UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

(Mark One)

☒ **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

☐ **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: 001-36503

Foresight Energy LP

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or other jurisdiction of incorporation or organization)	80-0778894 (I.R.S. Employer Identification No.)
211 North Broadway, Suite 2600, Saint Louis, MO (Address of principal executive offices)	63102 (Zip code)

Registrant's telephone number, including area code: (314) 932-6160

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 ☐ No ☒

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 232.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒ (do not check if a smaller reporting company)	Smaller reporting company	☐

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

The aggregate market value of units held by non-affiliates as of June 30, 2016 was $41,702,566.

As of February 24, 2017, the registrant had 66,104,908 common units and 64,954,691 subordinated units outstanding.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain statements and information in this Annual Report on Form 10-K, and certain oral statements made from time to time by our representatives, may constitute “forward-looking statements.” The words “believe,” “expect,” “anticipate,” “plan,” “intend,” “foresee,” “outlook,” “estimate,” “potential,” “continues,” “may,” “will,” “seek,” “approximately,” “predict,” “anticipate,” “should,” “would,” “could” or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that the future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Known material factors that could cause our actual results to differ from those in the forward-looking statements are described in Part I. “Item 1A. Risk Factors.”

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

REFERENCES WITHIN THIS ANNUAL REPORT

All references to “FELP,” the “Partnership,” “we,” “us,” and “our” refer to the combined results of Foresight Energy LP and Foresight Energy LLC and its subsidiaries, unless the context otherwise requires or where otherwise indicated.

PART I

Item 1. Business

We mine and market coal from reserves and operations located exclusively in the Illinois Basin. We control 2.1 billion tons of proven and probable coal in the state of Illinois, which, in addition to making us one of the largest reserve holders in the United States, provides organic growth opportunities. Our reserves consist principally of three large contiguous blocks of uniform, thick, high heat content (high Btu) thermal coal which is ideal for highly productive longwall operations. Thermal coal is used by power plants and industrial steam boilers to produce electricity or process steam.

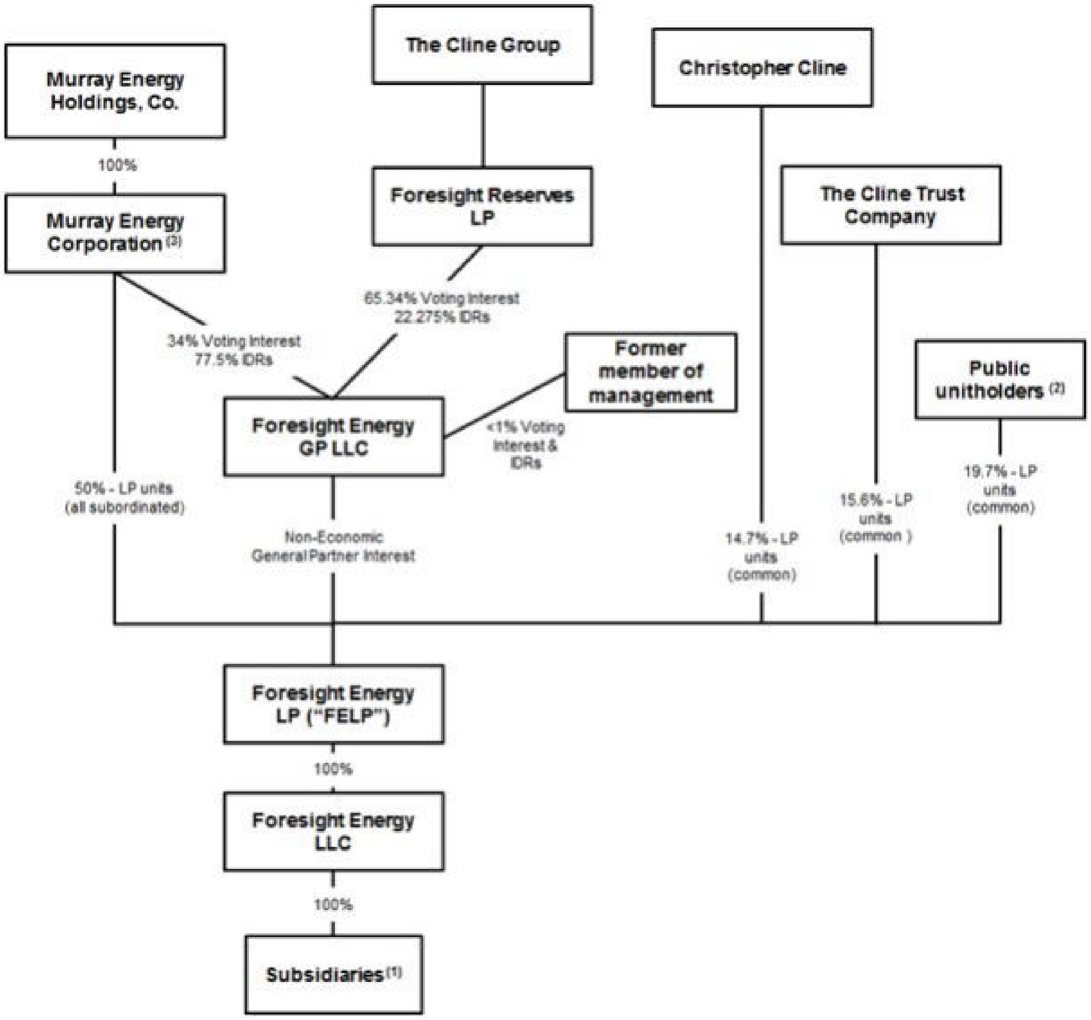
We own four mining complexes where we can operate four longwall mines and one continuous miner operation **.** We invested substantially to construct state-of-the-art, low-cost and highly productive mining operations and related transportation infrastructure. Our four mining complexes can collectively support up to nine longwalls, with a portion of the existing surface infrastructure available to be shared among most of our potential future longwalls. Mining operations at our Hillsboro complex have been idled since March 2015 due to a combustion event and we are uncertain as to when production will resume.

Our operations are strategically located near multiple rail and river transportation access points giving us cost-competitive transportation options. We have developed infrastructure that provides each of our four mining complexes with multiple transportation outlets including direct and indirect access to five Class I railroads. Our access to competing rail carriers as well as access to truck and barge transport provides us with operating flexibility and minimizes transportation costs. We own a 25 million ton per year barge-loading river terminal on the Ohio River and also have contractual agreements for 6 million tons per year of export terminal capacity in the Gulf of Mexico. We have long-term, fixed price transportation contracts from our mines to these terminals. These logistical arrangements provide transportation cost certainty and the flexibility to direct shipments to markets that provide the highest margin for our coal sales.

We market and sell our coal primarily to electric utility and industrial companies in the eastern half of the United States and the international market. We sell the majority of our domestic tonnages to electric utilities with installed pollution control devices. These devices, also known as scrubbers, are designed to eliminate substantially all emissions of sulfur dioxide.

Foresight Energy LP, a Delaware limited partnership formed on January 26, 2012, completed its initial public offering on June 23, 2014 and is listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “FELP.” We are managed and operated by the board of directors and executive officers of our general partner, Foresight Energy GP LLC (“FEGP”), which is owned by Foresight Reserves LP (“Foresight Reserves”), Murray Energy Corporation (“Murray Energy”), and a former member of management.

Below is a diagram of our organizational and ownership structure as of February 24, 2017:



(1) See Exhibit 21.1 for a list of subsidiaries.

(2) Includes common units held by executive officers and directors (other than Christopher Cline).

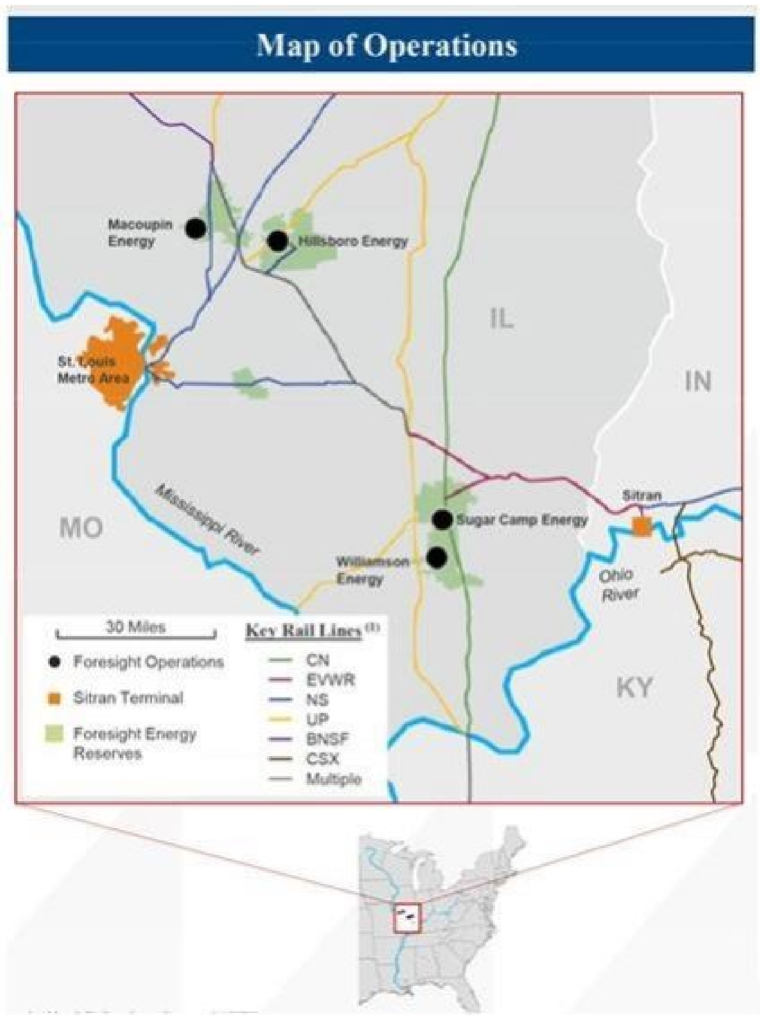
(3) Murray Energy, an affiliate of Murray Energy or a group of persons which includes Murray Energy or any of its affiliates (collectively, the "Murray Group") has the right to purchase all (but not less than all) of the outstanding Exchangeable PIK Notes on or prior to October 2, 2017 for cash at a price equal to 100% of the principal amount of the Exchangeable PIK Notes plus accrued interest. Upon such a purchase, the Murray Group will receive FELP limited partner units at the exchange rate defined in the Exchangeable PIK Notes indenture agreement. Murray Energy also has an option to purchase an additional 46% of the voting interests in FEGP for $15 million, which is conditioned upon its redemption of the Exchangeable PIK Notes on or prior to October 2, 2017. Also, as part of the global restructuring of our debt, warrants were issued to certain holders of our indebtedness which are exercisable following a Note Redemption. Please read Part II. "Item 8. Financial Statements and Supplementary Data, Note 10–Long Term Debt and Capital Lease Obligations" and Part II. "Item 8. Financial Statements and Supplementary Data, Note 15–Related-Party Transactions" for additional discussion.

Debt Restructuring

On August 30, 2016, we completed a global restructuring of our indebtedness. The restructuring transactions alleviated existing defaults and events of default across the Partnership's capital structure that resulted from the 2015 Delaware Chancery Court change-of-control litigation related to the purchase and sale agreement between Foresight Reserves and Murray Energy. See "Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt and Capital Lease Obligations" and "Item 8. Financial Statements and Supplementary Data – Note 15. Related-Party Transactions" for additional discussion of the restructuring transactions.

Mining Operations

Each of our four mining complexes operates in the Illinois Basin; with two located in Southern Illinois and two located in Central Illinois. Williamson, Sugar Camp and Hillsboro are longwall operations, and Macoupin is currently a continuous miner operation. The geology, mine plan, equipment and infrastructure at each of our Williamson, Sugar Camp and Hillsboro mines are relatively similar. Each of our mining complexes has its own preparation plant and support facilities. The following map shows the location of our mining complexes and transportation network:



(1) "CN": Canadian National line; "EVWR": the Evansville Western line; "NS": the Norfolk Southern line; "UP": Union Pacific line; "BNSF": BNSF Railway line; and "CSX": CSX Corporation line.

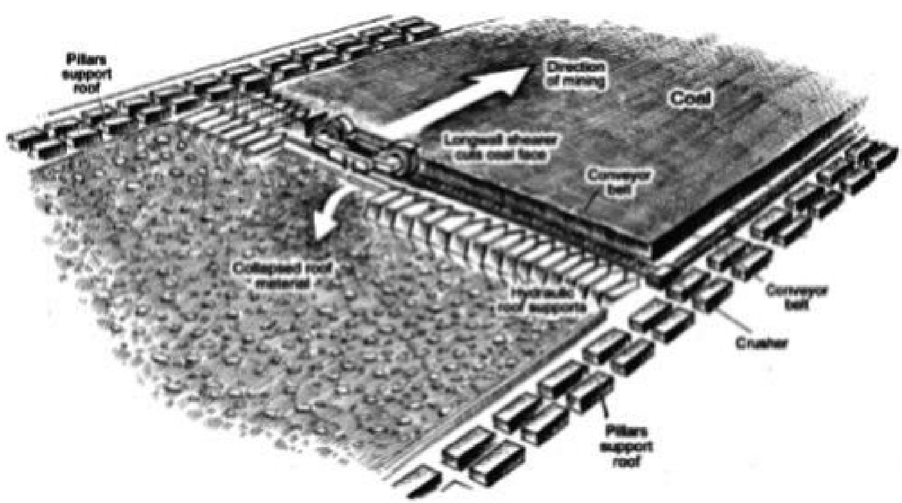
The table below summarizes our operations, available mining methods, transportation access, reserves and production:

Complex	Available Mining Methods (1)	Transportation Access (2)	Proven and Probable Reserves	Production (3) Year Ended December 31, 2016	2015	2014
			(In Millions of Tons)			
Williamson	LW, CM	Rail (CN), Barge (OHR, MSR), Truck	376.0	5.4	5.6	6.5
Sugar Camp	LW, CM	Rail (CN, NS, CSX, BNSF), Barge (OHR, MSR), Truck	1,336.5	11.4	10.6	9.1
Hillsboro	LW, CM	Rail (UP, NS, CN), Barge (OHR, MSR), Truck	322.1	-	1.9	5.6
Macoupin	CM, LW	Rail (UP, NS, CN), Barge (OHR, MSR), Truck	64.4	2.2	2.0	1.6
			2,099.0	19.0	20.1	22.8

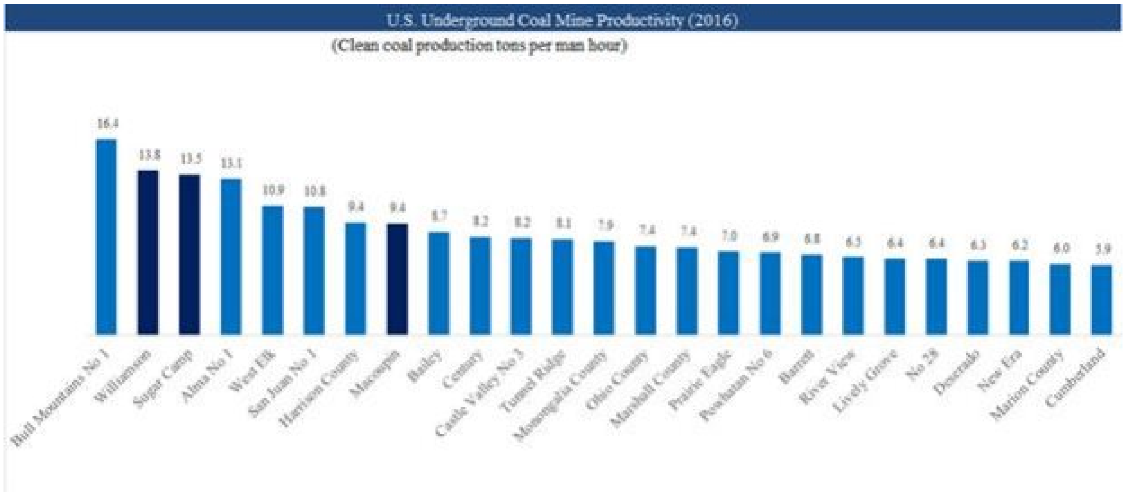
(1) LW: Longwall; CM: Continuous miner. Williamson, Sugar Camp and Hillsboro use CM for development sections only. Macoupin does not currently mine with a longwall.
(2) CN: Canadian National Railway Company; UP: Union Pacific Railroad Corporation; NS: Norfolk Southern Corporation; CSX: CSX Corporation; BNSF: BNSF Railway Company; OHR: Ohio River; MSR: Mississippi River.
(3) As reported by the Mine Safety and Health Administration ("MSHA"), inclusive of tons produced for certain mines in development.

Longwall mining is a highly-automated, underground mining technique that generates high volumes of low-cost coal production and is typically supported by one or two continuous mining units. While the continuous mining units contribute to coal production, the primary function is to prepare an area of the mine for longwall operations. A longwall mining system uses a shearer to cut the coal, self-advancing roof supports to protect the miners working at the longwall face and an armored face conveyor to transport the coal. The longwall mining system is highly productive due to the continuous nature of coal production and the high volume of coal produced relative to the number of personnel required to operate the system.

Below is an illustrative diagram of the longwall mining process:



We have been able to sustain our high productivity and low operating costs since we started our first longwall in 2008 and the high productivity at the newer mines we have developed demonstrates the repeatability of our mine design. The high productivity translates into low costs and, in 2016, our operations had an average cash cost of $22.32 per ton sold. Our mines that operated during 2016 were among the ten most productive underground coal mines in the United States on a clean tons produced per man hour basis based on MSHA data, as illustrated below.



Source: MSHA data. Note: The chart above displays the top 25 most productive underground mines out of 210 mines with over 100,000 tons produced during 2016 on a clean tons produced per man hour basis. Darker shading denotes mines owned by Foresight Energy LP. Mining operations at our Hillsboro complex have been idled since March 2015 due to a combustion event.

Williamson Mining Complex

Our Williamson mine is wholly-owned by our subsidiary Williamson Energy, LLC (“Williamson”) and is located in southern Illinois near the town of Marion. Williamson is the first mine we developed, with longwall mining production commencing in 2008. The mine operates in the Herrin No. 6 Seam, using one longwall system and two continuous miner units to develop the mains and gate roads for its longwall panels. Coal is washed at Williamson’s 2,000 tons-per-hour (“tph”) preparation plant, stockpiled and then shipped by rail or truck to our customers or a terminal. Williamson’s coal is shipped via the CN railroad to the Ohio and Mississippi Rivers to serve the domestic thermal market or to a terminal near New Orleans to serve the international thermal market. Williamson has access to several barge facilities on the Ohio and Mississippi Rivers and two vessel loading facilities near New Orleans. Williamson was the second most productive underground coal mine in the United States in 2016 on a clean tons produced per man hour basis based on MSHA data.

Sugar Camp Mining Complex

Our Sugar Camp mine is wholly-owned by our subsidiary Sugar Camp Energy, LLC (“Sugar Camp”), and is located in southern Illinois approximately 12 miles north of Williamson. Sugar Camp’s first longwall system began production in the first quarter of 2012 and its second longwall system began production in the second quarter of 2014. Sugar Camp’s original infrastructure, including its bottom development, slope belt, material handling system and rail loadout, supports both longwalls. Sugar Camp operates in the Herrin No. 6 Seam and uses a similar mine design and equipment as Williamson. With additional equipment, infrastructure and mine development, Sugar Camp has the capacity to add two incremental longwall systems. Coal is washed at Sugar Camp’s two 2,000 tph preparation plants, stockpiled and then shipped by rail or truck to our customers or a terminal. Sugar Camp has direct access to the CN railroad which can deliver its coal to the Ohio and Mississippi Rivers to serve the domestic thermal market or to two vessel loading facilities near New Orleans to serve the international thermal market. Sugar Camp also has indirect access to the NS, BNSF and CSX railroads. Sugar Camp was the third most productive underground coal mine in the United States in 2016 on a clean tons produced per man hour basis based on MSHA data.

Hillsboro Mining Complex

Our Hillsboro mine is wholly-owned by our subsidiary Hillsboro Energy LLC (“Hillsboro”), and is located in central Illinois near the town of Hillsboro. Hillsboro’s longwall mining system began production in the third quarter of 2012. The mine operates in the Herrin No. 6 Seam and uses similar mine design and similar equipment as Williamson and Sugar Camp. Coal is washed at Hillsboro’s 2,000 tph preparation plant, stockpiled and then shipped by rail or truck to our customers or a terminal. Hillsboro has direct access to the UP and NS railroads and indirect access to the CN railroad, which allows for the delivery of its coal directly to customers or to the Ohio and Mississippi Rivers in order to serve the domestic thermal market or the international thermal market through two terminals near New Orleans.

Our Hillsboro mine experienced an underground combustion event beginning in March 2015. Thus far, we have been unsuccessful at permanently extinguishing the fire. We continue to work closely with MSHA to gain re-entry to the mine. We are uncertain as to when production will resume at this operation but we are working closely with MSHA and the Illinois Office of Mines and Minerals Mine Safety and Training Division to ensure the safety of our employees throughout the process and to explore alternatives to safely resolve this issue.

Macoupin Mining Complex

Our Macoupin mine is wholly-owned by our subsidiary Macoupin Energy LLC (“Macoupin”), and is located in central Illinois near the town of Carlinville. We acquired the Macoupin mine in 2009 and sealed the majority of the previously mined area and implemented a new mine plan and design. In addition, the surface facilities were upgraded, including the rehabilitation of the preparation plant. Coal production began in 2009 with a single continuous miner super-section utilizing battery powered coal haulers. An additional continuous miner unit was added in 2011 using a flexible conveyor train system rather than coal haulers. Coal is washed at Macoupin’s 850 tph preparation plant, stockpiled and then shipped by rail or truck to our customers or a terminal. Macoupin has direct access to both the UP and NS railroads and indirect access to the CN railroad, which allows for the delivery of its coal directly to customers or to terminals at the Ohio and Mississippi Rivers to serve the domestic thermal market or the international thermal market through two terminals near New Orleans. Macoupin was the eighth most productive underground coal mine in the United States in 2016 on a clean tons produced per man hour basis based on MSHA data.

Transportation

Our coal is transported to our domestic customers and export terminal facilities by rail, barge and truck. Depending on the proximity of our customers to the mines and the transportation available to deliver coal to that customer, transportation costs can be a substantial part of the total delivered cost of coal. Because our reserves and mines are favorably located near multiple rail and river transportation options, we believe we can negotiate advantageous transportation rates, allowing us to keep our transportation costs relatively low while providing broad market access for our coal.

We have direct and indirect rail access to domestic customers via five Class I railroads, river access to domestic customers via various Ohio and Mississippi River terminals, and river and rail access to coal export terminals for shipping to international customers. We have agreements with rail carriers that vary in initial length from one to twenty years. We also have favorable access to the international market through the CN railroad and export terminals through long-term contractual arrangements. The international market provides us with an alternative to the domestic market and has historically been an important economic outlet for our coal. While transportation costs are higher for exports to the international market, we could, in certain market conditions, receive higher coal sale prices on export sales, which partially offset the higher transportation costs. Rates and practices of the transportation companies serving a particular mine or customer may affect our marketing efforts with respect to coal produced from the relevant mine.

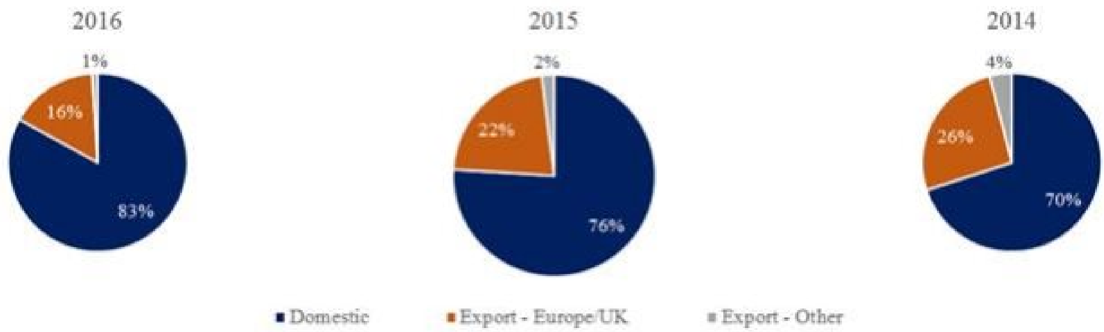
For the year ended December 31, 2016, approximately 31% of our coal sales volume was shipped to our domestic customers by barge, 52% to our domestic customers by rail or truck and 17% was shipped to our international customers.

Our Sitran terminal is a high-capacity coal transloading facility on the Ohio River near Evansville, Indiana to which each of our mines has access. The facility currently has a single rail loop, a bottom discharge rail car unloader, stacking tubes to facilitate ground storage and blending, barge loading capabilities and throughput capacity of 25 million tons of coal per year. The terminal has the potential for a dual rail loop that would have capacity for two loaded and two empty unit trains.

Coal Marketing and Sales

During the years ended December 31, 2016, 2015 and 2014, we generated total revenues of $875.8 million, $984.9 million and $1,109.4 million, respectively. Our primary domestic customers are electric utility and industrial companies in the eastern half of the United States. Our three largest customers in 2016 were Southern Company, EDF Trading and Dayton Power and Light Company, representing approximately 30.1%, 12.6% and 10.2% of our total coal sales revenues, respectively. If these three customers or any of our largest customers were to significantly reduce their purchases of coal from us, or if we were unable to sell coal to our largest customers on terms as favorable to us as the terms under our current contracts, our results of operations may be materially adversely affected.

The international thermal coal market has also been a substantial part of our business with direct and indirect sales to end users in Europe, South America, Africa and Asia. During the years ended December 31, 2016, 2015 and 2014, export tons represented approximately 17%, 24% and 30% of tons sold, respectively. The charts below illustrate our sales mix, by destination, for the years ended December 31, 2016, 2015 and 2014.



Our management actively monitors trends in contract pricing and seeks to enter into coal sales contracts at favorable prices. Many of our contracts allow us to substitute coal from our other mining complexes. For 2017, as of February 17, 2017, we have 16.9 million tons of our projected production contractually committed.

The terms of our coal supply agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these contracts, including price adjustment features, price reopener terms, coal quality requirements, quantity adjustment mechanisms, permitted sources of supply, future regulatory changes, extension options, force majeure provisions, and termination and assignment provisions, vary significantly by customer.

Most of our coal supply agreements contain provisions requiring us to deliver coal within certain ranges for specific quality characteristics such as heat content, sulfur, and ash. Failure to meet these conditions could result in substantial price reductions or suspension or termination of the contract at the election of the customer. Although the minimum volume to be delivered under a long-term contract is stipulated, either party may vary the timing of delivery based on certain contractual provisions. Contracts also typically contain force majeure provisions allowing for the suspension of performance by either party for the duration of specified events beyond the control of the affected party, including labor disputes. Some contracts may terminate upon continuance of an event of force majeure for an extended period. Some of our long-term contracts provide for a predetermined adjustment to the stipulated base price at times specified in the agreement or at other periodic intervals to account for changes in prevailing market prices.

In addition, most of our contracts contain provisions permitting us to adjust the base price due to compliance with new statutes, ordinances or regulations that affect our costs related to performance of the agreement. Also, some of our contracts contain provisions that allow for the recovery of certain costs incurred due to modifications or changes in the interpretations or application of any applicable government statutes.

Price reopener provisions are present in several of our long-term contracts. These 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. 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.

Competition

The United States coal industry is highly competitive, both regionally and nationally. In the Illinois Basin, we compete primarily with coal producers such as Peabody Energy Corporation; Alliance Resource Partners, L.P.; Murray Energy (an affiliate); Armstrong Energy Inc.; and Sunrise Coal LLC. Outside of the Illinois Basin, we compete broadly for coal sales with other United States-based producers of thermal coal, and we compete internationally with numerous global coal producers.

A number of factors beyond our control affect the markets in which we sell our coal. Continued demand for our coal and the prices obtained by us depend primarily on: the coal consumption patterns of the electricity industry in the United States and elsewhere around the world; the availability, location, cost of transportation and price of competing coal; and other electricity generation and fuel supply sources such as natural gas, oil, nuclear, hydroelectric and renewable energy. Coal consumption patterns are affected primarily by the demand for electricity, the amount of coal supply in the market, environmental and other governmental regulations and technological developments. The most important factors on which we compete are price, coal quality characteristics and reliability of supply.

Segments

We operate as a single reportable segment. See Part II. "Item 8. Financial Statements and Supplementary Data" for our consolidated revenues and total assets.

Employees and Labor Relations

As of December 31, 2016, we had 22 corporate employees and 777 employees working in mining and mining-related operations. None of our operations have employees represented by a union. In 2015, we entered into a management services agreement with a subsidiary of Murray Energy pursuant to which it provides certain management and administration services to us for a quarterly fee. Please read Part II. "Item 8. Financial Statements and Supplementary Data, Note 15–Related-Party Transactions" for additional discussion.

Environmental and Other Regulatory Matters

Our operations are subject to a variety of U.S. federal, state and local laws and regulations, such as those relating to employee health and safety; water discharges; air emissions; plant and wildlife protection; the restoration of mining properties; the storage, treatment and disposal of wastes; remediation of contaminants; surface subsidence from underground mining and the effects of mining on surface water and groundwater conditions.

We are not aware of any notice from a governmental agency of any material non-compliance with applicable laws, regulations, or permits that the Partnership has failed to address. However, there can be no assurance that violations will not occur in the future; that we will be able to always obtain, maintain or renew required permits; or that changes in these requirements or their enforcement or the discovery of new conditions will not cause us to incur significant costs and liabilities in the future. Due to the nature of the regulatory programs that apply to our mining operations, which can impose liability even in the absence of fault and often involve subjective criteria, it is not reasonable to expect any coal mining operation to be free of citations. Certain of our current and historical mining operations use or have used or store regulated materials which, if released into the environment, may require investigation and remediation. Under certain permits, we are required to monitor groundwater quality on and adjacent to our sites and to develop and implement plans to minimize and correct land subsidence, as well as impacts on waterways and wetlands, caused by our mining operations. Major regulatory requirements are briefly discussed below.

Mine Safety and Health

In the United States, the Coal Mine Health and Safety Act of 1969, the Federal Mine Safety and Health Act of 1977 (the “1977 Act”) and the Mine Improvement and New Emergency Response Act of 2006 (“MINER Act”) impose stringent mine safety and health standards on all aspects of mining operations. In 1978, MSHA was created to carry out the mandates of the 1977 Act and was granted enforcement authority. MSHA is authorized to inspect all underground mining operations at least four times a year and issue citations with civil penalties for the violation of a mandatory health and safety standard. MSHA review and approval is required for a number of miner safety and welfare plans including ventilation, roof control/bolting, safety training and ground control, refuse disposal and impoundments and respirable dust. Also, the State of Illinois has its own programs for mine safety and health regulation and enforcement.

Under the 1977 Act, MSHA has the authority to issue orders or citations to mine operators regardless of the degree of culpable conduct engaged in by the operator, and it must assess a penalty for each citation or order. Factors such as degree of negligence and gravity of the violation affect the amount of penalty assessed, and sometimes permit MSHA to issue orders directing withdrawal of miners from the mine or affected areas within the mine. The 1977 Act contains provisions that can impose criminal liability on the mine operator or individuals.

The MINER Act added more extensive health and safety compliance standards, and increased civil and criminal penalties. Some of the MINER Act requirements included stricter criteria for sealing off abandoned areas of mines, the addition of refuge alternatives, stricter requirements for conveyor belts, and upgrades to communication with and tracking of miners underground.

MSHA continues to promulgate rules that affect our mining operations. In March 2013, MSHA implemented a revised Pattern of Violations (“POV”) standard. Under the revised standard, mine operators are no longer entitled to a ninety day notice of potential POV. In addition, MSHA began screening for POV by using issued citations and orders, prior to their final adjudication. If a mine is designated as having a POV, MSHA will issue an order withdrawing miners from any areas affected by violations which pose a significant and substantial (“S&S”) hazard to the health and/or safety of miners. Once a mine is in POV status, it can be removed from that status only upon (i) a complete inspection of the entire mine with no S&S enforcement actions issued by MSHA or (ii) no POV-related withdrawal orders being issued by MSHA within ninety (90) days following the mine operator being placed on POV status. However, from time to time one or more of our operations may meet the POV screening criteria, and we cannot make assurances that one or more of our operations will not be placed into POV status, which could materially and adversely affect our results of operations.

In April 2014, MSHA issued, among other provisions, a final rule lowering certain standards for respirable dust. Specifically, the rule reduces the overall dust standard from 2.0 to 1.5 milligrams per cubic meter of air and cuts in half the standard from 1.0 to 0.5 for certain mine entries and miners with pneumoconiosis, as well as changes sampling protocols and increases governmental oversight. On August 1, 2016, Phase III of MSHA’s respirable dust rule, imposing these new limits, went into effect. These final rules could make compliance more costly and approval for ventilation plans in underground coal mines more difficult to obtain.

In July 2014, MSHA issued a proposed rule that would change its civil penalty criteria under 30 Code of Federal Regulation (“CFR”) Part 100. The proposed rule increases the civil penalties for those violations exhibiting more than ordinary negligence. While this rule is not final, it could, if implemented, increase the amount of civil penalties our operations pay to MSHA. MSHA has yet to adopt a final rule regarding these proposed changes to Part 100; however, in August 2016 and then again in January 2017, MSHA adjusted its existing civil penalties for inflation, which prior to these dates were last set in 2007. While these rules resulted in different relative impacts on particular penalty amounts, the net effect of these adjustments increased the amount of penalties that MSHA may impose on operators.

In January 2015, MSHA issued a final rule on the use of proximity detection systems on certain pieces of underground mining equipment. The rule requires, among other provisions, continuous mining machines to be equipped with electronic sensing devices that can detect the presence of miners in proximity to the machines and then cause moving or repositioning continuous mining machines to stop before contacting a miner. The final rule has a phase in period, depending upon the age of the continuous mining machine, of 8 to 36 months.

These requirements have, and will continue to have, a significant effect on our operating costs.

In June 2016, MSHA issued a request for information on approaches to control and monitor miners' exposures to diesel exhaust. While MSHA's existing regulations address health hazards to coal miners from exposure to diesel particulate matter ("DPM"), MSHA is requesting information on approaches that would improve control of DPM and diesel exhaust. Although no rule has been proposed, if a rule that lowered DPM emission limits is proposed and adopted, it could have a significant impact on our operating costs.

Black Lung

Under the United States Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator must secure payment of federal black lung benefits to claimants who have been diagnosed with pneumoconiosis and are current or former employees and must also pay into a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to July 1, 1973. The trust fund is funded by an excise tax on production sold domestically 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.

U.S. Environmental Laws

We are subject to various U.S. federal, state and local environmental laws. Some of these laws, as discussed below, impose stringent requirements on our coal mining operations. U.S. federal and state regulations require regular monitoring of our mines and other facilities to ensure compliance. U.S. federal and state inspectors are required to inspect our mining facilities on a frequent schedule. Future laws, regulations or orders, as well as future interpretations or more rigorous enforcement of existing laws, regulations or orders, may require increases in capital and operating costs, the extent of which we cannot predict.

The Surface Mining Control and Reclamation Act ("SMCRA")

SMCRA, which is administered by the Office of Surface Mining Reclamation and Enforcement ("OSM"), establishes mining, environmental protection and reclamation standards for all aspects of surface mining as well as many aspects of deep mining. Mine operators must obtain SMCRA permits and permit renewals from the OSM or the applicable state agency. Where state regulatory agencies have adopted federal mining programs under SMCRA, the state becomes the regulatory authority. Illinois has achieved primary control of enforcement through federal authorization. SMCRA also stipulates compliance with many other major environmental statutes, including: the Clean Air Act; the Endangered Species Act; the Clean Water Act of 1972 ("CWA"); the Resource Conservation and Recovery Act ("RCRA") and the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA").

SMCRA permit provisions include a complex set of requirements governing the following processes: coal prospecting; mine plan development; topsoil removal, storage and replacement; selective handling of overburden materials; mine pit backfilling and grading; protection of the hydrologic balance; subsidence control for underground mines; surface drainage control; mine drainage and mine discharge control and treatment; restoration to the approximate original contour; and re-vegetation. The disposal of coal refuse is also permitted under SMCRA. Both coarse refuse and slurry disposal areas, including the disposal of slurry underground, require permits from the Illinois Department of Natural Resources ("IDNR").

The mining permit application process is initiated by collecting baseline data to adequately characterize the pre-mine environmental condition of the permit area. This work includes surveys of culturally and historically important natural resources, soils, vegetation, and wildlife, as well as the assessment of surface and ground water hydrology, climatology and wetlands. In conducting this work, we collect geologic data to define and model the soil and rock structures and coal that we will mine. We develop mining and reclamation plans by utilizing this geologic data and incorporating elements of the environmental data. The mining and reclamation plan incorporates the provisions of SMCRA, state programs and other complementary environmental programs that regulate coal mining. Also included in the permit application are documents defining ownership and agreements pertaining to coal, minerals, oil and gas, water rights, rights of way and surface land, and documents required by the OSM's Applicant Violator System, including the mining and compliance history of officers, directors and principal owners of the entity.

Once a permit application is prepared and submitted to the regulatory agency, it goes through a completeness review and technical review. Public notice of the proposed permit is given that also provides for a comment period before a permit can be issued. Some SMCRA mine permits take over a year to prepare, depending on the size and complexity of the mine and may take months or years to be reviewed and issued. Regulatory authorities have considerable discretion in the timing of the permit issuance and the public and other agencies have rights to comment on and otherwise engage in the permitting process, including through intervention in the courts. Before a SMCRA permit is issued, a mine operator must submit a bond or otherwise secure the performance of reclamation obligations.

In July 2015, the OSM issued a new proposed revision to its Stream Buffer Zone Rule ("Stream Protection Rule"). OSM issued the final Stream Protection Rule in December 2016. The final rule significantly expands the baseline data requirements for permit applications by requiring extensive baseline data on hydrology, geology and aquatic biology; provides a definition of "material damage" that a permittee must prevent outside of the permitted area; requires additional monitoring during mining and reclamation; imposes new requirements related to listed and proposed threatened and endangered species under the Endangered Species Act; increases bonding requirements for stream restoration and restricts the use of certain types of bonds; and expands other restoration and stream protection requirements for both surface and underground mines. The final rule made slight changes to the proposed rule, such as clarifying the definition of "material damage to the hydrologic balance outside the permit area." The final rule defines this concept as an adverse impact on the quality or quantity of surface water or groundwater, or on the biological condition of a perennial or intermittent stream, and the final rule will measure compliance by determining whether the mining operation has caused or contributed to a violation of water quality standards promulgated under the Clean Water Act or to non-attainment of premining uses of surface water or groundwater. Additionally, the final rule prohibits mining operations that will result in a violation of the Endangered Species Act. The final rule also clarifies that longwall mining that uses planned subsidence is not prohibited, and that temporary impacts are allowed so long as they do not rise to the level of "material damage to the hydrologic balance outside the permit area." Under the rule, the regulatory authority is required to determine whether a permittee's proposed operation will cause "material damage," and if it does, then a permit will not be issued.

North Dakota filed suit opposing the rule in the United States District Court for the District of Columbia. The rule will likely face opposition in Congress in the upcoming legislative session. In February 2017, both the House and the Senate passed measures to revoke the Stream Protection Rule under the Congressional Review Act, which gives Congress the ability to repeal regulations promulgated in the last 60 days of the congressional session. On February 16, 2017, President Donald J. Trump signed a bill revoking the Stream Protection Rule, and prohibiting federal agencies from issuing a new rule that is substantially similar without authorization from Congress. In the absence of federal regulation amending the Stream Buffer Rule, states, such as Illinois, with primacy over their mining programs, may adopt and implement requirements similar to, or more stringent than, the Stream Protection Rule at the state level. Such requirements would likely add costs and delays to the SMCRA permitting process, add costs to our operations and reclamation activities, subject our operations to new risks of suspension or revocation of permits to conduct mining activities, and possibly diminish our ability to fully mine our reserves with the longwall method.

In November 2016, eighteen states filed suit challenging a rule recently finalized by the Fish and Wildlife Service and the National Marine Fisheries Service that expands the definitions of "critical habitat" and "adverse modification" in regulations implementing the Endangered Species Act ("ESA"). Whether an area is designated as critical habitat has implications under Section 7 of the ESA, which requires Federal agencies to consult on any action that "may affect" a listed species. Section 7 consultation is potentially triggered in the permitting of coal mining operations, and the new rule could impact our ability to obtain necessary permits. The states' lawsuit was filed soon after the election of President Trump, and it is possible that the Administration may decide not to defend the rule and, perhaps, ask for a judicial stay during a reconsideration of the rule.

The Abandoned Mine Land Fund, which is part of SMCRA, requires a fee on all coal produced. The proceeds are used to reclaim mine lands closed or abandoned prior to SMCRA's adoption in 1977. The fee on surface-mined coal is currently $0.28 per ton and the fee on deep-mined coal, which is applicable to our operations, is $0.12 per ton.

Various federal and state laws, including SMCRA, require us to obtain surety bonds or other forms of financial security to secure payment of certain long-term obligations, including mine closure and reclamation costs. In August 2016, the OSM issued a Policy Advisory discouraging state regulatory authorities from approving self-bonding arrangements. The Policy Advisory indicated that the OSM would begin more closely reviewing instances in which states accept self-bonds for mining operations. In the same month, the OSM also announced that it was beginning the rulemaking process to strengthen regulations on self-bonding. Although we do not use self-bonding, the elimination or restriction of this option may lead more parties to see third party bonding which could end up restricting supply and increasing our costs of maintaining our bonds.

As of December 31, 2016, we had outstanding surety bonds of $83.4 million primarily related to these matters. Changes in these laws or regulations could require us to obtain additional surety bonds or other forms of financial security.

Clean Air Act

The Clean Air Act and comparable state laws that regulate air emissions affect coal mining operations both directly and indirectly. Direct impacts on coal mining operations may occur through Clean Air Act permitting requirements or emission control requirements relating to particulate matter, such as fugitive dust, including future regulation of fine particulate matter measuring 2.5 micrometers in diameter or smaller. The Clean Air Act indirectly affects coal mining operations by extensively regulating the air emissions of sulfur dioxide, nitrogen oxides, mercury and other compounds emitted by coal-fired electricity generating plants.

Clean Air Act requirements that may directly or indirectly affect our operations include the following:

Acid Rain. Title IV of the Clean Air Act requires a two-phase reduction of sulfur dioxide emissions by electric utilities and applies to all coal-fired power plants generating greater than 25 megawatts of power. The affected electricity generators have sought to meet these requirements by, among other compliance methods, switching to lower sulfur fuels, installing pollution control devices, reducing electricity generating levels or purchasing sulfur dioxide emission allowances. We cannot accurately predict the effect of these provisions of the Clean Air Act on our customers and in turn, on our business in future years. We believe that implementation of the Act has resulted in increasing installations of pollution control devices as a control measure and thus, has created a growing market for our higher sulfur coal.

Fine Particulate Matter. The Clean Air Act requires the Environmental Protection Agency (“EPA”) to set standards, referred to as National Ambient Air Quality Standards (“NAAQS”), for certain pollutants. Areas that are not in compliance (referred to as “non-attainment areas”) with these standards must take steps to reduce emissions levels. The EPA promulgated NAAQS for particulate matter with an aerodynamic diameter less than or equal to 10 microns, or PM10, and for fine particulate matter with an aerodynamic diameter less than or equal to 2.5 microns, or PM2.5. Meeting current or potentially more stringent new PM2.5 standards may require reductions of nitrogen oxide and sulfur dioxide emissions. Future regulation and enforcement of the new PM2.5 standard will affect many power plants and coke plants, especially coal-fired power plants and all plants in non-attainment areas. Continuing non-compliance could prevent issuance of permits to facilities within the non-attainment areas

Ozone. Significant additional emissions control expenditures will be required at coal-fired power plants and coke plants to meet the current NAAQS for ozone. Nitrogen oxides, which are a by-product of coal combustion, can lead to the creation of ozone. Accordingly, emissions control requirements for new and expanded coal-fired power plants and industrial boilers and coke plants will continue to become more stringent in the years ahead. In October 2015, the EPA updated the NAAQS for ozone to 70 parts per billion (ppb), down from 75 ppb. The EPA has the authority to further strengthen ozone standards to protect public health, and the Clean Air Act requires periodic review of the NAAQS. If the NAAQS for ozone becomes more stringent in the future, it could increase the costs of operating coal-fired power plants.

Cross-State Air Pollution Rule (“CSAPR”). The CSAPR, which was intended to replace the previously developed Clean Air Interstate Rule (“CAIR”), requires states to reduce power plant emissions that contribute to ozone or fine particle pollution in other states. Under the CSAPR, emissions reductions were to have started January 1, 2012, for SO2 and annual NOx reductions, and May 1, 2012, for ozone season NOx reductions. Several states and other parties filed suits in the United States Court of Appeals for the District of Columbia Circuit in 2011 challenging the CSAPR. On August 21, 2012, the D.C. Circuit vacated the CSAPR and ordered the EPA to continue administering CAIR, pending the promulgation of a replacement rule. On April 29, 2014, the United States Supreme Court found that the EPA was complying with statutory requirements when it issued CSAPR and reversed the D.C. Circuit’s vacation of CSAPR. On October 23, 2014, the D.C. Circuit granted the EPA’s request to lift the stay on CSAPR. In July 2015 and on remand from the Supreme Court of the United States, the D.C. Circuit upheld the provisions of CSAPR against broad challenges to the rule, but granted certain limited relief to states that brought “as applied” challenges to their respective emissions budgets set by EPA. In November 2015, the EPA issued a proposed CSAPR Rule Update in part to address the D.C. Circuit's ruling regarding emissions budgets. The Rule Update proposes implementation of CSAPR's emission budgets in the 2017 ozone season. In September 2016, the EPA finalized the CSAPR Rule Update for the 2008 ozone NAAQS. Starting in May 2017, the rule will reduce summertime NOx emissions from power plants in 22 states in the eastern U.S. It is unclear what effect, if any, CAIR will have on our operations or results. Because U.S. utilities have continued to take steps to comply with CAIR, which requires similar power plant emissions reductions, and because utilities are preparing to comply with the Mercury and Air Toxics Standards regulations which require overlapping power plant emissions reductions, the practical impact of the reinstatement of CSAPR is expected to be limited.

However, the cost of compliance with CAIR and now CSAPR could add to pressure to shut down units, which may further adversely affect the demand for our coal.

Mercury and Air Toxic Standards ("MATS"). On December 16, 2011, the EPA issued the MATS to reduce emissions of toxic air pollutants, including mercury, other metals and acid gases, from new and existing coal and oil fired power plants. Under the final rule, existing power plants will have up to four years to comply with the MATS by installing or upgrading pollution controls, fuel switching, or using existing emissions controls as necessary to meet the compliance deadline. On June 29, 2015, the Supreme Court of the United States ruled that the EPA acted unreasonably when it determined that cost was irrelevant to the threshold finding that regulating these emissions was appropriate and necessary. This ruling did not overturn the rules in their entirety or allow previously-installed pollution controls to be removed. The EPA has acted to address the Supreme Court ruling by issuing a proposed supplemental finding that a consideration of costs would not change its threshold finding that regulation of these pollutants is appropriate and necessary. MATS has remained in place and, in April 2016, EPA issued its final supplemental finding confirming its earlier appropriate and necessary finding supporting MATS. These requirements could continue to significantly increase our customers' costs and to cause them to reduce their demand for coal, which may materially impact our results of operations. In August 2016, the EPA denied two petitions for reconsideration of startup and shutdown provisions in MATS, leaving in place the startup and shutdown provisions finalized in November 2014. The EPA also proposed changes to the electronic reporting requirements for MATS in an effort to streamline e-reporting requirements for power plants and make data about emissions more transparent and accessible to the public. EPA's actions pertaining to startup and shutdown provisions and e-reporting requirements will have limited impact on coal-fired power plants relative to the overall impact of MATS.

Greenhouse Gases ("GHG"). Increasing concern about GHG, including carbon dioxide, emitted from burning coal at electricity generation plants has led to efforts at all levels of government to reduce their emissions, which could require utilities to burn less or eliminate coal in the production of electricity. Congress has considered federal legislation to reduce GHG emissions which, among other things, could establish a cap and trade system for GHG, including carbon dioxide emitted by coal burning power plants, and requirements for electric utilities to increase their use of renewable energy such as solar and wind power. Also, the EPA has taken several recent actions under the Clean Air Act to regulate GHG emissions. These include the EPA's finding of "endangerment" to public health and welfare from GHG, its issuance in 2009 of the Final Mandatory Reporting of Greenhouse Gases Rule, which requires large sources, including coal-fired power plants, to monitor and report GHG emissions to the EPA annually starting in 2011, and issuance of its Prevention of Significant Deterioration ("PSD") and Title V Greenhouse Gas Tailoring Rule, which requires large industrial facilities, including coal-fired power plants, to obtain permits to emit, and to use best available control technology to curb GHG emissions. In response to recent Supreme Court and D.C. Circuit decisions, in August 2016 the EPA issued a proposed rule to revise existing PSD and Title V regulations to ensure that a source is not required to obtain a permit under the regulations solely because of GHG emissions. On September 20, 2013, the EPA proposed new source performance standards ("NSPS"), and in January 2014 issued final rules establishing NSPS, for GHG for new coal and oil-fired power plants, which likely will require partial carbon capture and sequestration to comply. On June 2, 2014, the EPA further proposed new regulations limiting carbon dioxide emissions from existing power generation facilities. The EPA issued its final rules, called the Clean Power Plan ("CPP"), in August 2015. Under the CPP, nationwide carbon dioxide emissions from existing plants would be reduced by 32% by 2030, while offering states and utilities flexibility in achieving these reductions. On February 9, 2016, the U.S. Supreme Court issued a temporary stay of the CPP regulations. On September 27, 2016, an *en banc* panel of the D.C. Circuit Court of Appeals held oral argument in the case challenging the CPP, and a decision is expected in early 2017. The Supreme Court stay will remain in place until the D.C. Circuit Court of Appeals rules on the merits of legal challenges to those regulations, and, if following a ruling by the D.C. Circuit Court of Appeals, a writ of certiorari from the Supreme Court is sought and granted, the stay will remain in place until the Supreme Court issues its decision on the merits. While the EPA's actions are subject to procedural delays and legal challenges, and efforts are underway in Congress to limit or remove the EPA's authority to regulate GHG emissions, they will remain in effect unless altered by the courts or Congress. It is possible that the Administration may decide not to defend these and other rules concerning GHG emissions, or may seek to modify or revoke these rules.

In October 2016, a U.S. District Judge in West Virginia ruled that the EPA explicitly neglected its duties under Section 321(a) of the Clean Air Act to study the effects of its regulations on jobs and ordered the EPA to come up with a compliance plan. The EPA indicated that it planned to consult with its Science Advisory Board and appeal the order to the Fourth Circuit. Unsatisfied with EPA's response, in January 2017, the federal judge ordered the agency to come up with an economic analysis of the effects of its regulations on the coal mining and power generating industries by July 1, 2017 and to put measures in place by the end of the year to continually monitor any losses or shifts in employment that result from its regulations. The EPA maintains that it has complied with the requirements of Section 321(a) and has appealed the judge's decision to the Fourth Circuit.

In a parallel litigation, 25 states and other parties filed lawsuits challenging EPA's final NSPS rules for carbon dioxide emissions from new, modified, and reconstructed power plants under the Clean Air Act. One of the primary issues in these lawsuits is EPA's establishment of standards of performance based on technologies including carbon capture and sequestration ("CCS"). New coal plants cannot meet the new standards unless they implement CCS, which reportedly is not yet commercially available or technically feasible. Oral arguments in this case are scheduled for April 2017. Should EPA's regulations be upheld by the court, they could materially impact the ability of customers to build new, or modify or reconstruct existing, coal-fired power plants, and thus reduce the demand for coal.

In addition to the above developments, 195 nations (including the United States) signed the Paris Agreement, a long-term, international framework convention designed to address climate change over the next several decades. This agreement entered into force in November 2016 after more than 70 countries, including the United States, ratified or otherwise agreed to be bound by the agreement. The United States was among the countries that submitted its declaration of intended greenhouse gas reductions in early 2015, stating its intention to reduce U.S. greenhouse gas emissions by 26-28% by 2025 compared to 2005 levels. Whether and to what extent the United States meets its stated intention likely depends on several factors, including whether the presently-stayed Clean Power Plan (or a comparable alternative) is implemented and the Trump Administration's reported reevaluation of the United States' continued participation in the Paris Agreement. Over the long term, international participation in the Paris Agreement framework could reduce overall demand for coal which could have a material adverse impact on us. These effects could be more adverse to the extent the United States ultimately participates in these reductions (whether via the Paris Agreement or otherwise).

Regional Emissions Trading. Nine northeast and mid-Atlantic states have cooperatively developed a regional cap and trade program, the Regional Greenhouse Gas Initiative ("RGGI"), intended to reduce carbon dioxide emissions from power plants in the region. There can be no assurance at this time that this, or similar state or regional carbon dioxide cap and trade programs (including the Western Climate Initiative, the Midwestern Greenhouse Gas Reduction Accord and the California Global Warming Solutions Act), in the states where our customers operate, will not adversely affect the future market for coal in the region.

Regional Haze. The EPA has initiated a regional haze program designed to protect and to improve visibility at and around national parks, national wilderness areas and international parks. This program restricts the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas. Moreover, this program may require certain existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxides, volatile organic chemicals and particulate matter. These limitations could adversely affect the future market for coal.

Resource Conservation and Recovery Act ("RCRA")

The RCRA affects coal mining operations by establishing requirements for the treatment, storage, and disposal of hazardous wastes. Certain coal mine wastes, such as overburden and coal cleaning wastes, are exempted from hazardous waste management.

Coal Ash Rule . Subtitle C of the RCRA exempted fossil fuel combustion wastes from hazardous waste regulation until the EPA completed a report to Congress and made a determination on whether the wastes should be regulated as hazardous. In 2000, the EPA concluded that coal combustion wastes do not warrant regulation as hazardous under the RCRA. Following a large spill of coal ash waste at a coal burning power plant in Tennessee in 2008, the EPA, in 2010, proposed two alternative sets of regulations governing the management and storage of coal ash: one would regulate coal ash and related ash impoundments at coal-fired power plants under federal regulations governing hazardous solid waste under Subtitle C of the RCRA and the other would regulate coal ash as a non-hazardous solid waste under Subtitle D. In December 2014, the EPA announced that it would regulate coal combustion wastes as a nonhazardous substance under Subtitle D of the RCRA rather than as hazard waste pursuant to the provisions of Subtitle C. On April 17, 2015, the EPA finalized regulations under the solid waste provisions ("Subtitle D") of RCRA and the finalized regulations became effective on October 19, 2015. While classifying coal combustion waste as a hazardous waste under Subtitle C would have led to more stringent requirements, the new rule could still increase customers' operating costs and may make coal less attractive for electric utilities. Under the new rule, entities storing coal combustion wastes are susceptible to litigation from citizen groups or other stakeholders. The Coal Ash Rule is currently being challenged in the D.C. Circuit by both environmental and industry groups. The ongoing efforts by environmental groups to expand energy companies' liability under RCRA could have potential adverse legal and business outcomes for coal-fired power plants.

Most state hazardous waste laws exempt coal combustion waste and instead treat it as either a solid waste or a special waste. These laws may also be revised, and the EPA and the U.S. Department of Interior ("DOI") have indicated that they intend to address placement of coal combustion waste on mine sites in a separate rulemaking. Additionally, in December 2016, Congress passed the Water Infrastructure Improvements for the Nation Act, which provides for the establishment of state and EPA permit programs for the control of coal combustion residuals and authorizes states to incorporate EPA's final rule for coal combustion residuals or develop other criteria that are at least as protective as the final rule. Any costs associated with handling or disposal of coal ash as hazardous waste would increase our customers' operating costs and potentially reduce their ability to purchase coal. In addition, potential liability for contamination caused by the past or future use, storage or disposal of ash could substantially increase.

Clean Water Act of 1972 ("CWA")

The CWA established in-stream water quality standards and treatment standards for wastewater discharge through the National Pollutant Discharge Elimination System ("NPDES"). Regular monitoring, reporting requirements and performance standards are requirements of NPDES permits that govern the discharge of pollutants into water.

Total Maximum Daily Load . Total Maximum Daily Load ("TMDL") regulations establish a process by which states may designate stream segments as "impaired" (not meeting present water quality standards). Additionally, states periodically review water quality standards and related effluent limits and consider adopting more stringent limits. Industrial dischargers, including coal mines and plants, will be required to meet new TMDL effluent standards or more stringent water quality standards for these stream segments. The adoption of new TMDL regulations or more stringent water quality standards in receiving streams could hamper or delay the issuance of discharge and Section 404 permits, and if issued, could require new effluent limitations for our coal mines and could require more costly water treatment, which could adversely affect our coal production or results of operations. States are also adopting anti-degradation regulations in which a state designates certain water bodies or streams as "high quality." These regulations would prohibit the degradation of water quality in these streams. Water discharged from coal mines to high quality streams will be required to meet or exceed new "high quality" standards. The designation of high quality streams at or in the vicinity of our coal mines could require more costly water treatment and could adversely affect our coal production or results of operations.

***Waters of the United States* .** In June 2015, the EPA published its final "Waters of the United States" rule, specifying the waterways that are subject to the jurisdiction of the EPA and the U.S. Army Corps of Engineers. The rule expands the scope of a navigable body of water to include tributaries that contain flowing water for some portion of a year. Although the rule is final, the U.S. Court of Appeals for the Sixth Circuit issued a nationwide stay of the rule in October 2015. On January 13, 2017, the Supreme Court agreed to review the Sixth Circuit's finding that it has jurisdiction to hear challenges to the rule. If upheld, the rule could pose additional permitting responsibilities for the coal industry, increasing costs, adding time to the permitting process, and potentially affecting coal supplies.

National Enforcement Initiative . In February 2016, the EPA announced its National Enforcement Initiatives for fiscal years 2017-2019, including an initiative called "Keeping Industrial Pollutants Out of the Nation's Waters," which focuses the EPA enforcement resources on certain industrial sectors including mining. Under the initiative, the EPA will use water pollution data to target potential violations of discharge permits and increase the scrutiny of compliance issues. The initiative raises the possibility of stricter permit standards and increased enforcement attention for companies and facilities that discharge wastewater to waters of the U.S.

Steam Electric Power Generating Effluent Guidelines . In addition, environmental groups filed a notice of intent to sue the EPA for failing to update effluent limitation guidelines ("ELG") under the Clean Water Act for coal-fired power plants to limit discharges of toxic metals from handling of coal combustion waste. In April 2013, the EPA released its proposed revised ELG to address toxic pollutants discharged from power plants, including discharges from coal ash ponds. On November 3, 2015, the EPA issued final revised ELG for the Steam Electric Power Generating category, effective January 4, 2016. These regulations, for the first time, set federal limits on certain metals in wastewater discharges from power plants. Individually and collectively, these regulations could make coal burning more expensive or less attractive for electric utilities and, in turn, impact the market for our products. Several industry groups have filed lawsuits challenging the rule. If the revised Steam Electric Power Generating Effluent Guidelines and the Coal Ash Rule survive legal challenges, they could increase coal plant retirements and costs to the power industry, adversely affecting the future market for coal.

Cooling Water Intake Structures . On May 19, 2014, the EPA finalized standards under Section 316(b) of the CWA that require the use of Best Technology Available ("BTA") for minimizing the injury and death of fish and other aquatic life from cooling-water intake structures at existing power plants. Because many coal-fired power plants utilize once-through cooling systems that are subject to this rule, implementation of the 316(b) regulations could, in addition to other regulatory burdens, result in further coal plant retirements and adversely affect the future market for coal.

CERCLA and Similar State Superfund Statutes

CERCLA and similar state laws affect coal mining by creating liability for the investigation and remediation of releases of regulated materials into the environment and for damages to natural resources. Under these laws, joint and several liability may be imposed on waste generators, current and former site owners or operators and others regardless of fault, for all related site investigation and remediation costs.

Permits

Mining companies must obtain numerous permits that impose strict regulations on various environmental and safety matters. These provisions include requirements for building dams; coal prospecting; mine plan development; topsoil removal, storage and replacement; protection of the hydrologic balance; subsidence control for underground mines; subsidence and surface drainage control; mine drainage and mine discharge control and treatment; and re-vegetation.

Required permits include mining and reclamation permits under the SMCRA (see “U.S. Environmental - The Surface Mining Control and Reclamation Act”), issued by the IDNR, and wastewater discharge, or NPDES, permits under the CWA, issued by the Illinois Environmental Protection Agency (“IEPA”). In addition to the required permits, for surface operations, the mining companies also need to obtain air quality permits from IEPA, fill and dredge permits from the United States Army Corps of Engineers and flood plain permits from the IDNR. For refuse disposal operations, the mining companies may need to obtain impounding permits or underground slurry disposal permits from the IDNR. In addition, MSHA approval for ventilation, roof control and numerous specific surface and underground operations must be obtained and maintained. The authorization and permitting requirements imposed by these and other governmental agencies are costly and may delay development or continuation of mining operations. In December 2014 the Council on Environmental Quality ("CEQ") released updated draft guidance discussing how federal agencies should consider the effects of GHG emissions and climate change in their National Environmental Policy Act (“NEPA”) evaluations. This type of analyses may increase the likelihood of future challenges to the NEPA documents prepared for actions requiring federal approval. The application review process may take years to complete, and agencies may ask for submission of additional studies, evaluations or other information. Regulatory authorities have considerable discretion in the timing of permit issuance. Additionally, many environmental laws and regulations provide the public with the opportunity to comment on draft permits, and otherwise engage in the permitting process. Permit applications are increasingly being challenged by environmental and other advocacy groups. Accordingly, we may experience difficulty or delays in obtaining mining permits or other necessary approvals, or even face denials of permits altogether.

Currently, we have the necessary permits for mining operations at each of the four complexes. Continued and expanded operations will require additional or renewed permits. These additional permits may include significant permit revisions to the SMCRA mining permit and fill and dredge permits; new NPDES, new SMCRA, new impounding, and possible CWA permits for additional refuse areas; and revisions to the SMCRA permit and a NPDES construction permit for additional bleeder shafts. Due to various and, sometimes, interrelated requirements from different agencies, it is not possible to predict an average or approximate time frame required to obtain all permits and approvals to operate new or expanded mines. In addition, expanded permitting activity in Illinois coupled with challenges from environmental groups will likely increase the various agencies’ permit and approval review time in the future.

Appeals of permits issued by the IEPA, including some CWA permits, are made to the Illinois Pollution Control Board (“IPCB”). The IPCB is an independent agency with five board members appointed by the Governor of the State of Illinois that both establishes environmental regulations under the Illinois Environmental Protection Act and decides contested environmental cases. Appeals before the IPCB are based on alleged violations of environmental laws as found in the permit and the accompanying permit record without additional testimony or evidence being taken. Appeals from the IPCB decisions are made to an Illinois appellate court.

Requests for an administrative review of permits issued by the IDNR, such as the SMCRA permits, are made to an IDNR hearing officer. Although the basis of the request for the administrative review is the alleged violations in the permit and the permit record, the administrative code rules allow for additional discovery and an evidentiary hearing. Appeals from the IDNR hearing officer’s decisions are made to an Illinois Circuit Court.

Item 1A. Risk Factors

An investment in our common units involves risks. Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should carefully consider the risks described below, together with the other information in this Annual Report on Form 10-K, before investing in our common units. Our business, financial condition, results of operation and cash available for distribution could be materially and adversely affected by future events. In such case, we might not be able to make distributions on our common units, the trading price of our common units could decline, and you could lose all or part of your investment in, and expected return on, our common units.

Risks Related to Our Business

We may not have sufficient cash from operations to enable us to resume payment of distributions.

Even though we are currently restricted under our debt documents from paying certain distributions, the amount of cash we will be able to distribute on our common and subordinated units in the future primarily depends upon the amount of cash we generate from our operations, which fluctuates from quarter to quarter based on, among other things:

- the amount of coal we are able to produce from our properties, which could be adversely affected by, among other things, operating difficulties and unfavorable geologic conditions;
- the market price of coal, which is affected by the supply of and demand for domestic and foreign coal;
- the level of our operating costs, including expenses to Murray Energy Corporation pursuant to the Management Services Agreement;
- the pricing terms contained in our long-term contracts;
- the price and availability of other fuels;
- cancellation or renegotiation of contracts;
- prevailing economic and market conditions;
- the impact of delays in the receipt of, failure to maintain, or revocation of, necessary governmental permits;
- the impact of existing and future environmental and climate change regulations, including those impacting coal-fired power plants;
- the loss of, or significant reduction in, purchases by our largest customers;
- the cost of compliance with new environmental laws;
- the effects of new or expanded health and safety regulations;
- air emission, wastewater discharge and other environmental standards for coal-fired power plants or coal mines;
- domestic and foreign governmental regulation, including changes in governmental regulation of the mining industry or the electric utility industry;
- the proximity to and capacity of transportation facilities;
- transportation costs; and
- force majeure events.

In addition, the actual amount of cash we have available for distribution depends on several other factors, including:

- restrictions in the agreements governing our indebtedness;
- our debt service requirements and other liabilities;
- the level and timing of capital expenditures we make;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- the amount of cash reserves established by our general partner; and
- the cost of acquisitions.

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business.

At December 31, 2016, our indebtedness (excluding our sale-leaseback arrangements) was approximately $1.4 billion. Our substantial indebtedness could adversely affect our results of operations, business and financial condition, and our ability to meet our debt obligations and resume payment of distributions to our unitholders:

- making it more difficult for us to satisfy our debt obligations;
- requiring a substantial portion of cash flow from operations to be dedicated to the payment of principal and interest on our indebtedness, therefore reducing our ability to use our cash flow to fund our operations, capital expenditures, future business opportunities and pay distributions;

- limiting our ability to obtain additional financing for working capital, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes;
- limiting our flexibility in planning for, or reacting to, changes in our business or the industry in which we operate, placing us at a competitive disadvantage compared to our competitors who have less leverage and who therefore may be able to take advantage of opportunities that our leverage prevents us from exploiting; and
- increasing our vulnerability to adverse economic, industry or competitive developments.

An extended decline in coal prices within the industry or increase in the costs of mining could continue to adversely affect our operating results and the value of our coal reserves.

Our operating results largely depend on the margins that we earn on our coal sales. Substantially all of our coal sales contracts are forward sales contracts under which customers agree to pay a specified price under their contracts for coal to be delivered in future years. The profitability of these contracts depends on our ability to adequately control the costs of the coal production underlying the contracts. Our margins reflect the price we receive for our coal less our cost of producing and transporting our coal and are impacted by many factors, including:

- the market price for coal;
- the supply of, and demand for, domestic and foreign coal;
- the supply of, and demand for, electricity;
- competition from other coal suppliers;
- the cost of using, and the availability of, other fuels, including the effects of technological developments;
- advances in power technologies;
- the efficiency of our mines;
- the amount of coal we are able to produce from our properties, which could be adversely affected by, among other things, mine fires, roof collapses, operating difficulties and unfavorable geologic conditions;
- the pricing terms contained in our long-term contracts;
- cancellation or renegotiation of contracts;
- legislative, regulatory and judicial developments, including those related to the release of GHGs;
- the value of the U.S. dollar;
- air emission, wastewater discharge and other environmental standards for coal-fired power plants or coal mines;
- delays in the receipt of, failure to receive, or revocation of necessary government permits;
- inclement or hazardous weather conditions and natural disasters;
- availability and cost or interruption of fuel, equipment and other supplies;
- transportation costs;
- availability of transportation infrastructure, including flooding and railroad derailments;
- availability of skilled employees; and
- work stoppages or other labor difficulties.

An extended decline in the price that we receive for our coal or increases in the costs of mining our coal could have a material adverse effect on our operating results and our ability to generate the cash flows we require to invest in our operations, satisfy our obligations and resume the payment of distributions to unitholders. To the extent our costs increase but pricing under these coal sales contracts remains fixed or declines, we will be unable to pass increasing costs on to our customers. If we are unable to control our costs, our profitability under our forward sales contracts may be impaired and our results of operations, business and financial condition, and our ability to make distributions to our unitholders could be materially and adversely affected.

Our future costs of production may be substantially higher than our historical costs due to a number of factors, including increased regulatory requirements applicable to coal mining, and the status of mining operations at our Hillsboro mine.

A decrease in the use of coal by electric utilities could affect our ability to sell the coal we produce.

The amount of coal consumed by the electricity generation industry is affected primarily by the overall demand for electricity and by environmental and other governmental regulations as well as by the price and availability of renewable energy sources, including biomass, hydroelectric, wind and solar power and other non-renewable fuel sources, including natural gas and nuclear power. The low price of natural gas has resulted, in some instances, in domestic generators increasing natural gas consumption while decreasing coal consumption. Future environmental regulation of GHG emissions could accelerate the use by utilities of fuels other than coal. Domestically, state and federal mandates for increased use of electricity derived from renewable energy sources could affect demand for our coal. A number of states have enacted mandates that require electricity suppliers to rely on renewable energy sources to generate a certain percentage of their power. 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 electricity generation industry could adversely affect the price of coal, which could negatively affect our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

A substantial amount of our coal is shipped through contractual arrangements with minimum volume requirements that are due regardless of whether coal is actually shipped or mined.

A substantial amount of the coal that we ship is through contractual arrangements that have minimum volume requirements. Failure to meet the minimum annual volume requirements can result in higher transportation costs to us on a per ton basis. The primary reason for making our minimum annual volume commitments was to secure long-term access to international markets (transportation to and through export terminals). To the extent coal pricing to export markets decline, we expect our sales volume to the export markets to also continue to decline thereby resulting in higher charges for shortfalls on minimum contractual throughput volume requirements. If our operations do not meet the minimum volume requirements then we could suffer from a shortage of cash due to the ongoing requirement to pay minimum payments despite a lack of shipping and the associated sales revenue. As a result, our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders may be materially adversely affected.

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

For the year ended December 31, 2016, we derived approximately 53% of our total coal sales revenues from our three largest customers, including 30% of our coal sales revenues from our largest customer. Negotiations to extend existing agreements or enter into long-term agreements with these and other customers may not be successful, and such customers may not continue to purchase coal from us. If these three customers or any of our top customers were to significantly reduce their purchases of coal from us, or if we were unable to sell coal to our top customers on terms as favorable to us as the terms under our current contracts, our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders may be materially adversely affected.

We may not be able to incur debt or access the debt and equity capital markets because of the state of the coal industry and the deterioration of the financial markets.

The cost of raising money in the debt and equity capital markets has increased substantially, particularly for the U.S. coal industry, while the availability of funds from those markets generally has diminished. The cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to those of our current debt and have reduced and, in some cases, ceased to provide funding to borrowers or determined to stop providing credit to the coal industry. We may be unable to incur indebtedness under credit facilities or term loans on reasonable terms or at all.

Our current capital structure restricts our ability to raise further debt, subject to exceptions that can be significant. Even if we were to need additional funding, due to these factors, we cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to refinance our existing indebtedness, take advantage of business opportunities or respond to competitive pressures, which could negatively affect our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

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

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

Our general partner has limited its liability regarding our obligations and under certain circumstances unitholders may have liability to repay distributions.

Our general partner has limited its liability under contractual arrangements between us and third parties so that the counterparties to such arrangements have recourse only against our assets, and not against 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 more favorable terms 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.

Unitholders may have to repay amounts wrongfully returned or distributed to them.

Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, or the Delaware Act, we may not make a distribution to our 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 are liable to the limited partnership for the distribution amount. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Failure to meet certain provisions in our coal supply agreements could result in economic penalties.

Most of our coal supply agreements contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as heat value, sulfur content, ash content, hardness and ash fusion temperature. Failure to meet these specifications could result in economic penalties, including price adjustments, purchasing replacement coal in a higher-priced open market, rejection of deliveries or termination of the contracts. In some of the contract price adjustment provisions, failure of the parties to agree on price adjustments may allow either party to terminate the contract.

Many agreements also contain provisions that permit the parties to adjust the contract price upward or downward for specific events, including changes in the laws regulating the timing, production, sale or use of coal. Moreover, a limited number of these agreements permit the customer to terminate the agreement if transportation costs increase substantially or, in the event of changes in regulations affecting the coal industry, such changes increase the price of coal beyond specified amounts. Additionally, a number of agreements provide that customers may terminate the agreement in the event a new or amended environmental law or regulation prevents or restricts the customer from utilizing coal supplied by us and/or requires material additional capital or operating expenditures to utilize such coal.

Certain of our customers may seek to defer contracted shipments of coal, which could affect our results of operations and liquidity.

From time to time, certain customers have sought and others may seek to delay shipments or request deferrals under existing agreements. There is no assurance that we will be able to resolve existing and potential deferrals on favorable terms, or at all. Any such deferrals may have an adverse effect on our business, results of operations and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

We sell a portion of our uncommitted tons in the spot market which is subject to volatility.

We derive a portion of our revenue from coal sales in the spot market, typically defined as contracts with terms of less than one year. The pricing in spot contracts is significantly more volatile than pricing through long-term coal supply agreements because it is subject to short-term demand swings. If spot market pricing for coal is unfavorable, this volatility could materially adversely affect our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

Some of our customers blend our coal with coal from other sources, making our sales dependent upon our customers locating additional sources of coal.

Our coal's characteristics, particularly the sulfur or chlorine content, are such that many of our customers blend our coal with other purchased supplies of coal before burning it in their boilers. Some of our current or future coal sales may therefore be dependent in part on those customers' ability to locate additional sources of coal with offsetting characteristics which may not be available in the future on terms that render the customers' overall cost of blended coal economic. A loss of business from such customers may materially adversely affect our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

Global economic conditions, or economic conditions in any of the industries in which our customers operate, and continued uncertainty in financial markets may have material adverse impacts on our business and financial condition that we cannot predict.

If economic conditions or factors that negatively affect the economic health of the U.S., Europe or Asia worsen, our revenues could be reduced and thus adversely affect our results of operations. Markets have historically experienced disruptions relating to volatility in security prices, diminished liquidity and credit availability, rating downgrades of certain investments and declining valuations of others, failure and potential failures of major financial institutions, high unemployment rates and volatility in interest rates. Such conditions may adversely affect the ability of our customers and suppliers to obtain financing to perform their obligations to us. Also, if the economic impact of a downturn impacts foreign markets disproportionately, global currencies may weaken against the U.S. dollar. A weaker U.S. dollar would unfavorably impact our ability to export our coal by making it more expensive for foreign buyers. We believe that deterioration or a prolonged period of economic weakness will have an adverse impact on our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume the payment of distributions to our unitholders.

Ongoing efforts to restore Hillsboro Energy's Deer Run Mine to production may ultimately not succeed.

Since March 26, 2015, underground mining at Hillsboro Energy's Deer Run Mine has been prevented by spontaneous combustion occurring within the mine. Hillsboro cannot restore the mine to production until such time as it can establish that the spontaneous combustion is extinguished and would no longer expose the workforce to a health and safety risk upon resumption of underground mining. On March 1, 2016, we asked MSHA for permission to take the next step of temporarily sealing the entire mine to reduce or eliminate oxygen flow paths into the mine and, since that time, have been undertaking steps to re-enter the mine upon satisfaction of certain conditions. We are uncertain as to when production will resume at this operation but we will continue to work closely with MSHA and the Illinois Office of Mines and Minerals Mine Safety and Training Division to ensure the safety of our employees throughout the process and to explore alternatives to safely resolving this issue. Additionally, the Deer Run Mine requires certain approvals from the MSHA to recommence mining. We can make no assurances that we will be able to resume production at the Deer Run Mine, and therefore, it may be permanently closed which would likely result in a material impairment of Hillsboro Energy's assets. If we are unable to regain access to the Deer Run Mine and we terminate the force majeure event, we may be obligated to pay the minimum royalty payment without the corresponding production and sales. As a result, our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders may be materially adversely affected.

A substantial amount of our coal reserves are leased or subleased and are subject to minimum royalty payments that are due regardless of whether coal is actually mined.

A substantial amount of the reserves that our operating companies lease are subject to minimum royalty payments, including those leases with affiliates. Failure to meet minimum production requirements could result in losses of prepaid royalties and, in some rare cases, could result in a loss of the lease itself. If certain operations do not meet production goals then we could suffer from a shortage of cash due to the ongoing requirement to pay minimum royalty payments without any corresponding production and coal sales. As a result, our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders may be materially adversely affected.

The availability or reliability of current transportation facilities could affect the demand for our coal or temporarily impair our ability to supply coal to our customers. In addition, our inability to expand our transportation capabilities and options could further impair our ability to deliver coal efficiently to our customers.

We depend upon rail, barge, ocean-going vessels and port facilities to deliver coal to customers. Disruption of these transportation services because of weather-related problems, infrastructure damage, strikes, lock-outs, lack of fuel or maintenance items, transportation delays, lack of rail or port capacity or other events could temporarily impair our ability to supply coal to customers and thus could adversely affect our results of operations, cash flows and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

Additionally, if there are disruptions of the transportation services provided by the railroad and we are unable to find alternative transportation providers to ship our coal, our business and profitability could be adversely affected. While we currently have contracts in place for transportation of coal from our facilities and have continued to develop alternative transportation options, there is no assurance that we will be able to renew these contracts or to develop these alternative transportation options on terms that remain favorable to us. Any failure to do so could have a material adverse impact on our financial position and results of operations as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

Significant increases in transportation costs could make our coal less competitive when compared to other fuels or coal produced from other regions.

Transportation costs represent a significant portion of the total cost of coal for our customers and the cost of transportation is an important factor in a customer's purchasing decision. Increases in transportation costs, including increases resulting from emission control requirements and fluctuations in the price of diesel fuel, could make coal a less competitive source of energy when compared to other fuels, such as natural gas, or could make our coal less competitive than coal produced in other regions of the U.S. or abroad.

Significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country and from abroad, including coal imported into the U.S. Coordination of the many eastern loading facilities, the large number of small shipments, terrain and labor issues all combine to make shipments originating in the eastern U.S. inherently more expensive on a per ton-mile basis than shipments originating in the western U.S. Historically, high coal transportation rates and transportation constraints from the western coal producing areas into eastern U.S. markets limited the use of western coal in those markets. However, a decrease in rail rates or an increase in rail capacity from the western coal producing areas to markets served by eastern U.S. producers could create major competitive challenges for eastern producers. Increased competition due to changing transportation costs could have an adverse effect on our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

Our ability to mine and ship coal may be affected by adverse weather conditions, which could have an adverse effect on our revenues.

Adverse weather conditions can impact our ability to mine and ship our coal and our customers' ability to take delivery of our coal. Lower than expected shipments by us during any period could have an adverse effect on our revenues. In addition, severe weather may affect our ability to conduct our mining operations and severe rain, ice or snowfall may affect our ability to load and transport coal. If we are unable to conduct our operations due to severe weather, it could have an adverse effect on our results of operations or business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

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

The coal mining industry is subject to increasingly strict regulations by federal, state and local authorities on matters such as:

- permits and other licensing requirements;
- water quality standards;
- miner and worker health and safety;
- remediation of contaminated soil, surface water and groundwater;
- air emissions;
- the discharge of materials into the environment, including wastewater;
- surface subsidence from underground mining;
- storage, treatment and disposal of petroleum products and substances which are regarded as hazardous under applicable laws or which, if spilled, could reach waterways or wetlands;
- storage and disposal of coal wastes including coal slurry under applicable laws;
- protection of human health, plant life and wildlife, including endangered and threatened species;
- reclamation and restoration of mining properties after mining is completed;
- wetlands protection;
- dam permitting; and
- the effects, if any, that mining has on groundwater quality and availability.

Because we engage in longwall mining, subsidence issues are particularly important to our operations. Failure to timely secure subsidence rights or any associated mitigation agreements could materially affect our results by causing delays or changes in our mining plan through stoppages or increased costs because of the necessity of obtaining such rights.

Because of the extensive and detailed nature of these regulatory requirements, it is extremely difficult for us and other underground coal mining companies in particular, as well as the coal industry in general, to comply with all requirements at all times. We have been cited for violations of regulatory requirements in the past, and we expect to be cited for violations in the future. None of our violations to date has had a material impact on our operations or financial condition, but future violations may have a material adverse impact on our business, result of operations or financial condition. While it is not possible to quantify all of the costs of compliance with applicable federal and state laws and associated regulations, those costs have been and are expected to continue to be significant. Compliance with these laws and regulations, and delays in the receipt of or failure to receive or revocation of necessary government permits, could substantially increase the cost of coal mining or have a material adverse effect on our results of operations, cash flows and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

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

The utility industry is subject to extensive regulation regarding the environmental impact of its power generation activities, particularly with respect to air emissions, which could affect demand for our coal. For example, the federal Clean Air Act and similar state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury, and other compounds emitted into the air from electric power plants, which are the largest end-users of our coal. A series of more stringent requirements relating to particulate matter, ozone, haze, mercury, sulfur dioxide, nitrogen oxide and other air pollutants will, or are expected to become effective in coming years. In addition, concerted conservation efforts that result in reduced electricity consumption could cause coal prices and sales of our coal to materially decline.

More stringent air emissions limitations may require significant emissions control expenditures for many coal-fired power plants and could have the effect of making coal-fired plants less profitable. As a result, some power plants may continue to switch to other fuels that generate less of these emissions or they may close. Any switching of fuel sources away from coal, closure of existing coal-fired plants, or reduced construction of new plants could have a material adverse effect on demand for and prices received for our coal.

It is possible that new environmental legislation or regulations may be adopted, or that existing laws or regulations may be differently interpreted or more stringently enforced, any of which could have a significant impact on our mining operations or our customers' ability to use coal.

Recent developments in the regulation of GHG emissions and coal ash could materially adversely affect our customers' demand for coal and our results of operations, cash flows and financial condition.

Coal-fired power plants produce carbon dioxide and other GHGs as a by-product of their operations. GHG emissions have received increased scrutiny from local, state, federal and international government bodies. Future regulation of GHGs could occur pursuant to U.S. treaty obligations or statutory or regulatory change. The EPA and other regulators are using existing laws, including the federal Clean Air Act, to limit emissions of carbon dioxide and other GHGs from major sources, including coal-fired power plants that may require the use of "best available control technology." For example, in 2011, the EPA issued regulations, including permitting requirements, restricting GHG emissions from any new U.S. power plants, and from any existing U.S. power plants that undergo major modifications that increase their GHG emissions. In response to recent decisions by the Supreme Court and the D.C. Circuit Court of Appeals, in August 2016, the EPA issued a proposed rule to revise its existing GHG permitting program to ensure that a source is not required to obtain a permit solely because of its GHG emissions. In addition, in June 2013, President Obama announced additional initiatives intended to reduce greenhouse gas emissions globally, including curtailing U.S. government support for public financing of new coal-fired power plants overseas and promoting fuel switching from coal to natural gas or renewable energy sources. Global treaties have been adopted that place restrictions on carbon dioxide and other GHG emissions. In October 2015, the EPA formally published final new source performance standards ("NSPS") for carbon dioxide emissions from new power plants. To meet the NSPS, new coal plants are likely to be required to install carbon capture and storage technology.

On August 3, 2015, President Obama and the EPA announced the final Clean Power Plan ("CPP"), which includes final emission guidelines for states to follow in developing plans to reduce GHG emissions from existing fossil fuel-fired electric generating units ("EGU"s) as well as limits on GHG emission rates for new, modified and reconstructed EGUs. Under the CPP, nationwide carbon dioxide emissions would be reduced by 32% by 2030, while offering states and utilities flexibility in achieving these reductions. On February 9, 2016, the U.S. Supreme Court issued a temporary stay of the CPP regulations. The stay will be in place until the D.C. Circuit Court of Appeals rules on the merits of legal challenges to those regulations, and, if following a ruling by the D.C. Circuit Court of Appeals, a writ of certiorari from the Supreme Court is sought and granted, the stay will remain in place until the Supreme Court issues its decision on the merits. An *en banc* panel of the D.C. Circuit Court of Appeals held oral argument in the case challenging the CPP on September 27, 2016. Lawsuits have also been filed in the D.C. Circuit challenging EPA's final NSPS rule for CO2 from new, modified, and reconstructed power plants under the CAA Section 111(b), which challenges EPA's establishment of standards of performance based on technologies including CCS. The finalization of the NSPS for new air pollutant sources under Section 111(b) is a prerequisite for the use of authority under Section 111(d) to regulate existing sources, which is the authoritative basis for the Clean Power Plan. After a short suspension to allow for consolidation, the briefing schedule resumed in October 2016 and oral arguments are scheduled for April 2017. Even without the legal challenges, demand for coal will likely be further decreased as a result of the CPP, potentially significantly, and could adversely impact our business.

In addition, state and regional climate change initiatives to regulate GHG emissions, such as the RGGI of certain northeastern and Mid-Atlantic states, the Western Climate Initiative, the Midwestern Greenhouse Gas Reduction Accord and the California Global Warming Solutions Act, either have already taken effect or may take effect before federal action. Further, governmental agencies have been providing grants or other financial incentives to entities developing or selling alternative energy sources with lower levels of GHG emissions, which may lead to more competition from those entities. There have also been several public nuisance lawsuits brought against power, coal, oil and gas companies alleging that their operations are contributing to climate change. The plaintiffs are seeking various remedies, including punitive and compensatory damages and injunctive relief. While the U.S. Supreme Court recently determined that such claims cannot be pursued under federal law, plaintiffs may seek to proceed under state common law.

In December 2014, the EPA announced that it had determined to regulate coal combustion wastes, sometimes referred to as coal ash or coal combustion by-products ("CCB"), as a nonhazardous substance under Subtitle D of the RCRA rather than as a hazardous waste product under Subtitle C of the RCRA. On April 17, 2015, the EPA finalized regulations under the solid waste provisions ("Subtitle D") of RCRA which became effective on October 19, 2015. While classification of CCB as a hazardous waste would have led to more stringent restrictions and higher costs, regulation under Subtitle D imposes certain requirements on management of CCBs and may still increase our customers' operating costs and potentially reduce their ability to purchase coal.

On November 3, 2015, the EPA revised effluent limit guidelines ("ELG") regulations for the Steam Electric Power Generating category, effective January 4, 2016. ELG regulations, for the first time, set federal limits on certain metals in wastewater discharges from power plants. The combined effect of the CCB and ELG rules has resulted in closures of some coal ash ponds at coal-fired power plants, and it could lead to closure of older coal-fired generating units that cannot comply with new standards. Individually and collectively, these regulations could impact the market for our products.

The enactment of these and other laws or regulations regarding emissions from the combustion of coal or other actions to limit such emissions, could result in electricity generators switching from coal to other fuel sources thereby reducing demand for our coal. Significant public opposition has also been raised with respect to the proposed construction of certain new coal-fueled electricity generating plants and certain new export transloading facilities due to the potential for increased air emissions. Such opposition, as well as any corporate or investor policies against coal-fired generation plants could also reduce the demand for our coal. Further, policies limiting available financing for the development of new coal-fueled power plants could adversely impact the global demand for coal in the future. The potential impact on us of future laws, regulations or other policies or circumstances will depend upon the degree to which any such laws, regulations or other policies or circumstances force electricity generators to diminish their reliance on coal as a fuel source. In view of the significant uncertainty surrounding each of these factors, it is not possible for us to reasonably predict the impact that any such laws, regulations or other policies may have on our results of operations, cash flows and financial condition as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders. However, such impacts could have a material adverse effect on our results of operations, cash flows and financial condition as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

Extensive governmental regulation pertaining to safety and health imposes significant costs on our mining operations and could materially and adversely affect our results of operations.

Federal and state safety and health regulations in the coal mining industry are among the most comprehensive and extensive systems for protection of employee safety and health affecting any U.S. industry. Compliance with these requirements imposes significant costs on us and can result in reduced productivity. New health and safety legislation, regulations and orders may be adopted that may materially and adversely affect our mining operations.

Federal and state health and safety authorities inspect our operations, and we anticipate a continued increase in the frequency and scope of these inspections. In recent years, federal authorities have also conducted special inspections of coal mines for, among other safety concerns, the accumulation of coal dust and the proper ventilation of gases such as methane. In addition, the federal government has announced that it is considering changes to mine safety rules and regulations, which could potentially result in or require additional safety training and planning, enhanced safety equipment, more frequent mine inspections, stricter enforcement practices and enhanced reporting requirements.

In addition, in March 2013, MSHA implemented a revised POV standard. Under the revised standard, mine operators are no longer entitled to a ninety day notice of potential POV. In addition, MSHA began screening for POV by using issued citations and orders, prior to their final adjudication. If a mine is designated as having a POV, MSHA will issue an order withdrawing miners from any areas affected by violations which pose a significant and substantial hazard to the health and/or safety of miners. Once a mine is in POV status, it can be removed from that status only upon (i) a complete inspection of the entire mine with no S&S enforcement actions issued by MSHA or (ii) no POV-related withdrawal orders being issued by MSHA within ninety (90) days following the mine operator being placed on POV status. Litigation testing the validity of the standard and its application by MSHA is ongoing. However, from time to time one or more of our operations may meet the POV screening criteria, and we cannot make assurances that one or more of our operations will not be placed into POV status, which could materially and adversely affect our results of operations.

In 2014, MSHA began implementation of a finalized new regulation titled "Lowering Miner's Exposure to Respirable Coal Mine Dust, Including Continuous Personal Dust Monitors." In addition to lowering the allowable respirable dust in certain areas of underground coal mines, the final rule changes dust sampling requirements, increases MSHA oversight, and could make ventilation plans more difficult to obtain, all of which is expected to increase mining costs. The final rule became effective in August 2016.

In June 2016, MSHA issued a request for information on approaches to control and monitor miners' exposures to diesel exhaust. While MSHA's existing regulations address health hazards to coal miners from exposure to DPM, MSHA is requesting information on approaches that would further improve control of DPM and diesel exhaust. Although no rule has been proposed, if a rule that lowered DPM emission limits is proposed and adopted, it would likely make compliance more costly.

We must compensate employees for work-related injuries. If adequate provisions for workers' compensation liabilities are not made, our future operating results could be harmed. Also, federal law requires we contribute to a trust fund for the payment of benefits and medical expenses to certain claimants. Currently, the trust fund is funded by an excise tax on coal production of $1.10 per ton for underground coal sold domestically, not to exceed 4.4% of the gross sales price. If this tax increases, or if we could no longer pass it on to the purchasers of our coal under our coal sales agreements, our operating costs could be increased and our results could be materially and adversely affected. If new laws or regulations increase the number and award size of claims, it could materially and adversely harm our business. In addition, the erosion through tort liability of the protections we are currently provided by workers' compensation laws could increase our liability for work-related injuries and have a material adverse effect on our results of operations, cash flows and financial condition as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

Extensive environmental regulations, including existing and potential future regulatory requirements, pertaining to discharge of materials into the environment, including wastewater, impose significant costs on our mining operations and could materially and adversely affect our production, cash flow and profitability.

Our mining operations are subject to numerous complex regulatory, compliance, and enforcement programs. While we believe we are in compliance with all environmental regulatory requirements, our operations have, from time to time, been issued violation notices from various agencies, including the IEPA. In July 2014, following issuance of a violation notice, we entered into a plan which resolves all outstanding violations regarding pumped mine discharges at our Sugar Camp operation and provides long-term water treatment and disposal capacity for that operation. We believe we are currently in compliance with the plan. However, we can make no assurances that Sugar Camp will not receive future violations notwithstanding the implementation of the plan, and these violations may result in the assessment of fines or penalties, or, a temporary or permanent suspension of the affected mining operations. Additionally, we cannot make assurances that one or more of our operations will not receive future violation notices that result in fines, penalties, mandatory corrective action plans, or suspension of mining activities. Such corrective action plans or suspensions could have a material adverse effect on our results of operations, cash flows and financial condition, as well as our ability to make distributions to our unitholders.

Additionally, regulatory agencies may, from time to time, add more stringent compliance requirements to our environmental permits either by rule, or regulation or during the permit renewal process. More stringent requirements could lead to increases in costs and could materially and adversely affect our production, cash flow and profitability. For example, on April 30, 2013, citing lack of resources and the priority of other matters, the EPA denied a petition brought by environmental groups seeking to add coal mines to the Clean Air Act section 111 list of stationary source categories, which would have had the effect of regulating methane emissions from coal mines in some manner. Following the environmental groups' challenge to EPA's denial, the United States Court of Appeals for the District of Columbia upheld the EPA's action in May 2014. However, the EPA could, in the future, determine to add coal mines to the list of regulated sources and impose emission limits on coal mines, which could have a significant impact on our mining operations.

We may be unable to obtain, maintain or renew permits necessary for our operations and to mine all of our coal reserves, which would materially and adversely affect our production, cash flow and profitability.

In order to develop our economically recoverable coal reserves, we must regularly obtain, maintain or renew a number of permits that impose strict requirements on various environmental and operational matters in connection with coal mining. These include permits issued by various federal, state and local agencies and regulatory bodies. Permitting rules, and the interpretations of these rules, are complex, change frequently, and are often subject to discretionary interpretations by regulators, all of which may make compliance more difficult or impractical and could result in the discontinuance of mine development or the development of future mining operations. The public, including non-governmental organizations, anti-mining groups and individuals, have certain statutory rights to comment upon and submit objections to requested permits and environmental impact statements prepared in connection with applicable regulatory processes, and otherwise engage in the permitting process, including bringing citizens' claims to challenge the issuance or renewal of permits, the validity of environmental impact statements or performance of mining activities. Our mining operations are currently, and may become in the future, subject to legal challenges before administrative or judicial bodies contesting the validity of our environmental permits under SMCRA and the CWA, among other statutory provisions. Accordingly, required permits may not be issued in a timely fashion or renewed at all, or permits issued or renewed may not be maintained, may be challenged or may be conditioned in a manner that may restrict our ability to efficiently and economically conduct our mining activities, any of which would materially reduce our production, cash flow, and profitability as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

We make no assurances that we will be able to obtain, maintain or renew any of the governmental permits that we need to continue developing our proven and probable coal reserves. Further, new legislation or administrative regulations or new judicial interpretations or administrative enforcement of existing laws and regulations, including proposals related to the protection of the environment and to human health and safety that would further regulate and tax the coal industry may also require us to change operations significantly or incur increased costs.

On June 29, 2015, the EPA and the U.S. Army Corps of Engineers published their final rule expanding the definition of "Waters of the United States" ("WOTUS Rule") that expands the jurisdiction of the EPA and the United States Army Corps of Engineers to regulate waters not previously regulated. The WOTUS Rule became effective on August 28, 2015 and, if fully implemented, will likely add an additional layer of permitting to activities involving previously non-jurisdictional waters and likely cause states that have jurisdiction over their own waters to enhance their already robust regulatory programs, adding delays to the permitting process and extending review times even further for regulatory agencies. On October 9, 2015, the United States Court of Appeals for the Sixth Circuit issued a temporary nationwide stay of the effectiveness of the WOTUS Rule while litigation regarding its legality progresses. The temporary stay could be lifted at any time. The WOTUS Rule has been challenged in several jurisdictions, both at the district and appellate court levels. In addition to issuing a nationwide stay, the Sixth Circuit ruled that district courts do not have jurisdiction to consider the matter. Industry groups opposed this decision and asked the Supreme Court to overturn the Sixth Circuit and send the cases back to the district courts. On January 13, 2017, the Supreme Court agreed to review the Sixth Circuit's finding that it has jurisdiction to hear challenges to the rule. This rule, if it becomes final, could impact our ability to timely obtain necessary permits. Such changes could have a material adverse effect on our financial condition and results of operations as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

In March 2014, the Illinois State Attorney General, the Illinois Department of Natural Resources and others entered into an order which has potentially far-reaching effects on the permitting process for mines in Illinois. While the final rules have yet to be promulgated, and thus the impact on the permitting process cannot yet be determined, the order could have the effect of extending the permit review and approval process. The inability to conduct mining operations or obtain, maintain or renew permits may have a material adverse effect on our results of operations, business and financial position, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

Competition within the coal industry may adversely affect our ability to sell coal and excess production capacity in the industry could put downward pressure on coal prices.

We compete with other producers primarily on the basis of price, coal quality, transportation cost and reliability of delivery. We cannot assure you that competition from other producers will not adversely affect us in the future. The coal industry has experienced consolidation in recent years, including consolidation among some of our major competitors. We cannot assure you that the result of current or further consolidation in the industry will not adversely affect us. In addition, potential changes to international trade agreements, trade concessions or other political and economic arrangements may benefit coal producers operating in countries other than the U.S., where our mining operations are currently located. We cannot assure you that we will be able to compete on the basis of price or other factors with companies that in the future may benefit from favorable trading or other arrangements. We compete directly for domestic and international coal sales with numerous other coal producers located in the U.S. and internationally, in countries such as Australia, China, India, South Africa, Indonesia, Russia and Colombia. The price of coal in the markets into which we sell our coal is also influenced by the price of coal in the markets in which we do not sell our coal because significant oversupply of coal from other markets could materially reduce the prices we receive for our coal. Increases in coal prices could encourage the development of expanded capacity by new or existing coal producers, which could result in lower coal prices. As a result, our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders may be materially adversely affected.

The benefits of reduced costs associated with the management services agreement and joint management with Murray Energy may not be realized.

We may not realize the reduction in selling, general and administrative costs which we expect under the management services agreement with Murray Energy or the expected procurement synergies resulting from increased purchasing power with third party vendors and lower pricing on equipment acquired from Murray Energy's manufacturing facilities.

Cost reimbursements due to our general partner and its affiliates for services provided to us or on our behalf reduce cash available for distribution to our unitholders. Our general partner determines the amount and timing of such reimbursements.

We are obligated under our partnership agreement to reimburse our general partner and its affiliates for all expenses they incur and payments they make on our behalf and have entered into a management services agreement with Murray Energy to provide operational services to us. Our partnership agreement does not limit the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner determines the expenses that are allocable to us. Under the management services agreement, we are obligated to pay Murray Energy $3.5 million per quarter for services provided to us, but we may agree to revise the management services agreement to provide for a different reimbursement amount. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates reduces the amount of cash available for distributions to our unitholders.

Foresight Reserves and Murray Energy own our general partner which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including Foresight Reserves and Murray Energy, have conflicts of interest with us and limited duties, and they may favor their own interests to our detriment and that of our unitholders.

Foresight Reserves and Murray Energy own and control our general partner and appoint all of the directors of our general partner. Although our general partner has a duty to manage us in a manner that it believes is not adverse to our interest, the executive officers and directors of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to Foresight Reserves and Murray Energy. Therefore, conflicts of interest may arise between Foresight Reserves, Murray Energy or their respective affiliates, including our general partner, on the one hand, and us and any of our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our common unitholders.

These conflicts include the following situations, among others:

- our general partner is allowed to take into account the interests of parties other than us, such as Foresight Reserves and Murray Energy, in exercising certain rights under our partnership agreement;
- neither our partnership agreement nor any other agreement requires Foresight Reserves or Murray Energy to pursue a business strategy that favors us;
- our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limits our general partner's liabilities and restricts the remedies available to unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty;
- Foresight Reserves, Murray Energy and their respective affiliates are not limited in their ability to compete with us and may offer business opportunities or sell assets to third parties without first offering us the right to bid for them;
- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the level of reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines the amount and timing of any cash expenditure and whether an 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 cash from operating surplus that is distributed to our unitholders, which, in turn, may affect the ability of the subordinated units to convert.
- when permitted pursuant to the terms of our debt agreements, 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 $125 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 the incentive distribution rights;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates, including Murray Energy, for any services rendered to us or entering into additional contractual arrangements with its affiliates on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner may exercise its right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- our general partner controls the enforcement of obligations that it and its affiliates owe to us;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of the board of directors of our general partner or the unitholders. This election may result in lower distributions to the common unitholders in certain situations.

We share key personnel with Murray Energy, including our chief executive officer and all of our sales and purchasing personnel, so there may be a conflict of interest in the duties of such personnel as they relate to Murray Energy and us. Such personnel have fiduciary duties to Murray Energy which may cause them to pursue business strategies that disproportionately benefit Murray Energy or which otherwise are not in the best interest of our unitholders. As a result, there may be instances where a conflict of interest arises between Murray Energy and us that could have an adverse effect on our business.

In addition, Murray Energy is one of our principal competitors, and Murray Energy, Foresight Reserves and their affiliates currently hold substantial interests in other companies in the energy and natural resource sectors. We may compete directly with Murray Energy or entities in which Murray Energy, Foresight Reserves or their affiliates have an interest for customers or acquisition opportunities and potentially will compete with these entities for new business or extensions of the existing services provided by us.

Our ability to collect payments from Murray Energy could be impaired if Murray Energy's creditworthiness deteriorates further or if production at the Murray Energy mine ceases.

We have two long-term financing arrangements with affiliates of Murray Energy for which we have $70.1 million in aggregate financing receivables recorded on our consolidated balance sheet as of December 31, 2016. Our ability to receive payments under these arrangements depends on the continued creditworthiness of the Murray Energy affiliates under which these financing arrangements are with as well as the continued operation of the Murray Energy mine under which these financing arrangements are based. If the operation of this Murray Energy mine was to cease or if Murray Energy's creditworthiness was to deteriorate further, then we would bear the risk for their payment default. The failure to collect payment under these financing arrangements may materially adversely affect our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

Our business requires substantial capital expenditures and we may not have access to the capital required to reach full development of 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 capital expenditures required to build-out our mines 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. We cannot assure you that we will be able to maintain our production levels 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. Our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders may be materially adversely affected if we cannot make such capital expenditures.

Major equipment and plant failures could reduce our ability to produce and ship coal and materially and adversely affect our results of operations.

We depend on several major pieces of mining equipment and preparation plants to produce and ship our coal, including, but not limited to, longwall mining systems, preparation plants, 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 ship coal and materially and adversely affect our results of operations, business and financial condition as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

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 and transportation operations.

We use equipment in our coal mining and transportation operations such as continuous miners, 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 results of operations, business and financial condition as well as our profitability as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

The development of a longwall mining system is a challenging process that may take longer and cost more than estimated, or not be completed at all.

The full development of our reserve base may not be achieved. We may encounter adverse geological conditions or delays in obtaining, maintaining or renewing required construction, environmental or operating or mine design permits. Construction delays cause reduced production and cash flow while certain fixed costs, such as minimum royalties and debt payments, must still be paid on a predetermined schedule.

Defects in title or loss of any leasehold interests in our properties could limit our ability to conduct mining operations on these properties or result in significant unanticipated costs.

A substantial amount of our coal reserves are leased or subleased from affiliates. A title defect or the loss of any lease upon expiration of its term, upon a default or otherwise, could adversely affect our ability to mine the associated reserves or process the coal that we mine. Title to most of our owned or leased properties and mineral rights is not usually verified until we make a commitment to mine a property, which may not occur until after we have obtained necessary permits and completed exploration of the property. In some cases, we rely on title information or representations and warranties provided by our lessors or grantors. Our right to mine certain of our reserves has in the past been, and may again in the future be, adversely affected if defects in title, boundaries or other rights necessary for mining exist or if a lease expires. Any challenge to our title or leasehold interests could delay the mining of the property and could ultimately result in the loss of some or all of our interest in the property. From time to time we also may be in default with respect to leases for properties on which we have mining operations. In such events, we may have to close down or significantly alter the sequence of such mining operations which may adversely affect our future coal production and future revenues. If we mine on property that we do not own or lease, we could incur liability for such mining and be subject to regulatory sanction and penalties.

In order to obtain, maintain or renew leases or mining contracts to conduct our mining operations on property where these defects exist, we may in the future have to incur unanticipated costs. In addition, we may not be able to successfully negotiate new leases or mining contracts for properties containing additional reserves, or maintain our leasehold interests in properties where we have not commenced mining operations during the term of the lease. Some leases have minimum production requirements. As a result, our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders may be materially adversely affected.

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

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate issues, are resulting in increased regulation of coal combustion in many jurisdictions, unfavorable lending policies by lending institutions and divestment efforts affecting the investment community, which could significantly affect demand for our products or our securities. Global climate issues continue to attract public and scientific attention. Some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. Numerous reports, such as the Fourth and Fifth Assessment Report of the Intergovernmental Panel on Climate Change, have also engendered concern about the impacts of human activity, especially fossil fuel combustion, on global climate issues. In turn, increasing government attention is being paid to global climate issues and to emissions of GHGs, including emissions of carbon dioxide from coal combustion by power plants.

Federal, state and local governments may pass laws mandating the use of alternative energy sources, such as wind power and solar energy, which may decrease demand for our coal products. The Clean Power Plan is one of a number of recent developments aimed at limiting GHG emissions which could limit the market for some of our products by encouraging electric generation from sources that do not generate the same amount of GHG emissions. Enactment of laws or passage of regulations regarding emissions from the combustion of coal by the U.S., states, or other countries, could also result in electricity generators further switching from coal to other fuel sources or additional coal-fueled power plant closures. For example, the Paris Agreement resulting from the 2015 United Nations Framework Convention on Climate Change contains commitments by numerous countries to reduce their GHG emissions. The Paris Agreement entered into force in November 2016. Currently, 132 of the 197 Parties to the Convention have ratified the Paris Agreement, and additional Parties may ratify, increasing the firm commitments by various nations with respect to future GHG emissions. These commitments could further disfavor coal-fired generation, particularly in the medium- to long-term.

Congress has extended certain tax credits for renewable sources of electric generation, which will increase the ability of these sources to compete with our coal products in the market. In addition, in January 2016, the U.S. Department of Interior announced a moratorium on issuing certain new coal leases on federal land while the Bureau of Land Management undertakes a programmatic review of the federal coal program. While none of our operations are located on federal lands impacted by this moratorium, these governmental actions do signal increased attention at the federal level to coal mining practices and the GHG emissions resulting from coal combustion.

There have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, promoting the divestment of fossil fuel equities and also pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. In California, for example, legislation was enacted in October 2015 requiring California's state pension funds to divest investments in companies that generate 50% or more of their revenue from coal mining by July 2017. Other activist campaigns have urged banks to cease financing coal-driven businesses. As a result, at least ten major banks enacted such policies in 2015, joined by at least 5 major banks in 2016. The impact of such efforts may adversely affect the demand for and price of securities issued by us, and impact our access to the capital and financial markets.

In addition, several well-funded non-governmental organizations have explicitly undertaken campaigns to minimize or eliminate the use of coal as a source of electricity generation. Collectively, these actions and campaigns could adversely impact our future financial results, liquidity and growth prospects.

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

Certain of our coal mining operations use or have used hazardous and other regulated materials and have generated hazardous wastes. In addition, one of our locations was used for coal mining involving hazardous materials prior to our involvement with, or operation of, such location. We may be subject to claims under federal and state statutes or common law doctrines for penalties, toxic torts and other damages, as well as for natural resource damages and for the investigation and remediation of soil, surface water, groundwater, and other media under laws such as the CERCLA, commonly known as Superfund, or the Clean Water Act. Such claims may arise, for example, out of current, former or threatened conditions at sites that we currently own or operate as well as at sites that we and companies we acquired owned or operated in the past, or sent waste to for treatment or disposal, and at contaminated sites that have always been owned or operated by third parties.

We have used coal ash for reclamation at our Macoupin mine. On December 19, 2014, the EPA issued a final rule concerning disposal and beneficial use of coal ash. In the final rule, the EPA determined that it would regulate coal ash as a nonhazardous material under Subtitle D of the RCRA. The EPA also clarified the definition of beneficial use of coal ash. Additionally, in the preamble to its final rule, the EPA affirmed "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)." While these requirements are less stringent than the proposed rule treating coal ash as a hazardous material under Subtitle C of the RCRA, we can make no assurances that the new rule, or the potential DOI and EPA rulemaking mentioned in the rule's preamble, will not increase our costs for the use of coal ash at Macoupin or expose us to additional liability through citizen suits brought under RCRA.

We are involved in legal proceedings that if determined adversely to us, could significantly impact our profitability, financial position or liquidity.

We are, and from time to time may become, involved in various legal proceedings that arise in the ordinary course of business. Some lawsuits seek fines or penalties and damages in very large amounts, or seek to restrict our business activities. In particular, we are subject to legal proceedings relating to our receipt of and compliance with permits under the SMCRA and the CWA and to other legal proceedings relating to environmental matters involving current and historical operations, ownership of land or permitting. It is currently unknown what the ultimate resolution of these proceedings will be, but these proceedings could have a material adverse effect on our results of operations, cash flows and financial condition as well as our ability to make distributions to our unitholders.

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

Federal or state regulatory agencies, including MSHA, IDNR and IEPA, have the authority under certain circumstances following significant health, safety or environmental incidents or pursuant to permitting authority to temporarily or permanently close one or more of our mines. If this occurred, we may be required to incur capital expenditures and/or additional expenses to re-open the mine. In the event that these agencies cause us to close one or more of our mines, our coal sales contracts generally permit us to issue force majeure notices which suspend our obligations to deliver coal under such contracts. However, our customers may challenge our issuances of force majeure notices in connection with these closures. If these challenges are successful, we may have to purchase coal from third-party sources, if available, to fulfill these obligations, incur capital expenditures to re-open the mine or negotiate settlements with the customers, which may include price reductions, the reduction of commitments or the extension of time for delivery or termination of such customers' contracts. Any of these actions could have a material adverse effect on our results of operations, cash flows and financial condition as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

We face numerous uncertainties in estimating our economically recoverable coal reserves.

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 engineering, economic and geological data assembled and analyzed by third parties and our staff, which includes various engineers. The reserve estimates as to both quantity and quality are updated from time to time to reflect production of coal from the reserves and new drilling or other data received. There are numerous uncertainties inherent in estimating quantities and qualities of coal and costs to mine recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves necessarily depend upon a number of factors and assumptions, any one of which may, if inaccurate, result in an estimate that varies considerably from actual results. These factors and assumptions include:

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

As a result, actual coal tonnage recovered from identified reserve areas or properties and revenues and expenditures with respect to our production from reserves may vary materially from estimates. These estimates thus may not accurately reflect our actual reserves. Any material inaccuracy in our estimates related to our reserves could result in lower than expected revenues, higher than expected costs or decreased profitability which could materially adversely affect our results of operations, business and financial condition as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

Our operations are subject to risks, some of which are not insurable, and we cannot assure you that our existing insurance would be adequate in the event of a loss.

We maintain insurance to protect against risk of loss but our coverage is subject to deductibles and specific terms and conditions. We cannot assure you that we will have adequate coverage or that we will be able to obtain insurance against certain risks, including certain liabilities for environmental pollution or hazards. We cannot assure you that insurance coverage will be available in the future at commercially reasonable costs, or at all, or that the amounts for which we are insured or that we may receive, or the timing of any such receipt, will be adequate to cover all of our losses. Uninsured events may adversely affect our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

We have future mine closure and reclamation obligations, the timing and amount of which are uncertain. In addition, our failure to maintain required financial assurances could affect our ability to secure reclamation and coal lease obligations, which could adversely affect our ability to mine or lease the coal.

In view of the uncertainties concerning future mine closure and reclamation costs on our properties, the ultimate timing and future costs of these obligations could differ materially from our current estimates. We estimate our asset retirement obligations for final reclamation and mine closure based upon detailed engineering calculations of the amount and timing of the future cash for a third party to perform the required work. Spending estimates are escalated for inflation and market risk premium, and then discounted at the credit-adjusted, risk-free rate. Our estimates for this future liability are subject to change based on new or amendments to existing applicable laws and regulations, the nature of ongoing operations and technological innovations. Although we accrue for future costs in our consolidated balance sheets, we do not reserve cash in respect of these obligations or otherwise fund these obligations in advance. As a result, we will have significant cash outlays when we are required to close and restore mine sites that may, among other things, affect our ability to satisfy our obligations under our indebtedness and other contractual commitments and resume payment of distributions to unitholders. We cannot assure you that we will be able to obtain financing on satisfactory terms to fund these costs, or at all.

In addition, regulatory authorities require us to provide financial assurance to secure, in whole or in part, our future reclamation projects. The amount and nature of the financial assurances are dependent upon a number of factors, including our financial condition and reclamation cost estimates. Changes to these amounts, as well as the nature of the collateral to be provided, could significantly increase our costs, making the maintenance and development of existing and new mines less economically feasible. Currently, the security we provide consists of surety bonds. The premium rates and terms of the surety bonds are subject to annual renewals. Our failure to maintain, or inability to acquire, surety bonds or other forms of financial assurance that are required by applicable law, contract or permit could adversely affect our ability to operate. That failure could result from a variety of factors including the lack of availability, higher expense or unfavorable market terms of new surety bonds or other forms of financial assurance. There can be no guarantee that we will be able to maintain or add to our current level of financial assurance. Additionally, any capital resources that we do utilize for this purpose will reduce our resources available for our operations and commitments as well as our ability to resume payment of distributions to our unitholders. As of December 31, 2016, we have outstanding surety bonds with third parties of $83.4 million for which we have posted $2.5 million of cash collateral and Foresight Reserves has provided a guarantee on an additional $50.5 million.

Significant increases in, or the imposition of new, taxes we pay on the coal we produce could materially and adversely affect our results of operations.

All of our mining operations are in Illinois. If Illinois was to impose a state severance tax or any other tax applicable solely to our Illinois operations, we may be significantly impacted and our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders could be materially and adversely affected. Any imposition of Illinois state severance tax or any county tax could disproportionately impact us relative to our competitors that are more geographically diverse.

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

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner has the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of (1) the average of the daily closing price of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (2) the highest per-unit price paid by our general partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Unitholders may also incur a tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from causing us to issue additional common units and exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Securities Exchange Act of 1934. As of February 27, 2016, Murray Energy owns 100.0% of our subordinated units. At the end of the subordination period, assuming no additional issuances of units (other than upon the conversion of the subordinated units), Murray Energy would own an aggregate of 50% of our common units.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders' voting rights by 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 and 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 ability to collect payments from our customers could be impaired if their creditworthiness deteriorates.

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 on 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 on payment default. We also have contracts to supply coal to energy trading and brokering customers under which those customers sell coal to end users. If the creditworthiness of any of our energy trading and brokering customers declines, we may not be able to collect payment for all coal sold and delivered to or on behalf of these customers. An inability to collect payment from these counterparties may materially adversely affect our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

All of our coal and controlled reserves are in Illinois making us vulnerable to risks associated with operating in a single geographic area.

Because we operate exclusively in Illinois, any disruptions to our operations due to adverse geographical conditions or changes to the Illinois regulatory environment could significantly impact our operations, reduce our sales of coal and adversely affect our results of operation and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

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

Our ability to operate our business and implement our strategies depends, in part, on the continued contributions of our executive officers and other key employees. The loss of any of our key senior executives could have a material adverse effect on our business unless and until we find a replacement. A limited number of persons exist with the requisite experience and skills to serve in our senior management positions. We may not be able to locate or employ qualified executives on acceptable terms. In addition, we believe that our future success will depend on our continued ability to attract and retain highly skilled personnel with coal industry experience. Competition for these persons in the coal industry is intense and we may not be able to successfully recruit, train or retain qualified managerial personnel. We may not be able to continue to employ key personnel or attract and retain qualified personnel in the future. Our failure to retain or attract key personnel could have a material adverse effect on our ability to effectively operate our business.

Our ability to operate our mines efficiently and profitably is dependent upon skilled mining labor. A shortage of skilled mining labor in the U.S. could decrease our labor productivity and increase our labor costs, which would adversely affect our profitability.

Efficient coal mining using complex and sophisticated techniques and equipment requires skilled laborers proficient in multiple mining tasks, including mining equipment maintenance. Any shortage of skilled mining labor reduces the productivity of experienced employees who must assist in training unskilled employees. If a shortage of experienced labor occurs, it could have an adverse impact on our labor productivity and costs and our ability to expand production in the event there is an increase in the demand for our coal, which could adversely affect our results of operations, business and financial condition, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

Terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war may negatively affect our business, financial condition and results of operations.

Terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war may negatively affect our business, financial condition and results of operations. Our business is affected by general economic conditions, fluctuations in consumer confidence and spending, and market liquidity, which can decline as a result of numerous factors outside of our control, such as terrorist attacks and acts of war. Future terrorist attacks against U.S. targets, rumors or threats of war, actual conflicts involving the U.S. or its allies, or military or trade disruptions affecting our customers could cause delays or losses in transportation and deliveries of coal to our customers, decreased sales of our coal and extension of time for payment of accounts receivable from our customers. Strategic targets such as energy-related assets may be at greater risk of future terrorist attacks than other targets in the U.S. It is possible that any, or a combination, of these occurrences could have a material adverse effect on our business, financial condition and results of operations, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

A cyber incident 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, process and record financial and operating data, communicate with our employees, analyze mining information, and estimate quantities of coal reserves, as well as other activities related to our businesses. We have implemented cyber security protocols and systems with the intent of maintaining the security of our operations and protecting our and our counterparties' confidential information against unauthorized access. Despite such efforts, we may be subject to cyber security breaches which could result in unauthorized access to our information systems or infrastructure.

Strategic targets, such as energy-related assets, may be at greater risk of future cyber-attacks than other targets in the United States. Deliberate cyber-attacks on, or security breaches in, our digital systems or information technology infrastructure, or that of third parties, 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 and results of operations. 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.

The holder or holders of our incentive distribution rights may elect to cause us to issue common units to them in connection with a resetting of the target distribution levels related to the incentive distribution rights, without the approval of the conflicts committee of our general partner's board of directors or the holders of our common units. This could result in lower distributions to holders of our common units.

Our general partner, the holder of our incentive distribution rights, has the right, at any time when there are no subordinated units outstanding and we have made cash distributions in excess of the then-applicable third target distribution for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our cash distribution levels at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution will be calculated as an amount equal to the prior cash distribution per common unit for the fiscal quarter immediately preceding the reset election (such amount is referred to as 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. The number of common units to be issued to our general partner will equal the number of common units that would have entitled the holder to an aggregate quarterly cash distribution for the quarter prior to the reset election equal to the distribution on the incentive distribution rights for the quarter 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 unit without such conversion. However, our general partner may transfer the incentive distribution rights at any time. It is possible that our general partner or a transferee could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when the holders of the incentive distribution rights expect that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, the holders of the incentive distribution rights may be experiencing, or may expect to experience, declines in the cash distributions it receives related to the incentive distribution rights and may therefore desire to be issued our common units rather than retain the right to receive incentive distributions based on the initial target distribution levels. 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 to the holders of the incentive distribution rights in connection with resetting the target distribution levels.

It is our policy to distribute a significant portion of our available cash to our unitholders, which could limit our ability to grow or make acquisitions.

Pursuant to our cash distribution policy, we intend to distribute a significant portion of our available cash to our unitholders and rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund potential acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy may impair our ability to grow.

Although we have currently suspended distributions, to the extent we resume paying distributions, 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 units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

We may issue additional units without unitholder approval which would dilute existing unitholder ownership interests.

In accordance with Delaware law and the provisions of our partnership agreement, we may issue additional partnership interests that are senior to the common units in right of distribution, liquidation and voting. Additionally, we are not limited in the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance of additional common units would have the following effects:

- our existing unitholders' proportionate ownership interest in us would decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units would be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution would 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 the common units may decline.

In addition, to the extent that we are unable to generate a sufficiently large return from investment of the proceeds of the issuance of additional units, such issuances would be dilutive to the existing unitholders.

Our partnership agreement replaces our general partner's fiduciary duties to holders of our units.

Our partnership agreement contains provisions that eliminate and replace the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law 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, or otherwise free of fiduciary duties to us and our unitholders. This 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 its affiliates;
- whether to exercise its call right;
- how to exercise its voting rights with respect to the units it owns;
- whether to exercise its registration rights;
- whether to elect to reset target distribution levels; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a unitholder is treated as having consented to the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership interest in us. Foresight Reserves and Murray Energy, as owners of our general partner, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. 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 generally required to make such determination, or take or decline to take such other action, in good faith, and is not subject to any higher standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- our general partner and its officers and directors are not liable for monetary damages or otherwise to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that such losses or liabilities were the result of conduct in which our general partner or its officers or directors engaged in bad faith, meaning that they believed that the decision was adverse to the interest of the partnership or, with respect to any criminal conduct, with knowledge that such conduct was unlawful; and
- our general partner will not be in breach of its obligations under the 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:

  (1) approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval; or

  (2) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, other than one where our general partner is permitted to act in its sole discretion, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee then it will be presumed that, in making its decision, taking any action or failing to act, the board of directors acted in good faith, and 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.

Our partnership agreement provides that the conflicts committee of the board of directors of our general partner may be comprised of one or more independent directors. If our general partner establishes a conflicts committee with only one independent director, your interests may not be as well served as if the conflicts committee were comprised of at least two independent directors. A single-member conflicts committee would not have the benefit of discussion with, and input from, other independent directors.

The Cline Group and Murray Energy Corporation each currently hold substantial interests in other companies in the coal mining business, including other coal reserves in Illinois. The Cline Group and Murray Energy Corporation each makes investments and purchases entities that acquire, own and operate coal mining businesses and transportation. These investments and acquisitions may include entities or assets that we would have been interested in acquiring. Therefore, The Cline Group, Murray Energy Corporation and certain other affiliates of our general partner may compete with us for investment opportunities and affiliates of our general partner may own an interest in entities that compete with us.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers, directors and Foresight Reserves. 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. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment for us and our unitholders.

Holders of our common units have limited voting rights and are not entitled to elect or remove our general partner or its directors, which could reduce the price at which the common units would trade.

Compared to the holders of common stock in a corporation, unitholders have limited voting rights and, therefore, limited ability to influence management's decisions regarding our business. Unitholders have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner, including the independent directors, is chosen entirely by the owners of our general partner, and not by our unitholders. Unlike publicly traded corporations, we do not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

If our unitholders are dissatisfied with the performance of our general partner, they have limited ability to remove our general partner. Unitholders are unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. In addition, any vote to remove our general partner during the subordination period must provide for the election of a successor general partner by the holders of a majority of the common units and a majority of the subordinated units, voting as separate classes. The owners of our general partner have the ability to prevent the removal of our general partner.

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 to a third party without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner to transfer their membership interests in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and executive officers of our general partner with their own designees and thereby exert significant control over the decisions taken by the board of directors and executive officers of our general partner. This effectively permits a "change of control" without the vote or consent of the unitholders.

The incentive distribution rights may be transferred to a third party without unitholder consent.

Our general partner or our sponsors may transfer their respective incentive distribution rights to a third party at any time without the consent of our unitholders. If our sponsors transfer their incentive distribution rights to a third party but retain their respective ownership interests in our general partner, 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 our sponsors had retained their ownership of the incentive distribution rights. For example, a transfer of incentive distribution rights by our sponsors could reduce the likelihood of our sponsors accepting offers made by us relating to assets owned by them, as they would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

Cost reimbursements due to our general partner and its affiliates for services provided to us or on our behalf reduce cash available for distribution to our unitholders. Our general partner determines the amount and timing of such reimbursements.

We are obligated under our partnership agreement to reimburse our general partner and its affiliates for all expenses they incur and payments they make on our behalf. Our partnership agreement does not limit the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner determines the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates reduces the amount of cash available for distributions to our unitholders.

The NYSE does not require a publicly traded 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 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. Accordingly, unitholders do not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

Our revenues and operating profits could be negatively impacted if we are unable to extend existing agreements at comparable pricing or enter into new agreements due to competition, environmental regulations affecting our customers' changing coal purchasing patterns or other variables.

We compete with other coal suppliers when renewing expiring agreements or entering into new agreements. If we cannot renew these coal supply agreements or find alternate customers willing to purchase our coal, our revenue and operating profits could suffer. Our customers may decide not to extend existing agreements or enter into new long-term contracts or, in the absence of long-term contracts, may decide to purchase fewer tons of coal than in the past or on different terms, including under different pricing terms or may decide not to purchase at all. Any decrease in demand may cause our customers to delay negotiations for new contracts or request lower pricing terms or seek coal from other sources. Furthermore, uncertainty caused by laws and regulations affecting electric utilities could deter our customers from entering into long-term coal supply agreements. Some long-term contracts contain provisions for termination due to environmental regulatory changes if such changes prohibit utilities from burning the contracted coal. In addition, a number of our long-term contracts are subject to price re-openers. If market prices are lower than the existing contract price, pricing for these contracts could reset to lower levels.

Coal mining operations are subject to inherent risks and are dependent on many factors and conditions beyond our control, any of which may adversely affect our productivity and our financial condition.

Our mining operations, including our transportation infrastructure, are influenced by changing conditions that can affect the safety of our workforce, production levels, delivery of our coal and costs for varying lengths of time and, as a result, can diminish our revenues and profitability. In particular, underground mining and related processing activities present inherent risks of injury to persons and damage to property and equipment. A shutdown of any of our mines or prolonged disruption of production at any of our mines or transportation of our coal to customers would result in a decrease in our revenues and profitability, which could be material. Certain factors affecting the production and sale of our coal that could result in decreases in our revenues and profitability include:

- adverse geologic conditions including floor and roof conditions, variations in seam height, washouts and faults;
- fire or explosions from methane, coal or coal dust or explosive materials;
- industrial accidents;
- seismic activities, ground failures, rock bursts, or structural cave-ins or slides;
- delays in the receipt of, or failure to receive, or revocation of necessary government permits;
- changes in the manner of enforcement of existing laws and regulations;
- changes in laws or regulations, including permitting requirements and the imposition of additional regulations, taxes or fees;
- accidental or unexpected mine water inflows;
- delays in moving our longwall equipment;
- railroad derailments;
- inclement or hazardous weather conditions and natural disasters, such as heavy rain, high winds and flooding;
- environmental hazards;
- interruption or loss of power, fuel, or parts;
- increased or unexpected reclamation costs;
- equipment availability, replacement or repair costs; and
- mining and processing equipment failures and unexpected maintenance problems.

These risks, conditions and events could (1) result in: (a) damage to, or destruction of value of, our coal properties, our coal production or transportation facilities, (b) personal injury or death, (c) environmental damage to our properties or the properties of others, (d) delays or prohibitions on mining our coal or in the transportation of coal, (e) monetary losses and (f) potential legal liability; and (2) could have a material adverse effect on our operating results and our ability to generate the cash flows we require to invest in our operations and satisfy our debt obligations. Our insurance policies only provide limited coverage for some of these risks and will not fully cover these risks. A significant mine accident could potentially cause a mine shutdown, and could have a substantial adverse impact on our results of operations, financial condition or cash flows, as well as our ability to meet our debt obligations and resume payment of distributions to our unitholders.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes or we were to become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to you would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. However, no ruling has been or will be requested regarding our treatment as a partnership for federal income tax purposes. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to you, likely causing a substantial reduction in the value of our common 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 amounts may be adjusted to reflect the impact of that law or interpretation on us. Several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced and the value of our common units could be negatively impacted.

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

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

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

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

You will be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

You will be required to pay federal income taxes and, in some cases, state and local income taxes on your share of our taxable income regardless of whether you receive cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability resulting from that income.

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 federal income tax purposes.

We will be considered to have terminated our 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. Chris Cline and Murray Energy collectively own, directly and indirectly, more than 50% of the total interests in our capital and profits. Therefore, a transfer by these parties of all or a portion of its interests in us, in conjunction with the trading of common units held by the public, could result in a termination of us as a partnership for federal income tax purposes. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once.

Our 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 for one calendar year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. If you report on a taxable year other than the calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in your taxable income for the year of termination. Our termination would not affect our classification as a partnership for federal income tax purposes, but instead, after our termination we would be treated as a new partnership for federal income tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the two short tax periods included in the year in which the termination occurs.

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

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income result in a decrease in your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis in those units, even if the price you receive is less than your original cost. In addition, because the amount realized includes a unitholder’s share of our nonrecourse liabilities, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

A substantial portion of the amount realized from the sale of your units, whether or not representing gain, may be taxed as ordinary income to you due to potential recapture items, including depreciation recapture. Thus, you may recognize both ordinary income and capital loss from the sale of your units if the amount realized on a sale of your units is less than your adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which you sell your units, you may recognize ordinary income from our allocations of income and gain to you prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

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

Investments in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (“IRAs”), and non-U.S. persons raise issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from 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 are subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. persons, 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 your tax advisor before investing in our common units.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest may reduce our cash available for distribution to you.

We have not requested a ruling from the IRS regarding our treatment as a partnership for federal income tax purposes. The IRS could adopt positions that differ from the positions we take in the future. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest by the IRS, and the outcome of such contest, may materially and adversely impact the market for our common units and the price at which they trade. The costs of any such contest would result in a reduction in cash available for distribution to our unitholders and would indirectly be borne by our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised Schedule K-1 to each unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

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

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

We generally prorate our items of income, gain, loss and deduction 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 IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month (the "Allocation Date"), instead of on the basis of the date a particular common unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders.

We have adopted certain valuation methodologies in determining unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely 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 common 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 timing or amount of taxable income or loss being allocated to you. It also could affect the amount of gain from your sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to your tax return without the benefit of additional deductions.

If your common units are the subject of a securities loan (e.g., a loan to a “short seller” to cover a short sale of common units), you may be considered as having disposed of those common units. If so, you would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the federal income tax consequence of loaning a partnership interest, if your common units are the subject of a securities loan you may be considered as having disposed of the loaned units. In that case, you may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and you may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by you and any cash distributions received by you as to those common units could be fully taxable as ordinary income. If you desire to assure your status as partner and avoid the risk of gain recognition from a securities loan, you are urged to modify any applicable brokerage account agreements to prohibit your broker from borrowing your common units.

You will likely be subject to state and local taxes and income tax return filing requirements in jurisdictions where you do not live as a result of investing in our common units.

In addition to federal income taxes, you will likely be subject to other taxes, including foreign, 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 own property now or in the future, even if you do not live in any of those jurisdictions. We own assets and conduct business in several states (including Illinois, Indiana and Missouri), each of which currently imposes a personal income tax and also imposes income taxes on corporations and other entities. You will likely be required to file state and local income tax returns and pay state and local income taxes in these states. Further, you may be subject to penalties for failure to comply with these requirements.

As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is your responsibility to file all U.S. federal, foreign, state and local tax returns.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Coal Reserves

We believe that we have sufficient reserves to replace capacity from depleting mines for the foreseeable future and that our current reserve base is one of our strengths. We estimate that we controlled over 2.1 billion tons, almost entirely through lease, of proven and probable recoverable reserves at December 31, 2016. Our coal reserve estimate is based on a study prepared by a third-party mining and geological consultant using data obtained from our drilling activities and other available geologic data. Our coal reserve estimates are periodically updated to reflect past coal production and other geologic and mining data. Acquisitions or sales of coal properties will also change these estimates. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam.

Our coal reserve estimates include reserves that can be economically and legally extracted or produced at the time of their determination. In determining whether our reserves meet this standard, we take into account, among other things, the possible necessity of revising a mining plan, changes in estimated future costs, changes in future cash flows caused by changes in costs required to be incurred to meet regulatory requirements and obtaining mining permits, variations in quantity and quality of coal, and varying levels of demand and their effects on selling prices. Further, the economics of our reserves are based on market conditions including contracted pricing, market pricing and overall demand for our coal. Thus, the actual value at which we no longer consider our reserves to be economic varies depending on the length of time in which the specific market conditions are expected to last. We consider our reserves to be economic at a price in excess of our cash costs to mine the coal and our ongoing replacement capital. See Part I. "Item 1A. Risk Factors—Risks Related to Our Business—We face numerous uncertainties in estimating our economically recoverable coal reserves."

Our mines are subject to private coal leases. Private coal leases normally have a stated term and usually give us the right to renew the lease for a stated period or to maintain the lease in force until the exhaustion of mineable and merchantable coal contained on the relevant site. These private leases provide for royalties to be paid to the lessor either as a fixed amount per ton or as a percentage of the sales price. Many leases also require payment of a minimum royalty, payable either at the time of execution of the lease or in periodic installments.

All of our recoverable coal reserves are assigned reserves as of December 31, 2016. All of our reserves are considered high sulfur coal, with average sulfur content ranging between 1.71% and 3.45% and high Btu coal, with Btu content ranging between 10,799 and 11,893 Btu per pound. The table below presents our estimated recoverable coal reserves at December 31, 2016.

Property Control	Seam	Average Seam Thickness (Feet)	Area (Acres)	In-Place Tons (1) (in 000's)	Clean Recoverable Tons (2) (in 000's) Proven	Probable	Total	Theoretical Coal Quality (As Received Basis) Sulfur %	Btu/lb
Williamson Energy, LLC	6	5.81	28,204	304,182	124,310	54,537	178,847	2.20	11,893
Williamson Energy, LLC	5	4.24	39,070	308,553	111,743	85,437	197,180	1.71	11,799
Sugar Camp Energy, LLC	6	6.40	101,884	1,211,055	341,733	394,231	735,964	2.46	11,820
Sugar Camp Energy, LLC	5	4.75	104,312	925,724	238,407	362,134	600,541	2.44	11,712
Hillsboro Energy LLC	6	7.68	28,606	433,743	94,342	227,768	322,110	3.45	10,940
Macoupin Energy LLC	6	6.44	11,366	135,124	34,922	29,488	64,410	3.33	10,799
Total Foresight Energy LP				3,318,381	945,457	1,153,595	2,099,052		

(1) In-Place Tons are on a dry basis.
(2) Clean Recoverable Tons are based on mining recovery, average theoretical preparation plant yield, 94% preparation plant efficiency and product moisture.

Each of the mining companies leases the reserves they mine pursuant to a series of leases with related entities under common ownership, Natural Resources Partners, LP ("NRP") and its subsidiaries, and other independent third parties in the normal course of business. The mineral reserve leases can generally be renewed as long as the mineral reserves are being developed and mined until all economically recoverable reserves are depleted or until mining operations cease. The leases require a production royalty at the greater amount of a base amount per ton or a percent of the gross selling price of the coal. Generally, the leases contain provisions that require the payment of minimum royalties regardless of the volume of coal produced or the level of mining activity. The minimum royalties are generally recoupable against production royalties over a contractually defined period of time (generally five to ten years). Some of these agreements also require overriding royalty and/or wheelage payments. Under the terms of some mineral reserve mining leases, we are to use commercially reasonable efforts to acquire additional mineral reserves in certain properties as defined in the agreements and are responsible for the acquisition costs and the assets are to be titled to the lessor.

See Part I. "Item 1. Business" for additional discussion and a map of our major mining facilities and Part III. "Item 13.Certain Relationships and Related Transactions and Director Independence" for a summary of key terms of mineral reserve leases with affiliated parties.

Item 3. Legal Proceedings

See Part II. "Item 8. Financial Statements and Supplementary Data, Note 22—Contingencies" in the notes to our consolidated financial statements in this Annual Report on Form 10-K for a description of certain of our pending legal proceedings, which are incorporated herein by reference. We are also party to various other litigation matters, in most cases involving ordinary and routine claims incidental to our business. We cannot reasonably estimate the ultimate legal and financial liability with respect to all pending litigation matters. However, we believe, based on our examination of such matters, that the ultimate liability will not have a material adverse effect on our financial position, results of operation or cash flows. As of December 31, 2016, we have $4.8 million accrued, in the aggregate, for various litigation matters.

Item 4. Mine Safety Disclosures

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act") and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 to this Annual Report on Form 10-K for the year ended December 31, 2016.

PART II.

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

The common units representing limited partnership' interests are listed on the New York Stock Exchange ("NYSE") under the symbol "FELP". On February 24, 2017, the closing market price for FELP common units was $6.55 per unit and there were 66,104,908 common units outstanding and 64,954,691 subordinated units outstanding. There were 3,564 record holders of our common units as of December 31, 2016.

The following table sets forth the range of high and low sales prices per common unit and the amount of cash distributions declared and paid with respect to each unit from January 1, 2015 to December 31, 2016.

Period	High	Low	Distribution per Limited Partner Unit
1st Quarter 2015	$ 18.73	$ 14.50	$0.37 (declared May 7, 2015, paid May 28, 2015)
2nd Quarter 2015	$ 15.90	$ 11.92	$0.38 (declared July 30, 2015, paid August 26, 2015)
3rd Quarter 2015	$ 12.80	$ 5.10	(a)
4th Quarter 2015	$ 8.76	$ 2.01	None.
1st Quarter 2016	$ 3.55	$ 1.07	None.
2nd Quarter 2016	$ 2.82	$ 1.07	None.
3rd Quarter 2016	$ 4.84	$ 1.50	None.
4th Quarter 2016	$ 8.33	$ 3.84	None.

(a) On October 29, 2015, we declared a quarterly distribution of $0.17 per unit payable on November 25, 2015 to common unitholders, while suspending the distribution on all subordinated units. Chris Cline and one additional common unitholder elected to forego the $0.17 per common unit distribution (and any arrearage rights related to the $0.17 paid distribution) on their collective 21.2 million common units.

All subordinated units are currently held by Murray Energy. The principal difference between our common units and subordinated units is that subordinated unitholders are not entitled to receive a distribution from operating surplus until the holders of common units have received the minimum quarterly distribution ("MQD") from operating surplus. The MQD is $0.3375 per unit for such quarter plus any cumulative arrearages of previously unpaid MQDs from previous quarters. Subordinated unitholders are not entitled to receive arrearages. The subordination period will end, and the subordinated units will convert to common units, on a one-for-one basis, on the first business day after the Partnership has paid the MQD for each of three consecutive, non-overlapping four-quarter periods ending on or after March 31, 2017 and there are no outstanding arrearages on the common units. Notwithstanding the foregoing, the subordination period will end on the first business day after the Partnership has paid an aggregate amount of at least $2.025 per unit (150.0% of the MQD on an annualized basis) on the outstanding common and subordinated units and the Partnership has paid the related distribution on the incentive distribution rights, for any four-quarter period and there are no outstanding arrearages on the common units.

Cash Distribution Policy

Our partnership agreement provides that our general partner will make a determination as to whether a distribution will be made, but our partnership agreement does not require us to pay distributions at any time or at any amount. To the extent the quarterly distribution is below the MQD, then common unitholders would accrue an arrearage equal to the shortfall amount to the MQD that would carry forward to future quarters and must be paid to common unitholders before any distributions from operating surplus to the subordinated unitholder is made. Given that distributions have not been paid beginning with the quarter ended December 31, 2015 arrearages have accrued to the benefit of common unitholders which shall be payable should future distributions be paid. However, there is no assurance as to the future cash distributions since they are dependent upon compliance with and restrictions within our various debt agreements, future earnings, cash flows, capital requirements, financial condition and other factors.

Our Senior Secured Credit Facilities, as amended on August 30, 2016, prohibit certain restricted payments, including discretionary dividends, until the later to occur of: (i) June 30, 2018 and (ii) the date on which our obligations under our revolving credit facility have been paid in full, after which restricted payments can be made of up to $25.0 million per year, subject to certain adjustments and exceptions. Our Senior Secured Credit Facilities do allow for the payment of certain limited tax distributions during 2017 and 2018.

Incentive Distribution Rights

Our general partner owns all of the incentive distribution rights ("IDRs"). IDRs represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the MQD and the target distribution levels (described below) have been achieved. Our general partner may transfer these IDRs separately from its general partner interest in us, subject to restrictions in our partnership agreement. Our general partner, as the IDR holder, will have the right, subsequent to the subordination period and subject to distributions exceeding the MQD by at least 150% for four consecutive quarters, to reset the target distribution levels and receive common units.

Percentage Allocation of Distributions from Operating Surplus

The following table illustrates the percentage allocation of available cash from operating surplus between the unitholders and the holder of our IDRs based on the specified target distribution levels. The amounts set forth under the column heading "Marginal Percentage Interest in Distributions" are the percentage interests of the IDR holders and the unitholders of any distributions from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Per Common Unit". The percentage interests shown for our unitholders and the holders of the IDRs for the MQD are also applicable to quarterly distribution amounts that are less than the MQD.

The percentage interests set forth below assumes no application of arrearages on common units.

	Total Quarterly Distribution Per Common Unit	Marginal Percentage Interest in Distributions	
		Unitholders	IDR Holders
Minimum quarterly distribution	$0.3375	100.0%	—
First target distribution	Above $0.3375 up to $0.3881	100.0%	—
Second target distribution	Above $0.3881 up to $0.4219	85.0%	15.0%
Third target distribution	Above $0.4219 up to $0.5063	75.0%	25.0%
Thereafter	Above $0.5063	50.0%	50.0%

Equity Compensation Plans

The information relating to our equity compensation plans required by Part II. "Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities" is incorporated by reference to such information as set forth in Part III. "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" contained herein.

Unregistered Sales of Equity Securities

See Part II. "Item 8. Financial Statements and Supplementary Data, Note 10–Long-Term Debt and Capital Lease Obligations" for discussion on the 2017 Exchangeable PIK Notes and Warrants.

Use of Proceeds from Registered Securities

None.

Issuer Purchases of Equity Securities

None.

Item 6. Selected Financial Data

The following tables set forth the selected historical consolidated financial data of the Partnership for each of the last five years and should be read in conjunction with the consolidated financial statements and notes thereto included elsewhere in this Annual Report on Form 10-K. Please read Part II. "Item 8. Financial Statements and Supplementary Data, Note 1–Organization and Basis of Presentation" for a discussion on the basis of presentation for the consolidated financial statements of the Partnership.

	For the Year Ended December 31,				
	2016	2015	2014	2013	2012
	(In Thousands, Except per Unit Data)				
Revenues					
Coal sales	$ 866,628	$ 979,179	$ 1,109,404	$ 957,412	$ 845,886
Other revenues	9,204	5,674	—	—	—
Total revenues	875,832	984,853	1,109,404	957,412	845,886
Costs and expenses:					
Cost of coal produced (excluding depreciation, depletion and amortization)	423,995	509,170	449,905	360,861	303,638
Cost of coal purchased	13,541	17,444	18,232	2,163	6,163
Transportation	139,659	171,733	221,178	196,638	171,679
Depreciation, depletion and amortization	164,212	195,415	169,767	162,177	124,552
Accretion on asset retirement obligations	3,376	2,267	1,621	1,527	1,368
Selling, general and administrative	25,265	31,357	33,683	32,295	41,528
Long-lived asset impairments	74,575	12,592	34,700	—	—
Transition and reorganization costs	6,889	21,433	—	—	—
Loss (gain) on commodity derivative contracts	23,752	(45,691)	(76,330)	(2,392)	(534)
Other operating income, net (1)	(22,161)	(13,424)	(2,837)	(300)	(10,759)
Operating income	22,729	82,557	259,485	204,443	208,251
Other expenses:					
Interest expense, net	149,201	117,311	113,030	115,897	82,580
Debt restructuring costs	21,821	3,930	—	—	—
Change in fair value of warrants	17,124	—	—	—	—
Loss on early extinguishment of debt	13,203	—	4,979	77,773	—
Net (loss) income	(178,620)	(38,684)	141,476	10,773	125,671
Less: net income (loss) attributable to noncontrolling interests	169	770	3,909	2,256	(160)
Net (loss) income attributable to controlling interests	(178,789)	(39,454)	137,567	$ 8,517	$ 125,831
Less: net income attributable to predecessor equity	—	23	67,375		
Net (loss) income attributable to limited partner units	$ (178,789)	$ (39,477)	$ 70,192		
Per Unit Data					
Net (loss) income subsequent to initial public offering per limited partner unit - basic and diluted	$ (1.37)	$ (0.30)	$ 0.54	n/a	n/a
Distributions declared per limited partner unit	$ —	$ 1.17	$ 0.38	n/a	n/a
Statements of Cash Flows					
Net cash provided by operating activities	$ 225,220	$ 200,412	$ 240,782	$ 180,971	$ 209,691
Net cash used in investing activities	$ (47,629)	$ (138,781)	$ (224,583)	$ (209,457)	$ (207,039)
Net cash (used in) provided by financing activities	$ (91,439)	$ (70,602)	$ (14,477)	$ 25,385	$ (26,525)
Balance Sheet Data (at period end)					
Cash and cash equivalents	$ 103,690	$ 17,538	$ 26,509	$ 24,787	$ 27,889
Property, plant, equipment and development, net	$ 1,318,937	$ 1,433,193	$ 1,522,488	$ 1,465,753	$ 1,401,721
Total assets	$ 1,689,011	$ 1,821,183	$ 1,896,721	$ 1,736,862	$ 1,679,497
Total long-term debt and capital lease obligations (2)	$ 1,391,063	$ 1,434,566	$ 1,341,740	$ 1,492,894	$ 1,045,720
Total partners' (deficit) capital	$ (154,593)	$ 18,883	$ 186,397	$ (95,163)	$ 280,541
Other Data					
Adjusted EBITDA (3)	$ 308,799	$ 338,408	$ 409,562	$ 363,438	$ 338,429

Tons produced (4)	19,040	20,097	22,547	17,991	15,080
Tons sold (4)	19,270	21,946	22,044	18,589	14,403
Coal sales realization per ton sold (5)	$ 44.97	$ 44.62	$ 50.33	$ 51.50	$ 58.73
Netback to mine realization per ton sold (6)	$ 37.73	$ 36.79	$ 40.29	$ 40.93	$ 46.81
Cash costs per ton sold (7)	$ 22.32	$ 23.67	$ 20.80	$ 19.46	$ 21.20

(1) For the year ended December 31, 2016, we recognized $20.0 million of other operating income related to business interruption insurance recoveries from the Hillsboro combustion event, which has idled the mine since March 2015. For the year ended December 31, 2015, $13.5 million was recognized as other operating income related to a settlement with Murray Energy resolving litigation between the Partnership and Murray Energy. For the year ended December 31, 2012, $10.0 million was recognized as other operating income for a legal settlement with a customer related to a coal sales contract.

(2) Includes current portion of long-term debt and capital lease obligations. Total long-term debt and capital lease obligations does not include $191.9 million as of December 31, 2016 and $193.4 million as of December 31, 2015, 2014, 2013 and 2012 of certain sale-leaseback financing obligations that are characterized as financing arrangements due to the involvement of certain of our affiliates in mining the reserves and utilizing the equipment related to the leases.

(3) We define Adjusted EBITDA as net (loss) income attributable to controlling interests before interest, income taxes, depreciation, depletion, amortization and accretion. Adjusted EBITDA is also adjusted for equity-based compensation, losses/gains on commodity derivative contracts , settlements of derivative contracts, changes in the fair value of the warrants and material nonrecurring or other items which may not reflect the trend of future results. As it relates to derivatives, the Adjusted EBITDA calculation removes the total impact of derivative gains/losses on net income (loss) during the period and then adds/deducts to Adjusted EBITDA the aggregate settlements during the period. Included in net loss (income) attributable to controlling interests during 2016 were insurances recoveries for the reimbursement of mitigation costs of $10.5 million, which was recorded in cost of coal sales (excluding depreciation, depletion and amortization), and business interruption proceeds of $20.0 million which was recorded in other operating income, net. Adjusted EBITDA is not a measure of performance defined in accordance with U.S. generally accepted accounting principles (U.S. GAAP). However, management believes that Adjusted EBITDA is useful to investors in evaluating our performance because it is a commonly used financial analysis tool for measuring and comparing companies in our industry in areas of operating performance. Management believes that the disclosure of Adjusted EBITDA offers an additional view of our operations that, when coupled with our U.S. GAAP results and the reconciliation to U.S. GAAP results, provides a more complete understanding of our results of operations and the factors and trends affecting our business. Adjusted EBITDA should not be considered as an alternative to net income. The primary limitation associated with the use of Adjusted EBITDA as compared to U.S. GAAP results are (i) it may not be comparable to similarly titled measures used by other companies in our industry, and (ii) it excludes financial information that some consider important in evaluating our performance. We compensate for these limitations by providing a reconciliation of Adjusted EBITDA to U.S. GAAP results to enable users to perform their own analysis of our operating results.

Below is a reconciliation between net (loss) income attributable to controlling interests and Adjusted EBITDA for the years ended December 31, 2016, 2015, 2014, 2013 and 2012.

	For the Year Ended December 31,				
	2016	**2015**	**2014**	**2013**	**2012**
			(In Thousands)		
Net (loss) income attributable to controlling interests	$ (178,789)	$ (39,454)	$ 137,567	$ 8,517	$ 125,831
Interest expense, net	149,201	117,311	113,030	115,897	82,580
Depreciation, depletion and amortization	164,212	195,415	169,767	162,177	124,552
Accretion on asset retirement obligations	3,376	2,267	1,621	1,527	1,368
Transition and reorganization costs (excluding equity-based compensation)	2,574	17,111	—	—	—
Equity-based compensation	5,106	13,704	5,024	—	4,632
Long-lived asset impairments	74,575	12,592	34,700	—	—
Loss (gain) on commodity derivative contracts	23,752	(45,691)	(76,330)	(2,392)	(534)
Settlements of commodity derivative contracts	12,644	61,223	19,204	(61)	—
Debt restructuring costs	21,821	3,930	—	—	—
Change in fair value of warrants	17,124	—	—	—	—
Loss on early extinguishment of debt	13,203	—	4,979	77,773	—
Adjusted EBITDA	$ 308,799	$ 338,408	$ 409,562	$ 363,438	$ 338,429

(4) Tons produced and tons sold do not include mines in development. Revenues and costs from mines in development are capitalized as mine development in our consolidated balances sheets.

(5) Calculated as coal sales divided by tons sold.

(6) Calculated as coal sales less transportation expense divided by tons sold.

(7) Calculated as cost of coal produced (excluding depreciation, depletion and amortization) divided by produced tons sold.

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

You should read the following discussion and analysis together with Part II. "Item 6. — Selected Financial Data" and our consolidated financial statements and related notes included elsewhere in this Annual Report on Form 10-K. This discussion contains forward-looking statements about our business, operations and industry that involve risks and uncertainties, such as statements regarding our plans, objectives, expectations and intentions. Our future results and financial condition may differ materially from those we currently anticipate as a result of the factors we describe under "Cautionary Statement Regarding Forward-Looking Statements," "Part I. Item 1A. Risk Factors" and elsewhere in this Annual Report on Form 10-K. All references to produced tons, sold tons, or cash cost per ton sold refer to clean tons of coal.

Overview

Foresight Energy LLC ("FELLC"), a perpetual-term Delaware limited liability company, was formed in September 2006 for the development, mining, transportation and sale of coal. Prior to June 23, 2014, Foresight Reserves owned 99.333% of FELLC and a member of FELLC's management owned 0.667%. On June 23, 2014, in connection with the initial public offering ("IPO") of Foresight Energy LP ("FELP"), Foresight Reserves and a member of FELLC's management contributed their ownership interests in FELLC to FELP in exchange for common and subordinated units in FELP. Because this transaction was between entities under common control, the contributed assets and liabilities of FELLC were recorded in the combined consolidated financial statements of FELP at FELLC's historical cost. FELP has been managed by Foresight Energy GP LLC ("FEGP") subsequent to the IPO.

On April 16, 2015, Murray Energy Corporation ("Murray Energy") and Foresight Reserves completed a transaction whereby Murray Energy acquired a 34% noncontrolling economic interest in FEGP and all of the outstanding subordinated units of FELP, representing a 50% ownership percentage of the Partnership's limited partner units.

The presented financial results include the combined financial position, results of operations and cash flow information of FELP and FELLC and its subsidiaries for all periods presented. In this Item 7, all references to "FELP," the "Partnership," "we," "us," and "our" refer to the combined results of FELP and FELLC and its subsidiaries, unless the context otherwise requires or where otherwise indicated.

We control 2.1 billion tons of coal reserves, almost all of which exist in three large, contiguous blocks of coal: two in central Illinois and one in southern Illinois. Since our inception, we have invested significantly in capital expenditures to develop what we believe are industry-leading, geologically similar, low-cost and highly productive mines and related infrastructure. We currently operate under one reportable segment with four underground mining complexes in the Illinois Basin: Williamson, Sugar Camp and Hillsboro, all three of which are longwall operations, and Macoupin, which is currently a continuous miner operation. The Williamson and Hillsboro complexes each operates with one longwall system and Sugar Camp operates with two longwall mining systems. Mining operations at our Hillsboro complex have been idle since March 2015 due to a combustion event. We are uncertain as to when production will resume at this operation

Our coal is sold to a diverse customer base, including electric utility and industrial companies in the eastern half of the United States as well as internationally (primarily into Europe). We generally sell a majority of our coal to customers at delivery points other than our mines, including, but not limited to, our river terminal on the Ohio River and ports near New Orleans.

Debt Restructuring

On December 4, 2015, the Delaware Court of Chancery issued a memorandum opinion concluding, among other things, that the purchase and sale agreement between Foresight Reserves and Murray Energy constituted a "change of control" under the indenture (the "2021 Senior Notes Indenture") governing our 7.875% Senior Notes due 2021 (the "2021 Senior Notes") and that an event of default occurred under the 2021 Senior Notes Indenture when we failed to offer to purchase the 2021 Senior Notes on or about May 18, 2015 (the "2015 Delaware Court of Chancery change-of-control litigation"). Because of the existence of "change of control" provisions and cross-default or cross-event of default provisions in our debt agreements, the purchase and sale agreement between Foresight Reserves and Murray Energy also resulted, directly or indirectly, in events of default under FELLC's credit agreement governing its senior secured credit facilities (the "Credit Agreement"), Foresight Receivables LLC's securitization program and certain other financing arrangements, including our longwall financing arrangements. The existence of an event of default prohibited us access to borrowings or other extensions of credit under our revolving credit facility and our failure to pay the semi-annual interest payments of $23.6 million due on February 15, 2016 and August 15, 2016 resulted in additional events of default.

On August 30, 2016 (the "Closing Date"), we completed a global restructuring of our indebtedness. The restructuring transactions (the "Restructuring Transactions") alleviated existing defaults and events of default across the Partnership's capital structure that resulted from the 2015 Delaware Chancery Court change-of-control litigation related to the purchase and sale agreement between

Foresight Reserves and Murray Energy. See "Item 8. Financial Statements and Supplemental Data – Note 10. Long-Term Debt and Capital Lease Obligations" and "Item 8. Financial Statements – Note 15. Related-Party Transactions" for additional discussion of the Restructuring Transactions.

Factors That Affect Our Results

Coal Sales. In recent years, domestic coal prices overall have weakened due to reduced demand from coal-fired plants and increased competition from natural gas. International prices have also declined significantly as a result of excess supply in the marketplace. More recently, coal prices have remained flat and in some instances increased slightly as supply and demand dynamics have become more balanced.

Demand for coal can increase due to unusually hot or cold weather as consumers use more electricity to air condition or heat their homes. Conversely, mild weather can result in softer demand for our coal. Adverse weather conditions, such as blizzards or floods, can affect our ability to mine and ship our coal and our customers' ability to take delivery of coal.

Cost of Coal Sales (Excluding Depreciation, Depletion and Amortization). Our cost of coal sales (excluding depreciation, depletion and amortization) includes, but is not limited to, labor and benefits, supplies, repairs, utilities, insurance, equipment rental, mine lease costs (royalties), property and subsidence costs, production taxes, belting, coal preparation and direct mine overhead. Each of these cost components has its own drivers, which can include the cost and availability of labor, changes in health care and insurance regulations and costs, the cost of consumable items or inputs into our supplies, changes in regulations impacting our industry, and/or our staffing levels. In addition, geology can unfavorably impact our costs by requiring incremental roof control support and higher water handling and equipment maintenance expenses. Certain of our royalties are dependent directly upon the price at which we sell our coal and our cost to transport the coal to our customers, in addition to having minimum payment requirements.

A variety of actions taken by regulatory agencies, including, but not limited to, climate change regulation, challenges to the issuance or renewal of our permits to operate and regulations governing the operations of our mines, could substantially increase compliance costs for us and our customers, reduce general demand for coal, or interrupt operations at one or more of our mining complexes.

Transportation. We generally sell our coal to customers at three distinct delivery points: either at our mines, at river terminals on the Ohio River, or at export terminals near New Orleans. Except for those sales that occur at our mine, we generally bear the transportation cost and risk to and through these terminals and we therefore do not report coal sales and transportation revenue separately in our consolidated statements of operations. Also, because we are responsible for the cost of transporting our coal to these various delivery points, we also bear the risk that our transportation expense will increase over time. Where possible, we enter into long-term transportation and throughput agreements to secure capacity and price certainty. These agreements generally require throughput of minimum annual volumes. Failure to meet the minimum annual volume requirements can result in higher transportation costs to us on a per ton basis. The primary reason for entering into minimum annual volume commitments is to secure long-term access to international markets and provide optionality between the domestic and international coal markets. To the extent coal pricing to international markets does not continue to improve, we will continue to incur substantial expenses for shortfalls on minimum contractual throughput volume requirements related to the export market.

Our transportation costs also correlate to the distance required to transport our coal to the buyers. As a result, the transport of our coal to domestic buyers has lower associated costs than the transport of our coal to international buyers. International sales incur higher transportation costs because the delivery requires us to transport coal first by rail to a seaborne export terminal and then load the coal onto the buyers' ships. In certain circumstances, the cost of transporting our coal to international buyers can be twice the cost of transporting our coal to domestic buyers.

Selling, general and administrative. Selling, general and administrative expense consists of our general corporate overhead expenses, including, but not limited to, management and administrative labor, corporate occupancy expenses, office expenses, and certain professional fees. Prior to Murray Energy's investment in the Partnership, all selling, general and administrative costs were variable based on actual costs incurred. In April 2015, a management services agreement ("MSA") was executed between FEGP and Murray American Coal, Inc. (the "Manager"), a wholly-owned subsidiary of Murray Energy, pursuant to which the Manager provides certain management and administration services to FELP for a quarterly fee, which is currently $3.5 million ($14.1 million on an annual basis), and is subject to future contractual escalations and adjustments. To the extent that FELP or FEGP directly incurs costs for any services covered under the MSA, then the Manager's quarterly fee is reduced accordingly. Also, to the extent that the Manager utilizes outside service providers to perform any of the services under the MSA, the Manager is responsible for those outside service provider costs.

Key Metrics

We assess the performance of our business using certain key metrics, which are described below and analyzed on a period-to -period basis. These key metrics include Adjusted EBITDA, production, tons sold, coal sales realization per ton sold, netback to mine realization per ton sold and cash cost per ton sold. Coal sales realization per ton sold is defined as coal sales divided by tons sold. Netback to mine realization per ton sold is defined as coal sales less transportation expense divided by tons sold. Cash cost per ton sold is defined as cost of coal produced (excluding depreciation, depletion and amortization) divided by produced tons sold.

We define Adjusted EBITDA as net income (loss) attributable to controlling interests before interest, income taxes, depreciation, depletion, amortization and accretion. Adjusted EBITDA is also adjusted for equity-based compensation, losses/gains on commodity derivative contracts , settlements of derivative contracts, changes in the fair value of the warrants and material nonrecurring or other items which may not reflect the trend of future results. As it relates to derivatives, the Adjusted EBITDA calculation removes the total impact of derivative gains/losses on net income (loss) during the period and then adds/deducts to Adjusted EBITDA the aggregate settlements during the period. Included in net loss (income) attributable to controlling interests during 2016 were insurances recoveries for the reimbursement of mitigation costs of $10.5 million, which was recorded in cost of coal sales (excluding depreciation, depletion and amortization), and business interruption proceeds of $20.0 million which was recorded in other operating income, net.

Adjusted EBITDA is not a measure of performance defined in accordance with U.S. GAAP. However, management believes that Adjusted EBITDA is useful to investors in evaluating our performance because it is a commonly used financial analysis tool for measuring and comparing companies in our industry in areas of operating performance. Management believes that the disclosure of Adjusted EBITDA offers an additional view of our operations that, when coupled with our U.S. GAAP results and the reconciliation to U.S. GAAP results, provides a more complete understanding of our results of operations and the factors and trends affecting our business. Adjusted EBITDA should not be considered as an alternative to net income (loss). The primary limitation associated with the use of Adjusted EBITDA as compared to U.S. GAAP results are (i) it may not be comparable to similarly titled measures used by other companies in our industry, and (ii) it excludes financial information that some consider important in evaluating our performance. We compensate for these limitations by providing a reconciliation of Adjusted EBITDA to U.S. GAAP results to enable users to perform their own analysis of our operating results.

Results of Operations

Comparison of Year Ended December 31, 2016 to Year Ended December 31, 2015

Coal Sales. The following table summarizes coal sales information during the years ended December 31, 2016 and 2015.

	Year Ended December 31,			
	2016	2015	Variance	
	(In Thousands, Except Per Ton Data)			
Coal sales	$ 866,628	$ 979,179	$ (112,551)	-11.5%
Tons sold	19,270	21,946	(2,676)	-12.2%
Coal sales realization per ton sold (1)	$ 44.97	$ 44.62	$ 0.35	0.8%
Netback to mine realization per ton sold (2)	$ 37.73	$ 36.79	$ 0.94	2.6%

(1) - Coal sales realization per ton sold is defined as coal sales divided by tons sold.
(2) - Netback to mine realization per ton sold is defined as coal sales less transportation expense divided by tons sold.

The decline in coal sales revenue from the prior year was due primarily to a decline in coal production as a result of the Hillsboro combustion event, which has idled the mine since March 2015, difficult coal market conditions driven by oversupply in the market, excess utility stockpiles and continued low natural gas prices. Coal sales realization per ton sold improved slightly from 2015 due to an improvement in export pricing during the second half of 2016. Offsetting the improved export pricing was a lower mix of international sales volumes during the current year. For the year ended December 31, 2016, we sold 17% of our coal to export markets as compared to 24% during 2015.

Other Revenues. Other revenues of $9.2 million and $5.7 million for the years ended December 31, 2016 and 2015, respectively, was primarily comprised of overriding royalty and lease revenues earned on the financing agreements entered into with affiliates of Murray Energy in April 2015. The increase over the prior year reflects these financing agreements being in place for the full year in 2016.

Cost of Coal Produced (Excluding Depreciation, Depletion and Amortization). The following table summarizes cost of coal produced (excluding depreciation, depletion and amortization) information for the years ended December 31, 2016 and 2015.

	Year Ended December 31, 2016	Year Ended December 31, 2015	Variance	
	(In Thousands, Except Per Ton Data)			
Cost of coal produced (excluding depreciation, depletion and amortization)	$ 423,995	$ 509,170	$ (85,175)	-16.7%
Produced tons sold	18,992	21,507	(2,515)	-11.7%
Cash cost per ton sold (1)	$ 22.32	$ 23.67	$ (1.35)	-5.7%
Tons produced	19,040	20,097	(1,057)	-5.3%

(1) - Cash cost per ton sold is defined as cost of coal produced (excluding depreciation, depletion and amortization) divided by produced tons sold.

The decrease during the current year was due to lower sales volumes as well as a reduction in our cash cost per ton sold. The improvement in cash cost per ton sold was driven by increased production at our non-Hillsboro mines which allowed for better leveraging of fixed costs and additional synergies related to the transaction with Murray Energy, including lower mine overhead costs and operational efficiencies. Additionally, the direct and indirect costs of the Hillsboro combustion event during 2016 were offset by $10.5 million in insurance recoveries for the reimbursement of mitigation costs.

Transportation. Our cost of transportation for the year ended December 31, 2016 decreased from the prior year primarily due to lower sales volumes. There was a decrease in transportation cost per ton sold during the current year due to lower international sales volumes, offset partially by $15.1 million of higher charges for shortfalls on minimum contractual throughput volumes during 2016.

Depreciation, Depletion and Amortization. The decrease in depreciation, depletion and amortization expense from 2015 was due to the decrease in tons sold during the year ended December 31, 2016, which resulted in less depreciation, depletion and amortization being released from coal inventory as well as the impact of certain assets becoming fully depreciated.

Selling, General and Administrative. The $6.1 million decline in selling, general and administrative expenses from the year ended December 31, 2016 was primarily due to a $7.1 million fully-vested equity award granted to the Partnership's former chief executive officer during the first quarter of 2015.

Long-lived Asset Impairments. During the years ended December 31, 2016 and 2015, we recorded impairment charges of $74.6 million and $11.6 million, respectively, related to certain prepaid royalties for which we determined recoupment was improbable. Also, during the year ended December 31, 2015, we recorded a charge to write-off the remaining $1.0 million in deferred longwall costs related to Hillsboro's current longwall panel, which is being abandoned as a result of the combustion event at the mine.

Transition and Reorganization Costs. As part of the Murray Energy transaction, we entered into the MSA with Murray Energy with the intent of optimizing and reorganizing certain corporate administrative functions and generating synergies between the two companies through the elimination of headcount and duplicative selling, general and administrative costs. Transition and reorganization costs were $6.9 million for the year ended December 31, 2016, as compared to $21.4 million for the year ended December 31, 2015. The costs for the current year period were comprised of the remaining retention compensation to certain employees during the transition period . Included in transition and reorganization costs for the year ended December 31, 2016 were $2.3 million of costs paid by Foresight Reserves which were recorded as capital contributions, $4.3 million of equity-based compensation for the accelerated vesting of certain equity awards, and $0.2 million of other one-time charges related to the Murray Energy transaction .

Loss (Gain) on Commodity Derivative Contracts. We recorded a loss on our commodity derivative contracts of $23.8 million for the year ended December 31, 2016, compared to a gain of $45.7 million for the year ended December 31, 2015. The loss during the current year was due to a substantial increase in the API 2 forward price curve during the second half of 2016, whereas during the prior year the API 2 forward price curve declined substantially. For the year ended December 31, 2016 and 2015, we had settlements of $12.6 million and $61.2 million, respectively, on commodity derivative contracts.

Other Operating Income, Net. We recorded other operating income of $22.2 million for the year ended December 31, 2016, compared to $13.4 million during the prior year. For the year ended December 31, 2016, we recognized $20.0 million of other operating income related to business interruption insurance recoveries from the Hillsboro combustion event, which has idled the mine since March 2015. For the year ended December 31, 2015, we recorded a $13.5 million favorable legal settlement with Murray Energy.

Interest Expense, Net . Interest expense, net for the year ended December 31, 2016 increased $31.9 million from the prior year period due primarily to higher effective interest rates under the new and amended debt instruments as well as higher interest rates charged on the term loan, revolving credit facility and A/R securitization facility borrowings prior to the Closing Date of the debt restructuring due to default interest rates being in effect.

Debt Restructuring Costs. The $21.8 million and $3.9 million of debt restructuring costs incurred during the years ended December 31, 2016 and 2015, respectively, represents legal and other advisor fees incurred as a result of the unfavorable ruling under the 2015 Delaware Court of Chancery change-of-control litigation.

Change in fair value of warrants. The warrants issued as part of the Restructuring Transactions are required to be accounted for as a liability at fair value and the fair value must be revalued at each balance sheet date until the earlier of the exercise of the warrants, their expiration, or until any feature requiring liability treatments expires or is modified. The resulting non-cash gain or loss on the fair value revaluation at each balance sheet date is recorded as non-operating expense in our consolidated statement of operations. During the year ended December 31, 2016, a loss of $17.1 million was recorded to adjust the warrants to fair value, which was primarily driven by the increase in the unit price of our stock subsequent to the Closing Date of the Restructuring Transactions.

Loss on early extinguishment of debt. The $13.2 million loss on the early extinguishment of debt recognized during the year ended December 31, 2016 was due to the write-off of $11.1 million of unamortized debt discount and debt issuance costs associated with the extinguishment of the 2021 Senior Notes and the reduction in borrowing capacity under our revolving facilities as well as the incurrence of $2.1 million in costs related to the modification of debt which were not deferred.

Adjusted EBITDA. Adjusted EBITDA declined $29.6 million from the prior year due primarily to lower sales volumes and less favorable coal derivative contract settlements during the current year. The table below reconciles net loss attributable to controlling interests to Adjusted EBITDA for the years ended December 31, 2016 and 2015.

	Year Ended December 31,	
	2016	2015
	(In Thousands)	
Net loss attributable to controlling interests (1)	$ (178,789)	$ (39,454)
Interest expense, net	149,201	117,311
Depreciation, depletion and amortization	164,212	195,415
Accretion on asset retirement obligations	3,376	2,267
Transition and reorganization costs (excluding amounts included in equity-based compensation) (2)	2,574	17,111
Equity-based compensation	5,106	13,704
Long-lived asset impairments	74,575	12,592
Loss (gain) on commodity derivative contracts	23,752	(45,691)
Settlements of commodity derivative contracts	12,644	61,223
Debt restructuring costs	21,821	3,930
Change in fair value of warrants	17,124	—
Loss on early extinguishment of debt	13,203	—
Adjusted EBITDA	$ 308,799	$ 338,408

(1) Included in net loss attributable to controlling interests during 2016 were insurance recoveries for the reimbursement of mitigation costs of $10.5 million, which were recorded in cost of coal sales (excluding depreciation, depletion and amortization), and business interruption proceeds of $20.0 million which were recorded in other operating income, net.

(2) Equity-based compensation of $4.3 million was recorded in transition and reorganization costs in the consolidated statements of operations for the years ended December 31, 2016 and 2015.

For a discussion on Adjusted EBITDA, please read Part II. "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Metrics."

Comparison of Year Ended December 31, 2015 to Year Ended December 31, 2014

Coal Sales. The following table summarizes coal sales information for the years ended December 31, 2015 and 2014.

	For the Year Ended December 31,			
	2015	2014	Variance	
	(In Thousands, Except Per Ton Data)			
Coal sales	$ 979,179	$ 1,109,404	$ (130,225)	-11.7%
Tons sold (1)	$ 21,946	22,044	(98)	-0.4%
Coal sales realization per ton sold (2)	$ 44.62	$ 50.33	$ (5.71)	-11.3%
Netback to mine realization per ton sold (3)	$ 36.79	$ 40.29	$ (3.50)	-8.7%

(1) - Excludes tons sold of 0.2 million during the year ended December 31, 2014 for our mine under development.
(2) - Coal sales realization per ton sold is defined as coal sales divided by tons sold.
(3) - Netback to mine realization per ton sold is defined as coal sales less transportation expense divided by tons sold.

Coal sales decreased $130.2 million from the year ended December 31, 2014 due to a decline in coal sales realization per ton sold of $5.71. The decline in coal sales realization per ton was due to a decline in realization per ton on both our domestic and international sales driven by weak coal market conditions as well as a lower mix of international shipments. Increased domestic shipments during the year ended December 31, 2015 offset the 1.3 million ton decrease in sales volumes to international markets from the year ended December 31, 2014. The decline in tons sold to the international market resulted in a corresponding decline in transportation expense during the year ended December 31, 2015, therefore, the netback to mine realization per ton sold decreased to a lesser extent than the coal sales realization per ton sold.

Other Revenues. Other revenues of $5.7 million recorded for the year ended December 31, 2015 were primarily comprised of overriding royalty and lease revenues earned on the financing agreements entered into with affiliates of Murray Energy in April 2015.

Cost of Coal Produced (Excluding Depreciation, Depletion and Amortization). The following table summarizes cost of coal produced (excluding depreciation, depletion and amortization) information for years ended December 31, 2015 and 2014.

	For the Year Ended December 31,			
	2015	2014	Variance	
	(In Thousands, Except Per Ton Data)			
Cost of coal produced (excluding depreciation, depletion and amortization)	$ 509,170	$ 449,905	$ 59,265	13.2%
Produced tons sold (1)	21,507	21,634	(127)	-0.6%
Cash cost per ton sold (2)	$ 23.67	$ 20.80	$ 2.87	13.8%
Tons produced (3)	20,097	22,547	(2,450)	-10.9%

(1) - Excludes tons sold of 0.2 million during the year ended December 31, 2014 for our mine under development.
(2) - Cash cost per ton sold is defined as cost of coal produced (excluding depreciation, depletion and amortization) divided by produced tons sold.
(3) - Excludes production of 0.2 million tons during the year ended December 31, 2014 for our mine under development.

The increase in cost of coal produced during the year ended December 31, 2015 was driven by a $2.87 per ton increase in cash cost per ton sold. The impact of the Hillsboro mine combustion event and increased costs at our Williamson and Sugar Camp operations primarily accounted for the increase in the cash cost per ton sold. The direct costs incurred during 2015 from our efforts to extinguish the fire at our Hillsboro mine was $20.2 million and the indirect impact of incurring salary and overhead costs at this mine without any corresponding production was $10.6 million. The higher cash cost per ton sold at our Williamson and Sugar Camp operations was driven by higher repairs, maintenance and longwall costs during the year ended December 31, 2015. Partially offsetting the higher costs discussed above was an $8.4 million favorable adjustment related to a refund from our utility provider during 2015.

Transportation. Transportation expense declined $49.4 million, or $2.21 per ton sold, from the year ended December 31, 2014 due to a 19.4% decline in international sales as well as lower charges during the year ended December 31, 2015 for shortfalls against contractual minimum volumes as a result of a favorable contractual amendment to reduce the required minimum volumes through Convent Marine Terminal ("CMT"), the export terminal owned by an affiliate prior to September 2015.

Depreciation, Depletion and Amortization. The increase in depreciation, depletion and amortization expense of $25.6 million from 2014 was primarily due to the reduction of coal inventory during 2015 and the second longwall at our Sugar Camp complex coming out of development in June 2014.

Long-lived Asset Impairments. During the years ended December 31, 2015 and 2014, we recorded an impairment charge of $11.6 million and $34.7 million, respectively, related to certain Hillsboro prepaid royalties for which we determined recoupment was improbable. Also, during the year ended December 31, 2015, we recorded a charge to write-off the remaining $1.0 million in deferred longwall costs related to Hillsboro's current longwall panel, which is being abandoned as a result of the mine fire.

Transition and Reorganization Costs. Transition and reorganization costs were $21.4 million for the year ended December 31, 2015. As part of the Murray Energy transaction, Foresight entered into the MSA with Murray Energy with the intent of optimizing and reorganizing certain corporate administrative functions and generating synergies between the two companies through the elimination of headcount and duplicate selling, general and administrative costs. The costs for the year ended December 31, 2015 are primarily comprised of retention compensation to certain employees during the transition period and termination benefits to employees whose positions were replaced by Murray Energy employees under the MSA. Included in these retention costs were $5.9 million of retention and transition salaries paid by FELP, $10.0 million of retention and severance costs paid by Foresight Reserves (which were recorded as capital contributions), $4.3 million of equity-based compensation for the accelerated vesting of certain equity awards, and $1.2 million of legal and various other one-time charges related to the Murray Energy transaction.

Gain on Commodity Derivative Contracts. We recorded a gain on our commodity derivative contracts of $45.7 million for the year ended December 31, 2015 compared to a $76.3 million gain for the year ended December 31, 2014. The API 2 coal index forward price curve declined significantly during both fiscal year 2015 and 2014, resulting in the large derivative gains. For the year ended December 31, 2015, we had settlements of $61.2 million on our commodity derivative contracts, of which $19.1 million were for coal derivative contracts settled prior to their contractual maturities.

Other Operating Income, Net. Other operating income, net increased $10.6 million from the year ended December 31, 2014 primarily due to a $13.5 million favorable legal settlement with Murray Energy during the first quarter of 2015.

Interest Expense, Net . Interest expense, net for the year ended December 31, 2015 increased $4.3 million from the prior year due primarily to higher interest charges on our Macoupin sale-leaseback obligation and lower interest charges capitalized in 2015. For the year ended December 31, 2015, we capitalized $1.9 million in interest expense as compared to $5.2 million during the prior year. The decrease in capitalized interest was due to capital spending on the development of Sugar Camp's second longwall mine along with the acquisition of an additional set of longwall shields during 2014.

Debt Restructuring Costs. The $3.9 million of debt restructuring costs incurred during the year ended December 31, 2015 represents legal and other advisor fees incurred as a result of the unfavorable ruling under the 2021 Senior Note bondholder lawsuit, including the negotiations with all of our creditors as a result of the default and the evaluation of our alternatives with respect to the restructuring of our indebtedness.

Adjusted EBITDA. Adjusted EBITDA declined $71.2 million from the year ended December 31, 2014 due to lower netback to mine realizations per ton sold and higher cash cost per ton sold during the year ended December 31, 2015. Partially offsetting the above was $42.0 million of incremental settlements on commodity derivative contracts and a favorable $13.5 million legal settlement with Murray Energy during 2015. The table below reconciles net (loss) income attributable to controlling interests to Adjusted EBITDA for the years ended December 31, 2015 and 2014.

	For the Year Ended December 31,	
	2015	**2014**
	(In Thousands)	
Net (loss) income attributable to controlling interests	$ (39,454)	$ 137,567
Interest expense, net	117,311	113,030
Depreciation, depletion and amortization	195,415	169,767
Accretion on asset retirement obligations	2,267	1,621
Transition and reorganization costs (excluding amounts included in equity-based compensation) (1)	17,111	—
Equity-based compensation	13,704	5,024
Long-lived asset impairments	12,592	34,700
Gain on commodity derivative contracts	(45,691)	(76,330)
Settlements of commodity derivative contracts	61,223	19,204
Debt restructuring costs	3,930	—
Loss on early extinguishment of debt	—	4,979
Adjusted EBITDA	$ 338,408	$ 409,562

(1) Equity-based compensation of $4.3 million was recorded in transition and reorganization costs in the consolidated statement of operations for the year ended December 31, 2015.

For a discussion on Adjusted EBITDA, please read Part II. "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Metrics."

Liquidity and Capital Resources

Our primary cash requirements include, but are not limited to, working capital needs, capital expenditures, and debt service costs (interest and principal). The consummation of the Restructuring Transactions on August 30, 2016 alleviated certain defaults and events of default across the Partnership's capital structure, which restored our access to borrowings under our Revolving Credit Facility, which had been restricted since December 2015. The commitments under our Revolving Credit Facility, which terminates in August 2018, were reduced by $100.0 million to $450.0 million effective December 31, 2016. During 2016, management focused on the preservation and growth of our liquidity. As of December 31, 2016, we had $103.7 million of cash on hand and unused capacity under our Revolving Credit Facility of $90.5 million. The August 30, 2016 amendment to the credit agreement ("Amended Credit Agreement") put in place an anti-hoarding provision, which prohibits new borrowings if the aggregate amount of our unrestricted cash and cash equivalents (taking into account certain pending applications of cash) exceeds $35.0 million both before and after giving effect to such borrowing when taking into account the intended use of such loan proceeds for bona fide purposes within 60 days.

Mandatory term loan prepayments are required to be made under our Term Loan based on an excess cash flow calculation, as defined in the Amended Credit Agreement, for the second half of fiscal year 2016 and full fiscal year 2017, sales of assets, net proceeds of insurance and condemnation awards and certain incurrence of indebtedness, subject, in each case, to customary exceptions and thresholds. The excess cash flow generated during the second half of fiscal year 2016 and business interruption insurance recoveries from the Hillsboro combustion event require that we prepay $26.9 million of Term Loan principal, $2.1 million of which was paid in 2016 and the remainder is due during the first quarter of 2017.

On February 13, 2017, we announced that we have commenced the process to refinance and extend the maturities of all or a portion of our existing indebtedness with the net proceeds from a combination of debt, equity financing and/or cash on hand. There can be no assurance regarding the results of the Partnership's refinancing and maturity extension efforts.

Our operations are capital intensive, requiring investments to expand, maintain or enhance existing operations and to meet environmental and operational regulations. Our future capital spending will be determined by the board of directors of our general partner. Our capital requirements consist of maintenance and expansion capital expenditures. Maintenance capital expenditures are cash expenditures made to maintain our then-current operating capacity or net income as they exist at such time as the capital expenditures are made. Our maintenance capital expenditures can be irregular, causing the amount spent to differ materially from period to period.

Expansion capital expenditures are cash expenditures made to increase, over the long-term, our operating capacity or net income as it exists at such time as the capital expenditures are made. Expansion capital expenditures have declined significantly since early-2015 and no significant expansion capital expenditure plans are currently planned. Future longwall development and the associated expansion capital expenditures will be dependent upon several factors, including permitting, demand, access to capital, equipment availability and the committed sales position at our existing mining operations.

Distributions

Our Senior Secured Credit Facilities, as amended on August 30, 2016, prohibit certain restricted payments, including discretionary dividends, until the later to occur of: (i) June 30, 2018 and (ii) the date on which our obligations under our revolving credit facility have been paid in full, after which restricted payments can be made of up to $25.0 million per year, subject to certain adjustments and exceptions. Our Senior Secured Credit Facilities allow for the payment of certain tax distributions during 2017 and 2018.

The following is a summary of cash provided by or used in each of the indicated types of activities during the years ended December 31, 2016, 2015, and 2014.

	Year Ended December 31,		
	2016	**2015**	**2014**
		(In Thousands)	
Net cash provided by operating activities	$ 225,220	$ 200,412	$ 240,782
Net cash used in investing activities	$ (47,629)	$ (138,781)	$ (224,583)
Net cash used in financing activities	$ (91,439)	$ (70,602)	$ (14,477)

Cash provided by operating activities increased $24.8 million during the year ended December 31, 2016 as the decline in net income, excluding non-cash items, during the current year was impacted significantly by the variances in working capital accounts and certain financing activities, including:

- $49.2 million of interest from the 2021 Senior Notes that was converted into new debt as part of the August 30, 2016 debt restructuring ($17.7 million of which was accrued for at December 31, 2015 and the remainder was a noncash financing transaction);
- $38.3 million favorable change in due from/to affiliates, net, which is a function of timing of cash collections;
- Favorable change in accrued interest driven by accrued PIK interest on the Exchangeable PIK Notes and the Second Lien Notes (will convert to principal in 2017);
- $20.1 million unfavorable change in inventories. Inventories lowered during both 2016 and 2015 however the impact was more significant during the prior year as coal stockpiles were depleted due to the combustion event at Hillsboro and coal production cuts in December 2015 to preserve liquidity and drawdown the excess coal inventory at our other mine sites.

Net cash used in investing activities was $47.6 million for the year ended December 31, 2016, compared to $138.8 million for the year ended December 31, 2015. The decline in net cash used in investing activities was in part due to a $30.4 million reduction in capital expenditures due to expansion capital for the second longwall mine at our Sugar Camp complex coming to an end in 2015, the strict controlling of maintenance capital expenditures to preserve liquidity, and the shutdown of production at our Hillsboro mine due to the combustion event. During 2016, we also received $4.4 million in cash proceeds from the sale of certain corporate assets. During the year ended December 31, 2015, we made a $75.0 million investment in the Murray Energy transport lease and overriding royalty agreements (see “Item 8. Financial Statements – Note 15. Related-Party Transactions”) and received $19.1 million in proceeds from the settlement of certain outstanding derivative contracts prior to the economically hedged sale transaction occurring.

Net cash used in financing activities was $91.4 million for the year ended December 31, 2016, compared to $70.6 million for the year ended December 31, 2015. During the year ended December 31, 2016, we repaid $26.8 million of principal under our A/R securitization program and $45.7 million of principal under our longwall financing and capital lease arrangements. We also incurred debt issuance costs of $15.7 million directly related to the debt restructuring. During the year ended December 31, 2015, we increased our net borrowings by $86.3 million and paid distributions of $152.4 million.

Net cash provided by operating activities declined $40.4 million to $200.4 million for the year ended December 31, 2015 primarily due to lower net income, excluding non-cash items, as compared to the year ended December 31, 2014. The impact of lower earnings was offset partially by favorable variances in working capital accounts from 2014, including $40.0 million in cash proceeds from the settlement of derivative contracts during 2015 and a $41.8 million favorable variance in inventory as Hillsboro’s coal stockpiles were depleted due to the mine fire and coal production was cut in December 2015 to preserve liquidity and drawdown the excess coal inventory at the other mine sites.

Net cash used in investing activities was $138.8 million for the year ended December 31, 2015, compared to $224.6 million for the year ended December 31, 2014. The decline in net cash used in investing activities was primarily due to a $144.7 million reduction in capital expenditures as a result of the second longwall mine at our Sugar Camp complex emerging from development in June 2014 as well as the receipt of $19.1 million in proceeds during 2015 from the settlement of certain outstanding coal derivative contracts. The cash receipts on these contracts were recorded as an investing activity given they were settled prior to the economically hedged sale transaction occurring. Offsetting the items above was a $75.0 million investment in the Murray Energy transport lease and overriding royalty agreements (see Part II. “Item 8. Financial Statements and Supplementary Data– Note 15. Related-Party Transactions” of this Annual Report on Form 10-K).

Net cash used in financing activities was $70.6 million for the year ended December 31, 2015, compared to $14.5 million used in financing activities for the year ended December 31, 2014. During the year ended December 31, 2015, we received net proceeds from our A/R securitization program of $41.0 million, increased our borrowings under our Revolving Credit Facility by $33.0 million and received proceeds from incremental term loan borrowings of $59.3 million. Also, during the year ended December 31, 2015, we repaid $44.4 million under our longwall financing and capital lease arrangements, repaid $2.6 million in short-term insurance financing, paid $2.8 million in debt issuance costs and paid $152.4 million in distributions to our limited partners and noncontrolling interests. The increased borrowings during 2015 were due in part to the $75.0 million invested in the Murray Energy transport lease and overriding royalty agreements.

Long-Term Debt and Sale-Leaseback Financing Arrangements

On August 30, 2016, we completed a global restructuring of our indebtedness. The Restructuring Transactions alleviated then existing defaults and events of default across the Partnership’s capital structure that resulted from the 2015 Delaware Court of Chancery change-of-control litigation related to the purchase and sale agreement between Foresight Reserves and Murray Energy. As a result of the Restructuring Transactions and the resolution of the 2015 Delaware Court of Chancery change-of-control litigation, certain of our outstanding long-term debt and capital lease obligations were no longer reflected as a current liability in the consolidated balance sheets and we were no longer subject to default interest rates.

On February 13, 2017, we announced that we have commenced the process to refinance and extend the maturities of all or a portion of our existing indebtedness with the net proceeds from a combination of debt, equity financing and/or cash on hand. There can be no assurance regarding the results of the Partnership’s refinancing and maturity extension efforts.

Exchange of 2021 Senior Notes for New Notes and Warrants and Redemption of 2021 Senior Notes

The Partnership exchanged $599.8 million in aggregate principal amount of the 2021 Senior Notes and the accrued and unpaid interest thereon for the following consideration:

- (i) $349.1 million in aggregate principal of Senior Secured Second Lien PIK Notes due 2021 (the “Second Lien Notes”);
- (ii) $299.9 million in aggregate principal of Senior Secured Second Lien Exchangeable PIK Notes due 2017 (the “Exchangeable PIK Notes,” and, together with the Second Lien Notes, the “New Notes”); and

- (iii) 516,825 warrants (the “Warrants”) to acquire newly issued common units of FELP (the “Common Units”) equal to 4.5% of the total limited partner units of FELP outstanding on the date of a Note Redemption (as defined below) (after giving effect to the full exercise thereof and the Note Redemption).

On the Closing Date, we also redeemed the remaining $175,000 in aggregate principal amount of 2021 Senior Notes that were not exchanged. Upon such redemption, the obligations under the 2021 Senior Notes were satisfied and discharged.

The Warrants were determined to meet the accounting criteria of a detachable freestanding derivative liability instrument and the fair value of the Warrants on the Closing Date was calculated to be $34.0 million. See Part II. “Item 8. Financial Statements and Supplementary Data– Note 17. Fair Value of Financial Instruments” for additional discussion on the fair value of the Warrants. A liability for the fair value of the Warrant was recorded on our consolidated balance sheet as of the Closing Date and the offset was recognized as a debt discount to the New Notes. The discount was allocated pro rata between the Second Lien Notes and the Exchangeable PIK Notes in proportion to the relative fair value of each instrument held by a person other than the Reserves Investor Group (See Part II. “Item 8. Financial Statements and Supplementary Data– Note 15. Related-Party Transactions”) on the Closing Date (only the unaffiliated holders of the New Notes received the Warrants on the Closing Date). The $25.0 million discount allocated to the Second Lien Notes and the $9.0 million discount allocated to the Exchangeable PIK Notes will be amortized using the effective interest method over their respective maturities.

Terms of the New Notes

The Second Lien Notes were issued pursuant to an indenture and have a maturity date of August 15, 2021. The Second Lien Notes bear interest at a rate of: (i) 9.0% per annum until August 15, 2018 and 10.0% per annum thereafter, in each case, payable in cash on each interest payment date; and (ii) 1.0% per annum payable in kind. Interest is payable semi-annually on February 15th and August 15th. We may redeem the Second Lien Notes in whole or in part subject to the redemption premiums and provisions in the indenture.

The Exchangeable PIK Notes were issued pursuant to an indenture (the “Exchangeable PIK Notes Indenture”) and have a maturity date of October 3, 2017 (the “Exchangeable PIK Notes Maturity Date”). The Exchangeable PIK Notes bear interest payable in kind at a rate of 15.0% per annum, payable on March 1, 2017 and October 3, 2017.

We may redeem, repurchase, refinance, defease or otherwise retire (any of the foregoing, a “redemption”) all of the Exchangeable PIK Notes on or prior to October 2, 2017 for cash at 100% of the principal amount thereof plus accrued interest (any such redemption, an “Exchangeable PIK Note Retirement”). In addition to the Exchangeable PIK Note Retirement, the Murray Group shall have the right to purchase all (but not less than all) of the Exchangeable PIK Notes on or prior to October 2, 2017 for cash at a price equal to 100% of the principal amount of the Exchangeable PIK Notes plus accrued interest (a “Murray Purchase,” and together with an Exchangeable PIK Note Retirement and any repayment of the Exchangeable PIK Notes in full in cash that occurs on the Exchangeable PIK Notes Maturity Date, a “Note Redemption”). Upon a Murray Purchase, the Murray Group will receive FELP units equal to the principal and interest settlement amount multiplied by the lesser of: (a) a number equal to one divided by 92.5% of the last thirty days weighted-average trading price or (b) 1.12007 common units per $1.00 principal amount of Exchangeable PIK Notes. The Partnership and Murray Energy may each purchase less than all of the outstanding Exchangeable PIK Notes, so long as the combination results in redemption of all of the Exchangeable PIK Notes. The Exchangeable PIK Note Retirement may be funded with the proceeds from an investment by the Murray Group or any member thereof in FELP , from general working capital or from any other source permitted by the indenture governing the Exchangeable PIK Notes (and subject to compliance with the Partnership’s other debt agreements). If the Exchangeable PIK Notes have not been redeemed or purchased for cash at 100% of the principal amount thereof plus accrued interest by the Exchangeable PIK Notes Maturity Date, then all outstanding Exchangeable PIK Notes (including all principal, interest and other amounts outstanding thereunder) shall be exchanged for common units representing 75% of FELP’s outstanding limited partner units on the Exchangeable PIK Notes Maturity Date, subject to adjustment on account of certain anti-dilution protections.

The obligations under the New Notes are unconditionally guaranteed on a senior secured basis by each of FELP’s wholly owned domestic subsidiaries that guarantee the Senior Secured Credit Facilities (other than Foresight Energy Finance Corporation) and on a senior unsecured basis by FELP and are or will be secured by second-priority perfected liens on substantially all of our and the subsidiary guarantors’ existing and future assets, subject to certain exceptions.

Senior Secured Credit Facilities

On the Closing Date, FELLC entered into an amendment to its senior secured credit facilities (as amended, the “Senior Secured Credit Facilities”), pursuant to which outstanding defaults under its existing credit agreement were waived and the credit agreement was amended and restated as set forth in the third amended and restated credit agreement (the “Amended Credit Agreement”). Pursuant to the Amended Credit Agreement, the $297.8 million term loan remained outstanding on the Closing Date and matures in August 2020 (the “Term Loan”) and the commitments under our $550.0 million revolving credit facility, which terminates in August 2018, were reduced to $450.0 million (the “Revolving Credit Facility”) effective December 31, 2016. As of December 31, 2016, we had $352.5 million in borrowings outstanding under the Revolving Credit Facility and $7.0 million in letters of credit. Outstanding borrowings under the Term Loan were $295.7 million as of December 31, 2016. In addition, the Amended Credit Agreement added an anti-hoarding provision under our Revolving Credit Facility which prohibits new borrowings if the aggregate amount of our unrestricted cash and cash equivalents (taking into account certain pending applications of cash) exceeds $35.0 million both before and after giving effect to such borrowing when taking into account the intended use of such loan proceeds for bona fide purposes within 60 days. Mandatory term loan prepayments are required to be made under our Term Loan based on an excess cash flow calculation, as defined in the Amended Credit Agreement, for the second half of fiscal year 2016 and full fiscal year 2017, sales of assets, proceeds of insurance and condemnation awards and certain incurrence of indebtedness, subject, in each case, to customary exceptions and thresholds.

Under the Amended Credit Agreement, borrowings under our Revolving Credit Facility bear interest at a rate equal to, at our option: (i) LIBOR (subject to a LIBOR floor of 0%) plus an applicable margin ranging from 3.50% to 4.50%; or (ii) a base rate plus an applicable margin ranging from 2.50% to 3.50%; in each case, determined in accordance with our consolidated net leverage ratio. Our Term Loan bears interest at a rate equal to, at our option: (i) LIBOR (subject to a LIBOR floor of 1.00%) plus 5.50%; or (ii) a base rate plus 4.50%. We are also required to pay a commitment fee of 0.50% to the lenders under the Revolving Credit Facility in respect of unutilized commitments thereunder and pay a fronting fee equal to 0.125% per annum of the amount available to be drawn under letters of credit. As of December 31, 2016, the weighted-average interest rate on Revolving Credit Facility and Term Loan borrowings was 5.3% and 6.5%, respectively.

The obligations under the Senior Secured Credit Facilities are unconditionally guaranteed on a senior unsecured basis by FELP and on a senior secured basis by our direct and indirect domestic subsidiaries and are or will be secured by first-priority perfected liens on substantially all of our and the subsidiary guarantors' existing and future assets, subject to certain exceptions.

The Senior Secured Credit Facilities require that we comply on a quarterly basis with certain financial covenants, including a minimum consolidated interest coverage ratio of 2.00:1.00 and a maximum senior secured net leverage ratio ranging from 3.50:1.00 for the fiscal quarter ended December 31, 2016 to 2.75:1.00 for the fiscal quarter ending March 31, 2021 and thereafter. Our Senior Secured Credit Facilities prohibit certain restricted payments, including discretionary dividends, until the later to occur of: (i) June 30, 2018 and (ii) the date on which our obligations under our Revolving Credit Facility have been paid in full, after which restricted payments can be made of up to $25.0 million per year, subject to certain adjustments and exceptions.

The Senior Secured Credit Facilities also require compliance with certain covenants that significantly restricts our ability to, among other things, (i) incur additional indebtedness, (ii) incur liens, (iii) pay dividends or make certain other restricted payments, investments or acquisitions, (iv) enter into certain transactions with affiliates, (v) merge or consolidate with another person, (vi) sell, assign, lease or otherwise dispose of all or substantially all of our assets, and (vii) make voluntary prepayments of certain debt, in each case subject to exceptions.

Trade A/R Securitization Program

In January 2015, Foresight Energy LP and certain of its wholly-owned subsidiaries, entered into a $70 million receivables securitization program (the "Securitization Program"). Under this Securitization Program, our subsidiaries sell all of their customer trade receivables (the "Receivables"), on a revolving basis, to Foresight Receivables LLC, a wholly-owned and consolidated special purpose subsidiary of Foresight Energy LP (the "SPV"). The SPV then pledges its interests in the Receivables to the securitization program lenders, which make loans to the SPV. The Securitization Program has a three-year maturity which expires on January 12, 2018. The borrowings under the Securitization Program are variable-rate and also carry a commitment fee for unutilized commitments.

In August 2016, we entered into an amended and restated receivables financing agreement pursuant to which the Securitization Program was amended to permanently reduce commitments to $50.0 million. As of December 31, 2016, we had borrowings outstanding of $14.2 million under the Securitization Program.

Longwall Financing Arrangements and Capital Lease Obligations

In November 2014, we entered into a sale-leaseback financing arrangement with a financial institution under which we sold a set of longwall shields and related equipment for $55.9 million and leased the shields back under three individual leases. We account for these leases as capital lease obligations since ownership of the longwall shields and related equipment transfer back to us upon the completion of the leases. Principal and interest payments are due monthly over the five-year terms of the leases. Aggregate termination payments of $2.8 million are due at the end of the lease terms. In connection with the Restructuring Transactions, we also executed waivers to cure outstanding defaults under the master lease agreements to our capital lease obligations. These waivers, among other things, ratified the existing terms of each applicable equipment financing agreement, provided the lessor with a waiver fee equal to one hundred basis points of the outstanding amount due under the agreement, increased the interest rate by one percent per annum, and, with respect to certain arrangements, released the lessor from any claims that such parties may have against the lessor with respect to the lease. As of December 31, 2016 , $36.3 million was outstanding under these capital lease obligations.

In March 2012, we entered into a finance agreement with a financial institution to fund the manufacturing of longwall equipment. Upon taking possession of the longwall equipment, the interim longwall finance agreement was converted into six individual capital leases with maturities of four and five years beginning on September 1, 2012. Principal and interest payments are due monthly over the terms of the leases. In connection with the Restructuring Transactions, we also executed waivers to cure outstanding defaults under the master lease agreements to our capital lease obligations. These waivers, among other things, ratified the existing terms of each applicable equipment financing agreement, provided the lessor with a waiver fee equal to one hundred basis points of the outstanding amount due under the agreement, increased the interest rate by one percent per annum, and, with respect to certain arrangements, released the lessor from any claims that such parties may have against the lessor with respect to the lease. As of December 31, 2016, $5.2 million was outstanding under these capital lease obligations.

In May 2010, we entered into a credit agreement with a financial institution to provide financing for longwall equipment and related parts and accessories. The financing agreement also provided for financing of loan fees and eligible interest during the construction of the longwall equipment. The financing arrangement is collateralized by the longwall equipment. Interest accrues on the note at a fixed rate per annum of 5.555% and is due semiannually in March and September until maturity. Principal is due in semiannual payments through maturity. On the Closing Date, we entered into an amendment to the 5.555% longwall financing credit agreement under which the lenders waived the existing defaults and the maturity date was accelerated by one year by increasing the last four semi-annual amortization payments. The new maturity date of the 5.555% longwall financing arrangement is September 2019. In addition, the senior secured leverage ratio financial maintenance covenant was amended to be consistent with the Amended Credit Agreement. The outstanding balance as of December 31, 2016 was $41.3 million.

In January 2010, we entered into a credit agreement with a financial institution to provide financing for longwall equipment and related parts and accessories. The financing agreement also provided for financing of the loan fees and eligible interest during the construction of the longwall equipment. The financing arrangement is collateralized by the longwall equipment. Interest accrues on the note at a fixed rate per annum of 5.78% and is due semiannually in June and December until maturity. Principal is due in semiannual payments through maturity. On the Closing Date, we entered into an amendment to the 5.78% longwall financing credit agreement under which the lenders waived the existing defaults and the maturity date was accelerated by one year by increasing the last three semi-annual amortization payments. The new maturity date of the 5.78% longwall financing arrangement is June 2019. In addition, the senior secured leverage ratio financial maintenance covenant was amended to be consistent with the Amended Credit Agreement. The outstanding balance as of December 31, 2016 was $39.2 million.

Sale-Leaseback Financing Arrangements - Affiliate

In 2009, Macoupin sold certain of its coal reserves and rail facility assets to WPP LLC, a subsidiary of Natural Resources Partners LP (“NRP”), and leased them back. The gross proceeds from this transaction were $143.5 million. As Macoupin has continuing involvement in the assets sold, the transaction is treated as a financing arrangement. At December 31, 2016, the outstanding balance of the sale-leaseback financing arrangement was $141.9 million and the effective interest rate was 13.7%.

In 2012, Sugar Camp sold certain rail facility assets to HOD LLC, a subsidiary of NRP, and leased them back. The gross proceeds from this transaction were $50.0 million. As Sugar Camp has continuing involvement in the assets sold, the transaction is treated as a financing arrangement. At December 31, 2016, the outstanding balance of the sale-leaseback financing arrangement was $50.0 million and the effective interest rate was 13.7%.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements, including operating leases, coal reserve leases, take-or-pay transportation obligations, indemnifications and financial instruments with off-balance sheet risk, such as bank letters of credit and surety bonds. Liabilities related to these arrangements are generally not reflected in our consolidated balance sheets and, except for the coal reserve leases, take-or-pay transportation obligations and operating leases, we do not expect any material impact on our cash flows, results of operations or financial condition to result from these off-balance sheet arrangements.

From time to time, we use bank letters of credit to secure our obligations for certain contracts and other obligations. At December 31, 2016, we had $7.0 million of letters of credit outstanding.

Regulatory authorities require us to provide financial assurance to secure, in whole or in part, our future reclamation projects. We had outstanding surety bonds with third parties of $83.4 million as of December 31, 2016 to secure reclamation and other performance commitments. We have posted cash collateral of $2.5 million to our surety bond provider and Foresight Reserves has provided a guarantee on $50.5 million of the surety bonds.

Contractual Obligations

The following is a summary of our significant contractual obligations as of December 31, 2016, by year:

	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
			(In Millions)		
Long-term debt (principal and interest) (1)	$ 1,721.2	$ 470.0	$ 550.4	$ 700.8	$ —
Sale-leaseback financing arrangements (2)	268.3	21.0	42.0	42.0	163.3
Capital lease obligations (principal and interest)	45.0	17.9	27.1	—	—
Operating lease obligations	6.7	3.3	3.1	0.3	—
Take-or-pay transportation arrangements (3)	312.3	49.6	103.1	104.7	54.9
Coal reserve lease and royalty obligations (4)	505.2	59.7	119.3	86.5	239.7
Unconditional purchase obligations (5)	37.9	37.9	—	—	—
Total (6)	$ 2,896.6	$ 659.4	$ 845.0	$ 934.3	$ 457.9

(1) Includes our Exchangeable PIK Notes, Second Lien Notes, Revolving Credit Facility, Term Loan, Trade A/R Securitization Program and the 5.555% and 5.78% longwall financing arrangements. The payment-in-kind interest on the Exchangeable PIK Notes and the Second Lien Notes rolls into the principal balance and gets paid as principal at maturity. The calculated cash interest expense assumes no voluntary early principal repayments and is based on the actual interest rates as of December 31, 2016 . If the Exchangeable PIK Notes have not been redeemed or purchased for cash at 100% of the principal amount thereof plus accrued interest by the Exchangeable PIK Notes Maturity Date, then all outstanding Exchangeable PIK Notes (including accrued interest) shall be exchanged for Common Units representing 75% of FELP’s outstanding limited partner units on the Exchangeable PIK Notes Maturity Date, subject to adjustment on account of certain anti-dilution protections.

(2) Represents the minimum annual payments required under our Macoupin and Sugar Camp sale-leaseback financing arrangements.

(3) Includes our various take-or-pay arrangements associated with rail and terminal facility commitments for the delivery of coal through the initial arrangement term.

(4) Comprised of the future minimum cash payments due under our various coal reserve lease and royalty obligations through the initial royalty term.

(5) We have open purchase agreements with approved vendors for most types of operating expenses. However, our specific open purchase orders (which have not been recognized as a liability) under these purchase agreements are not material and typically allow for cancellation or return without penalty. The commitments in the table above relate only to committed capital purchases as of December 31, 2016 and committed coal purchases with Murray Energy. The contractual table above does not include our obligations under the MSA with Murray Energy, please read Part II. “Item 8. Financial Statements and Supplementary Data, Note 15–Related-Party Transactions” for a discussion on the terms of this contractual arrangement.

(6) The contractual obligation table does not include asset retirement obligations. Asset retirement obligations result primarily from statutory, rather than contractual obligations and the ultimate timing and amount of the obligations are an estimate. As of December 31, 2016, we have $44.9 million recorded in our consolidated balance sheet for asset retirement obligations.

We lease certain surface rights, mineral reserves, mining, transportation, and other equipment under various lease agreements with related entities under common ownership, NRP and its subsidiaries, and other independent third parties in the normal course of business. The mineral reserve leases can generally be renewed as long as the mineral reserves are being developed and mined until all economically recoverable reserves are depleted or until mining operations cease. The leases require a production royalty at the greater amount of a base amount per ton or a percent of the gross selling price of the coal. Generally, the leases contain provisions that require the payment of minimum royalties regardless of the volume of coal produced or the level of mining activity. The minimum royalties are generally recoupable against production royalties over a contractually defined period of time (generally five to ten years). Some of these agreements also require overriding royalty and/or wheelage payments. Under the terms of some mineral reserve mining leases, we are to use commercially reasonable efforts to acquire additional mineral reserves in certain properties as defined in the agreements and are responsible for the acquisition costs and the assets are to be titled to the lessor. Transportation throughput agreements generally require a per ton fee amount for coal transported and contain certain escalation clauses and/or renegotiation clauses. For certain transportation assets, we are responsible for operations, repairs, and maintenance and for keeping transportation facilities in good working order. Surface rights, mining, and other equipment leases require monthly payments based upon the specified agreements. Certain of these leases provide options for the purchase of the property at various times during the life of the lease, generally at its then fair market value. We also lease rail cars, certain office space and equipment under leases with varying expiration dates.

See Part III. "Item 13. Certain Relationships and Related Transactions and Director Independence" for a discussion of the above leases and agreements with affiliated parties.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based on our financial statements, which have been prepared in accordance with U.S. GAAP, which requires that we make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and the related disclosure of contingent assets and liabilities. We base these estimates on historical experience and on various other assumptions that we consider reasonable under the circumstances. On an ongoing basis we evaluate our estimates. Actual results may differ from these estimates. Of these significant accounting policies, we believe the following may involve a higher degree of judgment or complexity.

Sale-Leaseback Financing Arrangements. In 2009, Macoupin sold certain of its coal reserves to WPP LLC, an affiliate of Natural Resource Partners LP ("NRP"), and leased them back. The gross proceeds from this transaction were $143.5 million, and were used for capital expenditures relating to the rehabilitation of the Macoupin mine and for other capital items. Similarly, in 2012, Sugar Camp sold certain rail facilities to HOD LLC, an affiliate of NRP, and leased them back. The gross proceeds from this transaction were $50.0 million, and were used for capital expenditures, to pay down our revolving credit facility and for general corporate purposes. In both transactions, because we had continuing involvement in the assets sold, the transactions were treated as sale-leaseback financing arrangements.

Interest is accrued on the outstanding principal amounts of the financing arrangements using an implied interest rate, which was initially determined at inception of the lease and is adjusted for changes in future expected amounts and timing of payments based on the mine plans and also, for the Macoupin sale-leaseback only, the future expected sales price of its coal. Payments are applied first against accrued interest and any excess is then applied against the outstanding principal. Revisions to the mine plans, which occur periodically as changes are made to estimates of the quantity and the timing of tons to be mined, will impact the effective interest rate. We account for such changes by adjusting in the current period, the life-to-date interest previously recorded on the sale-leaseback to reflect the new effective interest rate as if it was applied from the inception of the transaction (i.e., retroactively applied). The implied effective interest rate was 13.7% and 13.9% as of December 31, 2016 and 2015, respectively, on the Macoupin sale-leaseback financing arrangement and 13.7% and 13.2% for the Sugar Camp sale-leaseback financing arrangement as of December 31, 2016 and 2015, respectively. If there is a material change to the mine plans, the impact of a change in the effective interest rate to the consolidated statements of operations could be significant.

Prepaid Royalties. Prepaid royalties consist of recoupable minimum royalty payments under various lease agreements. The contractual recoupment periods are generally five to ten years from the payment date. During the year ended December 31, 2016, we established a $74.6 million reserve against our contractual prepaid royalties between Colt LLC ("Colt"), a subsidiary of Foresight Reserves, and our Hillsboro and Macoupin subsidiaries. We recorded the impairment charge given that our ability to recoup these minimum royalty payments within the remaining recoupment period was improbable in light of, among other factors:

- the remaining recoupment periods available, as a whole, on these minimum annual royalty payments and the necessary time required to obtain permits on these reserves,
- our ability to raise the capital necessary to develop the reserves and the necessary infrastructure was unfavorably impacted by the Restructuring Transactions, which resulted in covenants that significantly restrict our ability to incur any additional indebtedness, and
- current and forecasted market conditions, which are impacted by supply and demand dynamics, natural gas prices, weather, economic conditions and the regulatory environment.

We previously recorded aggregate impairment charges to reserve against contractual prepaid royalties between Hillsboro and WPP given the remaining time available under the five-year recoupment periods, the current idling of the mine as a result of the mine fire, and coal based on current and forecasted near-term market conditions, which are impacted by natural gas prices, weather, economic conditions and the regulatory environment.

We continually evaluate our ability to recoup prepaid royalty balances which includes, among other things, assessing mine production plans, our access to capital markets, sales commitments, current and forecasted future coal market conditions, the time necessary to obtain required permits and the remaining years available for recoupment. As of December 31, 2016, we had recorded on the consolidated balance sheet prepaid royalties of $16.9 million, net of reserves.

Warrant Liability. The Warrants were determined to meet the criteria of a detachable freestanding derivative liability instrument and a liability for the fair value of the Warrants was recorded in our consolidated balance sheet as of the Closing Date and the offset was recognized as a debt discount to the New Notes. The Warrants are required to be accounted for as a liability at fair value and the fair value must be revalued at each balance sheet date until the earlier of the exercise of the Warrants, their expiration, or until any of the features requiring liability treatment expires or is modified. The resulting non-cash gain or loss on the fair value revaluation at each balance sheet date is recorded as non-operating expense in our consolidated statement of operations

The fair value of the Warrants was calculated using the Black-Scholes pricing model (including the use of a binomial lattice to model the conversion and redemption scenarios for the Exchangeable PIK Notes) which is based, in part, upon unobservable inputs for which there is little or no market data (Level 3), requiring the Partnership to develop its own assumptions. A stock price volatility of 70%, a dividend yield of 0% and a risk-free forward rate of 2.61% was used in the Black-Scholes pricing model. If factors change and different assumptions are used, the change in estimated fair value could be materially different. The change in the common unit price of our stock is the predominant input affecting the fair value of the Warrants. Generally, as the market price of our common unit increases, the fair value of the Warrants increases, and conversely, as the market price of our common unit decreases, the fair value of the Warrants decreases. A 10% increase in the fair value of our common units as of December 31, 2016 would have increased the fair value of the Warrants by $4.0 million. Also, to a lesser extent, a significant increase in the volatility of the market price of the Partnership's common unit, in isolation, would result in a higher fair value measurement; and a significant decrease in volatility would result in a lower fair value measurement.

Asset Retirement Obligations. Our asset retirement obligations ("ARO") consist of estimated spending related to reclaiming surface land and support facilities at our mines in accordance with federal and state reclamation laws as required by each mining permit. Obligations are incurred at the time mine development commences or when construction begins in the case of support facilities, refuse areas and slurry ponds.

The liability is determined using discounted cash flow techniques and is reduced to its present value at the end of each period. We estimate our ARO liabilities for final reclamation and mine closure based upon detailed engineering calculations of the amount and timing of the future cash cost for a third party to perform the required work. Spending estimates are escalated for inflation, and market risk premium, and then discounted at the credit-adjusted, risk-free rate. The credit-adjusted, risk-free interest rates were 8.5%, 9.8%, and 6.6% at December 31, 2016, 2015, and 2014, respectively. We record an ARO asset associated with the discounted liability for final reclamation and mine closure. Accretion on the ARO begins at the time the liability is incurred. Upon initial recognition of a liability, a corresponding amount is capitalized as part of the carrying amount of the related long-lived asset. The ARO asset for equipment, structures, buildings, and mine development is amortized over its expected life on a units-of-production basis. The ARO liability is then accreted to the projected spending date. As changes in estimates occur (such as mine plan revisions, changes in estimated costs, or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free rate.

On at least an annual basis, we review our entire reclamation liability and make necessary adjustments for permit changes as granted by state authorities, changes in the timing of reclamation activities and revisions to cost estimates, the occurrence of new liabilities from additional disturbances and productivity assumptions. Any difference between the recorded amount of the liability and the actual cost of reclamation will be recognized as a gain or loss when the obligation is settled. At December 31, 2016, our consolidated balance sheet reflected asset retirement obligations of $44.9 million, including amounts classified as a current liability. We estimate the aggregate undiscounted cost of final mine closures, at 2016 costs, to be approximately $101.8 million as of December 31, 2016.

New Accounting Standards Issued and Not Yet Adopted

In January 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2017-01, which clarifies the definition of a business to assist entities with evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. This standard is effective for fiscal years beginning after December 15, 2017. We do not expect this new guidance to have a material impact on our consolidated financial statements.

In November 2016, the FASB issued ASU 2016-18 which clarified the presentation requirements of restricted cash within the statement of cash flows. Under ASU 2016-18, the changes in restricted cash and restricted cash equivalents during the period should be included in the beginning and ending cash and cash equivalents balance reconciliation on the statement of cash flows. When cash, cash equivalents, restricted cash or restricted cash equivalents are presented in more than one line item within the statement of financial position, an entity shall calculate a total cash amount in a narrative or tabular format that agrees to the amount shown on the statement of cash flows. Details on the nature and amounts of restricted cash should also be disclosed. This standard is effective for fiscal years beginning after December 15, 2017. We expect this new guidance to require adjustments to the presentation of our consolidated financial statements. As of December 31, 2016, we had restricted cash of $13.4 million, of which $10.7 million is included in current asset and $2.6 million is included in long-term other assets.

In May 2014, the FASB issued ASU 2014-09 that introduces a new five-step revenue recognition model in which 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. This ASU also requires disclosures sufficient to enable users to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers, including qualitative and quantitative disclosures about contracts with customers, significant judgments and changes in judgments, and assets recognized from the costs to obtain or fulfill a contract. In July 2015, the FASB delayed the effective date until annual and interim periods beginning after December 31, 2017. We intend to adopt ASU 2014-09 as of January 1, 2018 using the modified retrospective approach. While we have not yet completed our review of the impact of the new standard, we do not currently anticipate a material impact on our revenue recognition practices. We are still evaluating disclosure requirements under the new standard and we will continue to evaluate the standard as well as additional changes, modifications or interpretations which may impact our current conclusions.

In March 2016, the FASB issued ASU 2016-09, *Compensation – Stock Compensation,* which was issued to simplify the accounting for share-based payment transactions, including income tax consequences, the classification of awards as equity or liabilities, an option to recognize gross equity-based compensation expense with actual forfeitures recognized as they occur and the classification on the statement of cash flows. This pronouncement is effective for reporting periods beginning after December 15, 2016. We do not expect the adoption of this update to have a material impact on our consolidated financial statements.

In February 2016, the FASB updated guidance regarding the accounting for leases. This update requires lessees to recognize a lease liability and a lease asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The update also expands the required quantitative and qualitative disclosures surrounding leases. This update is effective for fiscal years beginning after December 15, 2018 and interim periods within those fiscal years, with earlier application permitted. This update will be applied using a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We are currently evaluating the effect of this update on our consolidated financial statements.

In July 2015, the FASB issued ASU 2015-11, *Inventory: Simplifying the Measurement of Inventory* , which simplifies the measurement of inventories valued under most methods. Under this new guidance, inventories valued under these methods would be valued at the lower of cost and net realizable value, with net realizable value defined as the estimated selling price less reasonable costs to sell the inventory. The new guidance is effective prospectively for fiscal periods starting after December 15, 2016 and early adoption is permitted. We do not expect the adoption of ASU 2015-11 to have a significant effect on our consolidated financial statements or related disclosures.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

We have commodity price risk as a result of changes in the market value of our coal. We try to minimize this risk by entering into fixed price coal supply agreements and, from time to time, commodity hedge agreements. As of February 17, 2017, we had the following contracted minimum sales commitments for the years ending December 31, 2017 and 2018:

	Priced	Unpriced (or Index Based)	Total
		(Tons, in Millions)	
Year ending December 31, 2017	15.2	1.7	16.9
Year ending December 31, 2018	6.8	4.0	10.8

As of December 31, 2016, we have 0.5 million tons economically hedged with forward coal derivative contracts tied to the API 2 coal price index to partially mitigate coal price risk through 2017. The impact of our economic hedges to fix the selling price on unpriced (or index-based) coal sales contracts and forecasted sales is not reflected in the table above. A 10% change in the API 2 index would result in a $3.7 million change in the fair value of these derivative contracts.

Interest Rate Risk

We are exposed to market risk associated with interest rates due to our existing level of indebtedness. At December 31, 2016, of our $1,433.3 million in long-term debt and capital lease obligation principal outstanding, $662.4 million of outstanding borrowings have interest rates that fluctuate based on changes in market interest rates. We currently do not hedge the interest on portions of our borrowings with variable interest rates, although we may do so from time to time in order to manage risks associated with floating interest rates. A one percentage point increase in the interest rates related to variable interest borrowings would result in an annualized increase in interest expense of approximately $6.6 million.

As of December 31, 2016, we had cash and cash equivalents of $103.7 million. D ue to the short-term duration and the low risk profile of interest bearing cash accounts, we do not believe that a one percent change in interest rates would have a material impact on our interest income.

Credit Risk

We have credit risk associated with our customers and counterparties in our coal sales agreements, financing arrangements and commodity hedge contracts, including with our affiliates. We have procedures in place to assist in determining the creditworthiness and credit limits for such customers and counterparties. Generally, credit is extended based on an evaluation of the customer's financial condition. Collateral is not generally required, unless credit cannot be established. At December 31, 2016, no allowance was recorded for uncollectible accounts receivable as all amounts were deemed collectible.

Item 8. Financial Statements and Supplementary Data

EY Audit Opinion

Report of Independent Registered Public Accounting Firm

The Board of Directors of Foresight Energy GP LLC and
Unitholders of Foresight Energy LP

We have audited the accompanying consolidated balance sheets of Foresight Energy LP (the "Partnership") as of December 31, 2016 and 2015, and the related consolidated statements of operations, partners' capital (deficit), and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements and schedule 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as 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 Foresight Energy 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. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Ernst & Young LLP

St. Louis, Missouri
March 1, 2017

Foresight Energy LP
Consolidated Balance Sheets

	December 31, 2016	December 31, 2015
	(In Thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 103,690	$ 17,538
Accounts receivable	54,905	61,325
Due from affiliates	16,891	16,615
Financing receivables - affiliate	2,904	2,689
Inventories, net	43,052	50,652
Prepaid expenses	8,482	5,498
Prepaid royalties	3,136	5,386
Deferred longwall costs	13,310	18,476
Coal derivative assets	7,650	26,596
Other current assets	12,961	5,565
Total current assets	266,981	210,340
Property, plant, equipment and development, net	1,318,937	1,433,193
Due from affiliates	1,843	2,691
Financing receivables - affiliate	67,235	70,139
Prepaid royalties	13,765	70,300
Coal derivative assets	—	22,027
Other assets	20,250	12,493
Total assets	$ 1,689,011	$ 1,821,183
Liabilities and partners’ (deficit) capital		
Current liabilities:		
Current portion of long-term debt and capital lease obligations	$ 368,993	$ 1,434,566
Current portion of sale-leaseback financing arrangements	1,372	—
Accrued interest	29,760	24,574
Accounts payable	60,971	55,192
Accrued expenses and other current liabilities	43,592	35,807
Asset retirement obligations	7,273	18
Due to affiliates	20,904	8,536
Total current liabilities	532,865	1,558,693
Long-term debt and capital lease obligations	1,022,070	—
Sale-leaseback financing arrangements	190,497	193,434
Asset retirement obligations	37,644	43,277
Warrant liability	51,169	—
Other long-term liabilities	9,359	6,896
Total liabilities	1,843,604	1,802,300
Limited partners' capital (deficit):		
Common unitholders (66,105 and 65,192 units outstanding as of December 31, 2016 and 2015, respectively)	100,628	186,660
Subordinated unitholders (64,955 units outstanding as of December 31, 2016 and 2015)	(255,221)	(166,061)
Total limited partners' (deficit) capital	(154,593)	20,599
Noncontrolling interests	—	(1,716)
Total partners' (deficit) capital	(154,593)	18,883
Total liabilities and partners' (deficit) capital	$ 1,689,011	$ 1,821,183

See accompanying notes.

Foresight Energy LP
Consolidated Statements of Operations

	For the Year Ended December 31, 2016	2015	2014
	(In Thousands, Except per Unit Data)		
Revenues			
Coal sales	$ 866,628	$ 979,179	$ 1,109,404
Other revenues	9,204	5,674	—
Total revenues	875,832	984,853	1,109,404
Costs and expenses:			
Cost of coal produced (excluding depreciation, depletion and amortization)	423,995	509,170	449,905
Cost of coal purchased	13,541	17,444	18,232
Transportation	139,659	171,733	221,178
Depreciation, depletion and amortization	164,212	195,415	169,767
Accretion on asset retirement obligations	3,376	2,267	1,621
Selling, general and administrative	25,265	31,357	33,683
Long-lived asset impairments	74,575	12,592	34,700
Transition and reorganization costs	6,889	21,433	—
Loss (gain) on commodity derivative contracts	23,752	(45,691)	(76,330)
Other operating income, net	(22,161)	(13,424)	(2,837)
Operating income	22,729	82,557	259,485
Other expenses:			
Interest expense, net	149,201	117,311	113,030
Debt restructuring costs	21,821	3,930	—
Change in fair value of warrants	17,124	—	—
Loss on early extinguishment of debt	13,203	—	4,979
Net (loss) income	(178,620)	(38,684)	141,476
Less: net income attributable to noncontrolling interests	169	770	3,909
Net (loss) income attributable to controlling interests	(178,789)	(39,454)	137,567
Less: net income attributable to predecessor equity	—	23	67,375
Net (loss) income attributable to limited partner units	$ (178,789)	$ (39,477)	$ 70,192
Net (loss) income available to limited partner units - basic and diluted:			
Common unitholders	$ (90,015)	$ (16,043)	$ 35,154
Subordinated unitholders	$ (88,774)	$ (23,434)	$ 35,038
Net (loss) income per limited partner unit - basic and diluted:			
Common unitholders	$ (1.37)	$ (0.25)	$ 0.54
Subordinated unitholders	$ (1.37)	$ (0.36)	$ 0.54
Weighted average limited partner units outstanding - basic and diluted:			
Common units	65,829	65,098	64,790
Subordinated units	64,955	64,934	64,739
Distributions declared per limited partner unit	$ —	$ 1.17	$ 0.38

See accompanying notes.

Foresight Energy LP
Consolidated Statements of Partners' (Deficit) Capital

	Limited Partners						
	Common Unitholders	Number of Common Units	Subordinated Unitholders	Number of Subordinated Units	Predecessor Equity (Deficit)	Noncontrolling Interests	Total Partners' (Deficit) Capital
	(In Thousands, Except Unit Data)						
Balance at January 1, 2014	$ —	—	$ —	—	$ (104,407)	$ 9,244	$ (95,163)
Net income	35,154	—	35,038	—	67,375	3,909	141,476
Non-cash distributions	—	—	—	—	(12,187)	—	(12,187)
Contribution of net assets to Foresight Energy LP	(51,354)	—	(53,524)	—	104,878	—	—
Issuance of common units, net of offering costs	322,813	64,738,895	—	64,738,895	—	—	322,813
Cash distributions	(71,537)	—	(92,683)	—	(4,949)	(5,222)	(174,391)
Equity-based compensation	5,024	—	—	—	—	—	5,024
Issuance of equity-based awards	—	92,417	—	—	—	—	—
Distribution equivalent rights on LTIP awards	(231)	—	—	—	—	—	(231)
Net settlement of withholding taxes on issued LTIP awards	(944)	—	—	—	—	—	(944)
Balance at December 31, 2014	$ 238,925	64,831,312	$ (111,169)	64,738,895	$ 50,710	$ 7,931	$ 186,397
Net (loss) income	(16,043)	—	(23,434)	—	23	770	(38,684)
Capital contributions from Foresight Reserves LP	5,665	—	5,654	—	—	—	11,319
Contribution of net assets to Foresight Energy LP	25,643	—	34,988	—	(50,733)	(9,898)	—
Cash distributions	(79,733)	—	(72,100)	—	—	(519)	(152,352)
Equity-based compensation	13,704	—	—	—	—	—	13,704
Issuance of equity-based awards	—	361,077	—	215,796	—	—	—
Distribution equivalent rights on LTIP awards	(623)	—	—	—	—	—	(623)
Net settlement of withholding taxes on issued LTIP awards	(878)	—	—	—	—	—	(878)
Balance at December 31, 2015	$ 186,660	65,192,389	$ (166,061)	64,954,691	$ —	$ (1,716)	$ 18,883
Net (loss) income	(90,015)	—	(88,774)	—	—	169	(178,620)
Cash distributions	—	—	—	—	—	(182)	(182)
Deemed distribution - acquisition of variable interest entities	(922)	—	(907)	—	—	1,729	(100)
Capital contribution from Foresight Reserves LP	525	—	521	—	—	—	1,046
Equity-based compensation	5,106	—	—	—	—	—	5,106
Issuance of equity-based awards	—	912,284	—	—	—	—	—
Distribution equivalent rights on LTIP awards	84	—	—	—	—	—	84
Net settlement of withholding taxes on issued LTIP awards	(810)	—	—	—	—	—	(810)
Balance at December 31, 2016	$ 100,628	66,104,673	$ (255,221)	64,954,691	$ —	$ —	$ (154,593)

See accompanying notes.

Foresight Energy LP
Consolidated Statements of Cash Flows

	For the Year Ended December 31,		
	2016	2015	2014
	(In Thousands)		
Cash flows from operating activities			
Net (loss) income	$ (178,620)	$ (38,684)	$ 141,476
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation, depletion and amortization	164,212	195,415	169,767
Amortization of debt issuance costs and debt discount	12,580	6,878	7,022
Equity-based compensation	5,106	13,704	4,749
Loss (gain) on commodity derivative contracts	23,752	(45,691)	(76,330)
Settlements of commodity derivative contracts	12,644	61,223	19,204
Realized gains on commodity derivative contracts included in investing activities	—	(19,073)	(7,345)
Change in fair value of warrants	17,124	—	—
Long-lived asset impairments	74,575	12,592	34,700
Transition and reorganization expenses paid by Foresight Reserves (affiliate)	2,333	10,032	—
Current period interest expense converted into debt	31,484	—	—
Non-cash debt extinguishment expense	11,124	—	4,681
Other	4,897	5,208	2,097
Changes in operating assets and liabilities:			
Accounts receivable	6,420	19,586	(21,921)
Due from/to affiliates, net	12,940	(25,345)	5,930
Inventories	7,858	27,994	(13,787)
Prepaid expenses and other current assets	(7,608)	(250)	(7,807)
Prepaid royalties	(15,790)	(18,945)	(23,475)
Commodity derivative assets and liabilities	3,938	(1,911)	(1,891)
Accounts payable	5,779	(5,014)	9,424
Accrued interest	22,905	(562)	(2,509)
Accrued expenses and other current liabilities	5,537	874	1,189
Other	2,030	2,381	(4,392)
Net cash provided by operating activities	225,220	200,412	240,782
Cash flows from investing activities			
Investment in property, plant, equipment and development	(54,584)	(85,026)	(229,725)
Investment in financing arrangements with Murray Energy (affiliate)	—	(75,000)	—
Settlement of certain coal derivatives	—	19,073	7,345
Return of investment on financing arrangements with Murray Energy (affiliate)	2,689	2,172	—
Acquisition of an affiliate	(100)	—	(3,822)
Proceeds from sale of equipment	4,366	—	1,619
Net cash used in investing activities	(47,629)	(138,781)	(224,583)
Cash flows from financing activities			
Net change in borrowings under revolving credit facility	—	33,000	60,500
Net change in borrowings under A/R securitization program	(26,800)	41,000	—
Proceeds from other long-term debt and capital lease obligations	—	59,325	85,620
Payments on other long-term debt and capital lease obligations	(45,692)	(44,440)	(307,607)
Payments on short-term debt	(739)	(2,559)	—
Distributions paid	(182)	(152,352)	(174,391)
Proceeds from issuance of common units (net of underwriters' discount)	—	—	329,875
Initial public offering costs paid (other than underwriters' discount)	—	—	(7,206)
Debt issuance costs paid	(15,735)	(2,751)	(297)
Other	(2,291)	(1,825)	(971)
Net cash used in financing activities	(91,439)	(70,602)	(14,477)
Net increase (decrease) in cash and cash equivalents	86,152	(8,971)	1,722
Cash and cash equivalents, beginning of period	17,538	26,509	24,787
Cash and cash equivalents, end of period	$ 103,690	$ 17,538	$ 26,509

See accompanying notes.

Notes to Consolidated Financial Statements

1. Organization and Basis of Presentation

Foresight Energy LLC ("FELLC"), a perpetual-term Delaware limited liability company, was formed in September 2006 for the development, mining, transportation and sale of coal. Prior to June 23, 2014, Foresight Reserves, LP ("Foresight Reserves") owned 99.333% of FELLC and a member of FELLC's management owned 0.667%. On June 23, 2014, in connection with the initial public offering ("IPO") of Foresight Energy LP ("FELP"), Foresight Reserves and a member of management contributed their ownership interests in FELLC to FELP for which they were issued common and subordinated units in FELP. FELP has been managed by Foresight Energy GP LLC ("FEGP") since the IPO. On April 16, 2015, Murray Energy Corporation ("Murray Energy") and Foresight Reserves completed a transaction whereby Murray Energy acquired a 34% noncontrolling economic interest in FEGP and all of the outstanding subordinated units of FELP, representing a 50% ownership percentage of the Partnership's limited partner units.

As used hereafter in this report, the terms "Foresight Energy LP," "FELP," the "Partnership," "we," "us" or like terms, refer to the combined consolidated results of Foresight Energy LP, and FELLC and its consolidated subsidiaries and affiliates, unless the context otherwise requires or where otherwise indicated. The information presented in this Annual Report on Form 10-K contains, for all periods presented, the combined consolidated financial results of Foresight Energy LP, FELLC, and VIEs for which FELLC or its subsidiaries are the primary beneficiary.

The Partnership operates in a single reportable segment and currently has four underground mining complexes in the Illinois Basin: Williamson Energy, LLC ("Williamson"); Sugar Camp Energy, LLC ("Sugar Camp"); Hillsboro Energy, LLC ("Hillsboro"); and Macoupin Energy, LLC ("Macoupin"). Mining operations at our Hillsboro complex have been idled since March 2015 due to a combustion event (the "Hillsboro combustion event"). We are uncertain as to when production will resume at this operation. Our mined coal is sold to a diverse customer base, including electric utility and industrial companies primarily in the eastern half of the United States, as well as overseas markets. Intercompany transactions, including those between consolidated VIEs, and FELP and its consolidated subsidiaries, are eliminated in consolidation.

2. Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles ("U.S. GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of income and loss during the reporting period. Actual results could differ from those estimates.

Revenue Recognition

Once mines are in production, coal sales include sales to customers of coal produced and, from time to time, the re-sale of coal purchased from third parties or from one of our affiliates. The Partnership recognizes sales at the time legal title and risk of loss pass to the customer at contracted amounts that are fixed or determinable. For domestic coal sales, this generally occurs when coal is loaded onto railcars at the mine or onto barges at terminals. For coal sales to international markets, this generally occurs when coal is loaded onto an ocean vessel. Quality and weight adjustments are recorded as necessary based on contract specifications as a reduction or increase to coal sales and accounts receivable.

Transportation Expenses

Costs related to the handling and transporting of coal to the point of sale are included in coal inventory in the consolidated balance sheets. Upon the recognition of the sale, these costs are included in transportation expenses in the consolidated statements of operations.

Cash and Cash Equivalents

The Partnership considers cash deposits with original maturities of less than three months to be cash and cash equivalents. Cash and cash equivalents are stated at cost, which approximates fair value.

Allowance for Doubtful Accounts

The Partnership evaluates the need for an allowance for uncollectible receivables based on a review of account balances that are likely to be uncollectible, as determined by such variables as customer creditworthiness, the age of the receivables and disputed amounts. Historically, credit losses have been insignificant. At December 31, 2016 and 2015, no allowance was recorded for uncollectible accounts receivable as all amounts were deemed collectible.

Inventories, Net

Inventories are valued at the lower of average cost or market. Parts and supplies inventory consists of spare parts for equipment and supplies used in the mining process. A reserve is established for items determined to be obsolete or in excess of quantities needed. Raw coal represents coal stockpiles that require processing through a preparation plant prior to shipment to a customer. Clean coal represents coal stockpiles that will be sold in its current condition. Coal inventory costs include labor, equipment costs, supplies, transportation costs incurred prior to the transfer of title to customers, depreciation, depletion, amortization and direct mine operating overhead.

Deferred Longwall Costs

The Partnership defers the direct costs associated with longwall moves, including longwall set-up costs, labor and supply costs to perform the move and refurbishment costs of longwall equipment. These deferred costs are expensed on a units-of-production basis into cost of coal produced (excluding depreciation, amortization and depreciation) over the panel benefited by these costs, which has historically approximated one year.

Prepaid Royalties

Prepaid royalties consist of recoupable minimum royalty payments due under various lease agreements entered into by the Partnership. Prepaid royalties expected to be recouped within one year are classified as current assets in the Partnership's consolidated balance sheets. The Partnership continually evaluates its ability to recoup prepaid royalty balances, which includes, among other factors, assessing mine production plans, sales commitments, future coal market conditions and remaining years available for recoupment. The contractual recoupment periods on the prepaid royalty balances generally range from five to ten years from the date the minimum royalty was paid.

Murray Energy Transport Lease and Overriding Royalty Agreements

In April 2015, American Century Transport LLC ("American Transport"), a subsidiary of the Partnership, entered into a purchase and sale agreement (the "PSA") with American Energy Corporation ("American Energy"), a subsidiary of Murray Energy, pursuant to which American Energy sold to American Transport certain mining and transportation assets for $63.0 million. Concurrent with the PSA, American Transport entered into a lease agreement (the "Transport Lease") with American Energy pursuant to which (i) American Transport leased to American Energy a tract of real property, two coal preparation plants and related coal handling facilities at the Transport Mine situated in Belmont and Monroe Counties, Ohio and (ii) American Transport receives from American Energy a fee ranging from $1.15 to $1.75 for every ton of coal mined, processed and/or transported using such assets, subject to a quarterly recoupable minimum fee of $1.7 million. The Transport Lease is being accounted for as a direct financing lease. The unearned income is reflected as other revenue over the term of the lease using the effective interest method. Any amounts in excess of the contractual minimums are recorded as other revenue when earned.

Also, in April 2015, American Century Minerals LLC ("Minerals"), a newly created subsidiary of the Partnership, entered into an overriding royalty agreement ("ORRA") with Murray Energy subsidiaries' American Energy and Consolidated Land Company (collectively, "AEC"), pursuant to which AEC granted to Minerals an overriding royalty interest ranging from $0.30 to $0.50 for each ton of coal mined, removed and sold from certain coal reserves situated near the Century Mine in Belmont and Monroe Counties, Ohio for $12.0 million. The ORRA is subject to a minimum recoupable quarterly fee of $0.5 million. This overriding royalty was accounted for as a financing arrangement. The payments the Partnership receives with respect to the ORRA are reflected partially as a return of the initial investment (reduction in the affiliate financing receivable) and partially as other revenue over the life of the agreement using the effective interest method. Any amounts in excess of the contractual minimums are recorded as other revenue when earned.

Property, Plant, Equipment and Development, Net

Property, plant and equipment are recorded at cost. Costs that extend the useful lives or increase the productivity of the assets are capitalized, while normal repairs and maintenance that do not extend the useful life or increase the productivity of the asset are expensed as incurred. Asset retirement obligations for the various assets have been recorded as components of the primary assets to which they relate. Interest costs applicable to major additions are capitalized during the construction period. Interest costs capitalized into property, plant, equipment and development, net for the years ended December 31, 2016, 2015, and 2014, were $0.5 million, $1.9 million, and $5.2 million, respectively. Property, plant and equipment are depreciated using the straight-line method over the estimated useful lives of the assets. Machinery and equipment under capital lease agreements are amortized using the straight-line method over the useful lives of the assets given that, in each case, ownership transfers at the end of the lease terms. The cost of acquiring land (subsidence) rights and mineral rights is amortized using the units-of-production method over the mineral reserves benefited by the costs. The estimated useful lives of machinery and equipment, buildings and structures and other categories are as follows:

Machinery and equipment	3–20 years
Buildings and structures	3–40 years
Other	3–20 years

Costs of developing new mines or expanding the capacity of existing mines are capitalized and amortized using the units-of-production method over the mineral reserves benefited by the development. Costs related to locating coal deposits and evaluating the economic viability of such deposits are expensed as incurred. During the development phase, the Partnership establishes access to the mineral reserves and makes other preparations for commercial production. Development costs principally include clearing land, building roads, sinking shafts, driving slopes and developing refuse areas, ventilation and transportation passageways at the mines. Development costs also include the build-out of the Partnership's transportation infrastructure. Costs incurred during the mine development phase are capitalized and proceeds from the incidental sale of coal during development are recorded as a reduction of the related mine development costs. For reporting in the statements of cash flows, cash expended in the investment in mining rights, equipment and development during the development phase is reported net of capitalized coal sales.

Impairment of Depreciable Assets

The Partnership records impairment losses on de preciable assets used in operations when events and circumstances indicate that assets might be impaired and the undiscounted cash flows estimated to be generated by those assets are less than their carrying amounts. Impairment losses are measured by comparing the estimated fair value of the impaired asset to its carrying amount. There were no impairment losses recorded on depreciable assets during the years ended December 31, 2016, 2015 and 2014.

Debt Issuance Costs

The Partnership capitalizes costs incurred in connection with the issuance of debt and the establishment of credit facilities and capital leasing arrangements. Debt financing costs related to revolving credit facilities are recorded as an asset in our consolidated balance sheets and deferred issuance costs related to non-revolving facilities is recorded as a contra to the debt balance. These costs are amortized as an adjustment to interest expense over the life of the borrowing or term of the credit facility using either the effective interest method or straight-line method, as applicable. Amortization expense of $7.5 million, $6.0 million and $6.1 million is included in interest expense for the years ended December 31, 2016, 2015, and 2014, respectively. As of December 31, 2016 and 2015, unamortized debt issuance costs were $19.3 million and $21.4 million, respectively.

Sale-Leaseback Financing Arrangements

The Partnership is party to two arrangements in which it sold assets to an affiliate and immediately leased those assets back from the affiliates. Because the Partnership has continued involvement in the assets sold, the proceeds received on the sale of the assets were recorded as long-term financing arrangements (liabilities) in our consolidated balance sheets. Under both of these arrangements, the Partnership pays a fixed minimum payment, as well as contingent payments for volumes in excess of the contractual minimum payments. Interest is accrued on the outstanding principal amounts of the financing arrangements using an implied interest rate, which was initially determined at inception of the lease and is adjusted for changes in expected amounts and timing of future payments based on the mine plans. Payments are first applied against accrued interest and any excess is applied against the outstanding principal. The Partnership accounts for such changes by adjusting in the current period, the life-to-date interest previously recorded on the sale-leaseback to reflect the new effective interest rate as if it was applied from the inception of the transaction (i.e., retroactively applied). If there is a material change to the mine plans, the impact of a change in the effective interest rate to the consolidated statements of operations could be significant.

Asset Retirement Obligations

The Partnership's asset retirement obligations ("ARO") consist primarily of spending estimates related to reclaiming surface land, refuse areas, slurry ponds and support facilities at the Partnership's underground mines in accordance with federal and state reclamation laws as required by each mining permit. These obligations are typically incurred at the time development of a mine commences for underground mines or when construction begins for support facilities, refuse areas and slurry ponds. The Partnership estimates its ARO for final reclamation and mine closure based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and a market risk premium and then discounted at a credit-adjusted, risk-free rate. Upon initial recognition of a liability, a corresponding amount is capitalized as part of the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value and the capitalized cost is amortized over the useful life of the related asset on a units-of-production basis. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free interest rate.

Derivative Financial Instruments

The Partnership from time to time utilizes derivative financial instruments principally to manage exposures to non-domestic coal prices. The Partnership records the fair value of each instrument as either an asset or liability in the consolidated balance sheets and the change in fair value of each instrument is recorded in the consolidated statements of operations.

Coal contracts provide for the physical purchase or sale of coal in quantities expected to be used or sold by the Partnership over a reasonable period in the normal course of business, and are not recognized in the consolidated balance sheets.

Warrant Liability

Our warrant liability is required to be accounted for at fair value and the fair value must be revalued at each balance sheet date until the earlier of the exercise of the warrants, their expiration, or until any of the features requiring liability treatment expires or is modified. The resulting non-cash gain or loss on the fair value revaluation at each balance sheet date is recorded as non-operating expense (income) in our consolidated statements of operations.

Fair Value

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a given measurement date. Valuation techniques used must maximize the use of observable inputs and minimize the use of unobservable inputs. A fair value hierarchy has been established that prioritizes the inputs to valuation techniques used to measure fair value.

The hierarchy, as defined below, gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs.

Level 1 is defined as observable inputs, such as quoted prices in active markets for identical assets.

Level 2 is defined as observable inputs other than Level 1 prices. These include quoted prices for similar assets or liabilities in an active market, quoted prices for identical assets and liabilities in markets that are not active, or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.

Level 3 is defined as unobservable inputs in which little or no market data exists, therefore, requiring an entity to develop its own assumptions.

The carrying value of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term nature of these instruments.

Variable Interest Entities (VIEs)

VIEs are primarily entities that lack sufficient equity to finance their activities without additional financial support from other parties or whose equity holders, as a group, lack one or more of the following characteristics: (a) direct or indirect ability to make decisions, (b) obligation to absorb expected losses or (c) right to receive expected residual returns. VIEs must be evaluated quantitatively and qualitatively to determine the primary beneficiary, which is the reporting entity that has (a) the power to direct activities of a VIE that most significantly impact the VIEs economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. The primary beneficiary is required to consolidate the VIE for financial reporting purposes.

To determine a VIE's primary beneficiary, the Partnership performs a qualitative assessment to determine which party, if any, has the power to direct activities of the VIE and the obligation to absorb losses and/or receive its benefits. This assessment involves identifying the activities that most significantly impact the VIE's economic performance and determine whether it, or another party, has the power to direct those activities. When evaluating whether the Partnership is the primary beneficiary of a VIE, the Partnership performs a qualitative analysis that considers the design of the VIE, the nature of the Partnership’s involvement and the variable interests held by other parties. If that evaluation is inconclusive as to which party absorbs a majority of the entity’s expected losses or residual returns, a quantitative analysis would be performed to determine the primary beneficiary. The income attributable to consolidated variable interest entities is recorded as net income attributable to noncontrolling interests in the consolidated statements of operations.

Income Taxes

We are not a taxable entity for federal or state income tax purposes; the tax effect of our activities accrues to the unitholders. While Section 7704(a) of the tax code generally provides that publicly traded partnerships will be treated as corporations for federal income tax purposes, if 90% or more of a partnership's gross income for every taxable year it is publicly traded consists of "qualifying income," the partnership may continue to be treated as a partnership for federal income tax purposes (the "Qualifying Income Exception"). Qualifying income includes income and gains derived from the mining, transportation and marketing of minerals and natural resources, such as coal. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income.

We currently meet the Qualifying Income Exception and expect to continue to qualify prospectively for this exception. As such, each of our unitholders will take into account their respective share of our items of income, gain, loss and deduction in computing their federal income tax liability as if the unitholder had earned such income directly, even if we make no cash distributions to the unitholder. Distributions we make to a unitholder generally will not give rise to income or gain taxable to such unitholder, unless the amount of cash distributed exceeds the unitholder's adjusted tax basis. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. Individual unitholders have different investment basis depending upon the timing and price of acquisition of their partnership units. Furthermore, each unitholder's tax accounting methods, which are partially dependent upon the unitholder's tax position, differs from the accounting methods followed in our consolidated financial statements. Accordingly, the aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder's tax attributes in our partnership is not available to us.

Our tax counsel provided an opinion at the time of the IPO that FELP will be treated as a partnership. However, as is customary, no ruling has been or will be requested from the Internal Revenue Service ("IRS") regarding our classification as a partnership for federal income tax purposes.

FELLC, its subsidiaries and controlled entities were established as limited liability companies, and thus for federal and, if applicable, state and local income tax purposes, are treated as pass-through entities. Therefore, no provision for income taxes was included in the consolidated financial statements.

Supplemental Cash Flow Information

The following is supplemental information to the consolidated statements of cash flows:

	For the Year Ended December 31,		
	2016	2015	2014
		(In Thousands)	
Supplemental disclosure of cash flow information:			
Cash interest paid, net of amount capitalized	$ 80,542	$ 111,155	$ 108,517
Supplemental disclosure of noncash investing and financing activities:			
Interest converted into debt	$ 49,203	$ —	$ —
Fair value of warrants issued	$ 34,045	$ —	$ —
Noncash capital contribution from Foresight Reserves LP (affiliate)	$ 1,046	$ 11,319	$ —
Noncash member distribution to Foresight Reserves	$ —	$ —	$ 12,187
Modifications to capital lease obligations	$ 663	$ —	$ —
Short-term insurance financing	$ 4,252	$ 2,806	$ —

Newly Adopted Accounting Standards

In April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-06, *Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions* . ASU 2015-06 specifies that for purposes of calculating historical earnings per unit under the two-class method, the earnings of a transferred business before the date of a dropdown transaction should not be allocated to the limited partnership and therefore earnings per unit of the limited partners would not change as a result of the dropdown transaction. We adopted ASU 2015-06 during 2016 and it did not have an effect on our consolidated financial statements or related disclosures.

In April 2015, the FASB issued ASU 2015-03, *Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs* . ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. We adopted ASU 2015-03 on a retrospective basis during 2016. The adoption of ASU 2015-03 did not affect our results of operations or cash flows, but it required us to reclassify the deferred financing costs associated with certain of our long-term debt. We reclassified approximately $15.9 million of our deferred financing costs as of December 31, 2015 to long-term debt and capital lease obligations in our consolidated balance sheet to adhere to ASU 2015-03. The deferred financing costs associated with our revolving credit facility and trade A/R securitization program continue to be presented as an asset on the consolidated balance sheets.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows: Classification of Certain Cash Receipts and Payments* , which provides guidance on eight specific cash flow issues with the objective of reducing diversity in practice. The guidance is effective for interim and annual periods beginning after December 15, 2017. We early adopted this standard during the current year and as a result presented all cash costs for debt prepayment and debt extinguishment as cash outflows from financing activities. The prior periods presented had no such cash costs which required reclassification as a result of adoption of this standard.

In August 2014, the FASB issued ASU 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* , which requires management of the entity to evaluate whether there is substantial doubt about the entity's ability to continue as a going concern. This ASU was effective for the annual reporting period ending after December 15, 2016. We adopted this standard and it did not have an impact on our consolidated financial statements or disclosures given the completion of the debt restructuring in August 2016 and the Partnership's financial condition and expected operating outlook at the time of adoption.

New Accounting Standards Issued and Not Yet Adopted

In January 2017, the FASB issued ASU 2017-01, which clarifies the definition of a business to assist entities with evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. This standard is effective for fiscal years beginning after December 15, 2017. We do not expect this new guidance to have a material impact on our consolidated financial statements.

In November 2016, the FASB issued ASU 2016-18 which clarifies the presentation requirement of restricted cash within the statement of cash flows. Under ASU 2016-18, the changes in restricted cash and restricted cash equivalents during the period should be included in the beginning and ending cash and cash equivalents balance reconciliation on the statement of cash flows. When cash, cash equivalents, restricted cash or restricted cash equivalents are presented in more than one line item within the statement of financial position, an entity shall calculate a total cash amount in a narrative or tabular format that agrees to the amount shown on the statement of cash flows. Details on the nature and amounts of restricted cash should also be disclosed. This standard is effective for fiscal years beginning after December 15, 2017. We expect this new guidance to require adjustments to the presentation of our consolidated financial statements. As of December 31, 2016, we had restricted cash of $13.3 million, of which $10.7 million is included in current assets and $2.6 million is included in other long-term assets.

In March 2016, the FASB issued ASU 2016-09, *Compensation – Stock Compensation,* which was issued to simplify the accounting for share-based payment transactions, including income tax consequences, the classification of awards as equity or liabilities, an option to recognize gross equity-based compensation expense with actual forfeitures recognized as they occur and the classification on the statement of cash flows. This pronouncement is effective for reporting periods beginning after December 15, 2016. We do not expect the adoption of this update to have a material impact on our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09 that introduces a new five-step revenue recognition model in which 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. This ASU also requires disclosures sufficient to enable users to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers, including qualitative and quantitative disclosures about contracts with customers, significant judgments and changes in judgments, and assets recognized from the costs to obtain or fulfill a contract. In July 2015, the FASB delayed the effective date until annual and interim periods beginning after December 31, 2017. We intend to adopt ASU 2014-09 as of January 1, 2018 using the modified retrospective approach. While we have not yet completed our review of the impact of the new standard, we do not currently anticipate a material impact on our revenue recognition practices. We are still evaluating disclosure requirements under the new standard and we will continue to evaluate the standard as well as additional changes, modifications or interpretations which may impact our current conclusions.

In February 2016, the FASB updated guidance regarding the accounting for leases. This update requires lessees to recognize a lease liability and a lease asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The update also expands the required quantitative and qualitative disclosures surrounding leases. This update is effective for fiscal years beginning after December 15, 2018 and interim periods within those fiscal years, with earlier application permitted. This update will be applied using a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We are currently evaluating the effect of this update on our consolidated financial statements.

In July 2015, the FASB issued ASU 2015-11, *Inventory: Simplifying the Measurement of Inventory* , which simplifies the measurement of inventories valued under most methods. Under this new guidance, inventories valued under these methods would be valued at the lower of cost and net realizable value, with net realizable value defined as the estimated selling price less reasonable costs to sell the inventory. The new guidance is effective prospectively for fiscal periods starting after December 15, 2016 and early adoption is permitted. We do not expect the adoption of ASU 2015-11 to have a significant effect on our consolidated financial statements or related disclosures.

3. Restructuring Transactions

On December 4, 2015, the Delaware Court of Chancery issued a memorandum opinion concluding, among other things, that the purchase and sale agreement between Foresight Reserves and Murray Energy (see Note 15) constituted a change of control under the indenture (the “2021 Senior Notes Indenture”) governing our 7.875% Senior Notes due 2021 (the “2021 Senior Notes”) and that an event of default occurred under the 2021 Senior Notes Indenture when we failed to offer to purchase the 2021 Senior Notes on or about May 18, 2015 (the “2015 Delaware Court of Chancery change-of-control litigation”). Because of the existence of “change of control” provisions and cross-default or cross-event of default provisions in our debt agreements, the purchase and sale agreement between Foresight Reserves and Murray Energy also resulted, directly or indirectly, in events of default under FELLC’s credit agreement governing its senior secured credit facilities (the “Credit Agreement”), Foresight Receivables LLC’s securitization program and certain other financing arrangements, including our longwall financing arrangements. The existence of an event of default prohibited us access to borrowings or other extensions of credit under our revolving credit facility and our failure to pay the semi-annual interest payments on the 2021 Senior Notes of $23.6 million due on February 15, 2016 and August 15, 2016 resulted in additional events of default.

On August 30, 2016 (the “Closing Date”), we completed a global restructuring of our indebtedness. The restructuring transactions (the “Restructuring Transactions”) alleviated existing defaults and events of default across the Partnership’s capital structure that resulted from the 2015 Delaware Court of Chancery change-of-control litigation related to the purchase and sale agreement between Foresight Reserves and Murray Energy. See Notes 10 and 15 for additional discussion on the debt restructuring and certain governance and other matters impacted by the Restructuring Transactions.

During the years ended December 31, 2016 and 2015, we incurred legal and financial advisor fees of $21.8 million and $3.9 million, respectively, related to the above issues, which have been recorded as debt restructuring costs in the consolidated statements of operations.

4. Transition and Reorganization Costs

In April 2015, in connection with Murray Energy acquiring an ownership interest in the Partnership and its general partner, we entered into a Management Services Agreement (the “MSA”) with Murray American Coal Inc. (the “Manager”), a subsidiary of Murray Energy, with the intent of optimizing and reorganizing certain corporate administrative functions and generating synergies between the two companies through the elimination of headcount and duplicate selling, general and administrative expenses (see Note 15). The costs were primarily comprised of retention compensation to certain employees during the transition period and termination benefits to employees whose positions were eliminated as a result of the MSA. Transition and reorganization costs were comprised of the following for the years ended December 31, 2016, 2015 and 2014:

	For the Year Ended December 31,		
	2016	2015	2014
		(In Thousands)	
Retention compensation paid by Foresight Reserves and pushed down to FELP	$ 2,333	$ 10,032	$ —
Equity-based compensation	4,315	4,322	—
Cash retention and termination benefits	—	5,878	—
Legal and other charges	241	1,201	—
Transition and reorganization costs	$ 6,889	$ 21,433	$ —

5. Commodity Derivative Contracts

The Partnership has commodity price risk for its coal sales as a result of changes in the market value of its coal. To minimize this risk, we enter into long-term, fixed price coal supply sales agreements and coal derivative swap contracts.

As of December 31, 2016 and 2015, we had outstanding coal derivative swap contracts to fix the selling price on 0.5 million tons and 1.1 million tons, respectively. Swaps are designed so that the Partnership receives or makes payments based on a differential between fixed and variable prices for coal. The coal derivative contracts are economic hedges to certain future unpriced (indexed) sales commitments and expected sales through 2017. The coal derivative swap contracts are indexed to the Argus API 2 price index, the benchmark price for coal imported into northwest Europe. The coal derivative contracts are accounted for as freestanding derivatives and any gains or losses resulting from adjusting these contracts to fair value are recorded into earnings. We record the fair value of all positions with a given counterparty on a gross basis in the consolidated balance sheets (see Note 17).

We have diesel fuel price exposure in our transportation and production processes and therefore are subject to commodity price risk as a result of changes in the market value of diesel fuel. During the years ended December 31, 2016 and 2015 , to limit our exposure to diesel fuel price volatility, we had swap agreements with financial institutions which provided a fixed price per unit for the volume of purchases being hedged. As of December 31, 2016, we had no diesel swap agreements outstanding .

We have master netting agreements with all of our counterparties that allow for the settlement of contracts in an asset position with contracts in a liability position in the event of default. We manage counterparty risk through the utilization of investment grade commercial banks, diversification of counterparties and our counterparty netting arrangements.

The settlements of commodity derivative contracts and (loss) gain on commodity derivative contracts for the years ended December 31, 2016, 2015 and 2014 are as follows:

	For the Year Ended December 31,		
	2016	2015	2014
		(In Thousands)	
Settlements of commodity derivative contracts	$ 12,644	$ 61,223	$ 19,204
(Loss) gain on commodity derivative contracts	$ (23,752)	$ 45,691	$ 76,330

We received $19.1 million and $7.3 million in proceeds during the years ended December 31, 2015 and 2014, respectively, from the settlement of derivatives that were reclassified from an operating cash flow activity to an investing activity in the consolidated statements of cash flows because the derivative contracts were settled prior to the expiration of their contractual maturities and prior to the delivery date of the underlying sales contracts.

6. Accounts Receivable

Accounts receivable consists of the following:

	December 31, 2016	December 31, 2015
	(In Thousands)	
Trade accounts receivable	$ 42,862	$ 56,013
Other receivables	12,043	5,312
Total accounts receivable	$ 54,905	$ 61,325

7. Inventories, Net

Inventories, net consist of the following:

	December 31, 2016	December 31, 2015
	(In Thousands)	
Parts and supplies	$ 18,712	$ 24,276
Raw coal	4,907	1,906
Clean coal	19,433	24,470
Total inventories, net	$ 43,052	$ 50,652

8. Property, Plant, Equipment and Development, Net

Property, plant, equipment and development, net consist of the following:

	December 31, 2016	December 31, 2015
	(In Thousands)	
Land, land rights and mineral rights	$ 99,909	$ 99,676
Machinery and equipment	1,186,450	1,140,256
Machinery and equipment under capital leases	102,662	126,401
Buildings and structures	246,132	248,946
Development costs	774,297	750,177
Other	9,156	9,369
Property, plant, equipment and development	2,418,606	2,374,825
Less: accumulated depreciation, depletion and amortization	(1,099,669)	(941,632)
Property, plant, equipment and development, net	$ 1,318,937	$ 1,433,193

9. Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities consist of the following:

	December 31, 2016	December 31, 2015
	(In Thousands)	
Employee compensation, benefits and payroll taxes	$ 13,065	$ 12,393
Taxes other than income	6,819	6,560
Liquidated damages	5,828	6,404
Litigation reserve	4,800	2,347
Royalties (non-affiliate)	4,117	3,707
Other	8,963	4,396
Total accrued expenses and other current liabilities	$ 43,592	$ 35,807

10. Long-Term Debt and Capital Lease Obligations

Long-term debt and capital lease obligations consist of the following:

	December 31, 2016	December 31, 2015
	(In Thousands)	
2021 Second Lien Notes	$ 349,100	$ —
2017 Exchangeable PIK Notes	299,859	—
2021 Senior Notes	—	600,000
Revolving Credit Facility	352,500	352,500
Term Loan	295,667	297,750
Trade A/R Securitization Program	14,200	41,000
5.78% longwall financing arrangement	39,217	50,423
5.555% longwall financing arrangement	41,250	51,563
Capital lease obligations	41,457	62,710
Subtotal - Total principal outstanding on long-term debt and capital lease obligations	1,433,250	1,455,946
Unamortized deferred financing costs and debt discounts	(42,187)	(21,380)
Total long-term debt and capital lease obligations	1,391,063	1,434,566
Less: current portion	(368,993)	(1,434,566)
Non-current portion of long-term debt and capital lease obligations	$ 1,022,070	$ —

On August 30, 2016, we completed a global restructuring of our indebtedness. The Restructuring Transactions described below alleviated the then existing defaults and events of default across the Partnership's capital structure that resulted from the 2015 Delaware Court of Chancery change-of-control litigation. As a result of the Restructuring Transactions and the resolution of the 2015 Delaware Court of Chancery change-of-control litigation, certain of our outstanding long-term debt and capital lease obligations are no longer reflected as a current liability in the consolidated balance sheets and we are no longer subject to default interest rates.

Also, as a result of the Restructuring Transactions, a loss on the early extinguishment of debt of $13.2 million was recognized during the year ended December 31, 2016 for the write-off of $11.0 million of unamortized debt discount and debt issuance costs associated with the extinguishment of our 7.875% Senior Notes due 2021 and the reduction in borrowing capacity under our Revolving Credit Facility and due to the incurrence of $2.2 million in costs related to the modification of our debt which were expensed in accordance with the authoritative accounting literature on debt modifications. Lender and third-party professional fees totaling $13.5 million were deferred and will be amortized over the remaining lives of the respective debt instruments.

Exchange of 2021 Senior Notes for New Notes and Warrants

On the Closing Date, the Partnership exchanged $599.8 million in aggregate principal amount of our 2021 Senior Notes and the accrued and unpaid interest thereon for the following consideration:

- (i) $349.1 million in aggregate principal of Senior Secured Second Lien PIK Notes due 2021 (the "Second Lien Notes");
- (ii) $299.9 million in aggregate principal of Senior Secured Second Lien Exchangeable PIK Notes due 2017 (the "Exchangeable PIK Notes," and, together with the Second Lien Notes, the "New Notes"); and
- (iii) 516,825 warrants (the "Warrants") to acquire newly issued common units of FELP (the "Common Units") equal to 4.5% of the total limited partner units of FELP outstanding on the date of a Note Redemption (as defined below) (after giving effect to the full exercise thereof and the Note Redemption).

On the Closing Date, we also redeemed the remaining $175,000 in aggregate principal amount of 2021 Senior Notes that were not exchanged. Upon such redemption, the obligations under the 2021 Senior Notes and the 2021 Senior Notes Indenture were satisfied and discharged.

A liability of $34.0 million for the fair value of the Warrants was recorded in our consolidated balance sheet as of the Closing Date and the offset was recognized as a debt discount to the New Notes. The discount was allocated pro rata between the Second Lien Notes and the Exchangeable PIK Notes in proportion to the relative fair value of each instrument held by a person other than the Reserves Investor Group (as defined in Note 15) on the Closing Date (only the unaffiliated holders of the New Notes received the Warrants on the Closing Date). The $25.0 million discount allocated to the Second Lien Notes and the $9.0 million discount allocated to the Exchangeable PIK Notes is being amortized using the effective interest method over their respective maturities.

Terms of the New Notes

The Second Lien Notes were issued pursuant to an indenture and have a maturity date of August 15, 2021. The Second Lien Notes bear interest at a rate of: (i) 9.0% per annum until August 15, 2018 and 10.0% per annum thereafter, in each case, payable in cash on each interest payment date; and (ii) 1.0% per annum payable in kind. Interest is payable semi-annually on February 15th and August 15th, commencing on February 15, 2017. Interest expense on the Second Lien Notes is being recorded such that a constant effective interest rate is recognized over the duration of the notes. The Partnership may redeem the Second Lien Notes in whole or in part subject to the redemption premiums and provisions in the indenture.

The Exchangeable PIK Notes were issued pursuant to an indenture (the "Exchangeable PIK Notes Indenture) and have a maturity date of October 3, 2017 (the "Exchangeable PIK Notes Maturity Date"). The Exchangeable PIK Notes bear interest payable in kind at a rate of 15.0% per annum, payable on March 1, 2017 and October 3, 2017.

We may redeem, repurchase, refinance, defease or otherwise retire (any of the foregoing, a "redemption") all of the Exchangeable PIK Notes on or prior to October 2, 2017 for cash at 100% of the principal amount thereof plus accrued interest (any such redemption, an "Exchangeable PIK Note Retirement"). In addition to the Exchangeable PIK Note Retirement, Murray Energy, an affiliate of Murray Energy or a group of persons which includes Murray Energy or any of its affiliates (collectively, the "Murray Group") shall have the right to purchase all (but not less than all) of the Exchangeable PIK Notes on or prior to October 2, 2017 for cash at a price equal to 100% of the principal amount of the Exchangeable PIK Notes plus accrued interest (a "Murray Purchase," and together with an Exchangeable PIK Note Retirement and any repayment of the Exchangeable PIK Notes in full in cash that occurs on the Exchangeable PIK Notes Maturity Date, a "Note Redemption"). Upon a Murray Purchase, the Murray Group will receive FELP units equal to the principal and interest settlement amount multiplied by the lesser of: (a) a number equal to one divided by 92.5% of the last thirty days weighted-average trading price or (b) 1.12007 common units per $1.00 principal amount of Exchangeable PIK Notes. The Partnership and Murray Energy may each purchase less than all of the outstanding Exchangeable PIK Notes, so long as the combination results in redemption of all of the Exchangeable PIK Notes. The Exchangeable PIK Note Retirement may be funded with the proceeds from an investment by the Murray Group or any member thereof in FELP, from general working capital or from any other source permitted by the Exchangeable PIK Notes Indenture (and subject to compliance with the Partnership's other debt agreements). If the Exchangeable PIK Notes have not been redeemed or purchased for cash at 100% of the principal amount thereof plus accrued interest by the Exchangeable PIK Notes Maturity Date, then all outstanding Exchangeable PIK Notes (including all principal, interest and other amounts outstanding thereunder) shall be exchanged for common units representing 75% of FELP's outstanding limited partner units on the Exchangeable PIK Notes Maturity Date, subject to adjustment on account of certain anti-dilution protections.

The obligations under the New Notes are unconditionally guaranteed on a senior secured basis by each of FELP's wholly owned domestic subsidiaries that guarantee the Senior Secured Credit Facilities (other than Foresight Energy Finance Corporation) and on a senior unsecured basis by FELP and are or will be secured by second-priority perfected liens on substantially all of our and the subsidiary guarantors' existing and future assets, subject to certain exceptions.

Senior Secured Credit Facilities

On the Closing Date, FELLC entered into an amendment to its senior secured credit facilities (as amended, the "Senior Secured Credit Facilities"), pursuant to which outstanding defaults under its existing credit agreement were waived and the credit agreement was amended and restated as set forth in the third amended and restated credit agreement (the "Amended Credit Agreement"). Pursuant to the Amended Credit Agreement, $297.8 million in term loans remained outstanding on the Closing Date and mature in August 2020 (the "Term Loan") and the commitments under our $550.0 million revolving credit facility (the "Revolving Credit Facility"), which terminates in August 2018, was reduced to $450.0 million on December 31, 2016. The Amended Credit Agreement also adds an anti-hoarding provision under our Revolving Credit Facility which prohibits new borrowings if the aggregate amount of our unrestricted cash and cash equivalents (taking into account certain pending applications of cash) exceeds $35.0 million both before and after giving effect to such borrowings when taking into account the intended use of such loan proceeds for bona fide purposes within 60 days. Mandatory term loan prepayments are required to be made based on an excess cash flow calculation, as defined by the Amended Credit Agreement, for the second half of fiscal year 2016 and full fiscal year 2017, sales of assets, certain proceeds from net insurance recoveries and condemnation awards and certain incurrence of indebtedness, subject, in each case, to customary exceptions and thresholds. The excess cash flow generated during the second half of fiscal year 2016 and business interruption insurance recoveries from the Hillsboro combustion event require that we prepay $26.9 million of Term Loan principal, $2.1 million of which was paid in 2016 and the remainder is due during the first quarter of 2017.

Under the Amended Credit Agreement, borrowings under our Revolving Credit Facility bear interest at a rate equal to, at our option: (i) LIBOR (subject to a LIBOR floor of 0%) plus an applicable margin ranging from 3.50% to 4.50%; or (ii) a base rate plus an applicable margin ranging from 2.50% to 3.50%; in each case, determined in accordance with our consolidated net leverage ratio. Our Term Loans bear interest of a rate equal to, at our option: (i) LIBOR (subject to a LIBOR floor of 1.00%) plus 5.50%; or (ii) a base rate plus 4.50%. We are also required to pay a commitment fee of 0.50% to the lenders under the Revolving Credit Facility in respect of unutilized commitments thereunder and pay a fronting fee equal to 0.125% per annum of the amount available to be drawn under letters of credit. As of December 31, 2016, we had $352.5 million in borrowings outstanding under the Revolving Credit Facility and $7.0 million in letters of credit. As of December 31, 2016, the weighted-average interest rate on Revolving Credit Facility and Term Loan borrowings was 5.3% and 6.5%, respectively.

The obligations under the Senior Secured Credit Facilities are unconditionally guaranteed on a senior unsecured basis by FELP and on a senior secured basis by our direct and indirect domestic subsidiaries and are or will be secured by first-priority perfected liens on substantially all of our and the subsidiary guarantors' existing and future assets, subject to certain exceptions.

The Senior Secured Credit Facilities require that we comply on a quarterly basis with certain financial covenants, including a minimum consolidated interest coverage ratio of 2.00:1.00 and a maximum senior secured net leverage ratio ranging from 3.50:1.00 for the fiscal quarter ended December 31, 2016 to 2.75:1.00 for the fiscal quarter ending March 31, 2021 and thereafter. Our Senior Secured Credit Facilities prohibit certain restricted payments, including discretionary dividends, until the later to occur of: (i) June 30, 2018 and (ii) the date on which our obligations under our revolving credit facility have been paid in full, after which restricted payments can be made of up to $25.0 million per year, subject to certain adjustments and exceptions.

The Senior Secured Credit Facilities also require compliance with certain covenants that significantly restricts our ability to, among other things, (i) incur additional indebtedness, (ii) incur liens, (iii) pay dividends or make certain other restricted payments, investments or acquisitions, (iv) enter into certain transactions with affiliates, (v) merge or consolidate with another person, (vi) sell, assign, lease or otherwise dispose of all or substantially all of our assets, and (vii) make voluntary prepayments of certain debt, in each case subject to exceptions.

Longwall Financing Arrangements and Capital Lease Obligations

In January 2010, Sugar Camp Energy LLC entered into a credit agreement with a financial institution to provide financing for longwall equipment and related parts and accessories. The financing arrangement is collateralized by the longwall mine equipment. Interest accrues on the note at a fixed rate per annum of 5.78% and is due semiannually in June and December until maturity. On the Closing Date, we entered into an amendment to the 5.78% longwall financing credit agreement under which the lenders waived the existing defaults and the maturity date was accelerated by one year by increasing the last three semi-annual amortization payments. The new maturity date of the 5.78% longwall financing arrangement is June 2019. In addition, the senior secured leverage ratio financial maintenance covenant was amended to be consistent with the Amended Credit Agreement. The outstanding balance as of December 31, 2016 was $39.2 million.

In May 2010, Hillsboro Energy LLC entered into a credit agreement with a financial institution to provide financing for longwall equipment and related parts and accessories. The financing arrangement is collateralized by the longwall mine equipment. Interest accrues on the note at a fixed rate per annum of 5.555% and is due semiannually in March and September until maturity. On the Closing Date, we entered into an amendment to the 5.555% longwall financing credit agreement under which the lenders waived the existing defaults and the maturity date was accelerated by one year by increasing the last four semi-annual amortization payments. The new maturity date of the 5.555% longwall financing arrangement is September 2019. In addition, the senior secured leverage ratio financial maintenance covenant was amended to be consistent with the Amended Credit Agreement. The outstanding balance as of December 31, 2016 was $41.3 million.

In March 2012, FELLC entered into a finance agreement with a financial institution to fund the manufacturing of longwall equipment. Upon taking possession of the longwall equipment during the third quarter of 2012, this interim longwall finance agreement was converted into individual leases with maturities of four and five years beginning on September 1, 2012. These leases contain a bargain purchase option at the end of the lease term and are accounted for as capital lease obligations. Principal and interest payments are due monthly over the terms of the leases. In connection with the Restructuring Transactions, we executed waivers to cure outstanding defaults under the master lease agreements to our capital lease obligations. These waivers, among other things, ratified the existing terms of each applicable equipment financing agreement, provided the lessor with a waiver fee equal to one hundred basis points of the outstanding amount due under the agreement, increased the interest rate by one percent per annum, and, with respect to certain arrangements, released the lessor from any claims that such parties may have against the lessor with respect to the lease. These capital lease obligations bear interest ranging from 5.4% to 6.3%, and principal and interest payments are due monthly over the terms of the leases. As of December 31, 2016, $5.2 million was outstanding under these capital lease obligations.

In November 2014, the Partnership entered into a sale-leaseback financing arrangement with a financial institution under which it sold a set of longwall shields and related equipment to a financial institution for $55.9 million and leased the shields back under three individual leases. We account for these leases as capital lease obligations since ownership of the longwall shields and related equipment transfer back to us upon the completion of the leases. In connection with the Restructuring Transactions, we also executed waivers to cure outstanding defaults under the master lease agreements to our capital lease obligations. These waivers, among other things, ratified the existing terms of each applicable equipment financing agreement, provided the lessor with a waiver fee equal to one hundred basis points of the outstanding amount due under the agreement, increased the interest rate by one percent per annum, and, with respect to certain arrangements, released the lessor from any claims that such parties may have against the lessor with respect to the lease. These capital lease obligations bear interest at 5.762% and principal and interest payments are due monthly over the five-year terms of the leases. Aggregate termination payments of $2.8 million are due at the end of the lease terms. As of December 31, 2016, $36.3 million was outstanding under these capital lease obligations.

Trade Accounts Receivable Securitization Program

In January 2015, Foresight Energy LP and certain of its wholly-owned subsidiaries, entered into a $70 million receivables securitization program (the "Securitization Program"). Under this Securitization Program, our subsidiaries sell all of their customer trade receivables (the "Receivables"), on a revolving basis, to Foresight Receivables LLC, a wholly-owned and consolidated special purpose subsidiary of Foresight Energy LP (the "SPV"). The SPV then pledges its interests in the Receivables to the securitization program lenders, which make loans to the SPV. When cash is collected from customers on the Receivables, it is temporarily held in a restricted cash account for a short duration and then is transferred to an unrestricted cash account, subject to the sufficiency of our borrowing base and certain other contractual provisions. The Securitization Program has a three-year maturity which expires on January 12, 2018. The borrowings under the Securitization Program are variable-rate and also carry a commitment fee for unutilized commitments.

In August 2016, we entered into an amended and restated receivables financing agreement pursuant to which commitments under the facility were reduced to $50.0 million. We recorded a loss on extinguishment of debt charge of $0.1 million to write-off a portion of the deferred debt issue costs for the reduction in commitments as part of a forbearance agreement with the lenders. As of December 31, 2016, we had borrowings outstanding of $14.2 million under the Securitization Program.

Maturity Tables

The following summarizes the contractual principal maturities of long-term debt and capital lease obligations as of December 31, 2016:

	Long-Term Debt	Capital Lease Obligations
	(In Thousands)	
2017	$ 360,392	$ 15,986
2018	386,644	11,471
2019	24,806	14,000
2020	—	—
2021	619,951	—
Thereafter	—	—
Total	$ 1,391,793	$ 41,457

The aggregate amounts of remaining minimum lease payments on the Partnership's capital lease obligations are $ 45.0 million. Minimum payments from 2017 through 2021 are as follows:

	2017	2018	2019	2020	2021
Minimum lease payments	$ 17,915	$ 12,635	$ 14,471	$ —	$ —

11. Sale-Leaseback Financing Arrangements – Affiliate

Macoupin Energy Sale-Leaseback Financing Arrangement

In January 2009, Macoupin entered into a sales agreement with WPP, LLC ("WPP") and HOD, LLC ("HOD") (subsidiaries of Natural Resource Partners LP ("NRP")) to sell certain mineral reserves and rail facility assets (the "Macoupin Sales Arrangement"). NRP is an affiliate of the Partnership (see Note 15). Macoupin received $143.5 million in cash in exchange for certain mineral reserve and transportation assets. Simultaneous with the closing, Macoupin entered into a lease with WPP for mining the mineral reserves (the "Mineral Reserves Lease") and with HOD for the use of the rail loadout and rail loop (the "Macoupin Rail Loadout Lease" and the "Rail Loop Lease," respectively). The Mineral Reserves Lease is a 20-year noncancelable lease that contains renewal elections for six additional five-year terms. The Macoupin Rail Loadout Lease and the Rail Loop Lease are 99 year noncancelable leases. Under the Mineral Reserves Lease, Macoupin makes monthly payments equal to the greater of $5.40 per ton or 8.00% of the sales price, plus

$0.60 per ton for each ton of coal sold from the leased mineral reserves, subject to a minimum royalty of $4.0 million per quarter through December 31, 2028. After the initial 20-year term, the annual minimum royalty is $10,000 per year. The minimum royalty is recoupable on future tons mined. If during any quarter the tonnage royalty under the Mineral Reserves Lease and tonnage fees paid under the Macoupin Rail Loadout and Rail Loop Leases discussed below exceed $4.0 million, Macoupin may generally recoup any unrecouped quarterly payments made during the preceding 20 quarters on a first paid, first recouped basis. The Macoupin Rail Loadout Lease and Rail Loop Lease require an aggregate payment of $3.00 ($1.50 for the rail loop facility and $1.50 for the rail load-out facility) for each ton of coal loaded through the facility for the first 30 years, up to 3.4 million tons per year. After the initial 30-year term, Macoupin would pay an annual rental payment of $20,000 per year for usage of the rail loadout and rail loop. The Macoupin Sales Arrangement, Mineral Reserves Lease, Macoupin Rail Loadout Lease and Rail Loop Lease are collectively accounted for as a financing arrangement (the "Macoupin Sale-Leaseback"). This financing arrangement is recourse to Macoupin and not recourse to Foresight Energy LP or any of its other subsidiaries. We are currently in dispute with WPP in regards to the application of the recoupment provision within the Mineral Reserves Lease (see Note 22).

At December 31, 2016 and 2015, the amount outstanding under the Macoupin Sale-Leaseback was $141.9 million and $143.5 million, respectively. The effective interest rate on the financing obligation was 13.7% and 13.9% as of December 31, 2016 and 2015, respectively. Interest expense was $16.3 million, $18.8 million and $16.3 million for the years ended December 31, 2016, 2015 and 2014, respectively. As of December 31, 2016 and 2015, interest of $0 and $0.5 million, respectively, was accrued in the consolidated balance sheets for the Macoupin Sale-Leaseback.

Sugar Camp Energy Sale-Leaseback Financing Arrangement

In March 2012, Sugar Camp entered into a sales agreement with HOD for which it received a total of $50.0 million in cash in exchange for certain rail loadout assets ("Sugar Camp Sales Agreement"). Simultaneous with the closing, Sugar Camp entered into a lease transaction with HOD for the use of the rail loadout (the "Sugar Camp Rail Loadout Lease"). The Sugar Camp Rail Loadout Lease is a 20-year noncancelable lease that contains renewal elections for 16 additional five-year terms. Under the Sugar Camp Rail Loadout Lease, Sugar Camp will pay a monthly royalty of $1.10 per ton for every ton of coal mined from specified reserves and loaded through the rail loadout. The royalty is subject to adjustment based on the time it takes for Sugar Camp to complete each longwall move. The royalty payments are subject to a minimum payment amount of $1.3 million per quarter for the first twenty years the lease is in effect. After the initial 20-year term, Sugar Camp would pay an annual rental payment of $10,000 per year. To the extent the minimum payment exceeds amounts owed based on actual coal loaded, the excess is recoupable within two years of payment. The Sugar Camp Sales Agreement and Sugar Camp Rail Loadout Lease are collectively accounted for as a financing arrangement (the "Sugar Camp Sale-Leaseback").

At December 31, 2016 and 2015, the amount outstanding under the Sugar Camp Sale-Leaseback was $50.0 million. The effective interest rate on the financing, which is derived from the timing and tons of coal to be mined as set forth in the current mine plan and the related cash payments, was 13.7% and 13.2% at December 31, 2016 and 2015, respectively. Interest expense recorded on the Sugar Camp Sale-Leaseback was $7.8 million, $5.4 million and $6.4 million for the years ended December 31, 2016, 2015 and 2014, respectively. As of December 31, 2016 and 2015, interest of $2.9 million and $1.6 million, respectively, was accrued in the consolidated balance sheets for the Sugar Camp Sale-Leaseback.

Maturity Tables

The following summarizes the maturities of expected principal payments, based on current mine plans, on the Partnership's sale-leaseback financing arrangements, and accrued interest at December 31, 2016:

	Sale-Leaseback Financing Arrangements	Accrued Interest
	(In Thousands)	
2017	$ 1,372	$ 2,930
2018	1,415	—
2019	2,454	—
2020	4,203	—
2021	4,239	—
Thereafter	178,186	—
Total	$ 191,869	$ 2,930

The aggregate amounts of remaining minimum lease payments on the Partnership's sale-leaseback financing arrangements are $ 268.3 million. Minimum payments from 2017 through 2021 are as follows:

	2017	2018	2019	2020	2021
Minimum lease payments	$ 21,000	$ 21,000	$ 21,000	$ 21,000	$ 21,000

12. Contractual Arrangements and Operating Leases

The Partnership leases certain surface rights, mineral reserves, mining, transportation and other equipment under various lease agreements with related entities under common control, other affiliated entities and independent third parties in the normal course of business.

The mineral reserve leases can generally be renewed as long as the mineral reserves are being developed and mined until all economically recoverable reserves are depleted or until mining operations cease. The lease agreements typically require a production royalty at the greater amount of a base amount per ton or a percent of the gross selling price of the coal. Generally, the leases contain provisions that require the payment of minimum royalties regardless of the volume of coal produced or the level of mining activity. The minimum royalties are generally recoupable against production royalties over a contractually defined period of time (typically five to ten years). Some of these agreements also require overriding royalty and/or wheelage payments. Under the terms of certain mineral reserve leases, the Partnership is to use commercially reasonable efforts to acquire additional mineral reserves in certain properties as defined in the agreements and is responsible for the acquisition costs and the assets are to be titled to the lessor. Transportation throughput agreements generally require a per ton fee amount for coal transported and contain certain escalation clauses and/or renegotiation clauses. For certain transportation assets, the Partnership is responsible for operations, repairs, and maintenance and for keeping the transportation facilities in good working order. Surface rights, mining, and other equipment leases require monthly payments based upon the specified agreements. Certain of these leases provide options for the purchase of the property at various times during the life of the lease, generally at its then-fair market value. The Partnership also leases certain office space, rail cars and equipment under leases with varying expiration dates.

The following table presents future minimum payments, by year, required under contractual royalty and throughput arrangements with related entities and third parties as of December 31, 2016:

	Royalties – Third Party	Royalties – Related Party	Transportation Minimums – Third Party
		(In Thousands)	
2017	$ 2,004	$ 57,667	$ 49,580
2018	2,004	57,667	50,880
2019	2,004	57,667	52,230
2020	2,004	43,667	53,630
2021	2,004	38,834	51,050
Thereafter	7,181	232,500	54,900
Total	$ 17,201	$ 488,002	$ 312,270

The following presents future minimum lease payments, by year, required under noncancelable operating leases with initial terms greater than one year, as of December 31, 2016:

	Operating Leases – Third Party	Operating Leases – Related Party
	(In Thousands)	
2017	$ 3,190	$ 155
2018	2,214	155
2019	539	150
2020	—	150
2021	—	100
Thereafter	—	—
Total	$ 5,943	$ 710

Total rental expense from operating leases for the years ended December 31, 2016, 2015, and 2014 was $12.4 million, $14.3 million, and $16.1 million, respectively. Included in rental expense is $8.5 million, $9.0 million, and $9.9 million for the years ended December 31, 2016, 2015 and 2014, respectively, of contingent rental payments to Williamson Transport, a subsidiary of NRP, for the rail loadout facility at Williamson Energy. We pay contingent rental fees, net of a fixed per ton amount received for maintaining the facility, on each ton of coal passed through the rail loadout facility.

13. Asset Retirement Obligations

The change in the carrying amount of asset retirement obligations was as follows:

	For the Year Ended December 31,		
	2016	2015	2014
		(In Thousands)	
Balance at beginning of period (including current portion)	$ 43,295	$ 35,580	$ 21,225
Accretion expense	3,376	2,267	1,621
Adjustments for liabilities incurred or changes in estimates	(1,283)	6,579	13,747
Expenditures for reclamation activities	(471)	(1,131)	(1,013)
Balance at end of period (including current portion)	44,917	43,295	35,580
Less: current portion of asset retirement obligations	(7,273)	(18)	(4,207)
Noncurrent portion of asset retirement obligations	$ 37,644	$ 43,277	$ 31,373

The credit-adjusted, risk-free interest rates used in determining the asset retirement obligations were 8.5%, 9.8% and 6.6% at December 31, 2016, 2015, and 2014, respectively.

14. Coal Workers' Pneumoconiosis and Workers' Compensation

Certain of our consolidated affiliates are responsible under Illinois statutes and the Federal Coal Mine Health and Safety Act of 1969, as amended, for medical and disability benefits to employees and their dependents resulting from occurrences of coal workers' pneumoconiosis disease ("CWP"). In addition, state statutes dictate that we provide income replacement and medical treatment for work-related traumatic injury claims, including survivor benefits for employment related deaths. Effective July 1, 2014, we terminated our guaranteed cost program in favor of a high deductible insurance program.

Our liability for CWP benefits was estimated by an independent actuary based on assumptions regarding medical costs, allocated loss adjustment expense, claim development patterns and interest rates. For the years ended December 31, 2016, 2015 and 2014, we recorded CWP (benefit)/expense of $(0.4) million, $1.4 million and $1.5 million, respectively, and have an aggregate CWP liability of $2.2 million and $3.0 million recorded in the consolidated balance sheets as of December 31, 2016 and 2015, respectively.

Our liability for workers compensation benefits was determined by a third-party administrator based on actual claims incurred and the expected development of those claims and claims incurred but not yet reported. For the years ended December 31, 2016, 2015 and 2014, we recorded workers' compensation claim expense of $3.9 million, $3.0 million and $1.4 million, respectively, and have a workers' compensation liability of $4.2 million and $2.2 million recorded in accrued expenses and other current liabilities in the consolidated balance sheets as of December 31, 2016 and 2015, respectively.

15. Related-Party Transactions

The chairman of our general partner's board of directors and the controlling member of Foresight Reserves, Christopher Cline, directly and indirectly beneficially owns a 31% and 4% interest in the general and limited partner interests of NRP, respectively. We routinely engage in transactions in the normal course of business with NRP and its subsidiaries and Foresight Reserves and its affiliates. These transactions include production royalties, transportation services, administrative arrangements, supply agreements, service agreements, land leases and sale-leaseback financing arrangements (see Note 11, sale-leaseback financing arrangements are excluded from the discussion and tables below). Also, in connection with the reorganization of the Partnership pursuant to the execution of the MSA, Foresight Reserves paid retention bonuses to certain Partnership employees which were recorded as capital contributions during the period of payment (see Note 18).

On April 16, 2015, Foresight Reserves and Murray Energy executed a purchase and sale agreement whereby Murray Energy paid Foresight Reserves $1.37 billion to acquire a 34% voting interest in FEGP, 77.5% of FELP's incentive distribution rights ("IDR") and 100% of the outstanding subordinated units in FELP. FEGP has continued to govern the Partnership subsequent to this transaction. Murray Energy has an option (the "GP Option"), as amended as part of the Restructuring Transactions, to purchase an additional 46%

of the voting interests in FEGP for $15 million and is also conditioned upon a Note Redemption prior to the Exchangeable PIK Notes Maturity Date (see Note 10 for additional discussion on the Note Redemption).

Reserves Investor Group Tender Offer and Exchange

In connection with the Restructuring Transactions, on the Closing Date, the Reserves Investor Group (as defined below) acquired, with cash, $105.4 million of the outstanding 2021 Senior Notes (the "Tender Offer"). The Reserves Investor Group includes Christopher Cline, the four trusts established for the benefit of Mr. Cline's children, Michael J. Beyer, the former Chief Executive Officer of FEGP, and owner of 0.66% of the voting and 0.225% of the economic interests of FEGP, and certain other limited liability companies owned or controlled by individuals with limited partner interests in Foresight Reserves through indirect ownership. Prior to the commencement of the Tender Offer, the Reserves Investor Group owned $83.0 million of the 2021 Senior Notes. The Reserves Investor Group then exchanged its aggregate $188.4 million of 2021 Senior Notes, plus $6.8 million of accrued and unpaid interest, for $179.9 million of Exchangeable PIK Notes and $15.2 million of Second Lien Notes (see Note 10 for additional discussion on the terms of the Exchangeable PIK Notes and Second Lien Notes). As of December 31, 2016, we have accrued $9.6 million of interest under the New Notes attributed to the Reserves Investor Group's ownership interest.

Murray Purchase Right

The Murray Group has the right to purchase all of the Exchangeable PIK Notes on or prior to October 2, 2017 for cash at a price equal to 100% of the principal amount of the Exchangeable PIK Notes plus accrued interest. Upon a Murray Purchase, the Murray Group will receive FELP units equal to the principal and interest settlement amount multiplied by the lesser of: (a) a number equal to one divided by 92.5% of the last thirty days weighted-average trading price or (b) 1.12007 common units per $1.00 principal amount of Exchangeable PIK Notes. See Note 10 for additional discussion.

Murray Energy Management Services Agreement

On April 16, 2015, the MSA was entered into pursuant to which the Manager will provide certain management and administration services to FELP for a quarterly fee of $3.5 million ($14.0 million on an annual basis), subject to contractual increases and other adjustments. To the extent FELP or FEGP directly incurs costs for certain services covered under the MSA, then the Manager's quarterly fee is reduced accordingly. Also, to the extent the Manager utilizes outside service providers to perform any of the services under the MSA, then the Manager is responsible for those outside service provider costs. The initial term of the MSA extends through December 31, 2022 and is subject to termination provisions, including termination if the Note Redemption does not occur prior to the Exchangeable PIK Notes Maturity Date and Murray Energy does not execute its GP Option. If Murray executes its GP Option, it has the right to increase the annual MSA fee to $20.0 million per year, subject to certain adjustments.

After taking into account the contractual adjustments for direct costs incurred by FELP, the amount of net expense due to the Manager for the years ended December 31, 2016 and 2015 was $8.9 million and $4.7 million, respectively.

Murray Energy Transport Lease and Overriding Royalty Agreements

For the years ended December 31, 2016 and 2015, we recorded other revenues of $5.9 million and $4.0 million, respectively, under the Transport Lease. The total remaining minimum payments under the Transport Lease was $91.8 million at December 31, 2016, with unearned income equal to $33.3 million. As of December 31, 2016, the outstanding Transport Lease financing receivable was $58.5 million, of which $2.7 million was classified as current in the consolidated balance sheet.

For the years ended December 31, 2016 and 2015, we recorded other revenues of $2.1 million and $1.4 million, respectively, under the ORRA. The total remaining minimum payments under the ORRA was $32.1 million at December 31, 2016, with unearned income equal to $20.4 million. As of December 31, 2016, the outstanding ORRA financing receivable was $11.7 million, of which $0.2 million was classified as current in the consolidated balance sheet.

Other Murray Transactions

During the years ended December 31, 2016 and 2015, we purchased $8.3 million and $3.3 million, respectively, in equipment, supplies and rebuild and other services from affiliates of Murray Energy. During the years ended December 31, 2016 and 2015, our subsidiaries provided $0.9 million and $0.2 million, respectively, in equipment, supplies and rebuild services to affiliates of Murray Energy.

From time to time, we purchase and sell coal to Murray Energy and its affiliates to, among other things, meet each of our customer contractual obligations. We also sell coal to Javelin Global Commodities Limited ("Javelin"), an international commodities marketing and trading joint venture owned by Murray En ergy, Uniper (formerly E.ON Global Commodities SE), and management of Javelin. During the years ended December 31, 2016 and 2015, we purchased $13.5 million and $17.4 million, respectively, in coal from Murray Energy and its affiliates and we sold $58.4 million and $23.1 million, respectively, of coal to Murray Energy and its affiliates, including Javelin. As of December 31, 2016, we had commitments to purchase $28.1 million in coal from Murray Energy and its affiliates and sell $37.0 million in coal to Murray Energy and its affiliates (including Javelin).

During the years ended December 31, 2016 and 2015, Murray Energy transported coal under our transportation agreement with a third-party rail company resulting in usage fees owed to the third-party rail company of $4.1 million and $11.0 million, respectively. These usage fees were billed to Murray Energy, resulting in no impact to our consolidated statements of operations. The usage of the railway line with this third-party rail company by Murray Energy counts towards the minimum annual throughput volumes with the third-party rail company, thereby reducing the Partnership's exposure to contractual liquidated damage charges. Similarly, during the years ended December 31, 2016 and 2015, we incurred $0 million and $0.2 million, respectively, of transportation fees incurred for shipments under one of Murray Energy's third-party transloading contracts.

During the year ended December 31, 2016 and 2015, we earned $1.2 million and $0.3 million, respectively, in other revenues for Murray Energy's usage of our Sitran terminal.

From time to time, we also reimburse Murray Energy for costs paid by them on our behalf, including certain insurance premiums.

2021 Senior Notes

On August 23, 2013, Cline Resource and Development Company ("CRDC") acquired $16.5 million of outstanding principal amounts of our 2021 Senior Notes (the "Original Purchase"). During September and October 2013, CRDC sold the Original Purchase primarily to affiliates, including $8.0 million to Chris Cline, $4.0 million to an entity controlled by John F. Dickinson, a director of our general partner's board of directors until December 31, 2015, and $3.7 million to two former executives of the Partnership. Additional amounts were acquired independently in 2015 by Chris Cline and The Cline Trust Company LLC, as discussed below.

As of December 31, 2015, Chris Cline owned $44.5 million of the outstanding principal on our 2021 Senior Notes. Chris Cline acquired $8.0 million in principal of the Original Purchase and during the year ended December 31, 2015, acquired an additional $36.5 million in principal from third parties in open market transactions. During the years ended December 31, 2015 and 2014, $1.9 million and $0.6 million, respectively, of interest on the 2021 Senior Notes was paid to Chris Cline. As of December 31, 2015, $1.3 million of interest on the 2021 Senior Notes was accrued to the benefit of Chris Cline.

The entity controlled by Mr. Dickinson owned $4.0 million of the outstanding principal on our 2021 Senior Notes as of December 31, 2015 and 2014, all of which was acquired from the Original Purchase. During the years ended December 31, 2015 and 2014, $0.3 million of interest on the 2021 Senior Notes was paid to Mr. Dickinson. As of December 31, 2015, $0.1 million of interest on the 2021 Senor Notes was accrued to the benefit of the entity controlled by Mr. Dickinson.

As of December 31, 2015, The Cline Trust Company LLC owned $10.0 million in principal of our 2021 Senior Notes, all of which was acquired during the year ended December 31, 2015. During the year ended December 31 2015, no interest had been paid to The Cline Trust Company LLC. As of December 31, 2015, $0.3 million of interest on the 2021 Senior Notes was accrued to the benefit of The Cline Trust Company LLC.

Also, Michael Beyer, the former chief executive officer of FELP, who resigned in May 2015, and Drexel Short, a former executive of our predecessor, who retired in March 2014, acquired $3.2 million and $0.5 million, respectively, from the Original Purchase. Mr. Beyer disposed of his 2021 Senior Notes in September of 2015. These former executives were no longer affiliates of the Partnership subsequent to their termination dates. For each of the years ended December 31, 2015 and 2014, $0.3 million of interest was paid to Mr. Beyer and Mr. Short, collectively, while they were affiliates of the Partnership.

Mineral Reserve Leases

Our mines have a series of mineral reserve leases with Colt, LLC ("Colt") and Ruger, LLC ("Ruger"), subsidiaries of Foresight Reserves. Each of these leases have initial terms of 10 years with six renewal periods of five years each, at the election of the lessees, and generally require the lessees to pay the greater of $3.40 per ton or 8.0% of the gross sales price, as defined in the respective agreements, of such coal. We also have overriding royalty agreements with Ruger pursuant to which we pay royalties equal to 8.0% of the gross selling prices, as defined in the agreements. Each of these mineral reserve leases generally require a minimum annual royalty payment, which is recoupable only against actual production royalties from future tons mined during the period of ten years following the date on which any such royalty is paid.

As of December 31, 2016, we have established a $74.6 million reserve against our contractual prepaid royalties between Colt and our Hillsboro and Macoupin subsidiaries. We determined that our ability to recoup these minimum royalty payments within the remaining recoupment period was improbable in light of, among other factors:

- the remaining recoupment period available, as a whole, on these minimum annual royalty payments and the necessary time required to obtain permits on these reserves,
- our ability to raise the capital necessary to develop the reserves and the necessary infrastructure was unfavorably impacted by the Restructuring Transactions which resulted in covenants that significantly restrict our ability to incur any additional indebtedness, and
- current and forecasted near-term market conditions.

We continually evaluate our ability to recoup prepaid royalty balances which includes, among other things, assessing mine production plans, our access to capital markets, sales commitments, current and forecasted future coal market conditions, the time necessary to obtain required permits and the remaining years available for recoupment.

We also lease mineral reserves under lease agreements with subsidiaries of NRP, including WPP, HOD, and Independence Energy, LLC ("Independence"). The initial terms of these agreements vary, however, each carries an option by the lessee to extend the leases until all merchantable and mineable coal has been mined and removed. Royalty payments under these arrangements are generally determined based on the greater of a minimum per ton amount (ranging from $2.50 per ton to $5.40 per ton) or a percentage of the gross sales price (generally 8.0% - 9.0%), as defined in the respective agreements. We are also subject under certain of these mineral reserve agreements to overriding royalties and/or wheelage fees. Our mineral reserve leases with NRP subsidiaries also require minimum quarterly or annual royalties which are generally recoupable on future tons mined and sold during the preceding five-year period from the excess tonnage royalty payments on a first paid, first recouped basis.

In July 2015, we provided notice to WPP declaring a force majeure event at our Hillsboro mine due to elevated carbon monoxide levels as a result of a mine fire, which has required the stoppage of mining operations since March 2015. As a result of the force majeure event, we have not made $46.0 million in minimum deficiency payments to WPP in accordance with the force majeure provisions of the royalty agreement. WPP is asserting that the stoppage of mining operations as a result of the combustion event does not constitute an event of force majeure under the royalty agreement (see Note 22).

As of December 31, 2016 and 2015, we have established a $34.0 million and $46.3 million reserve, respectively, against contractual prepaid royalties between Hillsboro and WPP given that the recoupment of these prior minimum royalty payments was improbable given the remaining recoupment period available and the Hillsboro combustion event, which has idled this mine since March 2015. The year over year decline in the reserve is attributed to the expiration of the recoupment period on certain of the minimum royalty payments. We continually evaluate our ability to recoup prepaid royalty balances which includes, among other things, the status of the Hillsboro combustion event, assessing mine production plans, sales commitments, current and forecasted future coal market conditions, and remaining years available for recoupment.

Transloading Agreements

Convent Marine Terminal Amendment

In August 2011, an affiliated company owned by Foresight Reserves acquired the IC RailMarine Terminal in Convent, Louisiana. This terminal, commonly referred to as the Convent Marine Terminal ("CMT"), is owned by Raven Energy LLC ("Raven"), an entity once controlled and beneficially owned by Christopher Cline. The terminal is designed to ship and receive commodities via rail, river barge and ocean vessel. We have a material handling agreement contract for throughput at the terminal under which we pay fees based on the tonnages of coal we move through the terminal, subject to minimum annual take-or-pay volume commitments. Effective May 1, 2015, the Partnership amended its material handling agreement with Raven to reduce the minimum annual throughput volume at CMT to 5.0 million tons and to extend the duration of the contract. In August 2015, The Cline Group sold Raven to an entity under which it does not have significant influence; therefore the business activities with Raven are no longer considered affiliate transactions subsequent to the sale date.

Limited Partnership Agreement

FEGP manages the Partnership's operations and activities as specified in the partnership agreement. The general partner of the Partnership is managed by its board of directors. Foresight Reserves and Murray Energy have the right to select the directors of the general partner. The members of the board of directors of the general partner are not elected by the unitholders and are not subject to reelection by the unitholders. The officers of the general partner manage the day-to-day affairs of the Partnership's business. The partnership agreement provides that the Partnership will reimburse its general partner for all direct and indirect expenses incurred or payments made by the general partner on behalf of the Partnership. No amounts were incurred by the general partner or reimbursed under the partnership agreement from the IPO date to December 31, 2016.

Other

Williamson leases property from Williamson Transport, an affiliate of NRP, under two surface leases with initial terms through October 15, 2031 and an option to extend the leases in five-year increments until all the coal leased from an NRP affiliate is mined on Williamson's premises. Williamson Transport has the option to put the land to Williamson for its fair market value as determined by an independent appraiser at any time during the lease term. Additionally, under a separate lease with an initial term through March 12, 2018, Williamson pays $5,000 per year for use of the premises and a fee, currently at $1.84 per ton, for each ton of coal produced at Williamson that is loaded through the Williamson rail loadout facility. Williamson Transport may elect to renew or extend the sublease for successive five-year periods. If Williamson Transport elects not to renew the sublease, Williamson has the option to buy the Williamson rail loadout facility for its fair market value as determined by an independent appraiser. Williamson receives a fee of $0.25 per ton from Williamson Transport for each ton of coal that is loaded through the Williamson rail loadout facility in exchange for operating the loadout.

We are party to two surface leases in relation to the coal preparation plant and rail loadout facility at Williamson with New River Royalty, a subsidiary of Foresight Reserves. The primary terms of the leases expire on October 15, 2021, but may be extended by New River Royalty for additional five-year terms under the same terms and conditions until all of the merchantable and mineable coal has been mined and removed from Williamson. Williamson is required to pay aggregate rent of $100,000 per year to New River Royalty under the leases. Additionally, New River Royalty may require Williamson to purchase any portion of either of the leased properties at any time while the leases are in effect for $3,000 per acre. Williamson Transport has the option to purchase any property optioned under the leases if Williamson does not perform its purchase obligation within fifteen days of receiving notice of its purchase obligation. Our Sitran terminal also leases land with New River Royalty for $50,000 per year under a lease that expires in 2020, and which can be extended at the option of the lessee in five year increments.

In January 2007, Chris Cline, Foresight Reserves, Adena Minerals LLC and their respective affiliates (collectively, "Adena Entities") and NRP executed a restricted business contribution agreement. The restricted business contribution agreement obligates the Adena Entities and their affiliates to offer NRP any business owned, operated or invested in by the Adena Entities, subject to certain exceptions, that either (a) owns, leases or invests in hard minerals or (b) owns, operates, leases or invests in identified transportation infrastructure relating to certain future mine developments by the Adena Entities in Illinois. NRP's acquisition of certain coal reserves and infrastructure assets related to our Macoupin, Hillsboro and Sugar Camp mining complexes, discussed above and in Note 11, were deals consummated under the restricted business contribution agreement with the Adena Entities. The Adena Entities are required to offer and could consummate additional deals under the restricted business contribution agreement in the future.

During the years ended December 31, 2016, 2015 and 2014, we purchased $6.6 million, $14.5 million and $18.1 million, respectively, in mining supplies from an affiliated joint venture under a supply agreement entered into in May 2013 (see Note 16).

The following table presents the affiliate amounts included in our consolidated balance sheets:

Affiliated Company	Balance Sheet Location	As of December 31, 2016	As of December 31, 2015
		(In Thousands)	
Foresight Reserves and affiliated entities (1)	Due from affiliates - current	$ —	$ 145
Murray Energy and affiliated entities (2)	Due from affiliates - current	16,784	16,316
NRP and affiliated entities	Due from affiliates - current	107	154
Total		$ 16,891	$ 16,615
Murray Energy and affiliated entities	Financing receivables - affiliate - current	$ 2,904	$ 2,689
Total		$ 2,904	$ 2,689
Murray Energy and affiliated entities	Due from affiliates - noncurrent	$ 1,843	$ 2,691
Total		$ 1,843	$ 2,691
Murray Energy and affiliated entities	Financing receivables - affiliate - noncurrent	$ 67,235	$ 70,139
Total		$ 67,235	$ 70,139
Foresight Reserves and affiliated entities (3)	Prepaid royalties - current and noncurrent	$ 7,599	$ 69,555
NRP and affiliated entities (3)	Prepaid royalties - current and noncurrent	1,246	—
Total		$ 8,845	$ 69,555
Foresight Reserves and affiliated entities (1)	Due to affiliates - current	$ 1,373	$ 1,054
Murray Energy and affiliated entities	Due to affiliates - current	17,021	5,020
NRP and affiliated entities	Due to affiliates - current	2,510	2,462
Total		$ 20,904	$ 8,536

(1) – Includes amounts due to/from a joint venture partially owned by an affiliate of The Cline Group – see Note 16.
(2) – Includes amounts due from Javelin, a joint venture partially owned by Murray Energy.
(3) – Prepaid royalties with Foresight Reserves and affiliated entities is presented net of a $74,575 reserve as of December 31, 2016. Prepaid royalties with NRP and affiliated entities is presented net of a $33,965 and $46,306 reserve as of December 31, 2016 and 2015, respectively.

A summary of expenses/income incurred with affiliated entities is as follows for the years ended December 31, 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015	2014
	(In Thousands)		
Coal sales – Murray Energy and affiliated entities (1)	$ 58,395	$ 23,060	$ —
Overriding royalty and lease revenues – Murray Energy and affiliated entities (2)	$ 7,978	$ 5,387	$ —
Terminal revenues - Murray Energy and affiliated entities (2)	$ 1,226	$ 282	$ —
Royalty expense – NRP and affiliated entities (3)	$ 17,606	$ 29,773	$ 48,652
Royalty expense – Foresight Reserves and affiliated entities (3)	$ 13,921	$ 3,319	$ 11,282
Loadout services – NRP and affiliated entities (3)	$ 8,510	$ 9,032	$ 9,878
Purchased goods and services – Murray Energy and affiliated entities (4)	$ 8,305	$ 3,326	$ —
Purchased coal - Murray Energy and affiliated entities (5)	$ 13,541	$ 17,399	$ —
Land leases - Foresight Reserves and affiliated entities (3), (6)	$ 177	$ —	$ 100
Terminal fees – Foresight Reserves and affiliated entities (6)	$ —	$ 19,327	$ 43,951
Sales commissions - Murray Energy and affiliated entities (7)	$ 216	$ —	$ —
Management services – Murray Energy and affiliated entities (7)	$ 8,919	$ 4,667	$ —
Administrative fee income – Foresight Reserves and affiliated entities (8)	$ —	$ 52	$ 256

Principal location in the consolidated financial statements:

(1) – Coal sales
(2) – Other revenues
(3) – Cost of coal produced (excluding depreciation, depletion and amortization)
(4) – Cost of coal produced (excluding depreciation, depletion and amortization) and property, plant and equipment, as applicable
(5) – Cost of coal purchased
(6) – Transportation
(7) – Selling, general and administrative
(8) – Other operating income, net

The contractual commitment tables for operating leases and royalty agreements with affiliated parties are disclosed in Note 12. The contractual commitment tables for sales-leaseback arrangements with affiliated parties are disclosed in Note 11.

16. Variable Interest Entities (VIEs)

Our financial statements have historically included VIEs for which the Partnership or one of its subsidiaries was the primary beneficiary. Among those VIEs consolidated by the Partnership and its subsidiaries were Mach Mining, LLC; M-Class Mining, LLC; MaRyan Mining LLC; Patton Mining LLC; Viking Mining LLC; Coal Field Construction Company LLC; Coal Field Repair Services LLC; Logan Mining LLC; and LD Labor Company LLC (collectively, the "Contractor VIEs"). Each of the Contractor VIEs held a contract to provide one or more of the following services to a Partnership subsidiary: contract mining, processing and loading services, or construction and maintenance services. The Contractor VIEs generally received a nominal per ton fee ($0.01 to $0.02 per ton) above its cost of operations as compensation for services performed. All of these entities were determined not to have sufficient equity at risk and were therefore VIEs. The Partnership was determined to be the primary beneficiary of each of these entities given it controlled these entities under a contractual cost-plus arrangement. During the years ended December 31, 2016, 2015 and 2014, in aggregate, the Contractor VIEs earned income of $0.2 million, $0.5 million and $0.5 million, respectively, under the contractual arrangements with the Partnership which was classified as net income attributable to noncontrolling interests in the consolidated statements of operations.

On August 1, 2016, we acquired 100% of the outstanding equity units in each of the Contractor VIEs for aggregate cash consideration of $0.1 million. Because the Contractor VIEs have historically been consolidated as VIEs, and therefore represented entities under common control, the cash proceeds paid in excess of the net book values of the Contractor VIEs on the acquisition date was recorded as a deemed distribution in the statement of partners' (deficit) capital. We have not experienced any material changes to our operations from the acquisitions of the Contractor VIEs.

In January 2016, we contributed $2.5 million to a new entity, Foresight Surety LLC ("Foresight Surety"), whose purpose was to obtain and maintain a letter of credit for the benefit of one of our surety bond providers. We hold all of the economic units of Foresight Surety and a professional service provider with which we have had a long-standing relationship holds all of its voting rights. Foresight Surety is a VIE given that the holder of all of the economic rights has no ability to exercise power over it. We were determined to be the primary beneficiary of Foresight Surety, and therefore consolidate Foresight Surety, as the professional service provider with all of the voting rights was determined to be acting as our de facto agent and therefore we would aggregate voting power. In February 2016, Foresight Surety obtained a $2.5 million letter of credit with a lender for the benefit of one of our surety bond providers. The letter of credit is secured by the $2.5 million of cash we contributed to Foresight Surety.

In August 2013, FELLC effected a reorganization pursuant to which certain transportation assets were distributed to its members (the "2013 Reorganization"). Among the assets distributed were Adena and Hillsboro Transport. Subsequent to the 2013 Reorganization, both of these entities were identified as VIEs and continued to be consolidated by FELLC. As such, the aggregate net book values of Adena and Hillsboro Transport of $10.1 million on the distribution date was reclassified from predecessor members' equity to noncontrolling interest equity on the 2013 Reorganization date. During the years ended December 31, 2015 and 2014, Adena and Hillsboro Transport as VIEs earned income, in aggregate, of $0.3 million and $3.4 million, respectively, which was classified as net income attributable to noncontrolling interests in the consolidated statements of operations.

During the first quarter of 2015, Adena and Hillsboro Transport were contributed to us by Foresight Reserves and a member of management (see Note 18) and are therefore no longer consolidated as VIEs. The aggregate net book values of Adena and Hillsboro Transport of $9.9 million was reclassified from noncontrolling interest equity to limited partners' capital on the contribution dates.

The liabilities recognized as a result of consolidating the VIEs do not necessarily represent additional claims on the general assets of the Partnership outside of the VIEs; rather, they represent claims against the specific assets of the consolidated VIEs. Conversely, assets recognized as a result of consolidating these VIEs do not necessarily represent additional assets that could be used to satisfy claims against the Partnership's general assets. Long-term assets in the table below is comprised of restricted cash which provided collateral to an outstanding letter of credit. There are no other restrictions on the VIE assets that are reported in our general assets.

The total consolidated VIE assets and liabilities reflected in the Partnership's consolidated balance sheets are as follows:

	December 31, 2016	December 31, 2015
	(In Thousands)	
Assets:		
Current assets	$ —	$ 4,933
Long-term assets	2,500	—
Total assets	$ 2,500	$ 4,933
Liabilities:		
Current liabilities	$ —	$ 12,835
Long-term liabilities	—	2,955
Total liabilities	$ —	$ 15,790

In May 2013, an affiliate owned by The Cline Group and a third-party supplier of mining supplies formed a joint venture whose purpose is the manufacture and sale of supplies primarily for use by the Partnership in the conduct of its mining operations. The agreement obligates the Partnership's coal mines to purchase at least 90% of their aggregate annual requirements for certain mining supplies from the supplier parties, subject to exceptions as set forth in the agreement. The initial term of the amended agreement is five years and expires in April 2018. The supplies sold under this arrangement result in an agreed-upon fixed profit percentage for the joint venture. This joint venture was determined to be a VIE given that the equity holders do not have the obligation to absorb the expected losses or the right to receive the expected residual returns of the joint venture as a result of the Partnership effectively guaranteeing a fixed-profit percentage on the supplies it purchases from the joint venture. We are not the primary beneficiary of this joint venture and, therefore, do not consolidate the joint venture, given that the power over the joint venture is conveyed through the board of directors of the joint venture and no party controls the board of directors.

17. Fair Value of Financial Instruments

The tables below set forth, by level, the Partnership's net financial assets and liabilities for which fair value is measured on a recurring basis:

	Fair Value at December 31, 2016			
	Total	Level 1	Level 2	Level 3
	(In Thousands)			
Coal derivative contracts	$ 7,315	$ —	$ 7,315	$ —
Warrant liability	(51,169)	—	—	(51,169)
Total	$ (43,854)	$ —	$ 7,315	$ (51,169)

	Fair Value at December 31, 2015			
	Total	Level 1	Level 2	Level 3
	(In Thousands)			
Coal derivative contracts	$ 48,623	$ —	$ 48,623	$ —
Diesel derivative contracts	(1,029)	—	(1,029)	—
Total	$ 47,594	$ —	$ 47,594	$ —

The Partnership's commodity derivative contracts are valued based on direct broker quotes and corroborated with market pricing data. During the years ended December 31, 2016, 2015 and 2014, there were no assets or liabilities that were transferred between Level 1 and Level 2.

The classification and amount of the Partnership's financial instruments measured at fair value on a recurring basis, which are presented on a gross basis in the consolidated balance sheets as of December 31, 2016 and 2015, are as follows:

	Fair Value at December 31, 2016			
	Current – Coal Derivative Assets	Long-Term – Coal Derivative Assets	Accrued Expenses	Warrant Liability
	(In Thousands)			
Coal derivative contracts	$ 7,650	$ —	$ (335)	$ —
Warrant liability	—	—	—	(51,169)
Total	$ 7,650	$ —	$ (335)	$ (51,169)

	Fair Value at December 31, 2015			
	Current – Coal Derivative Assets	Long-Term – Coal Derivative Assets	Accrued Expenses	Warrant Liability
	(In Thousands)			
Coal derivative contracts	$ 26,596	$ 22,027	$ —	$ —
Diesel derivative contracts	—	—	(1,029)	—
Total	$ 26,596	$ 22,027	$ (1,029)	$ —

The following is a reconciliation of the beginning and ending balances for assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3):

	Warrant Liability
	(In Thousands)
Balance at January 1, 2016	$ —
Purchases, issuances and settlements	34,045
Recorded fair value losses:	
Included in earnings - loss / (gain)	17,124
Balance at December 31, 2016	$ 51,169

On the Closing Date, FELP issued Warrants to the unaffiliated owners of the Second Lien Notes to purchase an amount of common units equal to an aggregate of 4.5% of the total limited partner units of FELP outstanding on the date of a Note Redemption (after giving effect to the full exercise of the Warrants and the Note Redemption, subject to certain anti-dilution protections), exercisable upon a Note Redemption and until the tenth anniversary of the Note Redemption. The exercise price of the Warrants is $0.8928 per Common Unit, subject to certain adjustments. The number of common units issuable upon the conversion of the Warrants will be determinable as of the date of a Note Redemption. If a Note Redemption does not occur on or prior to the Exchangeable PIK Notes Maturity Date, the Warrants will not become exercisable. The Warrants are required to be accounted for as a liability at fair value and the fair value must be revalued at each balance sheet date until the earlier of the exercise of the Warrants, their expiration, or until any of the features requiring liability treatment expires or is modified. The resulting non-cash gain or loss on the fair value revaluation at each balance sheet date is recorded as non-operating loss in our consolidated statements of operations

The fair value of the Warrants was calculated using the Black-Scholes pricing model (including the use of a binomial lattice to model the conversion and redemption scenarios for the Exchangeable PIK Notes) which is based, in part, upon unobservable inputs for which there is little or no market data (Level 3), requiring the Partnership to develop its own assumptions. A stock price volatility of 70%, a dividend yield of 0% and a risk-free forward rate of 2.61% was used in the Black-Scholes pricing model.

Long-Term Debt

The fair value of long-term debt as of December 31, 2016 and 2015 was $1,378.6 million and $1,244.3 million, respectively. The fair value of long-term debt was calculated based on the amount of future cash flows associated with each debt instrument discounted at the Partnership's current estimated credit-adjusted borrowing rate for similar debt instruments with comparable terms. This is considered a Level 3 fair value measurement.

18. Partners' Capital

Common and Subordinated Units

All subordinated units are currently held by Murray Energy. The principal difference between our common units and subordinated units is that subordinated unitholders are not entitled to receive a distribution from operating surplus until the holders of common units have received the minimum quarterly distribution ("MQD") from operating surplus. The MQD is $0.3375 per unit for such quarter plus any cumulative arrearages of previously unpaid MQDs from previous quarters. Also, subordinated unitholders are not entitled to receive arrearages. The subordination period will end, and the subordinated units will convert to common units, on a one-for-one basis, on the first business day after the Partnership has paid the MQD for each of three consecutive, non-overlapping four-quarter periods ending on or after March 31, 2017 and there are no outstanding arrearages on the common units. Notwithstanding the foregoing, the subordination period will end on the first business day after the Partnership has paid an aggregate amount of at least $2.025 per unit (150.0% of the MQD on an annualized basis) on the outstanding common and subordinated units and the Partnership has paid the related distribution on the incentive distribution rights, for any four-quarter period ending on or after March 31, 2015 and there are no outstanding arrearages on the common units. Given that distributions have not been paid beginning with the quarter ended December 31, 2015 arrearages have accrued to the benefit of common unitholders, should future distributions be paid. Our partnership agreement provides that our general partner will make a determination as to whether a distribution will be made, subject to, among other factors, compliance with our debt agreements. Our partnership agreement does not require us to pay distributions at any time or at any amount. Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders.

Incentive Distribution Rights ("IDRs")

Our IDRs are held by Murray Energy, Chris Cline and a former member of management. IDRs represent the right to receive an increasing percentage of quarterly distributions from operating surplus after the MQD and the target distribution levels (described below) have been achieved. Our general partner may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement. The IDR holders will have the right, subsequent to the subordination period and subject to distributions exceeding the MQD by at least 150% for four consecutive quarters, to reset the target distribution levels and receive common units.

Allocation of Net Income (Loss)

Our partnership agreement contains provisions for the allocation of net income and loss to the unitholders and the general partner. For purposes of maintaining partner capital accounts, the partnership agreement generally specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interest.

Percentage Allocation of Distributions from Operating Surplus

The following table illustrates the percentage allocation of distributions from operating surplus between the unitholders and the holders of our IDRs based on the specified target distribution levels. The amounts set forth under the column heading "Marginal Percentage Interest in Distributions" are the percentage interests of the IDR holders and the unitholders of any distributions from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Per Common Unit". The percentage interests shown for our unitholders and the IDR holders for the MQD are also applicable to quarterly distribution amounts that are less than the MQD.

The percentage interests set forth below excludes the impact of arrearages which would first be due to common unitholders before the IDR holders would receive a distribution.

	Total Quarterly Distribution Per Common Unit	Marginal Percentage Interest in Distributions	
		Unitholders	IDR Holders
Minimum quarterly distribution	$0.3375	100.0%	—
First target distribution	Above $0.3375 up to $0.3881	100.0%	—
Second target distribution	Above $0.3881 up to $0.4219	85.0%	15.0%
Third target distribution	Above $0.4219 up to $0.5063	75.0%	25.0%
Thereafter	Above $0.5063	50.0%	50.0%

Our partnership agreement sets forth the calculation to be used to determine the amount and priority of cash distributions that the common and subordinated unitholders and general partner will receive.

Equity Contributions and Distributions

The follow table summarizes the quarterly distribution paid per limited partner unit (except as noted) during the years ended December 31, 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015	2014
	(Per limited partner unit, except as noted)		
First Quarter	$ —	$ 0.36	n/a
Second Quarter	$ —	$ 0.37	n/a
Third Quarter	$ —	$ 0.38	$ 0.03
Fourth Quarter (a)	$ —	$ 0.06	$ 0.35

(a) **–** In November 2015, we paid a quarterly distribution of $0.17 per unit payable to common unitholders, while suspending the distribution on all subordinated units. Chris Cline and one additional common unitholder elected to forego the $0.17 per common unit distribution on their collective 21.2 million common units.

During the year ended December 31, 2016, Foresight Reserves incurred $1.0 million of one-time employee compensation costs classified as transition and reorganization costs for which it will not seek reimbursement from the Partnership. The noncash contribution from Foresight Reserves increased the Partnership's limited partners' capital accounts.

During the first quarter of 2015 (the "Contribution Date"), Foresight Reserves and a member of management contributed back to FELP, for no consideration, 100% of the equity of Sitran LLC ("Sitran"), Adena and Hillsboro Transport (the "Contributed Companies"). In addition, Foresight Reserves and a member of management contributed, for no consideration, Akin Energy LLC, an entity holding certain permits and development costs for a natural gas power generation facility. Because Sitran and Akin Energy were under common control, the Partnership's historical financial statements have been retrospectively adjusted to combine their financial position at historical cost and their results of operations. The equity values of Sitran and Akin Energy prior to the Contribution Date are included in predecessor equity in the statement of partners' capital (deficit). Hillsboro Transport and Adena were previously consolidated by the Partnership as VIEs; therefore the contribution did not result in a change in reporting entity (see Note 16). On the Contribution Date, the net book values of the Contributed Companies were reclassified from either predecessor equity or noncontrolling interest, as applicable, to limited partners' capital in the statement of partners' capital (pro rata between the common and subordinated units based on the number of units held by the contributing parties on the Contribution Date). The aggregate net book value of the Contributed Companies on the Contribution Date was $60.6 million.

During the year ended December 31, 2015, Foresight Reserves incurred $ 11.3 million of one-time employee compensation costs classified as transition and reorganization costs for which it will not seek reimbursement from the Partnership. The noncash contribution from Foresight Reserves increased the Partnership's limited partners' capital accounts. Of the $ 11.3 million contribution amount, $ 1.3 million was deferred as a prepaid expense and amortized over the required remaining retention period in 2016.

On June 23, 2014, in connection with the IPO, Foresight Reserves and a member of management each contributed their membership interests in FELLC to the Partnership in exchange for common and subordinated units of FELP. As a result, the members' deficit balance of $104.9 million at the time of the transfer was allocated, pro rata based on units outstanding, to common and subordinated unitholder capital accounts.

In connection with the acquisition of Seneca Rebuild on April 1, 2014, a deemed distribution in the amount of $0.3 million was recorded to reflect the excess of the purchase price paid by FELLC over the carrying value of the net assets acquired.

Noncontrolling Interests

Noncontrolling interests' equity and net income attributable to noncontrolling interests result from the consolidation of variable interest entities for which the Partnership has no equity interests.

On August 1, 2016, we acquired 100% of the outstanding equity units in each of the Contractor VIEs for aggregate cash consideration of $0.1 million. Because the Contractor VIEs have historically been consolidated as VIEs, and therefore represented entities under common control, the cash proceeds paid in excess of the net book values of the Contractor VIEs on the acquisition date was recorded as a deemed distribution in the statement of partners' (deficit) capital and the net book value of the Contractor VIEs on the acquisition date was reclassified from noncontrolling interest equity to limited partners equity. We do not expect any material changes to our operations from the acquisitions of the Contractor VIEs.

19. Equity-Based Compensation

Long-Term Incentive Plan

The Partnership has adopted a Long-Term Incentive Plan ("LTIP" or the "Plan") for employees, directors, officers and certain key third-parties (collectively, the "Participants"). The Plan allows for the issuance of equity-based compensation in the form of phantom units, unit awards, unit options, unit appreciation rights, restricted units, other unit-based awards, distribution equivalent rights, performance awards, and substitute awards to Participants. The LTIP awards granted thus far are phantom units, which upon satisfaction of vesting requirements, entitle the LTIP participant to receive FELP common units. The Board of Directors of the Partnership authorized 7.0 million common units to be granted under the LTIP, with 4.8 million units available for grant as of December 31, 2016. Grant levels and vesting requirements are recommended by the Partnership's chief executive officer, subject to the review and approval by the board of directors.

LTIP Awards

During the years ended December 31, 2016, 2015 and 2014, the Partnership granted 0, 1,838,099 and 595,075 phantom units, respectively, to employees under the LTIP. Of the phantom unit LTIP awards granted during the years ended December 31, 2015 and 2014, 431,750 and 72,500, respectively, were vested immediately on the grant date. This includes an equity award granted to the former chief executive officer of the Partnership in February 2015 of 215,954 common units and 215,796 subordinated units which fully-vested on the grant date. The remaining awards are considered time-based unit awards and generally cliff-vest, subject to continued employment, over the required service period (with accelerated vesting under certain instances). The required service periods vary but are generally three-year periods. Compensation expense for these awards is recognized on a straight-line basis over the requisite service period. Upon vesting, the Partnership will issue authorized and unissued shares of the Partnership's common units to the recipient. As of December 31, 2016, 203,918 phantom units granted to employees under the LTIP were non-vested.

Director Awards

During the years ended December 31, 2016, 2015 and 2014, the Partnership granted 58,851, 35,324 and 7,919 phantom units, respectively, to non-employee directors under the LTIP. These awards are considered time-based unit awards and vest ratably over a three-year period. Compensation expense for these awards is recognized on a straight-line basis over the requisite service period. As of December 31, 2016, 74,621 phantom units granted to nonemployee directors under the LTIP were non-vested.

Summary

For the year ended December 31, 2016, 2015 and 2014, our equity-based compensation expense was $5.1 million, $13.7 million and $5.0 million, respectively, net of forfeitures. During the year ended December 31, 2014, $0.3 million of equity-based compensation was capitalized into mine development costs. During the years ended December 31, 2016, 2015 and 2014, the Partnership's equity-based compensation is recorded in the consolidated statements of operations as follows:

	December 31,		
Location in statements of operations:	**2016**	**2015**	**2014**
Selling, general and administrative	2%	58%	63%
Transition and reorganization costs	84%	31%	—
Cost of coal produced (excluding depreciation, depreciation and amortization)	14%	11%	37%

As of December 31, 2016, the total unrecognized compensation expense for phantom unit awards that are expected to vest was $1.0 million. The non-vested phantom unit awards will be recognized over a weighted-average period of 1.0 year. The intrinsic value of the non-vested LTIP awards was $1.8 million as of December 31, 2016. All non-vested phantom units include tandem distribution incentive rights, which provide for the right to accrue quarterly cash distributions in an amount equal to the cash distributions the Partnership makes to unitholders during the vesting period and will be settled in cash upon vesting. The Partnership has $0.3 million accrued for this liability as of December 31, 2016. Any distributions accrued to a Participants' account will be forfeited if the related phantom award fails to vest according to the relevant vesting conditions.

A summary of LTIP award activity for the years ended December 31, 2015 and 2016 is as follows:

	Number of Units	**Weighted Average Grant Date Fair Value per Unit**
Non-vested grants at January 1, 2015	**601,109**	**$ 19.99**
Granted	1,873,423	$ 7.28
Vested	(652,786)	$ 17.25
Forfeited	(110,405)	$ 18.63
Non-vested grants at December 31, 2015	**1,711,341**	**$ 7.21**
Granted	58,851	$ 3.82
Vested	(1,421,662)	$ 4.76
Forfeited	(69,991)	$ 19.60
Non-vested grants at December 31, 2016	**278,539**	**$ 15.88**

During the years ended December 31, 2016, 2015 and 2014, the Partnership settled 509,378, 75,522 and 53,745 units, respectively, of vested equity awards in cash to satisfy the individual statutory minimum tax obligations of the LTIP participants.

20. Earnings per Limited Partner Unit

Limited partners' interest in net (loss) income attributable to the Partnership and basic and diluted earnings per unit reflect net (loss) income attributable to the Partnership subsequent to the June 23, 2014 closing date of the IPO. We compute earnings per unit ("EPU") using the two-class method for master limited partnerships as prescribed in Accounting Standards Codification ("ASC") 260, *Earnings Per Share* . The two-class method requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic EPU. In addition to the common and subordinated units, we have also identified the general partner interest and IDRs as participating securities. Under the two-class method, EPU is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

The Partnership's net (loss) income is allocated to the limited partners, including the holders of the subordinated units, in accordance with their respective ownership percentages, after giving effect to any special income or expense allocations and incentive distributions paid to the general partner, if any. The partnership agreement contractually limits distributions to available cash as determined by our general partner; therefore, undistributed earnings of the Partnership are not allocated to the IDR holder. There were no allocations of earnings to participating securities during the periods presented below. Basic EPU is computed by dividing net earnings attributable to unitholders by the weighted-average number of units outstanding during each period. Diluted EPU reflects the potential dilution of common equivalent units that could occur if equity participation units are converted into common units.

The following table illustrates the Partnership's calculation of net (loss) income per common and subordinated unit for the period indicated:

	Year Ended December 31,								
	2016			2015			2014		
	Common Units	Subordinated Units	Total	Common Units	Subordinated Units	Total	Common Units	Subordinated Units	Total
	(In Thousands, Except Per Unit Data)								
Numerator:									
Distributed earnings	$ —	$ —	$ —	$ 79,733	$ 72,100	$ 151,833	$ 24,619	$ 24,601	$ 49,220
Distributions in excess of earnings and undistributed (loss) earnings	(90,015)	(88,774)	(178,789)	(95,776)	(95,534)	(191,310)	10,535	10,437	20,972
Net (loss) income available to limited partner units	$ (90,015)	$ (88,774)	$ (178,789)	$ (16,043)	$ (23,434)	$ (39,477)	$ 35,154	$ 35,038	$ 70,192
Denominator:									
Weighted-average units to calculate basic EPU	65,829	64,955	130,784	65,098	64,934	130,032	64,790	64,739	129,529
Less: effect of dilutive securities (1)	—	—	—	—	—	—	—	—	—
Weighted-average units to calculate diluted EPU	65,829	64,955	130,784	65,098	64,934	130,032	64,790	64,739	129,529
Basic net (loss) income per unit	$ (1.37)	$ (1.37)	$ (1.37)	$ (0.25)	$ (0.36)	$ (0.30)	$ 0.54	$ 0.54	$ 0.54
Diluted net (loss) income per unit	$ (1.37)	$ (1.37)	$ (1.37)	$ (0.25)	$ (0.36)	$ (0.30)	$ 0.54	$ 0.54	$ 0.54

(1) Diluted EPU gives effect to all dilutive potential common units outstanding during the period using the treasury stock method. Diluted EPU excludes all dilutive potential units calculated under the treasury stock method if their effect is anti-dilutive. For the years ended December 31, 2016, 2015 and 2014, approximately 0.3 million, 1.7 million and 0.6 million, respectively, phantom units were anti-dilutive, and therefore were excluded from the diluted EPU calculation. Diluted EPU also is not impacted during the periods presented by any units which could be issued as a result of the Warrants or the Exchangeable PIK Notes. See Notes 10 and 17.

21. Risk Concentrations

Sales and Credit Risk

We determine creditworthiness for trade customers based on an evaluation of the customer's financial condition. Credit losses have historically been minimal. The aggregate outstanding trade receivable balance as of December 31, 2016 from customers representing greater than 10% of our total sales was $14.0 million. Also, as of December 31, 2016, we had outstanding accounts receivable and financing receivables with Murray Energy and its affiliates of $18.6 million and $70.1 million, respectively (see Note 15).

For the years ended December 31, 2016, 2015 and 2014, the following customers (aggregated at the parent company level) exceeded 10% of total coal sales:

	For the Year Ended December 31,		
	2016	2015	2014
	(Percentage of Total Coal Sales)		
Customer A	30%	22%	16%
Customer B	10%	12%	12%
Customer C	13%	11%	(A)
Customer D	(A)	(A)	11%

(A) – Less than 10% of total coal sales for this period.

During the years ended December 31, 2016, 2015 and 2014, export tons represented 17%, 24% and 30% of tons sold, respectively. Tons exported into Europe/UK during the years ended December 31, 2016, 2015 and 2014 represented approximately 16%, 22% and 26%, respectively, of total tons sold during those years. No other international geographic regions exceeded 10% of tons sold during the years ended December 31, 2016, 2015 and 2014. Our domestic coal sales are principally to electric utility companies in the eastern United States with installed pollution control devices.

Transportation

The Partnership depends on rail, barge, and export terminal systems to deliver coal to its customers. Disruption of these services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks, and other events could temporarily impair the Partnership's ability to supply coal to its customers, resulting in decreased shipments. As such, the Partnership has sought to diversify transportation options and has entered into long-term contracts with transportation providers to ensure transportation is available to transport its coal.

22. Contingencies

In December 2016, we reached settlement with the U.S. Equal Employment Opportunity Commission regarding discriminatory hiring practices. The aggregate settlement amount was $4.3 million of which our insurance covered $3.8 million.

In December 2016, we paid $3.7 million to settle the outstanding claims against us from certain railcar lessors asserting that our use of the railcars during the lease term cause damage to the railcars.

In August 2016, FELP completed its global restructuring. The restructuring transactions alleviated existing defaults and events of default across the Partnership's capital structure that resulted from the 2015 Delaware Court of Chancery Court change-of-control litigation related to the purchase and sale agreement between the significant equity holders in the Partnership's general partner, Foresight Reserves and Murray Energy. In conjunction with the completion of the global restructuring, the litigation has been dismissed with prejudice. See Note 3 for additional discussion.

In January 2016, certain plaintiffs filed suit against us in the United States District Court for the Central District of Illinois Springfield Division under the Worker Adjustment and Retraining Notification Act (the "WARN Act") claiming that they were terminated without cause. In September 2016, we agreed to pay certain plaintiffs $0.6 million to settle outstanding claims against us relating to the alleged violations.

In January 2016, WPP sent a demand letter to Macoupin claiming it had misapplied the royalty recoupment provision involving a coal mining lease and a rail infrastructure lease resulting in underpayments of $3.3 million. In April 2016, WPP and HOD filed a complaint in the Circuit Court of Macoupin County, Illinois. We do not believe that the royalty recoupment provision was misapplied and have continued to apply the recoupment provision consistently with prior periods. While we believe that the language of the agreements and the parties' course of performance thereunder support Macoupin's position, should we not prevail, we would be responsible for paying WPP for any recoupment taken that is found to contravene the contractual language.

In July 2015, we provided notice to WPP, a subsidiary of NRP, declaring a force majeure event at our Hillsboro mine due to a combustion event. As a result of the force majeure event, as of December 31, 2016, we have not made $46.0 million in minimum deficiency payments to WPP in accordance with the force majeure provisions of the royalty agreement. On November 24, 2015, WPP filed a Complaint in the Circuit Court of Montgomery County, Illinois, against Hillsboro. After we prevailed on various motions to dismiss the Complaint, as well as the First and Second Amended Complaints, WPP filed its Third Amended Complaint on January 16, 2017. In the Third Amended Complaint, WPP alleges that (i) the stoppage of mining operations as a result of the spontaneous combustion event does not constitute an event of force majeure under the royalty agreement, (ii) Hillsboro's reliance on the force majeure language is a breach of the royalty agreement, and (iii) that Hillsboro's failure to recommence mining is a further breach of the royalty agreement. Hillsboro denies each of these allegations. In addition, WPP, in the Third Amended Complaint, names Foresight Energy GP, LLC; Foresight Energy, LP; Foresight Energy, LLC; Foresight Energy Services, LLC; Coal Field Construction Company, LLC; and Patton Mining, LLC as defendants. The Third Amended Complaint alleges that the Foresight Defendants (i) are alter egos of Hillsboro, (ii) are direct participants in Hillsboro's conduct, and (iii) have tortiously interfered with the royalty agreement. Additionally, the Third Amended Complaint alleges that all of the defendants were negligent in the operation of the mine, and, further, the Third Amended Complaint seeks an order compelling "specific performance" of the royalty agreement by directing Hillsboro to recommence mining in a separate area of the mine. Motions to Dismiss have been filed addressing each of the non-contractual claims. . While we believe this is a force majeure event, as contemplated by the royalty agreement, and that the alleged claims are without merit, should we not prevail, we would be responsible for funding any minimum deficiency payment amounts during the shutdown period to WPP and potentially additional fees.

In November 2012, six citizens filed requests for administrative review of Revision No. 1 to Permit No. 399 for the Hillsboro mine. Revision No. 1 allowed for conversion of the currently permitted coal refuse disposal facility from a non-impounding to an impounding structure. On February 14, 2017, the Circuit Court of Montgomery County, Illinois upheld the hearing officer's decision that Revision No. 1 to Permit No. 399 for the Hillsboro mine was properly issued by IDNR. To the extent necessary, Hillsboro intends to continue its defense of the issuance of the permit.

We are also party to various other litigation matters, in most cases involving ordinary and routine claims incidental to our business.
We cannot reasonably estimate the ultimate legal and financial liability with respect to all pending litigation matters. However, we believe, based on our examination of such matters, that the ultimate liability will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. As of December 31, 2016, we have $4.8 million accrued, in aggregate, for various litigation matters.

Insurance Recoveries

We are currently in discussions with our insurance provider in regards to further potential recoveries under our policy related to the combustion event at our Hillsboro operation. During the year ended December 31, 2016, we recorded $10.5 million to cost of coal produced (excluding depreciation, depletion and amortization) in our consolidated statement of operations for the insurance recovery of mitigation costs (net of our policy deductible) and $20.0 million to other operating (income) expense related to business interruption insurance proceeds. However, there can be no assurances that we will receive any further insurance recoveries related to this incident.

Performance Bonds

We had outstanding surety bonds with third parties of $83.4 million as of December 31, 2016 to secure reclamation and other performance commitments. In February 2016, we were required to post cash collateral of $2.5 million to our surety bond provider and Foresight Reserves has provided a guarantee on $50.5 million of the surety bonds.

23. Employee Benefit Plans

The Partnership offers safe harbor 401(k) plans (the "Plans") for all employees who are eligible to participate. Employees are immediately eligible to participate upon becoming a full-time employee with the Partnership and its subsidiaries and affiliates. The Plans allow for the deferral of all or part of a participant's compensation, as defined by the Plans, up to the current limits provided by the Internal Revenue Service. The safe harbor matching feature calls for the Partnership to contribute 100% of the first 3% of compensation a participant contributes, and 50% of the next 2% of compensation contributed by the participant. Partnership contributions under the Plans for the years ended December 31, 2016, 2015, and 2014 were $3.0 million, $3.3 million, and $3.1 million, respectively.

24. Selected Quarterly Financial Information

A summary of the unaudited quarterly results for the years ended December 31, 2016 and 2015 is presented below:

	For the Year Ended December 31, 2016			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In Thousands, Except per Unit Data)			
Revenues	$ 166,085	$ 226,000	$ 230,825	$ 252,922
Operating income (loss)	$ 1,205	$ 12,585	$ 31,414	$ (22,475)
Net loss	$ (41,607)	$ (27,670)	$ (24,331)	$ (85,012)
Net loss attributable to limited partner units	$ (41,704)	$ (27,786)	$ (24,287)	$ (85,012)
Basic and diluted loss per limited partner unit	$ (0.32)	$ (0.21)	$ (0.19)	$ (0.65)

	For the Year Ended December 31, 2015			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In Thousands, Except per Unit Data)			
Revenues	$ 238,915	$ 251,222	$ 253,066	$ 241,650
Operating income (loss)	$ 70,058	$ 4,079	$ 38,079	$ (29,659)
Net income (loss)	$ 42,717	$ (25,280)	$ 8,188	$ (64,309)
Net income (loss) attributable to limited partner units	$ 42,283	$ (25,403)	$ 8,070	$ (64,427)
Basic and diluted income (loss) per limited partner unit	$ 0.33	$ (0.20)	$ 0.06	$ (0.49)

During the first, second and third quarters of 2016, we recognized debt restructuring costs of $9.7 million, $5.9 million, and $6.1 million, respectively.

During the third quarter of 2016, we recognized $10.5 million of insurance recoveries in cost of coal sales (excluding depreciation, depletion and amortization) related to the direct mitigation costs we incurred during 2015 and 2016 from the Hillsboro combustion event.

During the third quarter of 2016, we recognized a $13.2 million loss related to the early extinguishment of debt due to the restructuring of our debt.

During the fourth quarter of 2016, we recorded a long-lived asset impairment charge of $74.6 million related to certain affiliate prepaid royalties for which we determined recoupment was improbable.

During the fourth quarter of 2016, we recognized $20.0 million of other operating income related to business interruption insurance recoveries from the Hillsboro combustion event, which has idled the mine since March 2015.

During the fourth quarter of 2016, we recorded an $18.6 million loss for the change in fair value of the Warrants.

In the first quarter of 2015, $13.5 million was recognized as other operating income for a settlement agreement with Murray Energy resolving litigation between the Partnership and Murray Energy.

In the second, third and fourth quarters of 2015, we recorded transition and reorganization costs of $12.3 million, $5.0 million and $4.1 million, respectively, to reorganize certain corporate administrative functions to optimize synergies between the Partnership and Murray Energy.

In the fourth quarter of 2015, we recorded long-lived asset impairment charges of $12.6 million to impair $11.6 million of Hillsboro prepaid royalties with an affiliate and to write-off $1.0 million of deferred longwall costs at Hillsboro which are being abandoned as a result of the mine fire.

25. Subsequent Events

On February 13, 2017, we announced that we have commenced a process to refinance and extend the maturities of all or a portion of our existing indebtedness with the net proceeds from a combination of debt, equity financing and/or cash on hand. There can be no assurance regarding the results of the Partnership's refinancing and maturity extension efforts.

Foresight Energy LP

Schedule II — Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Written-off / Other	Balance at End of Period
			(In Thousands)			
2016						
Reserves deducted from asset accounts:						
Prepaid royalty recoupment reserve	$ 46,306	$ 74,575	$ —	$ —	$ (12,341)	$ 108,540
Reserve for materials and supplies	458	516	—	—	(254)	720
2015						
Reserves deducted from asset accounts:						
Prepaid royalty recoupment reserve	$ 34,700	$ 11,606	$ —	$ —	$ —	$ 46,306
Reserve for materials and supplies	—	458	—	—	—	458
2014						
Reserves deducted from asset accounts:						
Prepaid royalty recoupment reserve	$ —	$ 34,700	$ —	$ —	$ —	$ 34,700
Reserve for materials and supplies	—	—	—	—	—	—

Item 9. Changes in and Disagreements With Accountant on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

We evaluated, under the supervision and with the participation of our management, including our chief executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2016. Based on that evaluation, our management, including our chief executive officer and principal financial officer, concluded that the disclosure controls and procedures were effective in design and operation as of such date. There were no changes in our internal control over financial reporting during the fiscal quarter to which this report relates that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Changes in Internal Control over Financing Reporting

There have been no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2016 that have materially affected, or are reasonable likely to materially affect, our internal control over financial reporting.

Attestation Report of the Registered Public Accounting Firm

This Annual Report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our registered public accounting firm pursuant to rules of the SEC that permit us to provide only management's report in this Annual Report.

Management's Assessment of Internal Control Over Financial Reporting

Management of FELP is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(t) under the Securities Exchange Act of 1934. Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2016, with the participation of our chief executive officer and principal financial officer, based on the framework established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, or COSO. Based on this assessment, management concluded that the Partnership maintained effective internal control over financial reporting as of December 31, 2016.

Item 9B. Other Information

None.

P ART III.

Item 10. Directors, Executive Officers and Corporate Governance of the Managing General Partner

Management of Foresight Energy LP

We are managed and operated by the board of directors and executive officers of our general partner, Foresight Energy GP LLC, which is jointly owned by Foresight Reserves and Murray Energy. In accordance with the governing documents of Foresight Energy GP LLC, Foresight Reserves and Murray Energy have the right to appoint all members of the board of directors of our general partner, including those directors meeting the independence standards established by the NYSE. The directors are appointed by Foresight Reserves and Murray Energy in proportion to their respective voting interests in our general partner: Foresight Reserves' voting interest is approximately 66% and Murray Energy's voting interest is approximately 34%. Our unitholders will not be entitled to elect our general partner or its directors or otherwise directly participate in our management or operations. Our general partner owes certain contractual duties to our unitholders as well as a fiduciary duty to its owners.

The board of directors of our general partner has six directors, three of whom are independent as defined under the standards established by the NYSE and the Exchange Act. The NYSE does not require a listed publicly traded limited partnership, like us, to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating committee. However, our general partner is required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act.

Christopher Cline and Robert D. Moore allocate their time between managing our business and affairs and the business and affairs of Foresight Reserves and Murray Energy, respectively. The amount of time that they devote to our business and the business of the other companies varies in any given period based on a variety of factors. We expect that they will continue to devote as much time to the management of our business and affairs as is necessary for the proper conduct of our business and affairs. However, their duties to their other obligations may prevent them from devoting sufficient time to our business and affairs.

Neither our general partner nor Foresight Reserves receives any management fee or other compensation in connection with our general partner's management of our business, but we will reimburse our general partner for all expenses it incurs and payments it makes on our behalf. A wholly-owned subsidiary of Murray Energy provides certain management and administration services to the Partnership for a quarterly fee, which is subject to contractual adjustments. To the extent that FELP or FEGP directly incurs costs for any services covered under the MSA, then the Manager's quarterly fee is reduced accordingly. Also, to the extent that the Manager utilizes outside service providers to perform any of the services under the MSA, then the Manager is responsible for those outside service provider costs. The initial term of the MSA extends through December 31, 2022 and is subject to termination provisions.

Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates.

The following table shows information for the executive officers and directors of our general partner as of February 24, 2017. Directors hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Executive officers (other than Robert D. Moore) serve at the discretion of the board of directors of our general partner. Under the organizational documents of our general partner, any renewal or replacement of Robert D. Moore as Chief Executive Officer requires the consent of Murray Energy. There are no family relationships among any of our directors or executive officers. Some of our directors also serve as executive officers of Foresight Reserves.

Name	Age	Position
Christopher Cline	58	Chairman of the Board of Directors and Principal Strategy Advisor
Robert D. Moore	46	Director and President & Chief Executive Officer
G. Nicholas Casey	63	Director
Daniel S. Hermann	59	Director and Chairman of the Audit Committee
Brian D. Sullivan	49	Director
Paul H. Vining	61	Director
Rashda M. Buttar	48	Senior Vice President—General Counsel & Corporate Secretary
James T. Murphy	41	Vice President—Principal Financial Officer and Chief Accounting Officer

Christopher Cline is the Chairman of our general partner's board of directors and Principal Strategy Advisor, positions he has held since our inception in 2012. Mr. Cline has more than 30 years of experience in the coal industry. After attending Marshall University, he developed and operated over 25 coal mining, processing and transportation facilities in the Appalachian region and the Illinois Basin, including some of the most productive longwall mining operations in the country. During the past five years, Mr. Cline has focused his efforts primarily on developing Foresight Energy. The experience and qualifications that led to the conclusion that Mr. Cline should serve as a Director include his formation and leadership of the Partnership since its inception, significant and broad experience in the coal industry, and his proven business acumen.

Robert D. Moore is a member of the board of directors and President and Chief Executive Officer of our general partner. Mr. Moore has more than 25 years of experience in management, operations, finance, accounting, and acquisitions in the coal industry. He has been our President and Chief Executive Officer, and a member of the board of directors of our general partner, since May 2015. Mr. Moore also serves as Murray Energy Corporation's Executive Vice President, Chief Operating Officer, and Chief Financial Officer, a position he has held since August 2012, and he is a member of Murray Energy's board of directors. Mr. Moore has served as Murray Energy Corporation's Executive Vice President and Chief Financial Officer since September 2007. Mr. Moore was integral in Murray Energy's $3.05 billion acquisition of Consolidation Coal Company, from CONSOL Energy Inc., in December 2013. From 1993 to 2007, Mr. Moore held a number of financial and other senior management positions within Murray Energy. Mr. Moore received his Bachelor of Science degree from The Ohio State University in Accounting and Finance, his Certified Public Accountant certification from the State of Ohio, and his Master of Business Administration from The Ohio State University. The experience and qualifications that led to the conclusion that Mr. Moore should serve as a member of the board of directors of our general partner include his extensive knowledge of the coal industry and his financial expertise.

G. Nicholas Casey is an independent member of the board of directors of our general partner and a member of the Audit Committee. Mr. Casey was appointed to the board of directors of our general partner on September 9, 2015. Mr. Casey is currently a member of Lewis Glasser Casey & Rollins, PLLC, attorneys at law, where he served as managing member from 2008 to 2015. He is also a member of LGCR Government Solutions LLC, where he served as managing member from 2008 to 2014. Additionally, Mr. Casey serves as Treasurer of the American Bar Association and as a member of its Board of Governors. He also serves on the board of directors of Security National Trust, Inc. Mr. Casey received an undergraduate degree in accounting from the University of Kentucky and a law degree from West Virginia University College of Law. The experience and qualifications that led to the conclusion that Mr. Casey should serve as a Director include his extensive experience in accounting, business development, financing, real estate and management matters.

Daniel S. Hermann is an independent member of the board of directors of our general partner and also serves as Chairman of the Audit Committee. He was appointed to the board of directors of our general partner in September 2014. Mr. Hermann is the retired Chief Executive Officer of AmeriQual Group, LLC, a food packaging company and leading supplier of field rations to the United States Department of Defense. Prior to joining AmeriQual, he spent 23 years with Black Beauty Coal Company, where he held various titles, including President and Chief Executive Officer and Chief Financial Officer. During his tenure at Black Beauty, Mr. Hermann was part of a successful team that grew the company into the largest coal producer in the Illinois Basin. In 2003, Black Beauty was acquired by Peabody Energy and Mr. Hermann spent the next two years as Group Executive for Peabody's Midwest Division. Mr. Hermann is currently on the board of directors of Deaconess Health Systems and serves as Vice Chairman of the Board and also serves as a member of the Finance, Governance and Compensation Committees. He also serves as a Director of Fifth Third Bank Southern Indiana. Mr. Hermann holds a Bachelor of Science degree from Indiana State University in Evansville and was a certified public accountant. The experience and qualifications that led to the conclusion that Mr. Hermann should serve as a member of the board of directors of our general partner and as Chairman of the Audit Committee include his extensive knowledge of the coal industry and his financial expertise.

Brian D. Sullivan is a member of the board of directors of our general partner. He was appointed to the board of directors of our general partner on August 10, 2016. Mr. Sullivan is currently a managing member of Energy Resource Services, LLC, a consulting company that provides M&A and commercial advisory services to companies in the natural resources, energy and industrial sectors ("Energy Resource"), a position he has held since April 2016. Between September 2015 and March 2016, Mr. Sullivan was the Chief Commercial Officer for Bluestone Resources, Inc., an acquisition-focused oil and gas company. Between December 2010 and September 2015, Mr. Sullivan worked in various roles with Alpha Natural Resources, Inc. ("Alpha"), one of the largest coal companies in the United States, serving as the Executive Vice President and Chief Commercial Officer, and spent two years working for Alpha in Australia. Mr. Sullivan was also Senior Vice President and General Counsel to The United Company ("United"), a private diversified holding company headquartered in Bristol, Virginia, as well as to United's subsidiaries in the coal, and oil and gas businesses. In this position, which he held for almost 10 years beginning in 2001, he was responsible for all aspects of M&A activity, contract negotiation and administration, human resources, and litigation. Before his career with United, Mr. Sullivan was litigation counsel with Paul, Hastings, Janofsky & Walker LLP, in the firm's Atlanta office. He began in the legal profession in Washington D.C., in 1992 with Arent Fox LLP. Mr. Sullivan is a graduate of Duke University and graduated summa cum laude from the State University of New York at Buffalo School of Law. Mr. Sullivan has served on the boards of the Virginia Center for Coal and Energy

Research, the Virginia Coal Association, the National Mining Association, Pfeiffer University in Charlotte, Barter Theater (the State Theater of Virginia) and Crossroads Medical Mission. The experience and qualifications that led to the conclusion that Mr. Sullivan should serve as a member of the board of directors of our general partner include his legal background, extensive knowledge of the energy industry and his financial expertise.

Paul H. Vining is a member of the board of directors of our general partner. He was appointed to the board of directors of our general partner on January 1, 2016. Mr. Vining is currently the CEO of The Cline Group LLC, as well as President of Foresight Reserves LP and CEO of Cutlass Collieries LLC, the international development arm of The Cline Group. Mr. Vining previously served as president of Alpha Natural Resources (“Alpha”) from April 2012 until January 2015, which filed for reorganization under Chapter 11 of the United States Bankruptcy Code (the “Bankruptcy Code”) in August 2015. Prior to that, he served as executive vice president and chief operating officer of Alpha from May 2011 until April 2012. Mr. Vining served as chief executive officer of White Oak Resources from October 2010 until April 2011. He served as president and chief operating officer of Patriot Coal Corporation from July 2008 until September 2010, which filed for reorganization under Chapter 11 of the Bankruptcy Code in July 2012. Mr. Vining has over 35 years of experience in the coal business which in addition to the above includes being the chief executive officer of Magnum Coal Company, the top executive sales and trading positions for both Arch Coal and Peabody Energy, and key sales and commercial roles at AGIPCOAL USA, Island Creek Coal Company and A. T. Massey Coal Company. Mr. Vining earned his Bachelor of Science in Chemistry from the College of William and Mary as well as his Bachelor of Science in Mineral Engineering and Master of Science in Extractive Metallurgy from Columbia University’s Henry Krumb School of Mines. The experience and qualifications that led to the conclusion that Mr. Vining should serve as a member of the board of directors of our general partner include his extensive knowledge of the coal industry and his financial expertise.

Rashda M. Buttar is the Senior Vice President—General Counsel & Corporate Secretary of our general partner. Before joining the Partnership in September 2011, Ms. Buttar served as Vice President, Associate General Counsel and Corporate Secretary of Patriot Coal Corporation from 2007 to August 2011. Prior to joining Patriot Coal Corporation, Ms. Buttar served as the Assistant General Counsel and Assistant Corporate Secretary of TALX Corporation from 2003 to 2007. Ms. Buttar received her Juris Doctor from Saint Louis University School of Law and her undergraduate degree in Russian and Eastern European Studies and Political Science from Saint Louis University.

James T. Murphy is the Principal Financial Officer and Chief Accounting Officer of our general partner. Mr. Murphy has served is this capacity for our General Partner since June 2015. Mr. Murphy served as Controller of the General Partner of Foresight Energy LLC (the predecessor of the Partnership) from 2011 to 2015, and as VP & Controller of the General Partner or Foresight Energy LLC from December 2014 to June 2015. Mr. Murphy served as the Assistant Controller of Arch Coal Inc. from 2008 to 2011. Mr. Murphy is a certified public accountant and holds a Bachelor of Science in Business Administration from University of Missouri St. Louis.

Director Independence

Our board has determined that Messrs. Casey, Hermann and Sullivan are independent as defined by the rules of the NYSE and under Rule 10A-3 promulgated under the Exchange Act.

Non-management Director Meetings

Our non-management directors meet in an executive session at each regularly scheduled meeting of the board of directors of our general partner. The role of presiding director at each such meeting is rotated amount the non-management directors.

Communications with the Board of Directors

Interested parties may contact the chairpersons of any of our board committees, our board’s independent directors as a group or our full board in writing by mail to Foresight Energy LP, One Metropolitan Square, 211 North Broadway, Suite 2600, St. Louis, MO 63102, Attention: Corporate Secretary. All such communications will be delivered to the director or directors to whom they are addressed.

Committees of the Board of Directors

The board of directors of our general partner has an audit committee established in accordance with the Exchange Act and a synergy & conflicts committee. We do not currently have a compensation committee, but rather the board of directors of our general partner approves equity grants to directors and employees.

Audit Committee

We are required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act. Messrs. Casey, Hermann and Sullivan currently serve on our audit committee. The board of directors of our general partner has determined that Mr. Hermann qualifies as an "audit committee financial expert," as such term is defined under SEC rules.

The audit committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm, and (3) pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has been given unrestricted access to the audit committee and our management.

Synergy & Conflicts Committee

The members of the synergy and conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, including Foresight Reserves and Murray Energy, and must meet the independence standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors, along with other requirements in our partnership agreement. The members of the synergy and conflicts committee are current Messrs. Casey, Hermann and Sullivan. The independent members of the board of directors of our general partner serve on the synergy and conflicts committee to review specific matters that the board believes may involve conflicts of interest and determines to submit to the conflicts committee for review. The synergy and conflicts committee determines if the resolution of the conflict of interest is adverse to the interest of the partnership. Any matters approved by the synergy and conflicts committee are conclusively deemed to be approved by us and all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. In addition, the synergy and conflicts committee is responsible for reviewing, approving, or denying approval of: (i) any unbudgeted affiliate or synergy transactions involving us, in each case having a value in excess of $5.0 million; and (ii) any transaction which would, if consummated, provide financing for or be materially related to the redemption of the Exchangeable PIK Notes, and will be delegated all rights, power and authority of the board of directors of the general partner in respect thereof. In respect of the matters over which the synergy and conflicts committee has been delegated authority under clause (i) and (ii) of the last sentence, the synergy and conflicts committee: (i) has the right to retain independent financial and legal advisors of its own choosing; (ii) is empowered to act on behalf of us independently of any affiliates or interested directors; and (iii) has the power to enforce the decision made by it (including any decision to reject any proposed transaction with any affiliate of ours).

Corporate Governance

The board of directors of our general partner has adopted Corporate Governance Guidelines that outline important policies and practices regarding our governance. The board of directors of our general partner has also adopted a Code of Business Conduct and Ethics (the "Code") that applies to all employees and officers of Foresight Energy LP and Foresight Energy GP LLC, including its principal executive officer, principal financial and accounting officer, and members of the board.

Available Information

We file annual, quarterly and current reports, and amendments to those reports, and other information with the Securities and Exchange Commission ("SEC"). You may access and read our filings without charge through the SEC's website, at www.sec.gov. You may also read and copy any document we file at the SEC's public reference room located at 100 F Street, N.E., Room 1580, and Washington, D.C. 20549. Please call the SEC at 1-800- SEC-0330 for further information on the public reference room.

We also make the documents listed above, including our Corporate Governance Guidelines and the Code, available without charge under the Investors Relations tab of our website, www.foresight.com , Our annual, quarterly and current reports, and amendments to those reports, and other information filed with the SEC, are posted to the website as soon as practicable after we file or furnish them with the SEC. The information on our website is not part of this Annual Report on Form 10-K.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Overview of Compensation Program

We seek to ensure that the total compensation paid to our executive officers is fair, reasonable, and competitive. This compensation discussion and analysis ("CD&A") provides information about our compensation objectives and policies for 2016 for our principal executive officer, our principal financial officer and our other most highly compensated executive officer and is intended to place in perspective the information contained in the executive compensation tables that follow this discussion. This CD&A provides a general description of our compensation programs and specific information about its various components.

Throughout this discussion, the following individuals are referred to collectively as the "Named Executive Officers" and are included in the Summary Compensation Table:

- Robert D. Moore, President – Chief Executive Officer;
- Rashda M. Buttar, Senior Vice President — General Counsel & Corporate Secretary; and
- James T. Murphy, Vice President & Chief Accounting Officer.

Compensation Philosophy and Objectives

We believe our success depends on the continued contributions of our Named Executive Officers. While we do not maintain a formal compensation philosophy, our executive compensation programs are designed for the purpose of motivating and retaining experienced and qualified executive officers with compensation that recognizes individual merit and overall business results. Our compensation programs are also intended to support the attainment of our strategic objectives by tying the interests of our Named Executive Officers to those of our unitholders through the operational and financial performance goals.

The principal elements of our executive compensation programs for the 2016 year were base salary and annual cash incentives and the employee benefit arrangements made available to our full-time employees generally. The employee benefit arrangements provided to our Named Executive Officers consist of life and health insurance benefits, a qualified safe harbor 401(k) savings plan and paid vacation and holidays. In recent years we have not considered equity compensation awards to be a principal element of our compensation program and we did not grant equity-based incentive awards to the Named Executive Officers during the 2016 year.

Compensation Practices and Procedures

Role of the Board of Directors

We do not have a compensation committee. Material compensation decisions with respect to our Named Executive Officers are approved by the Board but, where appropriate, decisions are made in conjunction with the advice and recommendations of the Named Executive Officers. The responsibility of the Board may include reviewing base salary and incentive compensation levels, and in applicable years, administering our equity compensation plans.

Role of Principal Strategy Advisor in Compensation Decisions

As a Director and our Principal Strategy Advisor, Mr. Cline is closely involved in evaluating our overall executive compensation programs. Mr. Cline's specific role in determining compensation is to make recommendations to the other members of the Board on general compensation matters with respect to applicable Named Executive Officers. In making such recommendations, Mr. Cline takes into account his general business knowledge and experience and his specific knowledge of the market in which we compete for talent.

Role of Named Executive Officers in Compensation Decisions in 2016

In the role of President and Chief Executive Officer, Mr. Moore assisted in determining executive compensation by making recommendations to the other members of the Board on material compensation decisions for officers other than himself based upon his assessment of the individual performance of each executive officer and overall performance. In addition, in recommending specific levels or components of compensation, Mr. Moore, took into account his general business knowledge and experience and specific knowledge of the market in which we compete for talent. In the role of Senior Vice President — General Counsel & Corporate

Secretary, Ms. Buttar has also provided compensation recommendations regarding Named Executive Officer compensation other than her own and assisted in the administration of our compensation programs.

Role of Compensation Consultant

During 2016, we did not retain the services of a compensation consultant or conduct benchmarking or specific market review of our compensation levels or practices. Instead, our compensation levels and practices are established as noted above.

Components of the Compensation Program

For the year ended December 31, 2016, the principal components of compensation for the Named Executive Officers were base salary and annual cash incentives. We have determined not to grant equity awards with respect to services provided in the 2016 year.

Base Salary

We established the base salary for each Named Executive Officer based on consideration of many factors, including the individual's performance and experience, the pay of others on the executive team and our Board's assessment of the market in which we compete for talent. The base salary compensation is intended to provide security and a reliable, but not excessive, source of income to our Named Executive Officers. Our Board periodically reviews the base salaries of our Named Executive Officers and has the discretion to make adjustments based upon any factor it deems relevant, including those described above. Salaries paid to each of our Named Executive Officers for the 2016 year are reflected in the Summary Compensation Table.

Our Board did not make base salary decisions for Mr. Moore in 2016, as his compensation is generally not paid directly by us. Although Mr. Moore provides employment services to both Murray Energy Corporation and to us, he also has many overlapping roles and duties due to the close relationship that we maintain with Murray Energy Corporation following their investment in us. We will pay a predetermined annual fee to Murray Energy Corporation for Mr. Moore's services. While there is not a specific allocation to us with respect to Mr. Moore's services, we have determined that it would be appropriate to allocate a portion of the total compensation that he receives from Murray Energy Corporation to us within the Summary Compensation Table below. The allocated amount was determined by looking at the time that Mr. Moore spends at each of the respective companies as well as the time spend in his duties that may overlap and benefit both companies. It was determined that allocating $250,000 of Mr. Moore's compensation to us was a reasonable estimate of the portion of the payment that we make to Murray Energy Corporation for Mr. Moore's services.

Annual Cash Incentives

We provide each of our Named Executive Officers with an opportunity to earn an annual cash incentive. Following the completion of the 2016 year, the President and Chief Executive Officer made recommendations regarding annual incentive payments for Ms. Buttar and Mr. Murphy, and the Board will make decisions regarding Mr. Moore's annual incentive awards. The amount of each Named Executive Officer's annual cash incentive for any given year is based upon subjective determination of such individual's respective individual contributions to the Partnership, to successful mining operations and to our overall performance during the year, in the area for which they are responsible. Such annual cash incentives to our Named Executive Officers are discretionary and therefore not formally based upon any pre-established performance metrics or targeted to any specific level of compensation, although the Partnership's operational and strategic goals are also taken into consideration as appropriate.

Our company went through a significant restructuring during the 2016 year, and the Named Executive Officers were faced with various challenges and uncertainties. Ms. Buttar and Mr. Murphy received an annual incentive bonus that was due to our desire to retain and motivate our two independent members of management (meaning that neither executive has a personal or business relationship with our significant equity holders such as Murray Energy Corporation), and intended to reward the executives for their efforts on our behalf during the restructuring. The Board also determined that Mr. Moore should receive an annual incentive bonus in 2016 due to his significant role in our restructuring. Mr. Moore was critical to our successful reorganization, which included multiple transactions throughout the 2016 year such as the exchange of old senior notes for new notes and warrants, entering into new registration rights agreements, modifying credit facilities and entering into new credit agreements.

Retention Award Agreements

We entered into retention award agreements with Ms. Buttar and Mr. Murphy on February 26, 2016 (the "Retention Agreements"). The Retention Agreements are intended to recognize exceptional individual performance of each executive's duties and to retain the services of Ms. Buttar and Mr. Murphy for certain periods of time. The Retention Agreements provided each executive with an immediate cash retention payment that is subject to repayment by the executive on a pro-rata basis if the executive is terminated under certain conditions during a retention period that ends on June 4, 2017 for Ms. Buttar and February 26, 2018 for Mr.

Murphy. Ms. Buttar received a cash retention payment of $1,000,000, while Mr. Murphy received a cash retention payment of $450,000.

In the event that either executive is terminated for cause or voluntarily resigns without good reason prior to the end of the applicable retention period for that executive, the executive will be required to repay a portion of the cash payment calculated by using the number of days that have passed within the retention period. The executives will not be required to make a repayment of any portion of the retention payment amount in the event of a termination of employment for reasons other than a termination for cause or a voluntary resignation for good reason. For purposes of the Retention Agreements, the term “cause” shall mean: (i) an executive’s willful failure to perform his or her duties (other than a failure resulting from an incapacity due to physical or mental illness); (ii) an executive’s continuous willful failure to comply with the valid directives of any person that the executive reports to or the Board; (iii) an executive’s willful engagement in dishonesty, illegal conduct or gross misconduct that is materially injurious to us or our affiliates; (iv) an executive’s embezzlement, misappropriation or fraud; (v) an executive’s conviction of or a plea of nolo contendere to a crime that constitutes a felony (or a state law equivalent) or a crime that constitutes a misdemeanor that involves moral turpitude, if such felony or crime is work-related, materially impairs the executive’s ability to perform services for us, or results in material reputational or financial harm to us or our affiliates; or (vi) an executive’s material breach of any obligation under the Retention Agreement. A termination for “good reason” will occur if, without the executive’s consent, (a) we impose a reduction in base salary or a relocation of more than fifty miles; (b) we materially breach a term of the Retention Agreements or another agreement between us and the executive; (c) we fail to have a successor company assume the Retention Agreements; or (d) we impose a material adverse change in the executive’s title, authority, duties or responsibilities.

The Retention Agreements impose a non-solicitation restriction on each executive during the term of their employment and continuing for a one year period following a termination for any reason. The Retention Agreements also subject the executives to a non-disparagement restriction during the term of their employment and following their termination indefinitely.

Equity Compensation Awards

In connection with our initial public offering, we established a long-term incentive plan which permits the Board to grant a variety of different types of equity compensation awards. Although, historically we have granted common units and phantom units under the plan, but no awards were granted during the 2016 year.

Retirement and Other Benefits

Our Named Executive Officers are entitled to participate in group health, term life, and similar benefit plans available to all of our employees on the same terms as such employees. During 2016, Foresight Energy Services LLC maintained a plan intended to provide benefits under section 401(k) of the Code pursuant to which eligible employees are permitted to contribute portions of their compensation into a tax-qualified retirement account (the “401(k) Plan”). For 2016, the plan provided safe harbor matching contributions equal to 100% of the first 3% of eligible compensation contributed by a participant to his or her account and 50% of the next 2% of eligible compensation contributed. Each of the Named Executive Officers participated in the 401(k) Plan during the 2016 year and received company contributions into their accounts, as noted within the Summary Compensation Table below.

Perquisites

The Partnership may provide a limited amount of perquisites and personal benefits to the current Named Executive Officers, although no such benefits were provided during the 2016 year. On a going-forward basis we do not intend to provide the Named Executive Officers with benefits that are materially different than those provided to our employees generally.

Employment Agreements and Severance Benefits

We did not maintain any employment agreements or severance plans which covered our Named Executive Officers during the 2016 year.

Tax and Accounting Implications

Deductibility of Executive Compensation

We are a limited partnership and not a corporation for U.S. federal income tax purposes. Therefore, we believe that the compensation paid to the Named Executive Officers is not subject to the deduction limitations under Section 162(m) of the Internal Revenue Code and therefore is generally fully deductible for federal income tax purposes.

Accounting for Equity-Based Compensation

We granted equity compensation awards in previous years. For our unit-based compensation arrangements, we recorded compensation expense over the vesting period of the awards, as discussed further in Part II. "Item 8, Financial Statements and Supplementary Data, Note 19 - Equity-Based Compensation" in this Annual Report on Form 10-K.

Risk Assessment Related to our Compensation Structure

We believe our compensation programs for our Named Executive Officers, as well as our other employees, are appropriately structured and are not reasonably likely to result in material risk to us. We also believe our compensation programs are structured in a manner that does not promote excessive risk-taking that could harm our value or reward poor judgment. We believe we have allocated our compensation among base salary and short-term compensation programs in such a way as to not encourage excessive risk-taking. In particular, we generally do not adjust base annual salaries for the Named Executive Officers and other employees significantly from year to year, and therefore the annual base salary of our employees is not generally impacted by our overall financial performance or the financial performance of an operating segment.

Anti-Hedging Policies

Our insider trading policy prohibits our directors and executive officers from engaging in any hedging or similar practices designed to offset a decrease in the price of our units.

Report of Board of Directors

We do not have a compensation committee. Our Board has reviewed and discussed the Compensation Discussion and Analysis with management and, based on such review and discussions approved the Compensation Discussion and Analysis included herein.

- Christopher Cline
- Robert D. Moore
- Paul H. Vining
- Daniel S. Hermann
- G. Nicholas Casey
- Brian Sullivan

Executive Compensation

The following table summarizes the compensation we paid during the years ended December 31, 2016, 2015 and 2014, as applicable, to our Named Executive Officers.

Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($) (2)	Unit Awards ($) (3)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value & Nonqualified Deferred Compensation ($)	All Other Compensation (4)	Total ($)
Robert D. Moore, President & Chief Executive Officer (1)	2016	$ 250,000	$ 800,000	$ -	$ -	$ -	$ -	$ 1,050,000
	2015	$ 250,000	$ -	$ -	$ -	$ -	$ -	$ 250,000
Rashda M. Buttar, Senior Vice President - General Counsel & Corporate Secretary	2016	$ 450,000	$ 1,175,000	$ -	$ -	$ -	$ 15,606	$ 1,640,606
	2015	$ 339,423	$ 800,000	$ 200,000	$ -	$ -	$ 10,995	$ 1,350,418
	2014	$ 325,000	$ 175,000	$ 958,334	$ -	$ -	$ 11,210	$ 1,469,544
James T. Murphy, Vice President – Chief Accounting Officer	2016	$ 250,000	$ 625,000	$ -	$ -	$ -	$ 12,738	$ 887,738
	2015	$ 247,115	$ 725,000	$ 60,000	$ -	$ -	$ 9,323	$ 1,041,438

(1) We do not pay a base salary directly to Mr. Moore. Amounts reflected within the "Salary" column for Mr. Moore reflect the portion of his compensation that was determined appropriate to allocate to us pursuant to the services agreement that we maintain with Murray Energy Corporation. Further descriptions of the service agreement and our methodology for determining Mr. Moore's allocated salary costs are described within the Compensation Discussion and Analysis above.

(2) Amounts included within the Bonus column reflect annual incentive bonuses paid by us with respect to the 2016 year, although the payments were actually made within the first quarter of 2017.

(3) Unit award amounts for previous years reflect the aggregate grant date fair value of unit and phantom unit awards granted during the periods presented calculated in accordance with Accounting Standards Codification 718.

(4) "All Other Compensation" for 2016 consisted of the following: (i) for Ms. Buttar: $15,606 for annual life insurance premiums paid on a life insurance policy for her benefit, matching contributions made to the 401(k) Plan and parking fees paid by the Partnership on her behalf and (ii) for Mr. Murphy: $12,738 for annual life insurance premiums paid on a life insurance policy for his benefit, matching contributions made to the 401(k) Plan and parking fees paid by the Partnership on his behalf.

Grants of Plan-Based Awards

No grants of plan-based awards were made during the year ended December 31, 2016.

Outstanding Equity Awards at Fiscal Year-End

None of the Named Executive Officers held outstanding equity compensation awards as of December 31, 2016.

Option Exercises and Units Vested

No Named Executive Officer held option awards during 2016.

Pension and Nonqualified Deferred Compensation Benefits

None of our Named Executive Officers participate in any defined benefit pension or nonqualified deferred compensation plans.

Potential Payments upon Termination or Change in Control

Generally, none of our Named Executive Officers are parties to any plans or agreements which provide for benefits in connection with termination of employment or upon a change of control. Although we entered into the Retention Agreements with Ms. Buttar and Mr. Murphy during the 2016 year, the Retention Agreements do not provide the executives with additional payments or benefits upon a termination of employment or a change of control.

Director Compensation

The compensation of the directors of our general partner is set by the Board. Messrs. Cline, Moore and Vining received no director compensation. The directors who are eligible to receive compensation for their services to our Board will receive $125,000 in cash as an annual retainer fee, as well as a $15,000 retainer for services to our audit committee. The eligible directors will also receive an annual phantom unit award in the amount of $75,000 which will be designed to vest pro-rata over a three year period.

Each independent director of the Board serving as of January 25, 2016 received a one-time retention bonus. Each eligible director received a payment of $125,000, subject to pro-rata repayment by the director in the event that he voluntarily resigned from the Board or refused to stand for reelection, in either case during the twelve-month retention period ending January 25, 2017.

Name	Fees Earned or Paid in cash	Unit Award (1)	Option Awards	Non-Equity Incentive Plan Compensation	Change in Pension Value & Nonqualified Deferred Compensation	All Other Compensation (2)	Total
Daniel S. Hermann	$140,000	$75,000	-	-	-	$125,000	$340,000
Bennett Hatfield	-	-	-	-	-	$125,000	$125,000
G. Nicholas Casey	$140,000	$75,000	-	-	-	$125,000	$340,000
Brian Sullivan (3)	$140,000	$75,000	-	-	-	-	$215,000

(1) The values set forth reflect awards of phantom units and are based on the grant date fair value of the awards computed in accordance with FASB ASC 718. The grant date fair value is computed based upon the closing price of Foresight Energy LP's common units on the date of grant. As of December 31, 2016, Mr. Hermann, Mr. Casey and Mr. Sullivan had aggregate outstanding unvested awards of 74,621 units.
(2) The values set forth reflect one-time retention awards paid in 2016.
(3) Mr. Sullivan was appointed August 10, 2016.

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

The following table sets forth certain information as of February 24, 2017 regarding the beneficial ownership of common and subordinated units held by (a) each director of our managing general partner, (b) each executive officer of our managing general partner, (c) all such directors and executive officers as a group, and (d) each person known by our managing general partner to be the beneficial owner of 5% or more of our common units. Our managing general partner is owned by 65.34% by Foresight Reserves, 34.0% by Murray Energy Corporation, and 0.66% by Michael J. Beyer, the former Chief Executive Officer of our general partner. The address of each of Foresight Energy GP LLC, Christopher Cline, the Cline Trust Company and each of the directors and officers reflected in the table below is 3801 PGA Blvd., Suite 903, Palm Beach Gardens, Florida 33410. The address of Accipiter Capital Management, LLC is 3801 PGA Blvd., Suite 600, Palm Beach Gardens, Florida 33410. The percentage of units beneficially owned is based on 66,104,908 common units and 64,954,691 subordinated units outstanding.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Common and Subordinated Units Beneficially Owned
5% Unitholders:					
Murray Energy Corporation (1)	—	*	64,954,691	100.0%	50.0%
Christopher Cline	19,089,218	28.9%	—	*	14.7%
Cline Trust Company (2)	20,323,188	30.7%	—	*	15.6%
Accipiter Capital Management, LLC	7,622,302	11.5%	—	*	5.9%
Executive Officers and Directors (2) :					
Christopher Cline	(b)	(b)	(b)	(b)	(b)
Robert D. Moore	—	*	—	*	*
G. Nicholas Casey	3,302	*	—	*	*
Daniel S. Hermann	16,668	*	—	*	*
Brian D. Sullivan	—	*	—	*	*
Paul H. Vining	—	*	—	*	*
Rashda M. Buttar	44,467	*	—	*	*
James T. Murphy	8,666	*	—	*	*
Aggregate - executive officers and directors	73,103	*	—	*	*

* Less than one percent.

(1) Murray Energy Corporation's address is: 46226 National Road, St. Clairsville, OH, 43950. Murray Energy Corporation owns a 34% voting interest in our general partner. Robert E. Murray may be deemed to have voting and investment power over the common units. In addition, on or prior to October 2, 2017, Murray Energy and its affiliates, or a group of persons which includes Murray Energy may purchase all of the outstanding Exchangeable PIK Notes by paying a purchase price in cash equal to 100% of the principal amount of the Exchangeable PIK Notes to be purchased plus accrued and unpaid interest, if any, to (but excluding) the purchase date (the "Murray Purchase"). Immediately prior to the consummation of such a purchase of Notes (but subject to such purchase being consummated), the exchange rate for the Exchangeable PIK Notes will automatically become the lesser of (i) the exchange rate in effect on the business day immediately prior to the Murray purchase date, and (ii) a number equal to one divided by 92.5% of the 30 trading day volume weighted average price on the purchase date.

(2) Donald R. Holcomb, the manager of Cline Trust Company, may be deemed to have voting and investment power over the common units held of record by Cline Trust Company. The members of the Cline Trust Company are four trusts of which Mr. Holcomb is trustee, each of which owns an approximately equal interest in the Cline Trust Company: (i) The Alex T. Cline 2004 Irrevocable Trust, the beneficiary of which is Alex T. Cline, a child of Mr. Cline, (ii) The Candace L. Cline 2004 Irrevocable Trust, the beneficiary of which is Candace L. Cline, a child of Mr. Cline, (iii) The Christopher L. Cline 2004 Irrevocable Trust, the beneficiary of which is Christopher L. Cline, a child of Mr. Cline, and (iv) The Kameron N. Cline 2004 Irrevocable Trust, the beneficiary of which is Kameron N. Cline, a child of Mr. Cline. Mr. Holcomb is the former Vice President, Secretary and Treasurer of Cline Resource Development Company d/b/a The Cline Group ("CRDC"), which is wholly owned by Christopher Cline. Mr. Holcomb also served as the Chief Financial Officer of Foresight Reserves until March 31, 2013.

(3) Units held personally by Christopher Cline, as an individual, are included in the 5% Unitholders section above.

Equity Compensation Plan Information

The following table sets forth information with respect to compensation plans under which our equity is authorized for issuance.

Plan Category	Number of Units to Be Issued Upon Exercise of Outstanding Unit Options and Rights as of December 31, 2016	Weighted Average Exercise Price of Outstanding Unit Options and Rights	Number of Units Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) as of December 31, 2016
Equity compensation plans approved by unitholders:			
None	—	—	—
Equity compensation plans not approved by unitholders:			
Long-term incentive plan (1)	278,539	—	4,779,780
Total for equity compensation plans	278,539	—	4,779,780

(1) The Long-Term Incentive Plan ("LTIP") was adopted by our general partner in June 2014 in connection with our IPO and did not require approval by our unitholders. The LTIP contemplates the issuance of up to 7,000,000 common units to satisfy awards under the LTIP.

Item 13. Certain Relationships and Related Transactions and Director Independence

Certain Relationships and Related Transactions

The terms of the transactions and agreements disclosed in this section were determined by and among affiliated entities and, consequently, cannot be presumed to be the result of arm's-length negotiations. These terms are not necessarily at least as favorable to the parties to these transactions and agreements as the terms that could have been obtained from unaffiliated third parties.

Affiliated entities principally include: (a) Entities owned and controlled by Chris Cline, the majority owner of our general partner, (b) Murray Energy Corporation, owner of a 34% interest in our general partner and owner of all of the outstanding subordinated units, and (c) NRP and its affiliates, for which Chris Cline owns a beneficial interest in the general partner and limited partner interests.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with the formation, ongoing operation and any liquidation of Foresight Energy LP.

Formation Stage

The consideration received by Foresight Reserves and a member of management for the contribution of their interests	• Common and subordinated units of 47,238,895 and 64,738,895, respectively and • the incentive distribution rights

The net proceeds from the IPO were used to pay a $115.0 million special distribution to Foresight Reserves and a member of management and to repay $210.0 million of outstanding Term Loan principal.

Operational Stage

Distributions to our general partner and its affiliates	If distributions to the unitholders exceed the minimum quarterly distribution and other higher target levels, the IDR holders will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target level.
Payments to our general partner and its affiliates	Our general partner does not receive a management fee or other compensation for its management of Foresight Energy LP, but we reimburse our general partner and its affiliates for all expenses they incur and payments they make on our behalf. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us.
Liquidation Stage	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Registration Rights Agreement

Under our partnership agreement, we have agreed to register for resale under the Securities Act of 1933 and applicable state securities laws any common units, subordinated units or other limited partner interests proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts.

Transactions with Natural Resource Partners, L.P. and its Affiliates

We have engaged in a series of transactions with NRP and its affiliates, an entity in which Christopher Cline directly and indirectly beneficially owns 4% of the limited partnership interest. In addition to his 4% limited partnership ownership in NRP, Chris Cline also directly and indirectly beneficially owns 31% of the limited partnership interests in NRP's general partner. Foresight Reserves and its subsidiaries have sold to NRP or subsidiaries of NRP certain coal reserves and transportation assets in exchange for equity in NRP and its general partner as well as entering into a restricted business contribution agreement and leases under which we will make royalty payments and pay fees as we mine leased coal and use leased transportation facilities owned by NRP, all as more further described below. Subsidiaries of NRP for which we have transacted include HOD, WPP, Williamson Transport, LLC (“Williamson Transport”) and Independence Energy, LLC (“Independence”).

On January 4, 2007, Chris Cline, Foresight Reserves, Adena Minerals LLC and their respective affiliates (collectively, “Adena Entities”) and NRP executed a restricted business contribution agreement. The restricted business contribution agreement obligates the Adena Entities and their affiliates to offer NRP any business owned, operated or invested in by the Adena Entities, subject to certain exceptions, that either (a) owns, leases or invests in hard minerals or (b) owns, operates, leases or invests in identified transportation infrastructure relating to certain future mine developments by the Adena Entities in Illinois. NRP’s acquisition of certain coal reserves and infrastructure assets related to our Macoupin, Hillsboro and Sugar Camp mining complexes, discussed more fully below, were deals consummated under the restricted business contribution agreement with the Adena Entities. We are required to offer and could consummate additional deals under the Restricted Business Contribution Agreement in the future.

Williamson has a coal mining lease agreement with WPP with an initial term of 15 years and options for an additional five years or until all merchantable and mineable coal has been mined and removed. Williamson is required to pay the greater of 8.0% of the gross selling price or $2.50 per ton for the first eight million tons of clean coal mined from the leased premises in any calendar year. For all tonnage mined in excess of the eight million tons, the royalty is the greater of 5.0% of the gross selling price or $1.50 per ton of clean coal mined from the leased premises. In addition to the tonnage royalty, the quarterly minimum royalty is $2.0 million, payable on the 20th of January, April, July and October in each year this lease is in effect, for the prior quarter production. The minimum royalty is recoupable on future tons mined during the preceding nineteen quarters from the excess tonnage royalty on a first paid, first recouped basis. Furthermore, the lease provides for an overriding royalty of $0.10 per ton on the first 8.5 million tons mined from specific coal reserves outlined in the agreement. The lease also requires a wheelage payable at 0.5% of the gross selling price when foreign coal is transported over the premises. During the years ended December 31, 2016, 2015 and 2014, Williamson paid $14.6 million, $12.7 million and $19.8 million, respectively, in royalties and other payments to WPP under this coal lease.

Williamson leases property from Williamson Transport under two surface leases with initial terms through October 15, 2031 and an option to extend the leases in five-year increments until all the coal leased from an NRP affiliate is mined on Williamson’s premises. Williamson Transport has the option to put the land to Williamson for its fair market value as determined by an independent appraiser at any time during the lease term. Additionally, under a separate lease with an initial term through March 12, 2018, Williamson pays $5,000 per year for use of the premises and a fee currently at $1.84 per ton for each ton of coal produced at Williamson that is loaded through the Williamson Loadout facility, which escalates approximately $0.02 per year throughout the term of the agreement. Williamson Transport may elect to renew or extend the sublease for successive five-year periods. If Williamson Transport elects not to renew the sublease, Williamson has the option to buy the Williamson Loadout facility for its fair market value as determined by an independent appraiser. Williamson receives a fee of $0.25 per ton from Williamson Transport for each ton of coal that is loaded through the Williamson Loadout facility in exchange for operating the load out. During the years ended December 31, 2016, 2015 and 2014, Williamson Transport was paid $8.6 million, $8.9 million and $9.7 million, respectively, under these leases (net of the operating fee paid to Mach Mining, LLC).

Another of the entities sold by the Adena Entities to NRP on January 4, 2007 was Independence, which had previously been owned by Foresight Reserves. We had previously entered into a coal mining lease with Independence to lease a certain tract of approximately 3,500 acres adjacent to the Williamson mining complex to perform certain mining activities on the tract. The term of this agreement is 15 years and can be renewed for an additional five years or until all merchantable and mineable coal has been mined and removed.

Williamson is obligated to pay overriding royalties to WPP pursuant to a special warranty deed dated August 22, 1990 between its predecessors in interest, Coal Properties Corporation, Grantor and Fairview Land Company. Under this deed, WPP is owed an overriding royalty in the amount of $0.25 per ton for each ton of coal mined and sold by Williamson from the mineral reserves subject to the deed. During the years ended December 31, 2016, 2015 and 2014, Williamson paid overriding royalties to WPP under this agreement of $0 million, $0 million and $0.5 million, respectively, in overriding royalties to WPP under this agreement.

In January 2009, NRP acquired additional coal reserves and infrastructure assets related to Macoupin for $143.5 million. Simultaneous with the closing, Macoupin entered into a lease transaction with WPP and HOD for mining of the mineral reserves and for the rail facility, which we account for as a sale-leaseback financing arrangement. The mineral reserve mining lease is for a term of 20 years and can be extended for additional five-year terms limited to six such renewals. The lease requires a tonnage royalty equal to the greater of (i) 8% of the gross selling price of the coal plus $0.60 per ton or (ii) $5.40 per ton to be paid on the first 3.4 million tons of coal mined and sold in any given calendar year. Additionally, for the first 20-year term of the lease, Macoupin is required to pay a recoupable quarterly minimum deficiency payment equal to the difference between the tonnage royalty and $4.0 million. The lease also requires a wheelage fee of 0.5% of the gross selling price of any foreign coal transported across the property. During the years ended December 31, 2016, 2015 and 2014, Macoupin paid $12.2 million, $14.8 million and $16.2 million, respectively, in royalties and other payments to WPP under this mineral lease. We are currently in dispute with WPP in regards to the application of the recoupment provision within this agreement.

The Macoupin rail load-out facility and rail loop facility leases are for terms of 20 years with 16 renewals for five years each. For the first 30 years of the leases, each lease requires a payment of $1.50 per ton for every ton of coal loaded through the facility, up to 3.4 million tons per year. Annual rental payments of $10,000 per year are due after the expiration of the first 30 years. Macoupin is responsible for operations, repairs and maintenance and for keeping rail facilities in good working order. During the years ended December 31, 2016, 2015 and 2014, Macoupin paid $6.1 million, $6.5 million and $3.8 million, respectively, in payments to HOD under the rail facility leases.

Hillsboro entered into a coal mining lease agreement on September 10, 2009, with WPP. Under such agreement, Hillsboro leased certain mineral rights from WPP for a term of 20 years and can renew this lease for additional five-year terms, with a maximum of six terms or until all merchantable and mineable coal has been mined and removed. Hillsboro is required to pay WPP the greater of 8.0% of the gross selling price or $4.00 per ton and a fixed royalty in the amount set forth in the agreement for the coal mined from the leased premises. Hillsboro is subject to a minimum quarterly royalty under the agreement of $7.5 million until 2031, for the prior quarter's production. Beginning with the quarterly minimum royalty due April 20, 2032, the quarterly minimum will be $125,000 for each quarter of 2032 and each subsequent quarter. The minimum royalty is recoupable on future tons mined. If during any quarter the tonnage royalty exceeds the applicable quarterly minimum royalty, Hillsboro may recoup any unrecouped quarterly deficiency payments made during the preceding twenty quarters from the excess tonnage royalty on a first paid, first recouped basis. During the years ended December 31, 2016, 2015 and 2014, Hillsboro paid $0.4 million, $17.6 million and $28.6 million, respectively, to WPP under this lease. As of December 31, 2016, we paid WPP $34.0 million in advance minimum payments under this agreement that remain eligible for recoupment, all of which has been reserved for as we do not expect to recoup this balance based on the remaining recoupment period for certain minimum payments and the idling of the mine as a result of the mine fire.

In July 2015, we provided notice to WPP declaring a force majeure event at our Hillsboro mine due to elevated carbon monoxide levels as a result of a mine fire, which has required the stoppage of mining operations since March 2015. As a result of the force majeure event, we have not made $46.0 million in minimum deficiency payments to WPP in accordance with the force majeure provisions of the royalty agreement. WPP is asserting that the stoppage of mining operations as a result of the mine fire does not constitute an event of force majeure under the royalty agreement.

Williamson has a coal mining lease agreement with Independence the term of which runs through March 13, 2021 and can be renewed for additional five-year periods or until all merchantable and mineable coal has been mined and removed. Williamson is required to pay Independence the greater of 9.0% of the gross selling price or $2.85 per ton for the coal mined from the leased premises. In addition to the tonnage royalty, Williamson is required to pay a quarterly minimum royalty of $416,750 in each year this lease is in effect, for the prior quarter production. The minimum royalty is recoupable on future tons mined. If during any quarter the tonnage royalty exceeds the $416,750 quarterly minimum royalty, Williamson may recoup any unrecouped quarterly deficiency payments made during the preceding nineteen quarters from the excess tonnage royalty on a first paid, first recouped basis. The lease also has a provision for a wheelage payable at 0.5% of the gross selling price when foreign coal is transported over the premises. Williamson has an overriding royalty agreement with Independence. As such, Independence will receive an overriding royalty interest in the amount of $0.30 per ton for each ton of clean coal mined from certain mineral reserves identified in the agreement that Williamson controls or in the future will control that are sold to any third party for the life of the Williamson mining operations on the identified mineral reserves. During the years ended December 31, 2016, 2015 and 2014, Williamson paid $3.5 million, $4.9 million, and $3.8 million respectively, in royalties and other payments to Independence.

In March 2012, HOD acquired a rail load-out facility at Sugar Camp for $50.0 million The transaction includes a lease of the rail load-out to Sugar Camp for which Sugar Camp is required to pay to HOD a $1.10 per ton fee, subject to adjustment, on certain tonnages of coal loaded through the load-out during the first 20 years of the lease, subject to a minimum recoupable quarterly deficiency payment of $1.3 million. After the first 20 years, Sugar Camp may elect to extend the lease for additional 5-year terms up to a maximum of 16 times. Sugar Camp has the option to purchase the rail load-out for fair market value at any time after the expiration of the first 20 years and for the remainder of the lease. The lease also requires Sugar Camp to maintain and operate the load-out. During the years ended December 31, 2016, 2015 and 2014, Sugar Camp made $6.5 million, $6.3 million and $6.2 million, respectively, in payments to HOD under the load out lease.

In addition, we have entered into various ancillary agreements with NRP and its subsidiaries providing for acquisition of additional mineral rights within the assigned reserves of Williamson and Macoupin, all in support of our mining transactions with NRP for leased reserves.

As a result of these transactions and contracts, as of December 31, 2016, we had recorded to the consolidated balance sheet $2.6 million of net outstanding payable to NRP and its affiliates, $2.9 million in accrued interest and $191.9 million in sales-leaseback obligations. As a result of these transactions and contracts, as of December 31, 2015, we had $2.3 million of net outstanding payable to NRP and its affiliates, $2.1 million in accrued interest and $193.4 million in sales-leaseback obligations recorded to consolidated balance sheet. During the years ended December 31, 2016, 2015 and 2014, we paid NRP and its affiliates $51.9 million, $82.0 million and $88.7 million, respectively, in aggregate payments under the agreements described herein (inclusive of the sale-leaseback arrangements).

The following presents future minimum royalties, by year, required under noncancelable royalty agreements (inclusive of our sale-leaseback obligations) with NRP and its affiliates as of December 31, 2016 (in millions):

2017	$	60.7
2018		60.7
2019		60.7
2020		60.6
2021		57.8
Thereafter		395.8
Total minimum lease payments	$	696.3

Transactions With The Cline Group and its Affiliates

Reserves Investor Group Tender Offer and Exchange

In connection with the Restructuring Transactions, on the Closing Date, the Reserves Investor Group (as defined below) acquired, with cash, $105.4 million of the outstanding 2021 Senior Notes (the “Tender Offer”). The Reserves Investor Group includes Christopher Cline, the four trusts established for the benefit of Mr. Cline’s children, Michael J. Beyer, the former Chief Executive Officer of FEGP and owner of 0.66% of the voting and 0.225% of the economic interests of FEGP and certain other limited liability companies owned or controlled by individuals with limited partner interests in Foresight Reserves through indirect ownership. Prior to the commencement of the Tender Offer, the Reserves Investor Group owned $83.0 million of the 2021 Senior Notes. The Reserves Investor Group then exchanged their aggregate $188.4 million of 2021 Senior Notes, plus $6.8 million of accrued and unpaid interest, for $179.9 million of Exchangeable PIK Notes and $15.2 million of Second Lien Notes. As of December 31, 2016, we have accrued $9.6 million of interest expense under the new notes attributed to the Reserves Investor Group’s ownership interest.

Contribution of Assets

On February 25, 2015, Foresight Reserves and a member of management contributed 100% of the equity of Sitran, Adena and Hillsboro Transport to the Partnership. These entities were contributed for no consideration and had an aggregate net book value of approximately $60.6 million on the contribution date.

Coal Leases and Development Agreements

Williamson leases coal reserves from Colt. The term of this lease is for ten years with six renewal periods of five years each. Williamson is required to pay the greater of $3.40 per ton or 8.0% of the gross sales price of such coal. The minimum royalty for this lease, which is recoupable only against actual production royalty from future tons mined during the period of 10 years following the date on which any such minimum royalty is paid, is $2.0 million per year. During each of the years ended December 31, 2016, 2015 and 2014, Williamson paid $2.0 million in royalties to Colt under this coal lease. As of December 31, 2016, we paid Colt $5.6 million in advanced minimum royalty payments that remain eligible for recoupment.

Hillsboro leases coal reserves from Colt, the terms of which are identical but that each covers different reserves. The term of each of these leases is for five years with seven renewal periods of five years each. Hillsboro is required to pay the greater of $3.40 per ton or 8.0% of the gross sales price of such coal. The minimum royalty for each of these leases, which is recoupable only against actual production royalty from future tons during the period of 10 years following the date on which any such minimum royalty, is $4.0 million. Hillsboro paid $8.0 million in each of the years ended December 31, 2016, 2015 and 2014 in royalties to Colt under this coal lease. As of December 31, 2016, Hillsboro paid Colt $43.6 million in advance minimum payments under this agreement that remain eligible for recoupment, all of which has been reserved for as we do not expect to recoup this balance based on the remaining recoupment period.

Sugar Camp leases coal reserves from Ruger. The term of this lease is for ten years with six renewal periods of five years each. Sugar Camp is required to pay the greater of $3.40 per ton or 8.0% of the gross sales price of such coal. There is no minimum royalty associated with this lease. Sugar Camp has two overriding royalty agreements with Ruger pursuant to which Sugar Camp is given the right to mine certain reserves controlled by Ruger as lessee. Pursuant to these overriding royalty agreements, the total royalty that Sugar Camp will be required to pay for each ton of coal mined is equal to the difference between (i) the actual production royalty paid by Sugar Camp to the lessor of the reserves under the leases assumed by Sugar Camp from Ruger and (ii) the amount which is equal to 8% of the gross selling price of the coal mined under the leases. In addition to the overriding royalty, the remaining future minimum royalty for each of these agreements, which is recoupable only against actual overriding royalty during the period of ten years following the date on which such overriding royalty was paid, is $1.0 million. During the years ended December 31, 2016, 2015 and 2014, Sugar Camp paid $5.3 million, $3.1 million and $11.5 million, respectively, in royalties to Ruger under these coal lease and overriding royalty agreements described above. As of December 31, 2016, Sugar Camp paid Ruger $2.0 million in advanced minimum royalty payments under the overriding royalty agreements that remain eligible for recoupment.

Macoupin leases coal reserves from Colt under two leases, the terms of which are identical but that cover different reserves. The term of these leases is for ten years with six renewal periods of five years each. Macoupin is required to pay the greater of $3.40 per ton or 8.0% of the gross sales price of such coal. The remaining future minimum royalties for each of these leases, which is recoupable only against actual production royalty from future tons mined during the period of 10 years following the date on which any such minimum royalty is paid, is $2.0 million.

In June 2012, Macoupin leased additional coal reserves from Colt under another lease. The term of this lease is ten years with six renewal periods of five years each. Macoupin is required to pay the greater of $3.40 per ton or 8.0% of the gross sales price of such coal, subject to minimum annual payments of $0.5 million in 2013 and $2.0 million per year thereafter. Minimum annual payments are recoupable only against actual production royalty from future tons mined during the period of 10 years following the date on which any such minimum royalty is paid.

During each of the years ended December 31, 2016, 2015 and 2014, Macoupin paid $6.0 million in royalties to Colt under these coal leases. As of December 31, 2016, Macoupin paid Colt $31.0 million in advance minimum payments under this agreement that remain eligible for recoupment, all of which has been reserved for as we do not expect to recoup this balance based on the remaining recoupment period.

As of December 31, 2016 and 2015, the mines had $0.2 million and $0.1 million, respectively, in aggregate outstanding payables to Colt and Ruger under all of the leases above. During the years ended December 31, 2016, 2015 and 2014, we paid Colt and Ruger $21.3 million, $19.1 million and $27.5 million, respectively, in aggregate royalty payments under the agreements described herein.

The following presents future minimum royalties, by year, required under noncancelable royalty agreements with Foresight Reserves and its affiliates as of December 31, 2016 (in millions):

2017	$	18.0
2018		18.0
2019		18.0
2020		4.0
2021		2.0
Thereafter		-
Total minimum lease payments	$	60.0

Hillsboro 2 and 3 Development Agreement

Hillsboro has a development agreement with Colt (the “Hillsboro Development Agreement”) pursuant to which Colt has the ability to develop one or two additional longwall coal mines, previously identified as the “Hillsboro 2” and “Hillsboro 3” longwall mines and associated transportation infrastructure in coal reserves leased by Colt to Hillsboro. If Colt accepts the offer to develop a mine and associated transportation related infrastructure, Hillsboro will automatically acquire the option to purchase the fully developed mines, but not the transportation assets, for fair market value. Hillsboro will have the right to exercise this fair market value purchase option during a twelve month period that begins when Colt has first sold 100,000 tons of clean coal produced by the longwall method from any new mine. Hillsboro will not have an option to purchase the fully developed transportation assets, but will pay a commercially reasonable fair market price for their use. In the event Colt develops a mine and Hillsboro elects not to exercise its option to purchase the mine, Hillsboro will surrender its rights to the coal associated with that mine under its lease with Colt.

Macoupin Low Sulfur Longwall Development Agreement

Macoupin has a development agreement with Colt (the “Macoupin Development Agreement”) pursuant to which Colt has the ability to develop one longwall coal mine and associated transportation infrastructure in coal reserves previously identified by

Macoupin for a low sulfur longwall mine. If Colt accepts the option to develop the mine and associated infrastructure, then Macoupin will automatically acquire the option to purchase the fully developed mine, but not the transportation assets, for fair market value. Macoupin will have the right to exercise this fair market value purchase option during a twelve month period that begins when Colt has first sold 100,000 tons of clean coal produced by the longwall method from the new mine. Macoupin will not have an option to purchase the fully developed transportation assets, but will pay a commercially reasonable fair market price for their use. In the event Colt develops a mine and Macoupin elects not to purchase the mine, Macoupin will surrender its rights to the coal associated with that mine under its lease with Colt.

Sugar Camp 3 and 4 Development Agreement

Sugar Camp has a development agreement with Ruger (the "Sugar Camp Development Agreement") pursuant to which Ruger has the ability to develop one or two additional longwall coal mines and associated transportation infrastructure in coal reserves either leased by Ruger to Sugar Camp or reserves where Ruger has granted Sugar Camp the right to mine coal and pay a royalty to Ruger. These areas have been previously identified by Sugar Camp as the "Sugar Camp 3" and "Sugar Camp 4" longwall mines. If Ruger accepts the option to develop the mine and associated infrastructure, then Sugar Camp will automatically acquire the option to purchase the fully developed mine, but not the transportation assets, for fair market value. Sugar Camp will have the right to exercise this fair market value purchase option during a twelve month period that begins when Ruger has first sold 100,000 tons of clean coal produced by the longwall method from any new mine. Sugar Camp will not have an option to purchase the fully developed transportation assets, but will pay a commercially reasonable fair market price for their use. In the event Ruger develops a mine and Sugar Camp elects not to purchase the mine, Sugar Camp will surrender its rights to the coal associated with that mine under its lease and overriding royalty agreement with Ruger.

Mitigation Agreements

New River Royalty, LLC ("New River Royalty") (formerly Williamson Development Company LLC), an affiliate owned by Foresight Reserves, entered into mitigation agreements with each of Hillsboro, Macoupin, Sugar Camp and Williamson on August 12, 2010 ("Mitigation Agreements"). The Mitigation Agreements are contracts providing for the mitigation by each of the coal mining companies of subsidence damage to any structures located on certain surface lands owned by New River Royalty. Under these agreements, the mining companies are obligated to either repair any significant damage to structures on New River Royalty's surface lands caused by mine subsidence or compensate New River Royalty for the diminution in value of the structure caused by the subsidence damage, in satisfaction of their obligation under the Illinois Surface Coal Mining and Conservation and Reclamation Act, 225 ILCS 720/1.01 et. seq. As an alternative, under the Mitigation Agreements, the mining companies can elect to pay New River Royalty the appraised value of any structures expected to be impacted by subsidence activities prior to mining in exchange for a waiver of liability for any obligation to repair or compensate New River Royalty for any damage after subsidence occurs. Appraised values and diminution in value are determined by licensed appraisers.

Convent Marine Terminal Transloading Agreement

In August 2011, an affiliated company owned by Foresight Reserves acquired the IC RailMarine Terminal in Convent, Louisiana. This terminal, commonly referred to as the Convent Marine Terminal ("CMT"), is owned by Raven Energy LLC ("Raven"), an entity controlled by Chris Cline and beneficially owned by Christopher Cline, trusts for his children and entities beneficially owned by his management team. The terminal is designed to ship and receive commodities via rail, river barge and ocean vessel. We have a contract for throughput at the terminal that continues through December 31, 2021. We pay fees under the contract based on the tonnages of coal we move through the terminal, subject to minimum annual take-or-pay volume commitments throughout the duration of the contract. Effective May 1, 2015, the Partnership amended its material handling agreement with Raven to reduce the minimum annual throughput volume at CMT to 5.0 million tons and to extend the duration of the contract by one year to 2022. In August 2015, Raven was sold to entity under which Chris Cline does not have significant influence; therefore the Partnership's business activities with Raven are no longer considered affiliate transactions subsequent to August 2015. For the years ended December 31, 2015 and 2014, we paid $19.3 million and $41.9 million, respectively, to Raven (as an affiliate) under this agreement.

Affiliate Supply Agreement

On May 1, 2013, certain unaffiliated suppliers of mining products and Seneca Industries, Inc., one of our affiliates, formed a joint venture whose primary purpose is the manufacture and sale of certain mine supplies primarily for use by us in the conduct of our mining operations. In May 2013, we entered into an amendment to our existing supply agreement with the unaffiliated supplier parties that added the joint venture in which one of our affiliates owns 50% as a supplier party to the agreement, extended the term to April 2018 and updated the pricing provisions of the agreement. The agreement, as amended, obligates our mines to purchase at least 90% of their aggregate annual requirements for certain mine supplies from the supplier parties, subject to certain exceptions as set forth in the agreement. The mine supplies covered under this arrangement are sold pursuant to a price schedule incorporated into the agreement that is reviewed and, if necessary, adjusted every six months to result in an agreed-upon fixed profit percentage for the joint venture as set forth in the agreement. We and our affiliates purchased $6.6 million, $14.5 million and $18.1 million in mining supplies from the joint venture during the years ended December 31, 2016, 2015 and 2014, respectively.

2021 Senior Notes

On August 23, 2013, Cline Resource and Development Company ("CRDC") acquired $16.5 million of outstanding principal amounts of our 2021 Senior Notes (the "Original Purchase"), which bear interest at the rate of 7.875% annually. During September and October 2013, CRDC sold the Original Purchase primarily to affiliates, including $8.0 million to Chris Cline, $4.0 million to an entity controlled by John F. Dickinson, a former director of our general partner's board of directors, and $3.8 million to two former executives of the Partnership. Additional amounts were acquired independently in 2015 by Chris Cline and The Cline Trust Company LLC, as discussed below.

As of December 31, 2015 and 2014, Chris Cline owned $44.5 million and $8.0 million, respectively, of the outstanding principal on our 2021 Senior Notes. Chris Cline acquired $8.0 million in principal of the Original Purchase and during the year ended December 31, 2015, acquired an additional $36.5 million in principal from third parties in open market transactions. During the years ended December 31, 2015 and 2014, $1.9 million, $0.6 million, respectively, of interest on the 2021 Senior Notes was paid to Chris Cline, respectively. As of December 31, 2015, $1.3 million of interest on the 2021 Senior Notes was accrued to the benefit of Chris Cline.

The entity controlled by Mr. Dickinson owned $4.0 million of the outstanding principal on our 2021 Senior Notes as of December 31, 2015 and 2014, all of which was acquired from the Original Purchase. During the years ended December 31, 2015 and 2014, $0.3 million of interest on the 2021 Senior Notes was paid to Mr. Dickinson. As of December 31, 2015, $0.1 million of interest on the 2021 Senor Notes was accrued to the benefit of the entity controlled by Mr. Dickinson.

As of December 31, 2015, The Cline Trust Company LLC owned $10.0 million in principal of our 2021 Senior Notes, all of which was acquired during the year ended December 31, 2015. During the year ended December 31 2015, no interest had been paid to The Cline Trust Company LLC. As of December 31, 2015, $0.3 million of interest on the 2021 Senior Notes was accrued to the benefit of The Cline Trust Company LLC.

Also, Michael Beyer, the former chief executive officer of FELP, who resigned in May 2015, and Drexel Short, a former executive of our predecessor, who retired in March 2014, acquired $3.2 million and $0.5 million, respectively, from the Original Purchase. Mr. Beyer disposed of his 2021 Senior Notes in September of 2015. These former executives were no longer affiliates of the Partnership subsequent to their termination dates. During each of the years ended December 31, 2015 and 2014, $0.3 million of interest was paid to Mr. Beyer and Mr. Short, collectively, while they were affiliates of the Partnership.

Other Related Party Transactions

We are party to two surface leases in relation to the coal preparation plant and rail load out facility at Williamson with New River Royalty. The primary terms of the leases expire on October 15, 2021, but may be extended by Williamson for additional five-year terms under the same terms and conditions until all of the merchantable and mineable coal has been mined and removed from Williamson. Williamson is required to pay aggregate rent of $100,000 per year to New River Royalty under the leases. Additionally, New River Royalty may require Williamson to purchase any portion of either of the leased properties at any time while the leases are in effect for $3,000 an acre. Williamson Transport has the option to purchase any property optioned under the leases if Williamson does not perform its purchase obligation within fifteen days of receiving notice of its purchase obligation.

We are also party to a surface lease at our Sitran terminal with New River Royalty. The annual lease amount is $50,000 and the primary term of the lease expires on December 31, 2020, but it may be extended at the election of Sitran for successive five year periods.

Several affiliates by common ownership which own or lease property on which we conduct mining have obtained subsidence rights either from the surface owner or lessor. Normally, these rights permit us to subside the surface owner's property in exchange for subsidence mitigation. The extent of the mitigation is normally determined at the time we undermine the surface and the cost is normally not material to our operations. Because those subsidence rights were previously held by affiliates by common ownership, we have entered into global assignments of such rights in exchange for our obligation to satisfy all subsidence mitigation.

Transactions with Murray Energy Corporation and its Affiliates

On April 16, 2015, Foresight Reserves and Murray Energy executed a purchase and sale agreement whereby Murray Energy paid Foresight Reserves $1.37 billion to acquire a 34% voting interest in FEGP, 77.5% of FELP's incentive distribution rights ("IDR") and 100% of the outstanding subordinated units in FELP. FEGP has continued to govern the Partnership subsequent to this transaction. Murray Energy has an option (the "GP Option"), as amended as part of the Restructuring Transactions, to purchase an additional 46% of the voting interests in FEGP for $15 million, which is also conditioned upon a Note Redemption prior to the Exchangeable PIK Notes Maturity Date

Murray Purchase Right

The Murray Group has the right to purchase all of the Exchangeable PIK Notes on or prior to October 2, 2017 for cash at a price equal to 100% of the principal amount of the Exchangeable PIK Notes plus accrued interest. Upon a Murray Purchase, the Murray Group will receive FELP units equal to the principal and interest settlement amount multiplied by the lesser of: (a) a number equal to one divided by 92.5% of the last thirty days weighted-average trading price or (b) 1.12007 common units per $1.00 principal amount of Exchangeable PIK Notes.

Murray Management Services Agreement

In April 2015, a management services agreement ("MSA") was entered into between FEGP and Murray American Coal, Inc. (the "Manager"), a wholly-owned subsidiary of Murray Energy, pursuant to which the Manager will provide certain management and administration services to FELP for a quarterly fee, which is currently $3.5 million ($14.1 million on an annual basis) and is subject to future contractual escalations and adjustments. To the extent FELP or FEGP directly incurs costs for certain services covered under the MSA, then the Manager's quarterly fee is reduced accordingly. Also, to the extent the Manager utilizes outside service providers to perform any of the services under the MSA, then the Manager is responsible for those outside service provider costs. The initial term of the MSA extends through December 31, 2022 and is subject to termination provisions, including termination if the Note Redemption does not occur prior to the Exchangeable PIK Notes Maturity Date and Murray Energy does not execute its GP Option. If Murray executes its GP Option, it has the right to increase the annual MSA fee to $20.0 million per year.

After taking into account the contractual adjustments for direct costs incurred by FELP, the amount of net expense due to the Manager for the years ended December 31, 2016 and 2015 was $8.9 million and $4.7 million, respectively.

Murray Energy Transport Lease and Overriding Royalty Agreements

On April 16, 2015, American Century Transport LLC ("American Transport"), a newly created subsidiary of the Partnership, entered into a purchase and sale agreement (the "PSA") with American Energy Corporation ("American Energy"), a subsidiary of Murray Energy, pursuant to which American Energy sold to American Transport certain mining and transportation assets for $63.0 million. Concurrent with the PSA, American Transport entered into a lease agreement (the "Transport Lease") with American Energy pursuant to which (i) American Transport will lease to American Energy a tract of real property, two coal preparation plants and related coal handling facilities at the Transport Mine situated in Belmont and Monroe Counties, Ohio and (ii) American Transport will receive from American Energy a fee ranging from $1.15 to $1.75 for every ton of coal mined, processed and/or transported using such assets, subject to a quarterly recoupable minimum fee of $1.7 million. The Transport Lease is being accounted for as a direct financing lease. The total remaining minimum payments under the Transport Lease was $91.8 million at December 31, 2016, with unearned income equal to $33.3 million. The unearned income will be reflected as other revenue over the term of the lease using the effective interest method. Any amounts in excess of the contractual minimums will be recorded as other revenue when earned. As of December 31, 2016, the outstanding Transport Lease financing receivable was $58.5 million, of which $2.7 million was classified as current in the consolidated balance sheet.

Also, on April 16, 2015, American Century Minerals LLC ("Minerals"), a newly created subsidiary of the Partnership, entered into an overriding royalty agreement ("ORRA") with Murray Energy subsidiaries' American Energy and Consolidated Land Company (collectively, "AEC"), pursuant to which AEC granted to Minerals an overriding royalty interest ranging from $0.30 to $0.50 for each ton of coal mined, removed and sold from certain coal reserves situated near the Century Mine in Belmont and Monroe Counties, Ohio for $12.0 million. The ORRA is subject to a minimum recoupable quarterly fee of $0.5 million. This overriding royalty was accounted for as a financing arrangement. The payments the Partnership receives with respect to the ORRA will be reflected partially as a return of the initial investment (reduction in the affiliate financing receivable) and partially as other revenue over the life of the agreement using the effective interest method. Any amounts in excess of the contractual minimums will be recorded as other revenue when earned. The total remaining minimum payments under the ORRA was $32.1 million at December 31, 2016, with unearned income equal to $20.4 million. As of December 31, 2016, the outstanding ORRA financing receivable was $11.7 million, of which $0.2 million was classified as current in the consolidated balance sheet.

Other Murray Transactions

During the years ended December 31, 2016 and 2015, we purchased $8.3 million and $3.3 million, respectively, in equipment, supplies and rebuild and other services from affiliates of Murray Energy. During the years ended December 31, 2016 and 2015, our affiliate Coalfield Construction provided $0.9 million and $0.2 million, respectively, in equipment, supplies and rebuild services to affiliates of Murray Energy.

During the years ended December 31, 2016 and 2015, we purchased $13.5 million and $17.4 million, respectively, in coal from Murray Energy and its affiliates and we sold $58.4 million and $23.1 million, respectively, of coal to Murray Energy and its affiliates, including Javelin Global Commodities Limited ("Javelin"). Javelin is an international commodities marketing and trading joint venture owned by Murray Energy and Uniper (formerly E.ON Global Commodities SE).

During the years ended December 31, 2016 and 2015, Murray Energy transported coal under our transportation agreement with a third-party rail company resulting in usage fees owed to the third-party rail company of $4.1 million and $11.0 million, respectively. These usage fees were billed to Murray Energy, resulting in no impact to our consolidated statements of operations. The usage of the railway line with this third-party rail company by Murray Energy counts towards the minimum annual throughput volumes with the third-party rail company, thereby reducing the Partnership's exposure to contractual liquidated damage charges. Similarly, during the year ended December 31, 2016 and 2015, we incurred $0 million and $0.2 million, respectively, of transportation fees incurred for shipments under one of Murray Energy's third-party transloading contracts.

During the years ended December 31, 2016 and 2015, we earned $1.2 million and $0.3 million, respectively, in other revenues for Murray Energy's usage of Sitran.

From time to time, we also reimburse Murray Energy for costs paid by them on our behalf, including certain insurance premiums.

Transactions with our Contract Operators

Prior to August 2016, we operated each mine with a work force that was employed by a contractor that was not under common ownership by us, but is an "affiliate" of us due to our ability to exert control with respect to certain matters. We accounted for each of these operators as a variable interest entity. Due to the treatment of these contract operators as "variable interest entities," their assets, liabilities and results of operations are reflected in our consolidated financial statements. For the years ended December 31, 2016, 2015 and 2014, we paid $0.2 million, $0.5 million and $0.5 million, respectively, in the aggregate, plus reimbursement for actual costs incurred to these affiliated contract operators. On August 1, 2016, we acquired 100% of the outstanding equity units in each of the Contractor VIEs for aggregate cash consideration of $0.1 million. Because the Contractor VIEs have historically been consolidated as VIEs, and therefore represented entities under common control, the cash proceeds paid in excess of the net book values of the Contractor VIEs on the acquisition date was recorded as a deemed distribution in the consolidated statement of partners' (deficit) capital.

Procedures for Review, Approval and Ratification of Transactions with Related Persons

The information appearing under Part III. "Item 10. Directors, Executive Officers and Corporate Governance of the Managing Partner — Synergy & Conflicts Committee" is incorporated herein by reference.

Director Independence

The information appearing under Part III. "Item 10. Directors, Executive Officers and Corporate Governance of the Managing Partner — Director Independence" is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The following table presents fees for professional services rendered by our independent registered public accounting firm, Ernst and Young LLP, during the years ended December 2016 and 2015:

	Year Ended December 31,	
	2016	2015
	(In Thousands)	
Audit fees (1)	$ 1,013	$ 1,363
Audit-related fees (2)	—	4
Tax (3)	—	4
All other fees (4)	—	—
Total	$ 1,013	$ 1,371

(1) Audit fees represent fees for professional services rendered in connection with (i) the audit of our annual financial statements, including the audit of internal control over financial reporting (for the year ended December 31, 2015), (ii) the reviews of our quarterly reports on Form 10-Q and (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to the SEC. The amount recorded as audit fees, including out-of-pocket expenses, are for the current year audit irrespective of the period in which the related services are billed.

(2) Audit-related fees represent fees for assurance and related services. This category primarily includes services relating to fees for audits of employee benefit plans.

(3) Tax fees represent fees for professional services rendered in connection with tax compliance, tax advice and tax planning.

(4) All other fees represent fees for services not classified under the other categories listed above.

The charter of the audit committee of the board of directors of our general partner provides that the audit committee is responsible for reviewing and approving, in advance, any audit and permissible non-audit engagement or relationship between us and our independent auditors, other than as provided under the de minimis exception rule. All of the fees in the table above were approved in advance by the audit committee.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report on Form 10-K:

(1) Financial Statements—Set forth under Part II, Item 8. "Financial Statements and Supplementary Data"

(2) Financial Statement Schedules—Valuation and Qualifying Accounts—Set forth under Part II, Item 8. "Financial Statements and Supplementary Data." All other schedules are omitted because they are not applicable or the information is shown in the financial statements or notes thereto.

(3) Exhibits—Exhibits required to be filed by Item 601 of Regulation S-K are set forth in the Exhibit Index accompanying this Annual Report on Form 10-K and are incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on March 1, 2017.

Foresight Energy LP

By: Foresight Energy GP LLC,
its general partner

/s/ Robert D. Moore
Robert D. Moore
President, Chief Executive Officer and Director

/s/ James T. Murphy
James T. Murphy
Principal Financial Officer and Chief Accounting Officer

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

Signature	Title	Date
/s/ Robert D. Moore Robert D. Moore	President, Chief Executive Officer and Director	March 1, 2017
/s/ James T. Murphy James T. Murphy	Principal Financial Officer and Chief Accounting Officer	March 1, 2017
/s/ Christopher Cline Christopher Cline	Principal Strategy Officer and Chairman of the Board of Directors	March 1, 2017
/s/ Daniel S. Hermann Daniel S. Hermann	Director	March 1, 2017
/s/ Brian D. Sullivan Brian D. Sullivan	Director	March 1, 2017
/s/ Paul H. Vining Paul H. Vining	Director	March 1, 2017

*By: /s/ Robert D. Moore
Robert D. Moore, *Attorney-in-fact*

INDEX TO EXHIBITS

Exhibit Number	Description of Documents
2.1	Purchase and Sale Agreement dated as of April 16, 2015 by and between American Century Transport LLC and American Energy Corporation (incorporated by herein reference to Exhibit 2.11 on the Registrant’s Current Report on Form 8-K filed on April 21, 2015 (SEC File No. 001-36503)).
3.1	Certificate of Limited Partnership of Foresight Energy LP (f/k/a Foresight Energy Partners LP) (incorporated herein by reference to Exhibit 3.1 to the Registrant’s Registration Statement on Form S-1 filed on February 2, 2012 (SEC File No. 333-179304)).
3.2	Form of Partnership Agreement of Foresight Energy LP (incorporated herein by reference to Exhibit 3.1 to the Registrant’s Current Report on Form 8-K filed on June 23, 2014 (SEC File No. 001-36503)).
3.3	First Amendment to First Amended and Restated Agreement of Limited Partnership of Foresight Energy LP, dated as of August 30, 2016, entered into by Foresight Energy GP LLC (incorporated herein by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
4.1	Form of Long-Term Phantom Unit Agreement (incorporated herein by reference to Exhibit 4.4 to the Registrant’s Current Report on Form 8-K filed on June 23, 2014 (SEC File No. 001-36503)).
4.2	Form of Unit Award Agreement (incorporated herein by reference to Exhibit 4.5 to the Registrant’s Current Report on Form 8-K filed on June 23, 2014 (SEC File No. 001-36503)).
4.3	Indenture, dated as of August 30, 2016, by and among Foresight Energy LLC, Foresight Energy Finance Corporation, the Guarantors party thereto and Wilmington Savings Fund Society, FSB, as trustee (incorporated herein by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
4.4	Indenture, dated as of August 30, 2016, by and among Foresight Energy LLC, Foresight Energy Finance Corporation, the Guarantors party thereto, Wilmington Trust, National Association, as trustee and American Stock Transfer & Trust Company, LLC, as notes administrator and as exchange agent (incorporated herein by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
4.5	Warrant Agreement (including the Form of Warrant Certificate), dated as of August 30, 2016, between Foresight Energy LP and American Stock Transfer & Trust Company, LLC (incorporated herein by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.1	Form of Contribution, Conveyance and Assumption Agreement (incorporated herein by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed on June 23, 2014 (SEC File No. 001-36503)).
10.2	Form of Registration Rights Agreement (incorporated herein by reference to Exhibit 10.2 to the Registrant’s Current Report on Form 8-K filed on June 23, 2014 (SEC File No. 001-36503)).
10.3	Form of Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.3 to Amendment No. 7 to the Registrant’s Registration Statement on Form S-1 filed on May 7, 2014 (SEC File No. 333-179304)).
10.4	Credit Agreement, dated as of January 5, 2010, by and among Sugar Camp Energy LLC, as the borrower, Foresight Energy LLC, as a guarantor, Crédit Agricole Corporate and Investment Bank, as Administrative Agent (formerly known as Calyon New York Branch) and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme (formerly known as Calyon Deutschland Niederlassung Einer Französischen Societé Anonyme), as Hermes Agent (formerly known as CALYON Deutschland Niederlassung Einer Französischen Societé Anonyme) (the “Sugar Camp Credit Agreement”) (incorporated herein by reference to Exhibit 10.5 on the Registrant’s Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.5	First Amendment to the Sugar Camp Credit Agreement dated as of February 5, 2010, by and among Sugar Camp Energy LLC, Crédit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme (formerly known as Calyon Deutschland Niederlassung Einer Französischen Societé Anonyme), as Hermes Agent (incorporated herein by reference to Exhibit 10.6 on the Registrant’s Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).

Exhibit Number	Description of Documents
10.6	Second Amendment to the Sugar Camp Credit Agreement and First Amendment to Foresight Guarantee, dated as of August 4, 2010, by and among Sugar Camp Energy LLC, Crédit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme (formerly known as Calyon Deutschland Niederlassung Einer Französischen Societé Anonyme), as Hermes Agent (incorporated herein by reference to Exhibit 10.7 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.7	Third Amendment to the Sugar Camp Credit Agreement, dated as of September 24, 2010, by and among Sugar Camp Energy LLC, Crédit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme (formerly known as Calyon Deutschland Niederlassung Einer Französischen Societé Anonyme), as Hermes Agent (incorporated herein by reference to Exhibit 10.8 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.8	Fourth Amendment to the Sugar Camp Credit Agreement, dated as of May 27, 2011, by and among Sugar Camp Energy LLC, Crédit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme (formerly known as Calyon Deutschland Niederlassung Einer Französischen Societé Anonyme), as Hermes Agent (incorporated herein by reference to Exhibit 10.9 on Amendment 10 to the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-139304)).
10.9	Fifth Amendment to the Sugar Camp Credit Agreement and First Amendment to Guaranty, dated as of March 8, 2012, by and among Sugar Camp Energy LLC, Crédit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme (formerly known as Calyon Deutschland Niederlassung Einer Französischen Societé Anonyme), as Hermes Agent (incorporated herein by reference to Exhibit 10.10 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.10	Sixth Amendment to the Sugar Camp Credit Agreement and Second Amendment to Guaranty, dated as of August 23, 2013, by and among Sugar Camp Energy LLC, Crédit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme (formerly known as Calyon Deutschland Niederlassung Einer Französischen Societé Anonyme), as Hermes Agent (incorporated herein by reference to Exhibit 10.11 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.11	Guaranty of the Sugar Camp Credit Agreement by Foresight Energy LLC, as guarantor, in favor of Crédit Agricole Corporate and Investment Bank, as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme, as Hermes Agent dated May 27, 2011 (incorporated herein by reference to Amendment No. 10 to Exhibit 10.12 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.12	Credit Agreement, dated as of May 14, 2010, by and among Hillsboro Energy LLC, as the borrower, Foresight Energy LLC, as a guarantor, Credit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme, as Hermes Agent (the "Hillsboro Credit Agreement") (incorporated herein by reference to Amendment No. 10 to Exhibit 10.13 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.13	First Amendment to the Hillsboro Credit Agreement, dated as of June 17, 2010, by and among Hillsboro Energy LLC, Foresight Energy LLC, Crédit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme, as Hermes Agent (incorporated herein by reference to Exhibit 10.14 on the Registrant's Draft Registration Statement filed on February 18, 2014 (SEC File No. 333-179304)).

Exhibit Number	Description of Documents
10.14	Second Amendment to the Hillsboro Credit Agreement and First Amendment to Foresight Guaranty dated as of August 4, 2010, by and among Hillsboro Energy LLC, Foresight Energy LLC, Crédit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme, as Hermes Agent (incorporated herein by reference to Exhibit 10.15 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.15	Third Amendment to the Hillsboro Credit Agreement dated as of September 24, 2010, by and among Hillsboro Energy LLC, Foresight Energy LLC, Crédit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme, as Hermes Agent (incorporated herein by reference to Exhibit 10.16 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.16	Fourth Amendment to the Hillsboro Credit Agreement dated as of May 27, 2011, by and among Hillsboro Energy LLC, Foresight Energy LLC, Crédit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme, as Hermes Agent (incorporated herein by reference to Amendment No. 10 to Exhibit 10.17 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.17	Fifth Amendment to the Hillsboro Credit Agreement and First Amendment to Guaranty dated as of March 8, 2012, by and among Hillsboro Energy LLC, Foresight Energy LLC, Crédit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme, as Hermes Agent (incorporated herein by reference to Exhibit 10.18 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.18	Sixth Amendment to the Hillsboro Credit Agreement and Second Amendment to Guaranty dated as of August 16, 2013, by and among Hillsboro Energy LLC, Foresight Energy LLC, Crédit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme, as Hermes Agent (incorporated herein by reference to Exhibit 10.19 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.19	Guaranty of the Hillsboro Credit Agreement by Foresight Energy LLC, as guarantor, in favor of Crédit Agricole Corporate and Investment Bank (formerly known as Calyon New York Branch), as Administrative Agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme, as Hermes Agent dated May 27, 2011(incorporated herein by reference to Amendment No. 10 to Exhibit 10.20 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.20	Illinois Coal Lease dated July 1, 2002 from the United States of America, as Lessor acting through its legal agent, the Tennessee Valley Authority, ("TVA"), to Illinois Fuel Company, LLC, as Lessee ("Illinois Coal Lease"), which was assigned to Ruger Coal Company, LLC, with such assignment and transfer being consented to by TVA, by an Assignment and Assumption Agreement effective on August 4, 2009 ("Assignment and Assumption Agreement") by and among TVA, Illinois Fuel Company, LLC and Ruger Coal Company, LLC wherein TVA consented to "the mining of the Lease reserves by Sugar Camp Energy, LLC, and with Ruger Coal Company, LLC agreeing that Sugar Camp Energy, LLC can mine the Illinois Coal Lease reserves and consenting to the mining of such reserves in a Consent dated effective on January 22, 2010 between Ruger Coal Company, LLC and Sugar Camp Energy, LLC (with certain confidential information omitted, which omitted information is the subject of a confidential treatment request and has been filed separately with the Securities and Exchange Commission) (incorporated herein by reference to Amendment No. 10 to Exhibit 10.21 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.21	Amendment One to Illinois Coal Lease dated April 10, 2012 between United States of America, as Lessor acting through its legal agent, the Tennessee Valley Authority ("TVA"), and Illinois Fuel Company LLC, Lessee (as assigned to Ruger Coal Company LLC under that Assignment and Assumption Agreement dated August 4, 2009 by and among TVA, Illinois Fuel Company, LLC, Assignor and Ruger Coal Company LLC, Assignee, and expressly granting Sugar Camp Energy, LLC the right to mine the reserves subject to the lease) (with certain confidential information omitted, which omitted information is the subject of a confidential treatment request and has been filed separately with the Securities and Exchange Commission) (incorporated herein by reference to Exhibit 10.22 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).

Exhibit Number	Description of Documents
10.22	Amendment Two to Illinois Coal Lease effective as of August 30, 2012 by and between United States of America, as Lessor acting through its legal agent, the Tennessee Valley Authority ("TVA"), and Illinois Fuel Company LLC, Lessee (as assigned to Ruger Coal Company LLC under that Assignment and Assumption Agreement dated August 4, 2009 by and among TVA, Illinois Fuel Company, LLC, Assignor and Ruger Coal Company LLC, Assignee, and expressly granting Sugar Camp Energy, LLC the right to mine the reserves subject to the lease) (with certain confidential information omitted, which omitted information is the subject of a confidential treatment request and has been filed separately with the Securities and Exchange Commission) (incorporated herein by reference to Amendment No. 10 to Exhibit 10.23 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.23	Master Lease Agreement between PNC Equipment Finance, LLC, as Lessor and Foresight Energy Services LLC, as Lessee dated October 31, 2013, that Master Lease Guaranty delivered by Foresight Energy LLC in favor of PNC Equipment Finance, LLC in connection with Master Lease Agreement, and that Real Property Waiver for the benefit of PNC Equipment Finance, LLC by Williamson Energy LLC, Sugar Camp Energy LLC and Hillsboro Energy LLC dated October 31, 2013 (incorporated herein by reference to Exhibit 10.24 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.24	Master Lease Agreement dated March 30, 2012, among BB&T Equipment Finance Corporation ("BB&T"), as Lessor, Hillsboro Energy LLC, Sugar Camp Energy, LLC and Williamson Energy, LLC, collectively as Lessee, and Foresight Energy LLC, as guarantor (incorporated herein by reference to Exhibit 10.25 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.25	Coal Mining Lease between RGGS Land & Mineral LTD., L.P. and Sugar Camp Energy, LLC dated July 29, 2005 (with certain confidential information omitted, which omitted information is the subject of a confidential treatment request and has been filed separately with the Securities and Exchange Commission) (incorporated herein by reference to Amendment No. 10 to Exhibit 10.26 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.26	First Amendment to Coal Mining Lease between RGGS Land & Minerals, LTD., L.P. and Sugar Camp Energy LLC dated August 11, 2008 (incorporated herein by reference to Exhibit 10.27 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.27	Amendment dated December 21, 2010 to Coal Mining Lease between RGGS Land & Minerals, LTD., L.P. and Sugar Camp Energy, LLC (incorporated herein by reference to Exhibit 10.28 on the Registrant's Draft Registration Statement on Form S-1filed on February 18, 2014 (SEC File No. 333-179304)).
10.28	Surface Sublease between Sugar Camp Energy, LLC and HOD, LLC dated March 6, 2012 (incorporated herein by reference to Amendment No. 10 to Exhibit 10.29 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.29	Lease Agreement dated March 6, 2012 between HOD, LLC and Sugar Camp Energy, LLC (incorporated herein by reference to Amendment No. 10 to Exhibit 10.30 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.30	First Amendment to Lease Agreement dated August 23, 2013 between HOD, LLC and Sugar Camp Energy, LLC (incorporated herein by reference to Exhibit 10.31 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.31	Materials Handling and Storage Agreement by and among Raven Energy LLC of Louisiana, Foresight Energy LLC and Savatran LLC dated January 1, 2012 (with certain confidential information omitted, which omitted information is the subject of a confidential treatment request and has been filed separately with the Securities and Exchange Commission) (incorporated herein by reference to Exhibit 10.32 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.32	Coal Mining Lease and Sublease Agreement between WPP LLC and Hillsboro Energy LLC dated September 10, 2009 (incorporated herein by reference to Amendment No. 10 to Exhibit 10.33 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.33	Amendment No. 1 to the Coal Mining Lease and Sublease Agreement between WPP LLC and Hillsboro Energy LLC dated January 11, 2010 (incorporated herein by reference to Exhibit 10.34 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).

Exhibit Number	Description of Documents
10.34	Amendment No. 2 to the Coal Mining Lease and Sublease Agreement between WPP LLC and Hillsboro Energy LLC dated October 4, 2010 (incorporated herein by reference to Exhibit 10.35 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.35	Amendment No. 3 to the Coal Mining Lease and Sublease Agreement between WPP LLC and Hillsboro Energy LLC dated January 13, 2011 (incorporated herein by reference to Exhibit 10.36 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.36	Amendment No. 4 to the Coal Mining Lease and Sublease Agreement between WPP LLC and Hillsboro Energy LLC dated February 2, 2012 (incorporated herein by reference to Amendment No. 10 to Exhibit 10.37 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.37	Amendment No. 5 to the Coal Mining Lease and Sublease Agreement between WPP LLC and Hillsboro Energy LLC dated August 21, 2012 (incorporated herein by reference to Amendment No. 10 to Exhibit 10.38 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.38	Coal Mining Lease Agreement (5000 Foot Extension) between Independence Land Company, LLC and Williamson Energy, LLC dated March 13, 2006 (incorporated herein by reference to Amendment No. 10 to Exhibit 10.39 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.39	Amended and Restated Coal Mining Lease Agreement between WPP LLC and Williamson Energy, LLC dated August 14, 2006 (incorporated herein by reference to Amendment No. 10 to Exhibit 10.40 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.40	First Amendment to the Amended and Restated Coal Mining Lease Agreement between WPP LLC and Williamson Energy, LLC dated May 19, 2008 (incorporated herein by reference to Exhibit 10.41 on the Registrant's Draft Registration Statement filed on February 18, 2014 (SEC File No. 333-179304)).
10.41	Amendment to the Amended and Restated Coal Mining Lease Agreement between WPP LLC and Williamson Energy LLC, dated December 18, 2009 (incorporated herein by reference to Amendment No. 10 to Exhibit 10.42 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.42	Third Amendment to Amended and Restated Coal Mining Lease Agreement dated August 12, 2010 between WPP LLC and Williamson Energy, LLC (incorporated herein by reference to Amendment No. 10 to Exhibit 10.44 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.43	Fourth Amendment to Amended and Restated Coal Mining Lease Agreement dated June 30, 2011 but effective April 1, 2011 between WPP LLC and Williamson Energy, LLC (incorporated herein by reference to Amendment No. 10 to Exhibit 10.45 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.44	Partial Release of Leased Premises from Amended and Restated Coal Mining Lease Agreement dated June 30, 2011 between WPP LLC and Williamson Energy, LLC (incorporated herein by reference to Amendment No. 10 to Exhibit 10.46 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.45	Fifth Amendment to Amended and Restated Coal Mining Lease Agreement dated March 20, 2013 but effective March 1, 2013 between WPP LLC and Williamson Energy, LLC (incorporated herein by reference to Amendment No. 10 to Exhibit 10.47 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.46	Partial Release of Leased Premises from Amended and Restated Coal Mining Lease Agreement dated March 20, 2013 but effective March 1, 2013 between WPP LLC and Williamson Energy, LLC (incorporated herein by reference to Amendment No. 10 to Exhibit 10.48 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.47	Corrective Partial Release of Leased Premises from Amended and Restated Coal Mining Lease Agreement dated April 5, 2013 but effective March 1, 2013 between WPP LLC and Williamson Energy, LLC (incorporated herein by reference to Amendment No. 10 to Exhibit 10.49 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.48	Lease (Rail Load Out Lease) dated May 1, 2005 between Steelhead Development Company, LLC and Williamson Energy, LLC (incorporated herein by reference to Amendment No. 10 to Exhibit 10.50 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).

Exhibit Number	Description of Documents
10.49	Coal Mining Lease dated August 12, 2010 between Ruger Coal Company, LLC and Sugar Camp Energy, LLC (incorporated herein by reference to Amendment No. 10 to Exhibit 10.51 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.50	First Amendment to Coal Mining Lease between Ruger Coal Company, LLC and Sugar Camp Energy LLC dated November 4, 2011(incorporated herein by reference to Exhibit 10.52 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.51	Second Amendment to Coal Mining Lease between Ruger Coal Company, LLC and Sugar Camp Energy LLC dated July 24, 2012 (incorporated herein by reference to Amendment No. 10 to Exhibit 10.53 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.52	Coal Mining Lease and Sublease dated August 12, 2010 from Colt LLC to Williamson Energy, LLC (incorporated herein by reference to Amendment No. 10 to Exhibit 10.54 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.53	First Amendment to Coal Mining Lease and Sublease Agreement between Colt, LLC and Williamson Energy, LLC dated June 30, 2011 but effective April 1, 2011 (incorporated herein by reference to Amendment No. 10 to Exhibit 10.55 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.54	Second Amendment to Coal Mining Lease and Sublease Agreement between Colt LLC and Williamson Energy LLC dated February 13, 2013 but effective December 31, 2012 (incorporated herein by reference to Exhibit 10.56 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.55	Third Amendment to Coal Mining Lease and Sublease Agreement between Colt, LLC and Williamson Energy, LLC dated March 20, 2013 but effective March 1, 2013(incorporated herein by reference to Amendment No. 10 to Exhibit 10.57 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.56	Partial Release of Premises from Coal Mining Lease and Sublease between Colt, LLC and Williamson Energy, LLC, dated March 20, 2013 but effective March 1, 2013 (incorporated herein by reference to Amendment No. 10 to Exhibit 10.58 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.57	Overriding Royalty Agreement dated August 12, 2010 between Ruger Coal Company LLC and Sugar Camp Energy, LLC (incorporated herein by reference to Amendment No. 10 to Exhibit 10.59 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.58	Coal Mining Lease (For "Reserve 1" and "Reserve 3") dated August 12, 2010 between Colt LLC and Hillsboro Energy LLC (incorporated herein by reference to Amendment No. 10 to Exhibit 10.61 on the Registrant's Registration Statement on Form S-1 filed on May 22, 2014 (SEC File No. 333-179304)).
10.59	First Amendment to Coal Mining Lease (For "Reserve 1" and "Reserve 3") dated February 13, 2013 but effective December 31, 2013 between Colt LLC and Hillsboro Energy LLC (incorporated herein by reference to Exhibit 10.62 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.60	Coal Mining Lease (For "Reserve 2") dated August 12, 2010 between Colt LLC and Hillsboro Energy LLC (incorporated herein by reference to Exhibit 10.63 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.61	First Amendment to Coal Mining Lease (For "Reserve 2") dated August 21, 2012 between Colt LLC and Hillsboro Energy LLC (incorporated herein by reference to Exhibit 10.64 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).
10.62	Second Amendment to Coal Mining Lease (For "Reserve 2") dated February 13, 2013 between Colt LLC and Hillsboro Energy LLC (incorporated herein by reference to Amendment No. 6 to Exhibit 10.65 on the Registrant's Registration Statement on Form S-1 filed on April 24, 2014 (SEC Report No. 333-179304)).
10.63	Amendment and Restatement of the Short Phantom Equity Agreement dated December 21, 2012 among Foresight Energy Services LLC, Drexel Short, Foresight Management, LLC and Foresight Reserves, L.P. (incorporated herein by reference to Exhibit 10.69 on the Registrant's Draft Registration Statement on Form S-1 filed on February 18, 2014 (SEC File No. 333-179304)).

Exhibit Number	Description of Documents
10.64	Form of Unit Agreement (with Transfer Restrictions) (incorporated herein by reference to Exhibit 10.1 on the Registrant's Current Report on Form 8-K filed on February 10, 2015 (SEC File No. 001-36503)).
10.65	Form of Subordinated Unit Agreement (with Transfer Restrictions) (incorporated by herein reference to Exhibit 10.2 on the Registrant's Current Report on Form 8-K filed on February 10, 2015 (SEC File No. 001-36503)).
10.66	Receivables Financing Agreement dated January 13, 2015 between Foresight Receivables LLC, as Borrower, PNC Bank, National Association, as LC Bank and Administrative Agent, and Foresight Energy LLC, as initial Servicer (incorporated by herein reference to Exhibit 10.79 on the Registrant's Current Report on Form 10-K filed on March 10, 2015 (SEC File No. 001-36503)).
10.67	Purchase and Sale Agreement dated as of January 13, 2015 between various entities listed on schedule I hereto, as Originators, Foresight Energy LLC, as Servicer, and Foresight Receivables LLC, as Buyer (incorporated by herein reference to Exhibit 10.79 on the Registrant's Current Report on Form 10-K filed on March 10, 2015 (SEC File No. 001-36503)).
10.68	Foresight Energy LP Long-term Incentive Plan – Form of Unit Award Agreement (with Transfer Restrictions) (incorporated by herein reference to Exhibit 10.1 on the Registrant's Current Report on Form 8-K filed on February 10, 2015 (SEC File No. 001-36503)).
10.69	Foresight Energy LP Long-term Incentive Plan – Form of Subordinated Unit Award Agreement (with Transfer Restrictions) (incorporated by herein reference to Exhibit 10.1 on the Registrant's Current Report on Form 8-K filed on February 10, 2015 (SEC File No. 001-36503)).
10.70	Performance Guaranty between Foresight Energy LP and PNC Bank, National Association dated January 13, 2015 (incorporated by herein reference to Exhibit 10.80 on the Registrant's Current Report on Form 10-K filed on March 10, 2015 (SEC File No. 001-36503)).
10.71	First Amendment to Foresight Energy LP Long-Term Incentive Plan dated February 6, 2015 (incorporated by herein reference to Exhibit 10.81 on the Registrant's Current Report on Form 10-K filed on March 10, 2015 (SEC File No. 001-36503)).
10.72	Forbearance Agreement between Foresight Receivables, Foresight Energy LLC, certain subsidiaries of Foresight Energy LLC and PNC Bank, National Association, and certain other committed lenders dated January 27, 2016 (incorporated herein by reference to Exhibit 10.1 on the Registrant's Current Report on Form 10-Q filed on May 10, 2016 (SEC File No. 001-36503)).
10.73	Retention Award Agreement between Foresight Energy LP and Rashda M. Buttar dated February 26, 2016 (incorporated herein by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed February 26, 2016 (SEC File No. 001-36503)).
10.74	Retention Award Agreement between Foresight Energy LP and James T. Murphy dated February 26, 2016 (incorporated herein by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed February 26, 2016 (SEC File No. 001-36503)).
10.75	Transaction Support Agreement dated as of April 18, 2016 between Foresight Energy LLC, Foresight Energy LP and certain Consenting Lenders (incorporated herein by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on April 18, 2016 (SEC File No. 001-36503)).
10.76	Transaction Support Agreement dated as of May 17, 2016 between Foresight Energy LLC, Foresight Energy LP and certain of its subsidiaries and certain Consenting Noteholders (incorporated herein by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on May 23, 2016 (SEC File No. 001-36503)).
10.77	Registration Rights Agreement, dated as of August 30, 2016, by and between Foresight Energy LP and Murray Energy Corporation (incorporated herein by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.78	Registration Rights Agreement by and among Foresight Energy LP, Foresight Reserves, LP, Michael J. Beyer and the other parties signatory thereto (incorporated herein by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).

Exhibit Number	Description of Documents
10.79	Registration Rights Agreement, dated as of August 30, 2016, by and among Foresight Energy LP, and the other parties signatory thereto and any additional parties identified on the signature pages of any Joinder Agreement executed and delivered pursuant thereto (incorporated herein by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.80	First Amended and Restated Receivables Financing Agreement, dated as of August 30, 2016, by and among Foresight Receivables LLC, the persons from time to time party thereto as Lenders, Group Agents and LC Participants, PNC Bank, National Association, as both LC Bank and Administrative Agent, Foresight Energy LLC and Credit Agricole Corporate and Investment Bank and Atlantic Asset Securitization LLC (incorporated herein by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.81	Intercreditor Agreement (Securitization), dated as of August 30, 2016, by and among Citibank, N.A., as First Lien Agent, Wilmington Savings Fund Society, FSB, as Second Lien Collateral Agent, Foresight Energy LLC, each of the originators party thereto from time to time, Foresight Receivables LLC and PNC Bank, National Association (incorporated herein by reference to Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.82	Financing Side Letter, dated August 30, 2016, by and among Foresight Reserves, LP, and the other investors listed on Schedule A thereto, from time to time, Murray Energy Corporation and Foresight Energy LP (incorporated herein by reference to Exhibit 10.6 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.83	Indefeasible Assignment of Minimum Royalties under Coal Leases (Colt Assignment), dated as of August 30, 2016, by and between Colt LLC and Murray American Coal, Inc (incorporated herein by reference to Exhibit 10.7 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.84	Seventh Amendment to Credit Agreement, Third Amendment to Guaranty, and Waiver, dated as of August 30, 2016, by and among Hillsboro Energy LLC, Foresight Energy LLC, the Lender party thereto, Crédit Agricole Corporate and Investment Bank, as administrative agent, and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme, as Hermes agent (incorporated herein by reference to Exhibit 10.8to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.85	Seventh Amendment to Credit Agreement, Third Amendment to Guaranty, and Waiver, dated as of August 30, 2016, by and among Sugar Camp Energy, LLC, Foresight Energy LLC, the Lender party thereto, Crédit Agricole Corporate and Investment Bank, as administrative agent and Crédit Agricole Corporate and Investment Bank Deutschland, Niederlassung Einer Französischen Société Anonyme, as Hermes Agent (incorporated herein by reference to Exhibit 10.9 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.86	Amendment Agreement, dated as of August 30, 2016, by and among Foresight Energy LLC, certain subsidiaries of the Borrower signatory thereto as Subsidiary Guarantors, Foresight Energy LP, each of the Lenders party thereto and Citibank, N.A., as Administrative Agent and Collateral Agent (incorporated herein by reference to Exhibit 10.10 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.87	Second Lien Pledge and Security Agreement, dated as of August 30, 2016, by Foresight Energy LLC, Foresight Energy Finance Corporation and each of the subsidiaries of Foresight Energy LLC party thereto from time to time, in favor of Wilmington Savings Fund Society, FSB (incorporated herein by reference to Exhibit 10.11 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.88	Third Amended and Restated Credit Agreement, dated as of August 30, 2016, among Foresight Energy LLC, each lender from time to time party thereto and Citibank, N.A., as Administrative Agent, Collateral Agent and Swing Line Lender, and each L/C Issuer from time to time party thereto (incorporated herein by reference to Exhibit 10.12 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).

Exhibit Number	Description of Documents
10.89	Parent Guaranty, dated as of August 30, 2016, made by Foresight Energy LP in favor of the Secured Parties referred to in the Credit Agreement referred to therein (incorporated herein by reference to Exhibit 10.13 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.90	Intercreditor Agreement, dated as of August 30, 2016, by and among Foresight Energy LLC, Foresight Energy Finance Corporation, each of the Guarantors party thereto, Citibank, National Association, as the first lien administrative agent and collateral agent, Wilmington Savings Fund Society, FSB as the second lien collateral agent, Wilmington Trust, N.A., as trustee under the Exchangeable PIK Notes Indenture, Wilmington Savings Fund Society, FSB, as trustee under the Second Lien Notes Indenture, each hedge bank, cash management bank and each secured commodity swap counterparty party thereto from time to time, the third lien collateral agent for the third lien secured parties to the extent party thereto and each additional representative from time to time party thereto (incorporated herein by reference to Exhibit 10.14 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.91	Collateral Trust and Intercreditor Agreement, dated as of August 30, 2016, by and among Foresight Energy LLC, Foresight Energy Finance Corporation, the other Grantors from time to time party thereto, Wilmington Savings Fund Society, FSB, as Second Lien Notes Trust and Collateral Agent, and Wilmington Trust, National Association, as Exchangeable PIK Notes Trustee (incorporated herein by reference to Exhibit 10.15 to the Registrant's Current Report on Form 8-K filed on September 6, 2016 (SEC File No.001-36503)).
10.92	First Amendment to Transaction Support Agreement, dated as of July 15, 2016, by and among Foresight Energy GP LLC, Foresight Energy LLC, and Foresight Energy Finance Corporation (collectively, the “Issuers”), certain subsidiaries of the Issuers, and Foresight Energy LP and the Consenting Noteholders party thereto (incorporated herein by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on July 18, 2016 (SEC File No.001-36503)).
10.93	Joinder to Transaction Support Agreement, dated as of July 17, 2016, by and among the Issuers, certain subsidiaries of the Issuers, and Foresight Energy LP and the Consenting Noteholders party thereto (incorporated herein by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on July 18, 2016 (SEC File No.001-36503)).
10.94	Second Amendment to Transaction Support Agreement, dated as of July 15, 2016, by and among Foresight Energy LLC, certain subsidiaries thereof, and Foresight Energy LP and the Consenting Lenders party thereto (incorporated herein by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on July 18, 2016 (SEC File No.001-36503)).
10.95	Amended and Restated Transaction Support Agreement, dated July 22, 2016, by and among Foresight Energy LLC, certain subsidiaries thereof, Foresight Energy LP, the Cline Group (as defined therein), Murray Energy Corporation and the Consenting Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on July 25, 2016 (SEC File No.001-36503)).
10.96	Amended and Restated Transaction Support Agreement, dated July 22, 2016, by and among Foresight Energy GP LLC, Foresight Energy LLC, certain subsidiaries thereof, Foresight Energy LP, Foresight Reserves LP, the Cline Group (as defined therein), Murray Energy Corporation and the Consenting Noteholders party thereto (incorporated herein by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on July 25, 2016 (SEC File No.001-36503)).
10.97	Supplemental Indenture, dated as of August 24, 2016, by and among Foresight Energy LLC, Foresight Energy Finance Corporation and Wilmington Savings Fund Society, FSB (incorporated herein by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on August 25, 2016 (SEC File No.001-36503)).
21.1	List of Subsidiaries of Foresight Energy LP
23.1	Consent of Independent Registered Public Accounting Firm for Foresight Energy LP
24.1	Powers of Attorney
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2012.
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2012.

Exhibit Number	Description of Documents
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95.1	Mine Safety Disclosures
101	Interactive Data File (Form 10-K for the year ended December 31, 2016 filed in XBRL)

Exhibit 21.1

Subsidiaries of Foresight Energy LP

Name	Jurisdiction of Organization
Adena Resources LLC	Delaware
Akin Energy LLC	Delaware
American Century Mineral LLC	Delaware
American Century Transport LLC	Delaware
Coalfield Construction LLC	Delaware
Coalfield Repair Services LLC	Delaware
Foresight Coal Sales LLC	Delaware
Foresight Energy Labor LLC	Delaware
Foresight Energy LLC	Delaware
Foresight Energy Services LLC	Delaware
Foresight Energy Employee Services Corporation	Delaware
Foresight Energy Finance Corporation	Delaware
Foresight Receivables LLC	Delaware
Hillsboro Energy LLC	Delaware
Hillsboro Transport LLC	Delaware
LD Labor LLC	Delaware
Logan Mining LLC	Delaware
Mach Mining LLC	Delaware
Macoupin Energy LLC	Delaware
MaRyan Mining LLC	Delaware
M-Class Mining LLC	Delaware
Oeneus LLC d/b/a Savatran LLC	Delaware
Patton Mining LLC	Delaware
Sitran LLC	Delaware
Seneca Rebuild LLC	Delaware
Sugar Camp Energy, LLC	Delaware
Tanner Energy LLC	Delaware
Viking Mining LLC	Delaware
Williamson Energy, LLC	Delaware

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement (Form S-8 No. 333-196959) pertaining to the Foresight Energy LP Long-Term Incentive Plan of our report dated March 1, 2017, with respect to the consolidated financial statements and schedule of Foresight Energy LP, included in this Annual Report (Form 10-K) for the year ended December 31, 2016.

/s/ Ernst & Young LLP

St. Louis, Missouri
March 1, 2017

Exhibit 24.1

POWER OF ATTORNEY

KNOW ALL PEOPLE BY THESE PRESENTED, that each person whose signature appears below hereby appoints Robert D. Moore acting alone, his true and lawful attorney-in-fact with full power of substitution or re-substitution, for such person and in such person's name, place and stead, in any and all capacities, to sign on such person's behalf, Foresight Energy LP's Annual Report on Form 10-K to the Securities and Exchange Commission for the fiscal year ended December 31, 2016, and any amendments thereto, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact, full power and authority to do and perform each and every act and thing requisite or necessary to be done in and about the premises, as fully to all intents and purposes as such person might or could do in person, hereby ratifying and confirming all that said attorney-in-fact, or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have executed this Power of Attorney on the dates indicated.

Signature	Title	Date
/s/ Christopher Cline Christopher Cline	Chairman of the Board, Principal Strategy Advisor	March 1, 2017
/s/ G. Nicholas Casey G. Nicholas Casey	Director	March 1, 2017
/s/ Daniel S. Hermann Daniel S. Hermann	Director	March 1, 2017
/s/ Brian D. Sullivan Brian D. Sullivan	Director	March 1, 2017
/s/ Paul H. Vining Paul H. Vining	Director	March 1, 2017

Exhibit 31.1

**Certification by Chief Executive Officer pursuant to
Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934,
as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**

I, Robert D. Moore certify that:

1. I have reviewed this Annual Report on Form 10-K of Foresight Energy LP.;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:
    a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
    b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusion about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this annual report based on such evaluation; and
    d. disclosed in this annual report any change in the registrant's internal control over financial reporting that occurred during the quarterly period ended December 31, 2016 that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2017

/s/ Robert D. Moore

Robert D. Moore
President, Chief Executive Officer
and Director

Exhibit 31.2

Certification by Chief Financial Officer pursuant to
Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934,
as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, James T. Murphy certify that:

1. I have reviewed this Annual Report on Form 10-K of Foresight Energy LP.;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:
   a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
   b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusion about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the quarterly period ended December 31, 2016 that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2017

/s/ James T. Murphy

James T. Murphy
Principal Financial Officer and
Chief Accounting Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Foresight Energy LP (the "Partnership") on Form 10-K for the year ended December 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert D. Moore, President, Chief Executive Officer and Director of Foresight Energy GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Partnership.

By: /s/ Robert D. Moore
Robert D. Moore
President, Chief Executive Officer and Director
of Foresight Energy GP, LLC

Date: March 1, 2017

This certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Partnership for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability under that section. This certification shall not be deemed incorporated by reference in any filing under the Securities Act or Exchange Act, except to the extent that the Partnership specifically incorporates it by reference. A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Foresight Energy LP (the "Partnership") on Form 10-K for the year ended December 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, James T. Murphy, Principal Financial Officer and Chief Accounting Officer of Foresight Energy GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Partnership.

By: /s/ James T. Murphy
James T. Murphy
Principal Financial Officer and Chief Accounting Officer
of Foresight Energy GP, LLC

Date: March 1, 2017

This certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Partnership for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability under that section. This certification shall not be deemed incorporated by reference in any filing under the Securities Act or Exchange Act, except to the extent that the Partnership specifically incorporates it by reference. A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

MINE SAFETY DISCLOSURE

Our mine operations are subject to regulation by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Act") . MSHA inspects our mines on a regular basis and issues various citations and orders to our operators when its inspectors believe that a violation has occurred under the Mine Act. We disclose information regarding certain citations and orders issued by MSHA and related assessments and legal actions with respect to our coal mining operations. In evaluating the below information regarding mine safety and health, investors should take into account factors such as: (i) the number of citations and orders will vary depending on the size of a coal mine, (ii) the number of citations issued will vary from inspector to inspector and mine to mine, and (iii) citations and orders can be contested and appealed, and in that process are often reduced in severity and amount, and are sometimes dismissed or vacated.

Section 1503 of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") requires issuers to include in periodic reports filed with the Securities and Exchange Commission ("SEC") certain information relating to citations and orders for violations of standards under the Mine Act. The following tables disclose information required under the Dodd-Frank Act for the year ended December 31, 2016.

Mine Name / MSHA Identification Number	Section 104 S&S Citations Excluding 104(d) Citations / Orders (#)(1)	Section 104(b) Orders (#)(2)	Section 104(d) Citations and Orders (#)(3)	Section 110(b)(2) Violations (#)(4)	Section 107(a) Orders (#)(5)	Total Dollar Value of MSHA Assessments Proposed in Thousands ($)(6)	Total Number of Mining Related Fatalities (#) (7)	Received Notice of Pattern of Violations Under Section 104(e) (yes/no) (8)	Legal Actions Pending as of Last Day of Period (#)(9)	Legal Actions Initiated During Period (#) (9)	Legal Actions Resolved During Period (#) (9)
Mach No. 1 / 1103141	93	0	0	0	0	$283.54	0	No	15	15	17
MC No. 1 / 1103189	77	0	0	0	0	$223.78	0	No	73	13	40
Deer Run / 1103182	0	0	0	0	0	0	0	No	4	0	0
Shay No. 1 / 1100726	22	0	3	0	0	$69.85	0	No	2	3	13

(1) Mine Act Section 104 citations and orders for alleged violations of mandatory health or safety standards that could significantly and substantially contribute to a coal mine safety or health hazard. Excludes 104(d) orders.

(2) Mine Act Section 104(b) orders are for alleged failures to totally abate a citation within the period of time specified in the citation.

(3) Mine Act Section 104(d) citations and orders are for an alleged unwarrantable failure to comply with mandatory health or safety standards.

(4) Total number of flagrant violations issued under Section 110(b)(2) of the Mine Act.

(5) Mine Act Section 107(a) orders are for alleged conditions or practices that could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated and result in orders of immediate withdrawal from the area of the mine affected by the condition.

(6) Total dollar value of MSHA assessments proposed during the year ended December 31, 2016. These figures do not necessarily relate to the citations or orders issued by MSHA during the current reporting period or to the pending cases reported herein. Note that these figures represent assessments proposed by MSHA during the year ended December 31, 2016, including those contested or appealed.

(7) Total number of mining related fatalities during the year ended December 31, 2016.

(8) Mine Act Section 104(e) written notices are for an alleged pattern of violations of mandatory health or safety standards that could significantly and substantially contribute to a coal mine health or safety hazard.

(9) Any pending legal action before the Federal Mine Safety and Health Review Commission (the "Commission") involving a coal mine owned and operated by us. The number of legal actions pending as of December 31, 2016 that fall into each of the following categories is as follows:

Mine Name / MSHA Identification Number	Contests of Citations/ Orders referenced in Subpart B, 29CFR Part 2700	Contests of Proposed Penalties referenced in Subpart C, 29CFR Part 2700	Complaints for compensation referenced in Subpart D, 29CFR Part 2700	Complaints for discharge, discrimination, or interference referenced in Subpart E, 29CFR Part 2700	Applications for temporary relief referenced in Subpart F 29CFR Part 2700	Appeals of judges' decisions or orders to FMSHRC referenced in Subpart H 29CFR Part 2700
Mach No. 1 / 1103141	2	13	0	1	0	0
MC No. 1 / 1103189	50	23	0	0	0	0
Deer Run / 1103182	0	4	0	0	0	0
Shay No. 1 / 1100726	0	2	0	0	0	0