$2,113	$1,977	$4,385	$4,291
Current assets	$—	$—	$85	$69
Current liabilities	(56)	(43)	(1,380)	(1,431)
Noncurrent liabilities	(2,057)	(1,934)	(3,090)	(2,929)
Net obligation recognized	$(2,113)	$(1,977)	$(4,385)	$(4,291)
Amounts recognized in accumulated other comprehensive income consist of:				
Net actuarial gain	$8,102	$7,497	$3,394	$3,425
Net amount recognized	$8,102	$7,497	$3,394	$3,425

The components of the net periodic cost are as follows:

	CWP			Workers' Compensation		
	For the Years Ended December 31,			For the Years Ended December 31,		
	2016	2015	2014	2016	2015	2014
Service cost	$803	$255	$873	$1,299	$1,656	$1,799
Interest cost	72	65	214	132	146	185
Recognized net actuarial gain	(83)	(71)	(240)	(21)	(1)	(20)
State administrative fees and insurance bond premiums	—	—	—	207	425	617
Net periodic benefit cost	$792	$249	$847	$1,617	$2,226	$2,581

Amounts that are currently included in accumulated other comprehensive income are $136 and $34 for CWP benefits and workers' compensation benefits, respectively, that are expected to be recognized in 2017 net periodic benefit costs:

Assumptions:
The weighted-average discount rates used to determine benefit obligations and net periodic cost (benefit) are as follows:

	CWP			Workers' Compensation		
	For the Years Ended December 31,			For the Years Ended December 31,		
	2016	2015	2014	2016	2015	2014
Benefit obligations	4.40%	4.60%	4.21%	4.05%	4.26%	3.84%

Net periodic cost (benefit)	4.60%	4.21%	4.75%	4.26%	3.84%	4.57%

Assumed discount rates have a significant effect on the amounts reported for both CWP benefits and Workers' Compensation costs. A one-quarter percentage point change in assumed discount rate would have the following effect on benefit costs:

	0.25 Percentage Point Increase	0.25 Percentage Point Decrease
CWP costs (decrease) increase	$ (87)	$ 92
Workers' compensation costs (decrease) increase	$ (10)	$ 10

Cash Flows:

The Partnership does not intend to make contributions to the CWP or Workers' Compensation plans in 2017. We intend to pay benefit claims as they become due.

The following benefit payments, which reflect expected future claims as appropriate, are expected to be paid:

		Workers' Compensation		
	CWP Benefits	Total Benefits	Actuarial Benefits	Other Benefits
2017	$ 56	$1,487	$ 1,295	$ 192
2018	79	1,507	1,311	196
2019	130	1,546	1,345	201
2020	162	1,604	1,398	206
2021	201	1,650	1,439	211
Year 2022-2026	1,748	9,100	7,961	1,139

NOTE 15—OTHER BENEFIT PLANS:

Salaried Pension:

The Partnership is contractually obligated to fund 25% of the service cost for CPCC employees, which provide mining services to the Partnership, that participate in the CONSOL Energy Salaried Pension Plan. CONSOL Energy has non-contributory defined benefit retirement plans covering substantially all salaried employees through December 31, 2015. Effective December 31, 2015, CONSOL Energy's qualified defined benefit plans have been frozen. The benefits for these plans are based primarily on years of service and employees' pay. On September 30, 2014, the qualified pension plan was remeasured to reflect an announced plan amendment that would reduce future accruals of pension benefits as of January 1, 2015. The plan amendment called for a hard freeze of the qualified defined benefit pension plan on January 1, 2015 for employees who were under age 40 or had less than ten years of service as of September 30, 2014. Employees who were age 40 or over and had at least ten years of service would continue in the defined benefit pension plan unchanged. On August 31, 2015, the qualified pension plan was remeasured to reflect another announced plan amendment that reduced future accruals of pension benefits as of January 1, 2016. The plan amendment called for a hard freeze of the qualified defined benefit pension plan on January 1, 2016 for all remaining participants in the plan. The costs of these benefits during the years ended December 31, 2016, 2015 and 2014 were $884, $884 and $1,753, respectively. These costs are reflected in Operating and Other Costs in the Consolidated Statements of Operations.

Investment Plan:

The Partnership is contractually obligated to fund 25% of CPCC's portion of CONSOL Energy's investment plan. CONSOL Energy's investment plan is available to most employees. CONSOL Energy's plan includes company matching of 6% of eligible compensation contributed by eligible employees of CPCC. Total payments and costs were $2,014, $3,195 and $2,719 for the years ended December 31, 2016, 2015 and 2014, respectively. These costs are reflected in Operating and Other Costs in the Consolidated Statements of Operations.

In conjunction with the qualified pension plan changes, beginning January 1, 2015, CONSOL Energy contributed an additional 3% of eligible compensation into the 401(k) plan accounts for employees hired or rehired on or after October 1, 2014 or who were under age 40 or had less than 10 years of service as of September 30, 2014. This additional contribution was eliminated as of January 1, 2016. The Plan also provides for discretionary contributions ranging from 1% to 6% beginning January 1, 2016 and 1% to 4% for 2015 of eligible compensation for eligible employees (as defined by the Plan). For the year ended December 31, 2016, $2,271 was accrued as a discretionary contribution under this plan and is expected to be paid into employees accounts in the first quarter of 2017. There were no such discretionary contributions made for the years ended December 31, 2015 and 2014, respectively. These costs are reflected in Operating and Other Costs in the Consolidated Statements of Operations and recorded in Other Accrued Liabilities on the Consolidated Balance Sheet.

Long-Term Disability:

The Partnership is contractually obligated for its portion of a Long-Term Disability Plan available to all eligible full-time salaried employees of CPCC. The benefits for this plan are based on a percentage of monthly earnings, offset by all other income benefits available to the disabled.

	For the Years Ended		
	December 31, 2016	December 31, 2015	December 31, 2014
Benefit costs	$120	$ 138	$ 157
Discount rate assumption used to determine net periodic benefit costs	3.71 %	3.18 %	3.53 %

Long-Term Disability related liabilities are included in Deferred Credits and Other Liabilities-Other and Other Accrued Liabilities on the Consolidated Balance Sheets and amounted to $330 and $650 at December 31, 2016 and 2015, respectively.

NOTE 16—SUPPLEMENTAL CASH FLOW INFORMATION:

As of December 31, 2016, 2015 and 2014, the Partnership purchased goods and services related to capital projects in the amount of $759, $1,282 and $568, respectively, that are included in accounts payable.

The Partnership obtains capital lease arrangements for company-used vehicles. For the years ended December 31, 2016, 2015 and 2014, the Partnership entered into non-cash capital lease arrangements of $127, $139 and $43, respectively.

For the years ended December 31, 2016, 2015 and 2014, the Partnership paid interest expense, net of capitalized interest, of $7,734, $8,520 and $8,686, respectively.

The following are non-cash transactions that impact the operating, investing and financing activities of the Partnership.

Prior to IPO,

- The CFI Loan was retained by CONSOL Energy and considered a deemed contribution in the amount of $229,495.
- CONSOL Energy contributed stream credit assets to the Partnership in the amount of $8,131.
- OPEB liabilities were retained by CONSOL Energy and treated as a deemed contribution in the amount of $3,134.
- As of December 31, 2015 and 2014, there were capital equipment contributions of $21,945 and $5,324, respectively, between the Partnership and CONSOL Energy that are included in equity.

NOTE 17—CONCENTRATION OF CREDIT RISK:

The Partnership primarily markets thermal coal principally to electric utilities in the eastern United States. Revenues generated from end users based in the United States were 84%, 81%, and 87%, for the years ended December 31, 2016, 2015, and 2014 respectfully. The remaining revenues for those periods were generated from sales in which our coal was ultimately delivered into the global markets, predominately Asia and Europe, of which none was individually significant.

For the year ended December 31, 2016, coal sales to the following customers individually exceeded 10% of our revenues: Duke Energy and GenOn Energy Management.

For the year ended December 31, 2015, coal sales to the following customers individually exceeded 10% of our revenues: Duke Energy, GenOn Energy Management and XCoal Energy & Resources

For the year ended December 31, 2014, coal sales to the following customers individually exceeded 10% of our revenues: Duke Energy and GenOn Energy Management.

NOTE 18—COMMITMENTS AND CONTINGENT LIABILITIES:

The Partnership is subject to various lawsuits and claims with respect to such matters as personal injury, wrongful death, damage to property, exposure to hazardous substances, governmental regulations (including environmental remediation), employment and contract disputes and other claims and actions arising out of the normal course of business. We accrue the estimated loss for these lawsuits and claims when the loss is probable and can be estimated. Our current estimated accruals related to these pending claims, individually and in the aggregate, are immaterial to the financial position, results of operations or cash flows of the Partnership, and there are no material pending claims that would require disclosure in the financial statements individually or in the aggregate. It is possible that the aggregate loss in the future with respect to these lawsuits and claims could ultimately be material to the financial position, results of operations or cash flows of the Partnership; however, such amounts cannot be reasonably estimated.

At December 31, 2016, the Partnership is contractually obligated to CONSOL Energy for financial guarantees and letters of credit to certain third parties which were issued by CONSOL Energy on behalf of the Partnership. The maximum potential total of future payments that we could be required to make under these instruments is $71,296. The instruments are comprised of $733 employee-related and other letters of credit expiring in the next three years, $61,154 of environmental surety bonds expiring within the next three years, and $9,409 of employee-related and other surety bonds expiring within the next three years. Employee-related financial guarantees have primarily been provided to support various state workers' compensation and federal black lung self-insurance programs. Environmental financial guarantees have primarily been provided to support various performance bonds related to reclamation and other environmental issues. Other guarantees have been extended to support insurance policies, legal matters, full and timely payments of mining equipment leases, and various other items necessary in the normal course of business. These amounts have not been reduced for potential recoveries under recourse or collateralization provisions. Generally, recoveries under reclamation bonds would be limited to the extent of the work performed at the time of the default. No amounts related to these financial guarantees and letters of credit are recorded as liabilities on the financial statements. The Partnership's management believes that these guarantees will expire without being funded, and therefore the commitments will not have a material adverse effect on the financial condition of the Partnership.

NOTE 19—RELATED PARTY:

CONSOL Energy

The Consolidated Statements of Operations include expense allocations for certain corporate functions historically performed by CONSOL Energy, including allocations of general corporate expenses related to stock-based compensation, legal, treasury, human resources, information technology and other administrative services. Those allocations were based primarily on specific identification, head counts and coal tons produced. Also, centralized cash management activities for CONSOL Energy were utilized for collections and payments related to normal course of business accounts receivable and payments for goods and services. The balance of receivables/payables from CONSOL Energy and other affiliates are presented as contributions/distributions in these Consolidated Financial Statements. Management believes the assumptions underlying the Consolidated Financial Statements, including the assumptions regarding allocating general corporate expenses from CONSOL Energy are reasonable. Nevertheless, these statements may not include all of the actual expenses that would have been incurred by the Partnership and may not reflect our Consolidated Statements of Operations, Balance Sheets and Cash Flows had we been a stand-alone company during the periods presented. Actual costs that would have been incurred if the Partnership had been a stand-alone company would depend on multiple factors, including organizational structure and strategic decisions made in various areas, including information technology and infrastructure.

In conjunction with the IPO, the Partnership entered into several agreements, including an omnibus agreement, with CONSOL Energy. In connection with PA Mining Acquisition described in Note 2, on September 30, 2016, the General Partner and the Partnership entered into the First Amended and Restated Omnibus Agreement (the "Amended Omnibus Agreement") with CONSOL Energy and certain of its subsidiaries. Under the Amended Omnibus Agreement, CONSOL Energy will indemnify the Partnership for certain liabilities, including those relating to:

- all tax liabilities attributable to the assets contributed to the Partnership in connection with the PA Mining Acquisition (the "First Drop Down Assets") arising prior to the closing of the PA Mining Acquisition or otherwise related to the

Contributing Parties' contribution of the First Drop Down Assets to the Partnership in connection with the PA Mining Acquisition; and

- certain operational and title matters related to the First Drop Down Assets, including the failure to have (i) the ability to operate under any governmental license, permit or approval or (ii) such valid title to the First Drop Down Assets, in each case, that is necessary for the Partnership to own or operate the First Drop Down Assets in substantially the same manner as owned or operated by the Contributing Parties prior to the Acquisition.

The Partnership will indemnify CONSOL Energy for certain liabilities relating to the First Drop Down Assets, including those relating to:

- the use, ownership or operation of the First Drop Down Assets; and
- the Partnership's operation of the First Drop Down Assets under permits and/or bonds, letters of credit, guarantees, deposits and other pre-payments held by CONSOL Energy.

The Amended Omnibus Agreement amended the Partnership's obligations to CONSOL Energy with respect to the payment of an annual administrative support fee and reimbursement for the provision of certain management and operating services provided by CONSOL Energy, in each case to reflect structural changes in how those services are provided to the Partnership by CONSOL Energy.

Charges for services from CONSOL Energy include the following:

	For the Years Ended December 31,		
	2016	2015	2014
Operating and Other Costs	$4,251	$6,793	$6,707
Selling, General and Administrative Expenses	3,826	8,926	11,384
Total Services from CONSOL Energy	$8,077	$15,719	$18,091

At December 31, 2016 and December 31, 2015, the Partnership had a net payable to CONSOL Energy in the amount of $1,666 and $4,310, respectively. This payable includes reimbursements for business expenses, executive fees, stock-based compensation and other items under the omnibus agreement.

Purchases of supply inventory from Fairmont Supply Company, formerly a wholly-owned subsidiary of CONSOL Energy, were approximately $10,850 for the year ended December 31, 2014 and are included in Operating and Other Costs in the accompanying Consolidated Statements of Operations. On December 12, 2014, Fairmont Supply was sold by CONSOL Energy and is no longer a related party of CONSOL Energy or the Partnership.

CFI Loan

CPCC had several related party long-term notes with CONSOL Financial Inc. ("CFI"), a wholly owned subsidiary of CONSOL Energy, pursuant to which CPCC was the obligor. The loan represented multiple 10-year term notes between CPCC and CFI at the applicable federal funds rates in effect upon execution, which were due at various future dates throughout the year. In conjunction with the IPO, these notes were excluded from the Partnership's liabilities. Payments for these notes were $10,951 and $2,311 for the years ended December 31, 2015 and 2014, respectively. Proceeds from additional notes were $16,991 and $14,214 for the years ended December 31, 2015 and 2014, respectively. Interest Expense related to these notes was $6,050 and $11,918 for the years ended December 31, 2015 and 2014, respectively. These costs are included in Interest Expense in the accompanying Consolidated Statements of Operations.

NOTE 20—LONG-TERM INCENTIVE PLAN:

Under the CNX Coal Resources LP 2015 Long-Term Incentive Plan (the “LTIP”), our general partner may issue long-term equity based awards to directors, officers and employees of our general partner or its affiliates, or to any consultants, affiliates of our general partner or other individuals who perform services for us. These awards are intended to compensate the recipients thereof based on the performance of our common units and their continued service during the vesting period, as well as to align their long-term interests with those of our unitholders. We are responsible for the cost of awards granted under the LTIP and all determinations with respect to awards to be made under the LTIP will be made by the board of directors of our general partner or any committee thereof that may be established for such purpose or by any delegate of the board of directors or such committee, subject to applicable law, which we refer to as the plan administrator.

The LTIP limits the number of units that may be delivered pursuant to vested awards to 2,300,000 common units, subject to proportionate adjustment in the event of unit splits and similar events. Common units subject to awards that are canceled,
forfeited, withheld to satisfy exercise prices or tax withholding obligations or otherwise terminated without delivery of the
common units will be available for delivery pursuant to other awards.

The Partnership's general partner has granted equity-based phantom units that vest over a period of a director's continued service with the Partnership. The phantom units will be paid in common units or an amount of cash equal to the fair market value of a unit based on the vesting date. The awards may accelerate upon a change in control of the Partnership. Compensation expense is recognized on a straight-line basis over the requisite service period, which is generally the vesting term. The Partnership recognized $1,185 and $40 of compensation expense for the years ended December 31, 2016 and 2015, respectively, which is included in Selling, General and Administrative Expense in the Consolidated Statements of Operations. As of December 31, 2016, there is $1,892 of unearned compensation that will vest over a weighted average period of 2 years. The following represents the nonvested phantom units and their corresponding weighted average grant date fair value:

	Number of Units	Weighted Average Grant Date Fair Value per Unit
Nonvested at December 31, 2015	6,456	$ 14.39
Granted	392,688	$ 7.90
Vested	(7,389)	$ 13.51
Forfeited	(9,821)	$ 7.90
Nonvested at December 31, 2016	381,934	$ 7.90

NOTE 21—SUBSEQUENT EVENTS:

On January 30, 2017, the Board of Directors of our general partner declared a cash distribution to the Partnership's unitholders for the fourth quarter of 2016 of $0.5125 per common and subordinated unit and $0.4678 per class A preferred unit. The cash distribution will be paid on February 15, 2017 to the unitholders of record at the close of business on February 9, 2017.

SUPPLEMENTAL QUARTERLY INFORMATION (UNAUDITED):

	Three Months Ended			
	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016
Coal Sales	$56,541	$62,640	$ 66,922	$ 80,292
Freight Revenue	3,269	2,797	2,407	3,130
Other Income	(11)	1,780	485	865
Total Revenue	59,799	67,217	69,814	84,287
Operating and Other Costs	38,491	46,044	45,531	52,935
Depreciation, Depletion and Amortization	10,317	10,423	10,592	10,662
Freight Expense	3,269	2,797		