NATURAL RESOURCE PARTNERS LP
Form 10-K
March 07, 2019

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018 or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 1-31465
NATURAL RESOURCE PARTNERS L.P.
(Exact name of registrant as specified in its charter)

Delaware	35-2164875
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

1201 Louisiana Street, Suite 3400, Houston, Texas 77002
(Address of principal executive offices)
Registrant's telephone number, including area code (713) 751-7507
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 ý
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 ý
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 ý 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 ý No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See definition of "accelerated filer", "large accelerated filer", "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ¨		Accelerated Filer	ý
Non-accelerated Filer ¨	(Do not check if a smaller reporting company)	Smaller Reporting Company	ý
		Emerging Growth Company	¨

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

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

The aggregate market value of the common units held by non-affiliates of the registrant on June 30, 2018, was $248 million based on a closing price on that date of $31.40 per unit as reported on the New York Stock Exchange.

As of March 1, 2019, there were 12,261,199 common units outstanding.

Documents incorporated by reference: None.

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CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING STATEMENTS

Statements included in this 10-K may constitute forward-looking statements. In addition, we and our representatives may from time to time make other oral or written statements which are also forward-looking statements. Such forward-looking statements include, among other things, statements regarding: our business strategy; our liquidity and access to capital and financing sources; our financial strategy; prices of and demand for coal, trona and soda ash, and other natural resources; estimated revenues, expenses and results of operations; projected production levels by our lessees; Ciner Wyoming LLC's ("Ciner Wyoming") trona mining and soda ash refinery operations; the impact of governmental policies, laws and regulations, as well as regulatory and legal proceedings involving us, and of scheduled or potential regulatory or legal changes; and global and U.S. economic conditions.

These forward-looking statements speak only as of the date hereof and are made based upon our current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements. You should not put undue reliance on any forward-looking statements. See "Item 1A. Risk Factors" in this Annual Report on Form 10-K for important factors that could cause our actual results of operations or our actual financial condition to differ.

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PART I

As used in this Part I, unless the context otherwise requires: "we," "our," "us" and the "Partnership" refer to Natural Resource Partners L.P. and, where the context requires, our subsidiaries. References to "NRP" and "Natural Resource Partners" refer to Natural Resource Partners L.P. only, and not to NRP (Operating) LLC or any of Natural Resource Partners L.P.'s subsidiaries. References to "Opco" refer to NRP (Operating) LLC, a wholly owned subsidiary of NRP, and its subsidiaries. NRP Finance Corporation ("NRP Finance") is a wholly owned subsidiary of NRP and a co-issuer with NRP on the 10.50% Senior Notes due 2022 (the "2022 Notes").

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

Partnership Structure and Management

We are a publicly traded Delaware limited partnership formed in 2002. We own, manage and lease a diversified portfolio of mineral properties in the United States, including interests in coal, soda ash from trona and other natural resources.

Our business is organized into two operating segments:

Coal Royalty and Other—consists primarily of coal royalty properties and coal-related transportation and processing assets. Other assets include industrial mineral royalty properties, aggregates royalty properties, oil and gas royalty properties and timber. Our coal reserves are primarily located in Appalachia, the Illinois Basin and in the Northern Powder River Basin in the United States. Our aggregates and industrial minerals properties are located in a number of states across the United States. Our oil and gas royalty assets are primarily located in Louisiana.

Soda Ash—consists of our 49% non-controlling equity interest in Ciner Wyoming, a trona ore mining operation and soda ash refinery, in the Green River Basin of Wyoming. Ciner Resources, LP, our operating partner, mines the trona, processes it into soda ash and distributes the soda ash both domestically and internationally to the glass and chemicals industries.

In December 2018, we sold our construction aggregates business for $205 million, before customary purchase price adjustments and transaction expenses, and recorded a gain of $13.1 million. Our exit from the construction aggregates business enabled us to further reduce debt, focus on our Coal Royalty and Other and Soda Ash business segments and represented a strategic shift as we exited the operations of our construction aggregates business.

Our operations are conducted through Opco and our operating assets are owned by our subsidiaries. NRP (GP) LP, our general partner, has sole responsibility for conducting our business and for managing our operations. Because our general partner is a limited partnership, its general partner, GP Natural Resource Partners LLC, conducts its business and operations and the Board of Directors and officers of GP Natural Resource Partners LLC make decisions on our behalf. Robertson Coal Management LLC, a limited liability company wholly owned by Corbin J. Robertson, Jr., owns all of the membership interest in GP Natural Resource Partners LLC. Subject to the Board Representation and Observation Rights Agreement with certain entities controlled by funds affiliated with The Blackstone Group, L.P. (collectively referred to as "Blackstone") and affiliates of GoldenTree Asset Management LP (collectively referred to as "GoldenTree"), Mr. Robertson, Jr. is entitled to appoint the members of the Board of Directors of GP Natural Resource Partners LLC and has delegated the right to appoint one director to Blackstone.

The senior executives and other officers who manage NRP are employees of Western Pocahontas Properties Limited Partnership or Quintana Minerals Corporation, which are companies controlled by Mr. Robertson, Jr. These officers allocate varying percentages of their time to managing our operations. Neither our general partner, GP Natural Resource Partners LLC, nor any of their affiliates receive any management fee or other compensation in connection with the management of our business, but they are entitled to be reimbursed for all direct and indirect expenses incurred on our behalf.

We have regional offices through which we conduct our operations, the largest of which is located at 5260 Irwin Road, Huntington, West Virginia 25705 and the telephone number is (304) 522-5757. Our principal executive office is located at 1201 Louisiana Street, Suite 3400, Houston, Texas 77002 and our telephone number is (713) 751-7507.

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Segment and Geographic Information

The amount of 2018 revenue and other income from our two operating segments is shown below. For additional business segment information, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations" and "Item 8. Financial Statements and Supplementary Data—Note 8. Segment Information" in this Annual Report on Form 10-K, which are both incorporated herein by reference.

(In thousands)	Amount	% of Total
Coal Royalty and Other	$230,206	83%
Soda Ash	48,306	17%
Total	$278,512	100%

Coal Royalty and Other Segment

Our coal reserves are primarily located in the Appalachia Basin, the Illinois Basin and the Northern Powder River Basin in the United States. We lease our reserves to experienced mine operators under long-term leases. Approximately two-thirds of our royalty-based leases have initial terms of five to 40 years, with substantially all lessees having the option to extend the lease for additional terms. Leases include the right to renegotiate royalties and minimum payments for the additional terms. We also own and manage coal-related transportation and processing assets that generate additional revenues generally based on throughput or rents in the Illinois Basin. As described in the "—Other Coal Royalty and Other Segment Assets" section below, we also own oil and gas, aggregates and industrial mineral reserves that generate a portion of Coal Royalty and Other segment revenues.

Under our standard royalty lease, we grant the operators the right to mine and sell our reserves in exchange for royalty payments based on the greater of a percentage of the sale price or fixed royalty per ton. Lessees calculate royalty payments due to us and are required to report tons of minerals removed as well as the sales prices of the extracted minerals. Therefore, to a great extent, amounts reported as royalty revenue are based upon the reports of our lessees. We periodically audit this information by examining certain records and internal reports of our lessees and we perform periodic mine inspections to verify that the information that our lessees have submitted to us is accurate. Our audit and inspection processes are designed to identify material variances from lease terms as well as differences between the information reported to us and the actual results from each property.

In addition to their royalty obligations, our lessees are often subject to minimum payments, which reflect amounts we are entitled to receive even if no mining activity occurs during the period. Minimum payments are usually credited against future royalties that are earned as minerals are produced. In certain leases, the lessee is time limited on the period available for recouping minimum payments and such time is unlimited on other leases.

Because we do not operate any coal mines, our coal royalty business does not bear ordinary operating costs and has limited direct exposure to environmental, permitting and labor risks. Our lessees, as operators, are subject to environmental laws, permitting requirements and other regulations adopted by various governmental authorities. In addition, the lessees generally bear all labor-related risks, including retiree health care costs, black lung benefits and workers' compensation costs associated with operating the mines on our coal and aggregates properties. We pay property taxes on our properties, which are largely reimbursed by our lessees pursuant to the terms of the various lease agreements.

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Coal Reserves and Production Information

The following table presents coal reserves information as of December 31, 2018 for the properties that we own by major coal region:

	Proven and Probable Reserves (1)		
(Tons in thousands)	Underground	Surface	Total
Appalachia Basin			
Northern	366,633	2,934	369,567
Central	723,795	238,531	962,326
Southern	59,317	19,966	79,283
Total Appalachia Basin	1,149,745	261,431	1,411,176
Illinois Basin	302,002	5,074	307,076
Northern Powder River Basin	—	166,590	166,590
Gulf Coast	—	1,957	1,957
Total	1,451,747	435,052	1,886,799

(1) In excess of 94% of the reserves presented in this table are currently leased to third parties.

The following table presents the type of coal reserves by major coal region as of December 31, 2018:

	Type of Coal		
(Tons in thousands)	Thermal	Metallurgical (1)	Total
Appalachia Basin			
Northern	308,054	61,513	369,567
Central	541,625	420,701	962,326
Southern	58,957	20,326	79,283
Total Appalachia Basin	908,636	502,540	1,411,176
Illinois Basin	307,076	—	307,076
Northern Powder River Basin	166,590	—	166,590
Gulf Coast	1,875	82	1,957
Total	1,384,177	502,622	1,886,799

(1) For purposes of this table, we have defined metallurgical coal reserves as reserves located in seams that historically have been of sufficient quality and characteristics to be able to be used in the steel making process. Some of the reserves in the metallurgical category can also be used as thermal coal.

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The following table presents the sulfur content and the typical quality of our coal reserves by major coal region as of December 31, 2018:

(Tons in thousands)	Sulfur Content					Typical Quality [1]	
	Compliance Coal [2]	Low (<1.0%)	Medium (1.0% to 1.5%)	High (>1.5%)	Total	Heat Content (Btu per pound)	Sulfur (%)
Appalachia Basin							
Northern	46,647	46,847	905	321,815	369,567	12,873	2.89
Central	453,122	671,508	244,489	46,329	962,326	13,232	0.90
Southern	44,903	49,518	27,175	2,590	79,283	13,408	0.96
Total Appalachia Basin	544,672	767,873	272,569	370,734	1,411,176	13,148	1.43
Illinois Basin	—	—	2,152	304,924	307,076	11,474	3.29
Northern Powder River Basin	—	166,590	—	—	166,590	8,800	0.65
Gulf Coast	82	1,957	—	—	1,957	6,964	0.69
Total	544,754	936,420	274,721	675,658	1,886,799		

(1) Unless otherwise indicated, the coal quality information in this Annual Report and on the Form 10-K is reported on an as-received basis with an assumed moisture of 6% for Appalachian reserves, and site specific moisture values for Illinois (typically 12% moisture) and Northern Powder River Basin (typically 25% moisture).

(2) Compliance coal, when burned, emits less than 1.2 pounds of sulfur dioxide per million Btu and meets the sulfur dioxide emission standards imposed by Phase II of the Clean Air Act without blending with other coals or using sulfur dioxide reduction technologies. Compliance coal is a subset of low sulfur coal and is, therefore, also reported within the amounts for low sulfur coal.

Methodologies Used in Mineral Reserve Estimation

All of the reserves reported above are recoverable proven or probable reserves as determined by the SEC's Industry Guide 7 and are estimated by our internal reserve geologist or independent third party consultants. Significant internally generated reserve studies are reviewed by independent third party consultants. The technologies and economic data used in the estimation of our proven or probable reserves include, but are not limited to, drill logs, geophysical logs, geologic maps including isopach, mine and coal quality, cross sections, statistical analysis and available public production data. There are numerous uncertainties inherent in estimating the quantities and qualities of recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves depend upon a number of variable factors and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. See "Item 1A. Risk Factors—Risks Related to Our Business—Our reserve estimates depend on many assumptions that may be inaccurate, which could materially adversely affect the quantities and value of our reserves."

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The following table presents the type of coal production by major coal region for the year ended December 31, 2018:

	Type of Coal		
(Tons in thousands)	Thermal	Metallurgical	Total
Appalachia Basin			
Northern	2,152	1,035	3,187
Central	2,986	12,011	14,997
Southern	284	1,426	1,710
Total Appalachia Basin	5,422	14,472	19,894
Illinois Basin	2,739	—	2,739
Northern Powder River Basin	4,313	—	4,313
Total	12,474	14,472	26,946

Major Coal Producing Properties

The following table provides a summary of our major coal royalty properties and is followed by additional information for each property or lease name:

Region	Property/Lease Name	Operator	Coal Type	2018 Production (Millions of Tons)
Appalachia Basin				
Northern	Hibbs Run	Murray Energy Corporation	Thermal	1.5
Northern	Mettiki Coal	Alliance Resource Partners	Met/Thermal	1.1
Northern	Carter Roag	Metinvest	Met	0.4
Central	Contura-CAPP (VA)	Contura Energy, Inc.	Met	3.3
Central	Blackjewel-Lynch	Blackjewel LLC	Met/Thermal	2.3
Central	Coal Mountain	CM Energy Properties, LP and Ramaco Resources, Inc.	Met/Thermal	2.2
Central	Aracoma	Contura Energy, Inc.	Met/Thermal	1.7
Central	Pinnacle (1)	Mission Coal, LLC (2)	Met	1.1
Central	Kepler	Contura Energy, Inc.	Met	0.5
Central	Greenbrier Minerals	Coronado Coal	Met	0.4
Central	South Fork Coal	Xinergy Corp.	Met	0.2
Southern	Oak Grove	Mission Coal, LLC (2)	Met	1.4
Illinois Basin	Macoupin	Foresight Energy LP	Thermal	2.0
Illinois Basin	Williamson	Foresight Energy LP	Thermal	0.4
Illinois Basin	Hillsboro	Foresight Energy LP	Thermal	—
Northern Powder River Basin	Western Energy	Westmoreland Coal Company (2)	Thermal	4.3

(1) Pinnacle property is currently closed and not producing.
(2) Operator currently in bankruptcy.

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Appalachia Basin—Northern Appalachia

Hibbs Run. The Hibbs Run property is located in Marion County, West Virginia. In 2018, approximately 1.5 million tons were produced from this thermal property. We lease this property to a subsidiary of Murray Energy Corporation. Coal from this property is produced from longwall mines and shipped by rail to utility customers. The royalty rate for this property is a low fixed rate per ton and has a significant effect on the weighted average per ton revenue for the region.

Mettiki Coal. The Mettiki Coal property is located in Tucker and Grant Counties, West Virginia. In 2018, approximately 1.1 million tons metallurgical and thermal tons were produced from this property. We lease this property to a subsidiary of Alliance Resource Partners. Production comes from this mine via a longwall operation. Coal is shipped by truck to a local utility customer and by train to metallurgical customers. NRP pays an override royalty equal to the royalty received from Mettiki to Western Pocahontas Properties Limited Partnership per the terms of the deed.

Carter Roag. The Carter Roag property is located in Randolph and Upshur Counties, West Virginia. In 2018, approximately 0.4 million tons were produced from this metallurgical coal property. We lease this property to a subsidiary of Metinvest. Production comes from the Morgan Camp and Pleasant Hill room and pillar deep mines. The coal production is trucked to Carter Roag’s preparation plant situated at Star Bridge, West Virginia. The coal produced from this property is shipped via the CSX railroad to Baltimore and then by ocean vessel to Metinvest's steel mills in Ukraine.

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The map below shows the location of our major properties in Northern Appalachia:

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Appalachia Basin—Central Appalachia

Contura-CAPP (VA). The Contura-CAPP (VA) property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. In 2018, approximately 3.3 million tons were produced from this property, substantially all of which was metallurgical coal. We lease this property to subsidiaries of Contura Energy, Inc ("Contura Energy"). Production that comes from underground room and pillar and surface mines is trucked to one of two preparation plants. Coal is shipped via the CSX and Norfolk Southern railroads to utility and metallurgical customers.

Blackjewel-Lynch. The Blackjewel-Lynch (previously referred to as Resource Development) property is located in Harlan and Letcher Counties, Kentucky and Wise County, Virginia. In 2018, approximately 2.3 million tons of metallurgical and thermal coal were produced from this property. We lease this property to Blackjewel, LLC. Production comes from underground room and pillar and surface mines. This property has the ability to ship coal on the CSX and Norfolk Southern railroads to utility and metallurgical customers.

Coal Mountain. The Coal Mountain property is located in Wyoming County, West Virginia. In 2018, approximately 2.2 million tons of metallurgical coal were produced from the property. We lease this property to CM Energy Properties, LP and Ramaco Resources Inc. Metallurgical coal is produced from surface mining and metallurgical and thermal coal are produced from underground room and pillar mines and trucked to preparation plants on the property. Coal is shipped via the Norfolk Southern and CSX railroad to various utility customers and both domestic or export metallurgical customers.

Aracoma. The Aracoma property is located in Logan County, West Virginia. In November 2018, Alpha Natural Resources, Inc. (the former controlling company of the property) merged into Contura Energy. This property is now leased to a subsidiary of Contura Energy. Approximately 1.7 million tons of coal, substantially all of which is metallurgical coal, was produced in 2018 from the property. Coal is produced from underground room and pillar mines and transported by belt or truck to the preparation plant on the property. Coal is shipped via the CSX railroad to utility customers and to various domestic and export metallurgical customers.

Pinnacle. The Pinnacle property is located in Wyoming and McDowell Counties, West Virginia. In 2018, approximately 1.1 million tons of metallurgical coal was produced from our reserves on this property. We lease the property to a subsidiary of Mission Coal, LLC ("Mission Coal"), which filed for bankruptcy protection in 2018. Production came from a longwall mine and was transported by beltline to a preparation plant on the property. Coal was shipped via Norfolk Southern railroad to both domestic and export customers. The Pinnacle mine is currently closed and the preparation plant is idled.

Kepler. The Kepler property is located in Wyoming County, West Virginia. In 2018, approximately 0.5 million tons were produced from the property. We lease this property to a subsidiary of Contura Energy. In November 2018, Alpha Natural Resources, Inc. (the former controlling company of the property) merged into Contura Energy. Metallurgical coal is produced from two underground room and pillar mines that is transported by belt and truck to a preparation plant on the property. Coal is shipped via the Norfolk Southern railroad to various metallurgical customers.

Greenbrier Minerals. The Greenbrier Minerals property is located in Greenbrier County, West Virginia. In 2018, approximately 0.4 million tons were produced from the property. This property is leased to Coronado Coal. Metallurgical coal is produced from surface mines and transported by truck to a preparation plant. Coal is shipped via the CSX railroad to various export metallurgical customers.

South Fork Coal. The South Fork Coal property is located in Greenbrier County, West Virginia. In 2018, approximately 0.2 million tons were produced from the property. This property is leased to South Fork Coal Company, LLC, a subsidiary of Xinergy Corp. Metallurgical coal is produced from surface mines and transported by truck to a preparation plant. Coal is shipped via the CSX railroad to export metallurgical customers.

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The map below shows the location of our major properties in Central Appalachia:

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Appalachia Basin—Southern Appalachia

Oak Grove. The Oak Grove property is located in Jefferson County, Alabama. In 2018, approximately 1.4 million tons of metallurgical coal were produced from this property. We lease the property to a subsidiary of Mission Coal. Mission Coal filed for bankruptcy protection during 2018. Production comes from a longwall mine and is transported primarily by beltline to a preparation plant. Metallurgical coal is then shipped via railroad and barge to both domestic and export customers.

The map below shows the location of our major property in Southern Appalachia:

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Illinois Basin

Macoupin. The Macoupin property is located in Macoupin County, Illinois. The property is under lease to Macoupin Energy, a subsidiary of Foresight Energy LP ("Foresight Energy"). In 2018, approximately 2.0 million tons of thermal coal were sold from our property. Production is from an underground room and pillar mine. Coal is shipped via the Norfolk Southern or Union Pacific railroads or by barge to domestic utility or export customers.

Williamson. The Williamson property is located in Franklin and Williamson Counties, Illinois. The property is under lease to Williamson Energy, a subsidiary of Foresight Energy. In 2018, approximately 0.4 million tons of thermal coal were sold from our property. Production comes from a longwall mine. Coal is shipped primarily via the Canadian National railroad to domestic utility customers. Approximately 6.1 million tons of additional production was received in 2018 in the form of override royalty from an adverse property.

Hillsboro. The Hillsboro property is located in Montgomery and Bond Counties, Illinois. The property is under lease to Hillsboro Energy, a subsidiary of Foresight Energy. It had been idled since March 2015 until longwall panel development production resumed in January 2019. When fully active, production at the mine has historically come from longwall mining methods. Coal is shipped by rail via either the Union Pacific, Norfolk Southern or Canadian National railroads, or by barges to domestic utilities or export customers.

In addition to these properties, we own loadout and other transportation assets at the Williamson and Macoupin mines and at the Sugar Camp mines, which is also operated by Foresight Energy. See "—Coal Transportation and Processing Assets" below for additional information on these assets.

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The map below shows the location of our major properties in the Illinois Basin:

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Northern Powder River Basin

Western Energy. The Western Energy property is located in Rosebud and Treasure Counties, Montana. In 2018, approximately 4.3 million tons were produced from our property by a subsidiary of Westmoreland Coal Company. Coal is produced by surface dragline mining methods, and the coal is transported by either truck or beltline to the Colstrip generation station located at the mine mouth. Westmoreland Coal Company filed for bankruptcy protection during 2018.

The map below shows the location of our property in the Northern Powder River Basin:

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Coal Transportation and Processing Assets

We own transportation and processing infrastructure related to certain of our coal properties, including loadout and other transportation assets at Foresight Energy's Williamson and Macoupin mines in the Illinois Basin, for which we collect throughput fees or rents. We lease our Macoupin and Williamson transportation and processing infrastructure to subsidiaries of Foresight Energy and are responsible for operating and maintaining the transportation and processing assets at the Williamson mine that we subcontract to a subsidiary of Foresight Energy. In addition, we own rail loadout and associated infrastructure at the Sugar Camp mine, an Illinois Basin mine also operated by a subsidiary of Foresight Energy. While we own coal reserves at the Williamson and Macoupin mines, we do not own coal reserves at the Sugar Camp mine. The infrastructure at the Sugar Camp mine is leased to a subsidiary of Foresight Energy and we collect throughput fees. We recorded $23.9 million in revenue related to our coal transportation and processing assets during the year ended December 31, 2018.

Other Coal Royalty and Other Segment Assets

As of December 31, 2018, we owned an estimated 173 million tons of aggregates reserves primarily located in Kentucky and Indiana. We lease a portion of these reserves to third parties in exchange for royalty payments. The structure of these leases is similar to our coal leases, and these leases typically require minimum rental payments in addition to royalties. In addition, we hold overriding royalty interests in frac sand operations in Wisconsin and Texas and an overriding royalty interest in approximately 82 million tons of sand and gravel reserves in Washington. During 2018, our lessees produced 4.3 million tons from these properties and we received $4.7 million in aggregates royalty revenues, including overriding royalty revenues.

Through our 51% ownership of BRP LLC ("BRP"), a joint venture with International Paper Company, we own approximately 10 million mineral acres in 31 states that include the following assets:

- approximately 300,000 gross acres of oil and natural gas mineral rights primarily in Louisiana, of which over 53,000 acres were leased as of December 31, 2018;
- approximately 50 million tons of aggregates reserves primarily located in North Carolina, Arkansas and South Carolina and approximately 6 million tons of override royalty interest in South Carolina and Georgia;
- approximately 95,000 net mineral acres of coal rights (primarily lignite and some bituminous coal) in the Gulf Coast region, of which approximately 5,600 acres are leased in Louisiana, Mississippi and Texas;
- an overriding royalty interest of 1% (net) on approximately 25,000 mineral acres in Louisiana;
- copper rights in Michigan’s Upper Peninsula that are subject to a development agreement with a copper development company; and
- various other mineral rights including coalbed methane, metals, aggregates, water and geothermal, in several states throughout the United States.

While the vast majority of the 10 million acres owned by BRP remain largely undeveloped, BRP has an ongoing program to identify additional opportunities to lease its minerals to operating parties or otherwise monetize these assets.

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Soda Ash Segment

We own a 49% non-controlling equity interest in Ciner Wyoming. Ciner Resources LP, our operating partner, controls and operates Ciner Wyoming. Ciner Resources LP mines the trona, processes it into soda ash, and distributes the soda ash both domestically and internationally into the glass and chemicals industries. Ciner Resources LP is a publicly traded master limited partnership that depends on distributions from Ciner Wyoming in order to make distributions to its public unitholders.

Ciner Wyoming is one of the largest and lowest cost producers of soda ash in the world, serving a global market from its facility located in the Green River Basin of Wyoming. The Green River Basin geological formation holds the largest, and one of the highest purity, known deposits of trona ore in the world. Trona, a naturally occurring soft mineral, is also known as sodium sesquicarbonate and consists primarily of sodium carbonate, or soda ash, sodium bicarbonate and water. Ciner Wyoming processes trona ore into soda ash, which is an essential raw material in flat glass, container glass, detergents, chemicals, paper and other consumer and industrial products. The vast majority of the world's accessible trona reserves are located in the Green River Basin. According to historical production statistics, approximately one-quarter of global soda ash is produced by processing trona, with the remainder being produced synthetically through chemical processes. The costs associated with procuring the materials needed for synthetic production are greater than the costs associated with mining trona for trona-based production. In addition, trona-based production consumes less energy and produces fewer undesirable by-products than synthetic production.

Ciner Wyoming's Green River Basin surface operations are situated on approximately 880 acres in Wyoming, and its mining operations consist of approximately 23,500 acres of leased and licensed subsurface mining area. The facility is accessible by both road and rail. Ciner Wyoming uses seven large continuous mining machines and 14 underground shuttle cars in its mining operations. Its processing assets consist of material sizing units, conveyors, calciners, dissolver circuits, thickener tanks, drum filters, evaporators and rotary dryers.

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The following map provides an aerial overview of Ciner Wyoming's surface operations:

In trona ore processing, insoluble materials and other impurities are removed by thickening and filtering the liquor, a solution consisting of sodium carbonate dissolved in water. Ciner Wyoming then adds activated carbon to filters to remove organic impurities, which can cause color contamination in the final product. The resulting clear liquid is then crystallized in evaporators, producing sodium carbonate monohydrate. The crystals are then drawn off and passed through a centrifuge to remove excess water. The resulting material is dried in a product dryer to form anhydrous sodium carbonate, or soda ash. The resulting processed soda ash is then stored in on-site storage silos to await shipment by bulk rail or truck to distributors and end customers. Ciner Wyoming's storage silos can hold up to 65,000 short tons of processed soda ash at any given time. The facility is in good working condition and has been in service for 56 years.

Deca Rehydration. The evaporation stage of trona ore processing produces a precipitate and natural by-product called deca. "Deca," short for sodium carbonate decahydrate, is one part soda ash and ten parts water. Solar evaporation causes deca to crystallize and precipitate to the bottom of the four main surface ponds at the Green River Basin facility. The deca rehydration process enables Ciner Wyoming to recover soda ash from the deca-rich purged liquor as a by-product of the refining process. The soda ash contained in deca is captured by allowing the deca crystals to evaporate in the sun and separating the dehydrated crystals from the soda ash. The separated deca crystals are then blended with partially processed trona ore in the dissolving stage of the production process. This process enables Ciner Wyoming to reduce waste storage needs and convert what is typically a waste product into a usable raw material. Ciner Wyoming anticipates that its current deca stockpiles will be exhausted by 2023. In order to replace the volumes of soda ash produced from the deca rehydration process following exhaustion of those stockpiles, Ciner Wyoming will need to make significant capital expenditures over the next few years. See "Item 1A. Risk Factors—Risks Related to Our Business—We anticipate that Ciner Wyoming will need to increase capital expenditures in order to replace volumes of soda ash currently produced from the deca rehydration process, which could adversely affect Ciner Wyoming's profitability and ability to make cash distributions to us."

Shipping and Logistics. All of the soda ash produced is shipped by rail or truck from the Green River Basin facility. For the year ended December 31, 2018, Ciner Wyoming shipped approximately 93.5% of its soda ash to its customers initially via a single rail line owned and controlled by Union Pacific Railroad Company ("Union Pacific"). The Ciner Wyoming plant receives rail service exclusively from Union Pacific. The agreement with Union Pacific expires on December 31, 2019 and there can be no assurance that it will be renewed on terms favorable to Ciner Wyoming or at all. The rail freight rate charged under the agreement increases annually based on a published index tied to certain rail industry metrics. Ciner Resources Corporation leases a fleet of more than 2,000 hopper cars that serve as dedicated modes of shipment to its domestic customers. For export, Ciner Wyoming ships soda ash on unit trains consisting of approximately 100 cars to two primary ports: Port Arthur, Texas and Portland, Oregon. From these ports, the soda ash is loaded onto ships for delivery to ports all over the world. American Natural Soda Ash Corporation ("ANSAC") currently provides logistics and support services for all of Ciner Wyoming's export sales. For domestic sales, Ciner Resources Corporation provides similar services.

Customers. Ciner Wyoming's customers, including end users to whom ANSAC makes sales overseas, consist primarily of glass manufacturing companies, which account for 50% or more of the consumption of soda ash around the world; and chemical and detergent manufacturing companies. Ciner Wyoming's largest customer currently is ANSAC, which buys soda ash (through Ciner Resources Corporation, which serves as Ciner Wyoming's sales agent in its agreement with ANSAC) and other of its member companies for export to its customers. ANSAC accounted for approximately 52% of Ciner Wyoming's net sales in 2018. ANSAC takes soda ash orders directly from its overseas customers and then purchases soda ash for resale from its member companies pro rata based on each member's production volumes. ANSAC is the exclusive distributor for its members to the markets it serves. However, Ciner Resources Corporation, on Ciner Wyoming's behalf, negotiates directly with, and Ciner Wyoming exports to, customers in markets not served by ANSAC. During 2017, international sales were made through ANSAC as well as to affiliates of Ciner Resources Corporation.

In November 2018, Ciner Resources Corporation delivered a notice to terminate the membership in ANSAC, which is expected to be effective as of December 31, 2021. Until the effective termination date, ANSAC will continue to sell Ciner Wyoming's soda ash to ANSAC-designated overseas territories and continue to provide logistics and support services for Ciner Wyoming's other export sales. After the termination period, Ciner Resources Corporation will begin marketing soda ash directly into international markets which are currently being served by ANSAC, and Ciner Wyoming intends to utilize the distribution network that has already been established by the global Ciner Group. The

ANSAC agreement provides that in the event an ANSAC member exits or the ANSAC cooperative is dissolved, the exiting members are obligated for their respective portion of the residual net assets or deficit of the cooperative.

For customers in North America, Ciner Resources typically enters into contracts on Ciner Wyoming's behalf with terms ranging from one to three years. Under these contracts, customers generally agree to purchase either minimum estimated volumes of soda ash or a certain percentage of their soda ash requirements at a fixed price for a given calendar year. Although Ciner Wyoming does not have a "take or pay" arrangements with its customers, substantially all sales are made pursuant to written agreements and not through spot sales. In 2018, Ciner Wyoming had more than 70 domestic customers and has had long-term relationships with the majority of its customers.

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Leases and License. Ciner Wyoming is party to several mining leases and one license for its subsurface mining rights. Some of the leases are renewable at Ciner Wyoming's option upon expiration. Ciner Wyoming pays royalties to the State of Wyoming; the U.S. Bureau of Land Management and Rock Springs Royalty Company, an affiliate of Anadarko Petroleum, which are calculated based upon a percentage of the quantity or gross value of soda ash and related products at a certain stage in the mining process, or a certain sum per ton of such products. These royalty payments are typically subject to a minimum domestic production volume from the Green River Basin facility, although Ciner Wyoming is obligated to pay minimum royalties or annual rentals to its lessors and licensor regardless of actual sales. The royalty rates paid to Ciner Wyoming's lessors and licensor may change upon renewal of such leases and license.

As a minority interest owner in Ciner Wyoming, we do not operate and are not involved in the day-to-day operation of the trona ore mine or soda ash production plant. Our partner, Ciner Resources LP manages the mining and plant operations. We appoint three of the seven members of the Board of Managers of Ciner Wyoming and have certain limited negative controls relating to the company.

Significant Customers

We have a significant concentration of revenues with Foresight Energy and its subsidiaries, with total revenues of $54.6 million in 2018 from four different mining operations, including transportation and processing services, coal override and wheelage revenues. For additional information on significant customers, refer to "Item 8. Financial Statements and Supplementary Data—Note 16. Major Customers."

Competition

We face competition from land companies, coal producers, international steel companies and private equity firms in purchasing coal reserves and royalty producing properties. Numerous producers in the coal industry make coal marketing intensely competitive. Our lessees compete among themselves and with coal producers in various regions of the United States for domestic sales. Lessees compete with both large and small producers nationwide on the basis of coal price at the mine, coal quality, transportation cost from the mine to the customer and the reliability of supply. Continued demand for our coal and the prices that our lessees obtain are also affected by demand for electricity and steel, as well as government regulations, technological developments and the availability and the cost of generating power from alternative fuel sources, including nuclear, natural gas, wind, solar and hydroelectric power.

Ciner Wyoming's trona mining and soda ash refinery business faces competition from a number of soda ash producers in the United States, Europe and Asia, some of which have greater market share and greater financial, production and other resources than Ciner Wyoming does. Some of Ciner Wyoming's competitors are diversified global corporations that have many lines of business and some have greater capital resources and may be in a better position to withstand a long-term deterioration in the soda ash market. Other competitors, even if smaller in size, may have greater experience and stronger relationships in their local markets. Competitive pressures could make it more difficult for Ciner Wyoming to retain its existing customers and attract new customers, and could also intensify the negative impact of factors that decrease demand for soda ash in the markets it serves, such as adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of soda ash.

Title to Property

We owned substantially all of our coal and aggregates reserves in fee as of December 31, 2018. We lease the remainder from unaffiliated third parties. Ciner Wyoming leases or licenses its trona reserves. We believe that we have satisfactory title to all of our mineral properties, but we have not had a qualified title company confirm this belief. Although title to these properties is subject to encumbrances in certain cases, such as customary easements, rights-of-way, interests generally retained in connection with the acquisition of real property, licenses, prior reservations, leases, liens, restrictions and other encumbrances, we believe that none of these burdens will materially detract from the value of our properties or from our interest in them or will materially interfere with their use in the operation of our business.

For most of our properties, the surface, oil and gas and mineral or coal estates are not owned by the same entities. Some of those entities are our affiliates. State law and regulations in most of the states where we do business require the oil and gas owner to coordinate the location of wells so as to minimize the impact on the intervening coal seams. We do not anticipate that the existence of the severed estates will materially impede development of the minerals on our properties.

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Regulation and Environmental Matters

General

Operations on our properties must be conducted in compliance with all applicable federal, state and local laws and regulations. These laws and regulations include matters involving the discharge of materials into the environment, employee health and safety, mine permits and other licensing requirements, reclamation and restoration of mining properties after mining is completed, management of materials generated by mining operations, surface subsidence from underground mining, water pollution, legislatively mandated benefits for current and retired coal miners, air quality standards, protection of wetlands, plant and wildlife protection, limitations on land use, storage of petroleum products and substances which are regarded as hazardous under applicable laws and management of electrical equipment containing polychlorinated biphenyls (PCBs). Because of extensive, comprehensive and often ambiguous regulatory requirements, violations during natural resource extraction operations are not unusual and, notwithstanding compliance efforts, we do not believe violations can be eliminated entirely.

While it is not possible to quantify the costs of compliance with all applicable federal, state and local laws and regulations, those costs have been and are expected to continue to be significant. Our lessees in our coal and aggregates royalty businesses are required to post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closures, including the cost of treating mine water discharge when necessary. In many states our lessees also pay taxes into reclamation funds that states use to achieve reclamation where site specific performance bonds are inadequate to do so. Determinations by federal or state agencies that site specific bonds or state reclamation funds are inadequate could result in increased bonding costs for our lessees or even a cessation of operations if adequate levels of bonding cannot be maintained. We do not accrue for reclamation costs because our lessees are both contractually liable and liable under the permits they hold for all costs relating to their mining operations, including the costs of reclamation and mine closures. Although the lessees typically accrue adequate amounts for these costs, their future operating results would be adversely affected if they later determined these accruals to be insufficient. In recent years, compliance with these laws and regulations has substantially increased the cost of coal mining for all domestic coal producers.

In addition, the electric utility industry, which is the most significant end-user of thermal coal, is subject to extensive regulation regarding the environmental impact of its power generation activities, which has affected and is expected to continue to affect demand for coal mined from our properties. Current and future proposed legislation and regulations could be adopted that will have a significant additional impact on the mining operations of our lessees or their customers' ability to use coal and may require our lessees or their customers to change operations significantly or incur additional substantial costs that would negatively impact the coal industry.

Many of the statutes discussed below also apply to Ciner Wyoming's trona mining and soda ash production operations, and therefore we do not present a separate discussion of statutes related to those activities, except where appropriate.

Air Emissions

The Clean Air Act and corresponding state and local laws and regulations affect all aspects of our business. The Clean Air Act directly impacts our lessees' coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, on sources that emit various hazardous and non-hazardous air pollutants. The Clean Air Act also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants. There have been a series of federal rulemakings that are focused on emissions from coal-fired electric generating facilities, including the Cross-State Air Pollution Rule (CSAPR), regulating emissions of nitrogen oxide and sulfur dioxide, and the Mercury and Air Toxics Rule (MATS), regulating emissions of hazardous air pollutants. Installation of additional emissions control technologies and other measures required under these and other U.S. Environmental Protection Agency (EPA) regulations, including EPA's proposed rules to regulate greenhouse gas (GHG) emissions from new and existing fossil fuel-fired power plants, will make it more costly to operate coal-fired power plants and could make coal a less attractive or even effectively prohibited fuel source in the planning, building and operation of power plants in the future. These rules and regulations have resulted in a reduction in coal's share of power generating capacity, which has negatively impacted our lessees' ability to sell coal and our coal-related revenues. Further reductions in coal's share of power generating capacity as a result of compliance with existing or proposed rules and regulations would have a material adverse effect on our coal-related revenues.

Carbon Dioxide and Greenhouse Gas Emissions

In December 2009, EPA determined that emissions of carbon dioxide, methane, and other GHGs present an endangerment to public health and welfare because emissions of such gases are, according to EPA, contributing to warming of the Earth's atmosphere and other climatic changes. Based on its findings, EPA began adopting and implementing regulations to restrict emissions of GHGs under various provisions of the Clean Air Act.

In August 2015, EPA published its final Clean Power Plan (CPP) Rule, a multi-factor plan designed to cut carbon pollution from existing power plants, including coal-fired power plants. The rule requires improving the heat rate of existing coal-fired power plants and substituting lower carbon-emission sources like natural gas and renewables in place of coal. As promulgated, the rule would force many existing coal-fired power plants to incur substantial costs in order to comply or alternatively result in the closure of some of these plants, likely resulting in a material adverse effect on the demand for coal by electric power generators. The rule is being challenged by several states, industry participants and other parties in the United States Court of Appeals for the District of Columbia Circuit. In February 2016, the Supreme Court of the United States stayed the CPP Rule pending a decision by the District of Columbia Circuit as well as any subsequent review by the Supreme Court. In April 2017, the United States Court of Appeals for the District of Columbia Circuit granted EPA's motion to hold the litigation in abeyance. In December 2017, EPA issued a proposed rule repealing the CPP Rule and issued an Advance Notice of Proposed Rulemaking soliciting information regarding a potential replacement rule to the CPP Rule. In August 2018, EPA formally proposed the Affordable Clean Energy (ACE) Rule, which would replace the CPP Rule. The ACE Rule contemplates a narrower approach than the CPP Rule, focusing on efficiency improvements at existing power plants and eliminating the CPP Rule's broader goals that envisioned switches to non-fossil fuel energy sources and the implementation of efficiency measures on demand-side entities, which the EPA now considers beyond the reach of its authority under the Clean Air Act. The ACE Rule would also omit specific numerical emissions targets that had been established under the CPP Rule.

In October 2015, EPA published its final rule on performance standards for greenhouse gas emissions from new, modified, and reconstructed electric generating units. The final rule requires new steam generating units to use highly efficient supercritical pulverized coal boilers that use partial post-combustion carbon capture and storage technology. The final emission standard is less stringent than EPA had originally proposed due to updated cost assumptions, but could still have a material adverse effect on new coal-fired power plants. The final rule has been challenged by several states, industry participants and other parties in the United States Court of Appeals for the District of Columbia Circuit, but is not subject to a stay. In April 2017, the court granted EPA's motion to hold the litigation in abeyance while EPA reviews the rule.

President Obama also announced an emission reduction agreement with China's President Xi Jinping in November 2014. The United States pledged that by 2025 it would cut climate pollution by 26% to 28% from 2005 levels. China pledged it would reach its peak carbon dioxide emissions around 2030 or earlier, and increase its non-fossil fuel share of energy to around 20% by 2030. In December 2015, the United States was one of 196 countries that participated in the Paris Climate Conference, at which the participants agreed to limit their emissions in order to limit global warming to 2°C above pre-industrial levels, with an aspirational goal of 1.5°C. While there is no way to estimate the impact of these climate pledges and agreements, they could ultimately have an adverse effect on the demand for coal, both nationally and internationally, if implemented. President Trump has expressed a desire for the United States to withdraw from the Paris Climate Agreement or to re-negotiate its terms.

Hazardous Materials and Waste

The Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA or the Superfund law) and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. We could become liable under federal and state Superfund and waste management statutes if our lessees are unable to pay environmental cleanup costs relating to hazardous substances. In addition, we may have liability for environmental clean-up costs in connection with Ciner Wyoming's soda ash businesses.

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Water Discharges

Operations conducted on our properties can result in discharges of pollutants into waters. The Clean Water Act and analogous state laws and regulations create two permitting programs for mining operations. The National Pollutant Discharge Elimination System (NPDES) program under Section 402 of the statute is administered by the states or EPA and regulates the concentrations of pollutants in discharges of waste and storm water from a mine site. The Section 404 program is administered by the Army Corps of Engineers and regulates the placement of overburden and fill material into channels, streams and wetlands that comprise "waters of the United States." The scope of waters that may fall within the jurisdictional reach of the Clean Water Act is expansive and may include land features not commonly understood to be a stream or wetlands. In June 2015, EPA issued a new rule defining the scope of "Waters of the United States" (WOTUS) that are subject to regulation. The WOTUS rule was challenged by a number of states and private parties in federal district and circuit courts, and the rule was stayed on a nationwide basis by the Sixth Circuit Court of Appeals in October 2015. In January 2018, the United States Supreme Court ruled that challenges to the WOTUS rule are properly within the jurisdiction of the federal district courts rather than the Sixth Circuit or other federal appellate courts. In light of the Supreme Court's ruling, the Sixth Circuit lifted the nationwide stay. In February 2018, EPA and the Corps promulgated a rule delaying implementation of the 2015 WOTUS rule until 2020 and reinstating the regulatory definition of "Waters of the United States" that applied prior to the 2015 rule. Several federal district courts have enjoined the suspension rule, resulting in two different regulatory standards for determining the scope of jurisdiction under the Clean Water Act. Currently, the 2015 WOTUS rule is in effect in twenty-two states and Washington, D.C., while its predecessor remains in effect in the other twenty-eight. In December 2017, EPA and the Corps proposed a rule to repeal the WOTUS rule. In December 2018, EPA and the Corps issued a proposed rule revising the definition of "Waters of the United States." The Clean Water Act and its regulations prohibit the unpermitted discharge of pollutants into such waters, including those from a spill or leak. Similarly, Section 404 also prohibits discharges of fill material and certain other activities in waters unless authorized by the issued permit.

In connection with its review of permits, EPA has at times sought to reduce the size of fills and to impose limits on specific conductance (conductivity) and sulfate at levels that can be unachievable absent treatment at many mines. Such actions by EPA could make it more difficult or expensive to obtain or comply with such permits, which could, in turn, have an adverse effect on our coal-related revenues.

In addition to government action, private citizens' groups have continued to be active in bringing lawsuits against operators and landowners. Since 2012, several citizen group lawsuits have been filed against mine operators for allegedly violating conditions in their National Pollutant Discharge Elimination System ("NPDES") permits requiring compliance with West Virginia's water quality standards. Some of the lawsuits allege violations of water quality standards for selenium, whereas others allege that discharges of conductivity and sulfate are causing violations of West Virginia's narrative water quality standards, which generally prohibit adverse effects to aquatic life. The citizen suit groups have sought penalties as well as injunctive relief that would limit future discharges of selenium, conductivity or sulfate. The federal district court for the Southern District of West Virginia has ruled in favor of the citizen suit groups in multiple suits alleging violations of the water quality standard for selenium and in two suits alleging violations of water quality standards due to discharges of conductivity (one of which was upheld on appeal by the United States Court of Appeals for the Fourth Circuit in January 2017). Additional rulings requiring operators to reduce their discharges of selenium, conductivity or sulfate could result in large treatment expenses for our lessees.

Since 2013, several citizen group lawsuits have been filed against landowners alleging ongoing discharges of pollutants, including selenium and conductivity, from valley fills located at reclaimed mountaintop removal mining sites in West Virginia. In each case, the mine on the subject property has been closed, the property has been reclaimed, and the state reclamation bond has been released. Any determination that a landowner or lessee has liability for discharges from a previously reclaimed mine site could result in substantial compliance costs or fines and would result in uncertainty as to continuing liability for completed and reclaimed coal mine operations.

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Other Regulations Affecting the Mining Industry

Mine Health and Safety Laws

The operations of our coal lessees and Ciner Wyoming are subject to stringent health and safety standards that have been imposed by federal legislation since the adoption of the Mine Health and Safety Act of 1969. The Mine Health and Safety Act of 1969 resulted in increased operating costs and reduced productivity. The Mine Safety and Health Act of 1977, which significantly expanded the enforcement of health and safety standards of the Mine Health and Safety Act of 1969, imposes comprehensive health and safety standards on all mining operations. In addition, the Black Lung Acts require payments of benefits by all businesses conducting current mining operations to coal miners with black lung or pneumoconiosis and to some beneficiaries of miners who have died from this disease.

Mining accidents in recent years have received national attention and instigated responses at the state and national level that have resulted in increased scrutiny of current safety practices and procedures at all mining operations, particularly underground mining operations. Since 2006, heightened scrutiny has been applied to the safe operations of both underground and surface mines. This increased level of review has resulted in an increase in the civil penalties that mine operators have been assessed for non-compliance. Operating companies and their supervisory employees have also been subject to criminal convictions. The Mine Safety and Health Administration (MSHA) has also advised mine operators that it will be more aggressive in placing mines in the Pattern of Violations program, if a mine's rate of injuries or significant and substantial citations exceed a certain threshold. A mine that is placed in a Pattern of Violations program will receive additional scrutiny from MSHA.

Surface Mining Control and Reclamation Act of 1977

The Surface Mining Control and Reclamation Act of 1977 (SMCRA) and similar statutes enacted and enforced by the states impose on mine operators the responsibility of reclaiming the land and compensating the landowner for types of damages occurring as a result of mining operations. To ensure compliance with any reclamation obligations, mine operators are required to post performance bonds. Our coal lessees are contractually obligated under the terms of our leases to comply with all federal, state and local laws, including SMCRA. Upon completion of the mining, reclamation generally is completed by seeding with grasses or planting trees for use as pasture or timberland, as specified in the reclamation plan approved by the state regulatory authority. In addition, higher and better uses of the reclaimed property are encouraged.

Mining Permits and Approvals

Numerous governmental permits or approvals such as those required by SMCRA and the Clean Water Act are required for mining operations. In connection with obtaining these permits and approvals, our lessees may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production of coal may have upon the environment. The requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators, including our lessees, must submit a reclamation plan for reclaiming the mined property upon the completion of mining operations. Our lessees have obtained or applied for permits to mine a majority of the reserves that are currently planned to be mined over the next five years. Our lessees are also in the planning phase for obtaining permits for the additional reserves planned to be mined over the following five years. However, given the imposition of new requirements in the permits in the form of policies and the increased oversight review that has been exercised by EPA, there are no assurances that they will not experience difficulty and delays in obtaining mining permits in the future. In addition, EPA has used its authority to create significant delays in the issuance of new permits and the modification of existing permits, which has led to substantial delays and increased costs for coal operators.

Employees and Labor Relations

As of December 31, 2018, affiliates of our general partner employed 57 people who directly supported our operations. None of these employees were subject to a collective bargaining agreement.

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Website Access to Partnership Reports

Our Internet address is www.nrplp.com. We make available free of charge on or through our Internet website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. Information on our website is not a part of this report. In addition, the SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements and other information filed by us.

Corporate Governance Matters

Our Code of Business Conduct and Ethics, our Disclosure Controls and Procedures Policy and our Corporate Governance Guidelines adopted by our Board of Directors, as well as the charter for our Audit Committee are available on our website at www.nrplp.com. Copies of our annual report, our Code of Business Conduct and Ethics, our Disclosure Controls and Procedures Policy, our Corporate Governance Guidelines and our committee charters will be made available upon written request to our principal executive office at 1201 Louisiana St., Suite 3400, Houston, Texas 77002.

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ITEM 1A. RISK FACTORS

Risks Related to Our Business

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves. In addition, our debt agreements and our partnership agreement place restrictions on our ability to pay, and in some cases raise, the quarterly distribution under certain circumstances.

Because distributions on the common units are dependent on the amount of cash we generate, distributions fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter depends on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent primarily on cash flow, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits. The actual amount of cash we have to distribute each quarter is reduced by payments in respect of debt service and other contractual obligations, including distributions on the preferred units, fixed charges, maintenance capital expenditures and reserves for future operating or capital needs that the board of directors may determine are appropriate. We have significant debt service obligations and obligations to pay cash distributions on our preferred units. To the extent our board of directors deems appropriate, it may determine to decrease the amount of the quarterly distribution on our common units or suspend or eliminate the distribution on our common units altogether. In addition, because our unitholders are required to pay income taxes on their respective shares of our taxable income, our unitholders may be required to pay taxes in excess of any future distributions we make. Our unitholders' share of our portfolio income may be taxable to them even though they receive other losses from our activities. See "—Tax Risks to Our Unitholders—Our unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us. Our unitholders' share of our portfolio income may be taxable to them even though they receive other losses from our activities."

The agreements governing our indebtedness and preferred units restrict our ability to raise, and in some cases continue to pay, distributions on our common units. Opco’s revolving credit agreement, the indenture governing our 2022 Notes and our partnership agreement each require that we meet certain consolidated leverage tests in order to raise our quarterly distribution on the common units above the current level of $0.45 per quarter. The maximum leverage covenant under Opco’s revolving credit facility will step down permanently from 4.0x to 3.0x if we increase the common unit distribution above the current level of $0.45 per common unit per quarter. In addition, under our partnership agreement, to the extent we have paid any distributions on the preferred units in kind ("PIK units"), and such PIK units are still outstanding at any time after January 1, 2022, we will be prohibited from making any distributions with respect to our common units until we have redeemed all such PIK units in cash. For more information on restrictions on our ability to make distributions on our common units, see "Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" and "Item 8. Financial Statements and Supplementary Data—Note 13. Debt, Net."

Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects.

As of December 31, 2018, we and our subsidiaries had approximately $687.1 million of total indebtedness. The terms and conditions governing the indenture for NRP’s 2022 Notes and Opco’s revolving credit facility and senior notes:

- require us to meet certain leverage and interest coverage ratios;
-

require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industries in which we operate;

- increase our vulnerability to economic downturns and adverse developments in our business;
- limit our ability to access the bank and capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;
- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;

- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness;
- make it more difficult for us to satisfy our obligations under our debt agreements and increase the risk that we may default on our debt obligations; and
- limit management's discretion in operating our business.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations, including payment of distributions on the preferred units. If we do not have sufficient funds, we may be required to refinance all or part of our existing debt, borrow more money, or sell assets or raise equity at unattractive prices, including higher interest rates. We are required to make substantial principal repayments each year in connection with Opco's senior notes, with approximately $67 million due thereunder during 2019. In addition, Opco's revolving credit facility matures in April 2020. To the extent we borrow to make some of these payments, we may not be able to refinance these amounts on terms acceptable to us, if at all. We may not be able to refinance our debt, sell assets, borrow more money or access the bank and capital markets on terms acceptable to us, if at all. Our ability to comply with the financial and other restrictive covenants in our debt agreements will be affected by the levels of cash flow from our operations and future events and circumstances beyond our control. Failure to comply with these covenants would result in an event of default under our indebtedness, and such an event of default could adversely affect our business, financial condition and results of operations.

Prices for both metallurgical and thermal coal are volatile and depend on a number of factors beyond our control. Declines in prices could have a material adverse effect on our business and results of operations.

Coal prices continue to be volatile and prices could decline substantially from current levels. Production by some of our lessees may not be economic if prices decline further or remain at current levels. The prices our lessees receive for their coal depend upon factors beyond their or our control, including:

- the supply of and demand for domestic and foreign coal;
- domestic and foreign governmental regulations and taxes;
- changes in fuel consumption patterns of electric power generators;
- the price and availability of alternative fuels, especially natural gas;
- global economic conditions, including the strength of the U.S. dollar relative to other currencies;
- global and domestic demand for steel;
- tariff rates on imports and trade disputes, particularly involving the United States and China;
- the availability of, proximity to and capacity of transportation networks and facilities;
- weather conditions; and
- the effect of worldwide energy conservation measures.

Natural gas is the primary fuel that competes with thermal coal for power generation, and renewable energy sources continue to gain market share in power generation. The abundance and ready availability of cheap natural gas, together with increased governmental regulations on the power generation industry has caused a number of utilities to switch from thermal coal to natural gas and/or close coal-powered generation plants. This switching has resulted in a decline in thermal coal prices, and to the extent that natural gas prices remain low, thermal coal prices will also remain low. Reduced international demand for export thermal coal, principally into India and northern Europe, has also put downward pressure on thermal coal prices.

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Our lessees produce a significant amount of metallurgical coal that is used for steel production domestically and internationally. Since the amount of steel that is produced is tied to global economic conditions, declines in those conditions could result in the decline of steel, coke and metallurgical coal production. Since metallurgical coal is priced higher than thermal coal, some mines on our properties may only operate profitably if all or a portion of their production is sold as metallurgical coal. If these mines are unable to sell metallurgical coal, they may not be economically viable and may be temporarily idled or closed. Any potential future lessee bankruptcy filings could create additional uncertainty as to the future of operations on our properties and could have a material adverse effect on our business and results of operations.

To the extent our lessees are unable to economically produce coal over the long term, the carrying value of our reserves could be adversely affected. A long-term asset generally is deemed impaired when the future expected cash flow from its use and disposition is less than its book value. Future impairment analyses could result in additional downward adjustments to the carrying value of our assets.

Mining operations are subject to operating risks that could result in lower revenues to us.

Our revenues are largely dependent on the level of production of minerals from our properties, and any interruptions to or increases in costs of the production from our properties may reduce our revenues. The level of production and costs thereof are subject to operating conditions or events beyond our or our lessees' control including:

- difficulties or delays in acquiring necessary permits or mining or surface rights;
- reclamation costs and bonding costs;
- changes or variations in geologic conditions, such as the thickness of the mineral deposits and the amount of rock embedded in or overlying the mineral deposit;
- mining and processing equipment failures and unexpected maintenance problems;
- the availability of equipment or parts and increased costs related thereto;
- the availability of transportation networks and facilities and interruptions due to transportation delays;
- adverse weather and natural disasters, such as heavy rains and flooding;
- labor-related interruptions and trained personnel shortages; and
- mine safety incidents or accidents, including hazardous conditions, roof falls, fires and explosions.

While our lessees maintain insurance coverage, there is no assurance that insurance will be available or cover the costs of these risks. Many of our lessees are experiencing rising costs related to regulatory compliance, permitting and bonding, transportation, and labor. Increased costs result in decreased profitability for our lessees and reduce the competitiveness of coal as a fuel source. In addition, we and our lessees may also incur costs and liabilities resulting from third-party claims for damages to property or injury to persons arising from their operations. The occurrence of any of these events or conditions could have a material adverse effect on our business and results of operations.
The adoption of climate change legislation and regulations restricting emissions of greenhouse gases and other hazardous air pollutants have resulted in changes in fuel consumption patterns by electric power generators and a corresponding decrease in coal production by our lessees and reduced coal-related revenues.

Enactment of laws and passage of regulations regarding emissions from the combustion of coal by the U.S., some of its states or other countries, or other actions to limit such emissions, have resulted in and could continue to result in electricity generators switching from coal to other fuel sources and in coal-fueled power plant closures. Further, regulations regarding new coal-fueled power plants could adversely impact the global demand for coal. The potential financial impact on us of existing and future laws, regulations or other policies will depend upon the degree to which any such laws or regulations force electricity generators to diminish their reliance on coal as a fuel source. The amount of coal consumed for domestic electric power generation is affected primarily by the overall demand for electricity, the price and availability of competing fuels for power plants and environmental and other governmental regulations. We expect that substantially all newly constructed power plants in the United States will be fired by natural gas because of lower construction and compliance costs compared to coal-fired plants and because natural gas is a cleaner burning fuel. The increasingly stringent requirements of rules and regulations promulgated under the federal Clean Air Act have resulted in more electric power generators shifting from coal to natural-gas-fired power plants, or to other alternative energy sources such as solar and wind. In addition, the Clean Power Plan and proposed rules promulgated by the EPA on greenhouse

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gas emissions from new and existing power plants are expected to further limit the construction of new coal-fired generation plants in favor of alternative sources of energy and negatively affect the viability of existing coal-fired power generation. These changes have resulted in reduced coal consumption and the production of coal from our properties and are expected to continue to have an adverse effect on our coal-related revenues.

In addition to EPA's greenhouse gas initiatives, there are several other federal rulemakings that are focused on emissions from coal-fired electric generating facilities, including the Cross-State Air Pollution Rule (CSAPR), regulating emissions of nitrogen oxide and sulfur dioxide, and the Mercury and Air Toxics Rule (MATS), regulating emissions of hazardous air pollutants. Installation of additional emissions control technologies and other measures required under these and other EPA regulations have made it more costly to operate many coal-fired power plants and have resulted in and are expected to continue to result in plant closures. Further reductions in coal's share of power generating capacity as a result of compliance with existing or proposed rules and regulations would have a material adverse effect on our coal-related revenues. For more information on regulation of greenhouse gas and other air pollutant emissions, see "Items 1. and 2. Business and Properties—Regulation and Environmental Matters."

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate issues, are also resulting in unfavorable lending and investment policies by institutions, which could significantly affect our ability to raise capital.

Global climate issues continue to attract public and scientific attention. Numerous reports have engendered concern about the impacts of human activity, especially fossil fuel combustion, on global climate issues. In addition to government regulation of greenhouse gas and other air pollutant emissions, 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 fuels, such as coal. The impact of such efforts may adversely affect our ability to raise capital.

In addition to climate change and other Clean Air Act legislation, our businesses are subject to numerous other federal, state and local laws and regulations that may limit production from our properties and our profitability.

The operations of our lessees and Ciner Wyoming are subject to stringent health and safety standards under increasingly strict federal, state and local environmental, health and safety laws, including mine safety regulations and governmental enforcement policies. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our properties.

New environmental legislation, new regulations and new interpretations of existing environmental laws, including regulations governing permitting requirements, could further regulate or tax mining industries and may also require significant changes to operations, the incurrence of increased costs or the requirement to obtain new or different permits, any of which could decrease our revenues and have a material adverse effect on our financial condition or results of operations. Under SMCRA, our coal lessees have substantial reclamation obligations on properties where mining operations have been completed and are required to post performance bonds for their reclamation obligations. To the extent an operator is unable to satisfy its reclamation obligations or the performance bonds posted are not sufficient to cover those obligations, regulatory authorities or citizens groups could attempt to shift reclamation liability onto the ultimate landowner, which if successful, could have a material adverse effect on our financial condition.

In addition to governmental regulation, private citizens' groups have continued to be active in bringing lawsuits against coal mine operators and land owners that allege violations of water quality standards resulting from ongoing discharges of pollutants from reclaimed mining operations, including selenium and conductivity. Any determination that a landowner or lessee has liability for discharges from a previously reclaimed mine site would result in uncertainty as to continuing liability for completed and reclaimed coal mine operations and could result in substantial compliance costs or fines.

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Prices for soda ash are volatile. Any substantial or extended decline in soda ash prices could have an adverse effect on our results of operations.

The market price of soda ash directly affects the profitability of Ciner Wyoming's soda ash production operations. If the market price for soda ash declines, Ciner Wyoming's sales will decrease. Historically, the global market and, to a lesser extent, the domestic market for soda ash have been volatile, and those markets are likely to remain volatile in the future. The prices Ciner Wyoming receives for its soda ash depend on numerous factors beyond Ciner Wyoming's control, including worldwide and regional economic and political conditions impacting supply and demand. Glass manufacturers and other industrial customers drive most of the demand for soda ash, and these customers experience significant fluctuations in demand and production costs. Competition from increased use of glass substitutes, such as plastic and recycled glass, has had a negative effect on demand for soda ash. Substantial or extended declines in prices for soda ash could have a material adverse effect on our results of operations. In addition, Ciner Wyoming relies on natural gas as the main energy source in its soda ash production process. Accordingly, high natural gas prices increase Ciner Wyoming's cost of production and affect its competitive cost position when compared to other foreign and domestic soda ash producers.

An adverse outcome in our contingent consideration payment dispute with Anadarko could have an adverse effect on our business and liquidity.

In July 2017, Anadarko Holding Company and its subsidiary, Big Island Trona Company (together, "Anadarko") filed a lawsuit against Opco and NRP Trona LLC alleging that a July 2013 simplification of OCI Wyoming's ownership structure triggered an acceleration of an obligation under the purchase agreement with Anadarko to pay additional contingent consideration in full and demanded immediate payment of such amount, together with interest, court costs and attorneys' fees. We would be required to pay up to $40 million, plus interest, court costs and attorneys' fees if Anadarko prevails and is awarded the full damages it seeks. Any such payment could have a material adverse effect on our financial condition. For more information, see "Item 3. Legal Proceedings—Anadarko Contingent Consideration Payment Dispute."

We derive a large percentage of our revenues and other income from a small number of coal lessees.

Challenges in the coal mining industry have led to significant consolidation activity. In 2018, Contura Energy and Alpha Natural Resources merged, and our revenues from the two companies on a combined basis accounted for approximately 17% of our total revenues in 2018. In addition, we own significant interests in all four of Foresight Energy's mining operations, which accounted for approximately 22% of our total revenues in 2018. Certain other lessees have made acquisitions over the past few years resulting in their having an increased interest in our coal reserves. Any interruption in these lessees' ability to make royalty payments to us could have a disproportionate material adverse effect on our business and results of operations.

Bankruptcies in the coal industry could have a material adverse effect on our business and results of operations.

Due to the continued challenges in the coal business, a number of coal producers filed for protection under U.S. bankruptcy laws during 2018, including several of our coal lessees. To the extent our leases are accepted or assigned, pre-petition amounts will be cured in full, but we may ultimately make concessions in the financial terms of those leases in order for the reorganized company or new lessor to operate profitably going forward. To the extent our leases are rejected, operations on those leases will cease, and we will be unlikely to recover the full amount of our rejection damages claims. More of our lessees may file for bankruptcy in the future, which will create additional uncertainty as to the future of operations on our properties and could have a material adverse effect on our business and results of operations.

If our lessees do not manage their operations well, their production volumes and our royalty revenues could decrease.

We depend on our lessees to effectively manage their operations on our properties. Our lessees make their own business decisions with respect to their operations within the constraints of their leases, including decisions relating to:

- the payment of minimum royalties;
- marketing of the minerals mined;
- mine plans, including the amount to be mined and the method and timing of mining activities;
- processing and blending minerals;

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- expansion plans and capital expenditures;
- credit risk of their customers;
- permitting;
- insurance and surety bonding;
- acquisition of surface rights and other mineral estates;
- employee wages;
- transportation arrangements;
- compliance with applicable laws, including environmental laws; and
- mine closure and reclamation.

A failure on the part of one of our lessees to make royalty payments, including minimum royalty payments, could give us the right to terminate the lease, repossess the property and enforce payment obligations under the lease. If we repossessed any of our properties, we would seek a replacement lessee. We might not be able to find a replacement lessee and, if we did, we might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the existing lessee could be subject to bankruptcy proceedings that could further delay the execution of a new lease or the assignment of the existing lease to another operator. If we enter into a new lease, the replacement operator might not achieve the same levels of production or sell minerals at the same price as the lessee it replaced. In addition, it may be difficult for us to secure new or replacement lessees for small or isolated mineral reserves.

We are exposed to operating risks that we do not experience in the royalty business through our soda ash joint venture and through our ownership of certain coal transportation assets.

We do not have control over the operations of Ciner Wyoming. We have limited approval rights with respect to Ciner Wyoming, and our partner controls most business decisions, including decisions with respect to distributions and capital expenditures. Adverse developments in Ciner Wyoming’s business, including increased maintenance and expansion capital expenditures that we may be required to fund, would result in decreased distributions to NRP. In addition, we are ultimately responsible for operating the transportation infrastructure at Foresight Energy’s Williamson mine, and have assumed the capital and operating risks associated with that business. As a result of these investments, we could experience increased costs as well as increased liability exposure associated with operating these facilities.

A significant portion of Ciner Wyoming’s historical international sales of soda ash have been to ANSAC, and the termination of the ANSAC membership could adversely affect Ciner Wyoming’s ability to compete in certain international markets and Ciner Wyoming’s ability to make cash distributions to us.

ANSAC has historically been Ciner Wyoming’s largest customer for the years ended December 31, 2018, 2017 and 2016, accounting for 52.0%, 44.7% and 55.2%, respectively, of its net sales. Following termination of the membership in ANSAC, which will be effective December 31, 2021, there is no assurance that Ciner Wyoming will be able to retain existing foreign customers or secure new foreign customers or the related logistics arrangements on favorable terms. Adverse developments in Ciner Wyoming’s ability to transport soda ash and sell into the foreign markets currently served by ANSAC could result in lower cash distributions to us from Ciner Wyoming.

We anticipate that Ciner Wyoming will need to increase capital expenditures in order to replace volumes of soda ash currently produced from the deca rehydration process, which could adversely affect Ciner Wyoming’s profitability and ability to make distributions to us.

Ciner Wyoming anticipates that its current deca stockpiles will be exhausted by 2023. In order to replace the volumes of soda ash produced from the deca rehydration process following exhaustion of those stockpiles, Ciner Wyoming will need to make significant capital expenditures over the next few years. There is no assurance that any such additional investments will be executed successfully or in a timely manner to enable Ciner Wyoming to maintain soda ash production levels. In addition, if the capital for such investment projects cannot be obtained from alternative financing arrangements, Ciner Wyoming's cash flows may decline, which could limit Ciner Wyoming's ability to make cash distributions to us.

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Fluctuations in transportation costs and the availability or reliability of transportation could reduce the production of coal, soda ash and other minerals from our properties.

Transportation costs represent a significant portion of the total delivered cost for the customers of our lessees. Increases in transportation costs could make coal a less competitive source of energy or could make minerals produced by some or all of our lessees less competitive than coal produced from other sources. On the other hand, significant decreases in transportation costs could result in increased competition for our lessees from producers in other parts of the country.

Our lessees depend upon railroads, barges, trucks and beltlines to deliver minerals to their customers. Disruption of those transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks and/or other events could temporarily impair the ability of our lessees to supply coal to their customers and/or increase their costs. Many of our lessees are currently experiencing transportation-related issues due in particular to decreased availability and reliability of rail services and port congestion. Our lessees' transportation providers may face difficulties in the future that would impair the ability of our lessees to supply minerals to their customers, resulting in decreased royalty revenues to us.

In addition, Ciner Wyoming transports its soda ash by rail or truck and ocean vessel. As a result, its business and financial results are sensitive to increases in rail freight, trucking and ocean vessel rates. Increases in transportation costs, including increases resulting from emission control requirements, port taxes and fluctuations in the price of fuel, could make soda ash a less competitive product for glass manufacturers when compared to glass substitutes or recycled glass, or could make Ciner Wyoming's soda ash less competitive than soda ash produced by competitors that have other means of transportation or are located closer to their customers. Ciner Wyoming may be unable to pass on its freight and other transportation costs in full because market prices for soda ash are generally determined by supply and demand forces. In addition, rail operations are subject to various risks that may result in a delay or lack of service at Ciner Wyoming's facility, and alternative methods of transportation are impracticable or cost-prohibitive. For the year ended December 31, 2018, Ciner Wyoming shipped approximately 93.5% of its soda ash from the Green River facility on a single rail line owned and controlled by Union Pacific. Ciner Wyoming's current transportation contract with Union Pacific expires on December 31, 2019. There can be no assurance that this contract will be renewed on terms favorable to Ciner Wyoming or at all. Any substantial interruption in or increased costs related to the transportation of Ciner Wyoming's soda ash or the failure to renew the rail contract on favorable terms could have a material adverse effect on our financial condition and results of operations.

Our reserve estimates depend on many assumptions that may be inaccurate, which could materially adversely affect the quantities and value of our reserves.

Coal, aggregates and industrial minerals reserve engineering requires subjective estimates of underground accumulations of coal, aggregates and industrial minerals, and assumptions and are by nature imprecise. Our reserve estimates may vary substantially from the actual amounts of coal, aggregates and industrial minerals recovered from our reserves. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. Estimates of reserves necessarily depend upon a number of variables and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. These factors and assumptions relate to:

- future prices, operating costs, capital expenditures, severance and excise taxes, and development and reclamation costs;
- production levels;

- future technology improvements;
- the effects of regulation by governmental agencies; and
- geologic and mining conditions, which may not be fully identified by available exploration data.

Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and these variations may be material. As a result, undue reliance should not be placed on our reserve data that is included in this report.

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Our lessees could satisfy obligations to their customers with minerals from properties other than ours, depriving us of the ability to receive amounts in excess of minimum royalty payments.

Mineral supply contracts generally do not require operators to satisfy their obligations to their customers with resources mined from specific reserves. Several factors may influence a lessee’s decision to supply its customers with minerals mined from properties we do not own or lease, including the royalty rates under the lessee’s lease with us, mining conditions, mine operating costs, cost and availability of transportation, and customer specifications. In addition, lessees move on and off of our properties over the course of any given year in accordance with their mine plans. If a lessee satisfies its obligations to its customers with minerals from properties we do not own or lease, production on our properties will decrease, and we will receive lower royalty revenues.

A lessee may incorrectly report royalty revenues, which might not be identified by our lessee audit process or our mine inspection process or, if identified, might be identified in a subsequent period.

We depend on our lessees to correctly report production and royalty revenues on a monthly basis. Our regular lessee audits and mine inspections may not discover any irregularities in these reports or, if we do discover errors, we might not identify them in the reporting period in which they occurred. Any undiscovered reporting errors could result in a loss of royalty revenues and errors identified in subsequent periods could lead to accounting disputes as well as disputes with our lessees.

Our business is subject to cybersecurity risks.

Our business is increasingly dependent on information technologies and services. Threats to information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow. Although we utilize various procedures and controls to mitigate our exposure to such risks, cybersecurity attacks and other cyber events are evolving, unpredictable, and sometimes difficult to detect, and could lead to unauthorized access to sensitive information or render data or systems unusable.

We do not presently maintain insurance coverage to protect against cybersecurity risks. If we procure such coverage in the future, we cannot ensure that it will be sufficient to cover any particular losses we may experience as a result of such cyber attacks. Any cyber incident could have a material adverse effect on our business, financial condition and results of operations.

Risks Related to Our Structure

Unitholders may not be able to remove our general partner even if they wish to do so.

Our general partner manages and operates NRP. Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business. Unitholders have no right to elect the general partner or the directors of the general partner on an annual or any other basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have little practical ability to remove our general partner or otherwise change its management. Our general partner may not be removed except upon the vote of the holders of at least 66 2/3% of our outstanding common units (including common units held by our general partner and its affiliates and including common units deemed to be held by the holders of the preferred units who vote along with the common unitholders on an as-converted basis). Because of their substantial

ownership in us, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates and the holders of the preferred units.
In addition, the following provisions of our partnership agreement may discourage a person or group from attempting to remove our general partner or otherwise change our management:

- generally, if a person (other than the holders of preferred units) acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and
- our partnership agreement contains limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders’ ability to influence the manner or direction of management.

As a result of these provisions, the price at which the common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

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The preferred units are senior in right of distributions and liquidation and upon conversion, would result in the issuance of additional common units in the future, which could result in substantial dilution of our common unitholders' ownership interests.

The preferred units rank senior to our common units with respect to distribution rights and rights upon liquidation. We are required to pay quarterly distributions on the preferred units (plus any PIK units issued in lieu of preferred units) in an amount equal to 12.0% per year prior to paying any distributions on our common units. The preferred units also rank senior to the common units in right of liquidation and will be entitled to receive a liquidation preference in any such case.

The preferred units may also be converted into common units under certain circumstances. The number of common units issued in any conversion will be based on the then-current trading price of the common units at the time of conversion. Accordingly, the lower the trading price of our common units at the time of conversion, the greater the number of common units that will be issued upon conversion of the preferred units, which would result in greater dilution to our existing common unitholders. Dilution has the following effects on our common unitholders:

- an existing unitholder's proportionate ownership interest in NRP will decrease;
- the amount of cash available for distribution on each unit may decrease; and
- 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 the preferred units are converted into more than 66 2/3% of our common units, the holders of the preferred will have the right to remove our general partner.

We may issue additional common units or preferred units without common unitholder approval, which would dilute a unitholder's existing ownership interests.

Our general partner may cause us to issue an unlimited number of common units, without common unitholder approval (subject to applicable New York Stock Exchange (NYSE) rules). We may also issue at any time an unlimited number of equity securities ranking junior or senior to the common units (including additional preferred units) without common unitholder approval (subject to applicable NYSE rules). In addition, we may issue additional common units upon the exercise of the outstanding warrants held by Blackstone and Goldentree. The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- an existing unitholder's proportionate ownership interest in NRP will decrease;
- the amount of cash available for distribution on each unit may decrease; and
- the relative voting strength of each previously outstanding unit may be diminished; and the market price of the common units may decline.

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

If at any time our general partner and its affiliates own 80% or more of the common units, the general partner will have the right, but not the obligation, which it may assign to any of its affiliates, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a result, unitholders may be required to sell their common units at a time when they may not desire to sell them or at a price that is less than the price they would like to receive. They may also incur a tax liability upon a sale of their common units.

Cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to unitholders.

Prior to making any distribution on the common units, we reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred on our behalf. The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions. The general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates may provide us services for which we will be charged reasonable fees as determined by the general partner.

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Conflicts of interest could arise among our general partner and us or the unitholders.

These conflicts may include the following:

- We do not have any employees and we rely solely on employees of affiliates of the general partner;
- under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership;
- the amount of cash expenditures, borrowings and reserves in any quarter may affect cash available to pay quarterly distributions to unitholders;
- the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner's liability;
- under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not necessarily the result of arm's-length negotiations; and
- the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us.

In addition, Blackstone has certain consent rights and board appointment and observation rights. GoldenTree also has more limited consent rights. In the exercise of their applicable consent rights and/or board rights, conflicts of interest could arise between us and our general partner on the one hand, and Blackstone or GoldenTree on the other hand.

The control of our general partner may be transferred to a third party without unitholder consent. A change of control may result in defaults under certain of our debt instruments and the triggering of payment obligations under compensation arrangements.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the general partner of our general partner from transferring its general partnership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the Board of Directors and officers with its own choices and to control their decisions and actions.

In addition, a change of control would constitute an event of default under our debt agreements. During the continuance of an event of default under our debt agreements, the administrative agent may terminate any outstanding commitments of the lenders to extend credit to us and/or declare all amounts payable by us immediately due and payable. In addition, upon a change of control, the holders of the preferred units would have the right to require us to redeem the preferred units at the liquidation preference or convert all of their preferred units into common units. A change of control also may trigger payment obligations under various compensation arrangements with our officers.

Unitholders may not have limited liability if a court finds that unitholder actions constitute control of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner. Under Delaware law, however, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business. In addition, Section 17-607 of the

Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

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Tax Risks to Our Unitholders

Our tax treatment depends on our status as a partnership for U.S. 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 unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for U.S. federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based on our current operations and current Treasury regulations, we believe we satisfy the qualifying income requirement. However, we have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate and would likely be liable for state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders 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 our unitholders, likely causing a substantial reduction in the value of our units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of a similar tax on us in a jurisdiction in which we operate or in other jurisdictions to which we may expand could substantially reduce the cash available for distribution to our unitholders.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of Congress propose and consider substantive changes to the existing U.S. 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, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. Although there are no current legislative or administrative proposals, there can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a publicly traded partnership in the future.

However, any interpretation of or modification to the U.S. 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 U.S. 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 units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our units.

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Certain federal income tax preferences currently available with respect to coal exploration and development may be eliminated as a result of future legislation.

Changes to U.S. federal income tax laws have been proposed in a prior session of Congress that would eliminate certain key U.S. federal income tax preferences relating to coal exploration and development. These changes include, but are not limited to (i) repealing capital gains treatment of coal and lignite royalties, (ii) eliminating current deductions and 60-month amortization for exploration and development costs relating to coal and other hard mineral fossil fuels, and (iii) repealing the percentage depletion allowance with respect to coal properties. If enacted, these changes would limit or eliminate certain tax deductions that are currently available with respect to coal exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units. We are not aware of any current proposals with regard to these changes.

Our unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us. Our unitholders' share of our portfolio income may be taxable to them even though they receive other losses from our activities.

Because our unitholders are treated as partners to whom we allocate taxable income that could be different in amount than the cash we distribute, our unitholders are required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax due from them with respect to that income.

For our unitholders subject to the passive loss rules, our current operations include portfolio activities (such as our coal and mineral royalty businesses) and passive activities (such as our soda ash business). Any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset (i) our portfolio income, including income related to our coal and mineral royalty businesses, (ii) a unitholder’s income from other passive activities or investments, including investments in other publicly traded partnerships, or (iii) a unitholder’s salary or active business income. Thus, our unitholders' share of our portfolio income may be subject to federal income tax, regardless of other losses they may receive from us.

We may engage in transactions to reduce our indebtedness and manage our liquidity that generate taxable income (including income and gain from the sale of properties and cancellation of indebtedness income) allocable to our unitholders, and income tax liabilities arising therefrom may exceed any distributions made with respect to their units.

We may engage in transactions to reduce our leverage and manage our liquidity that would result in income and gain to our unitholders without a corresponding cash distribution. For example, we may sell assets and use the proceeds to repay existing debt, in which case, our unitholders could be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, we may pursue opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt that would result in “cancellation of indebtedness income” (also referred to as “COD income”) being allocated to our unitholders as ordinary taxable income. Our unitholders may be allocated income and gain from these transactions, and income tax liabilities arising therefrom may exceed any distributions we make to our unitholders. The ultimate tax effect of any such income allocations will depend on the unitholder's individual tax position, including, for example, the availability of any suspended passive losses that may offset some portion of the allocable income. Our unitholders may, however, be allocated substantial amounts of ordinary income subject to taxation, without any ability to offset such allocated income against any capital losses attributable to the unitholder’s ultimate disposition of its units. Our unitholders are encouraged to consult their tax advisors with respect to the consequences to them

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

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. 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 may materially and adversely impact the market for our units and the price at which they trade. In addition, our costs of any contest by the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

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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 and our current and former unitholders may be required to indemnify us for any taxes (including applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to 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 these 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 information statement to each unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former 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 and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

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

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

A substantial portion of the amount realized from a unitholder's sale of our units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depletion and depreciation recapture. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of units if the amount realized on a sale of such units is less than such unitholder's 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 a unitholder sells its units, such unitholder may recognize ordinary income from our allocations of income and gain to such unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

Our unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

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

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Tax-exempt entities face unique tax issues from owning our units that may result in adverse tax consequences to them.
Investment in our units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Further, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, subject to the proposed aggregation rules for certain similarly situated businesses or activities issued by the Treasury Department, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our units.
Non-U.S. Unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.
Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business (“effectively connected income”). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be “effectively connected” with a U.S. trade or business. As a result, distributions to a Non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a Non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale
The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a Non-U.S. unitholder’s sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interests in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-U.S. unitholders should consult a tax advisor before investing in our units.
We will treat each purchaser of our common units as having the same tax benefits without regard to the actual common units 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 our common units and for other reasons, 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 our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns.
We generally prorate our 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, 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 our 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 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 the use of the proration method we have adopted. 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.

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A unitholder whose units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of units) may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition. Because there are no specific rules governing the U.S. federal income tax consequences of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and the unitholder 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 units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their units are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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

In addition to U.S. federal income taxes, our unitholders are likely subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if our unitholders do not live in any of those jurisdictions. Our unitholders are likely required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We own property and conduct business in a number of states in the United States. Most of these states impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is the unitholder's responsibility to file all U.S. federal, state and local tax returns and pay any taxes due in these jurisdictions. Unitholders should consult with their own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 3. LEGAL PROCEEDINGS

NRP is involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, Partnership management believes these claims will not have a material effect on the Partnership's financial position, liquidity or operations. NRP is also currently involved in the legal proceedings described below.

Foresight Energy Disputes

In October 2018, our lawsuits against Foresight Energy and its subsidiaries Hillsboro Energy and Macoupin Energy were settled. The Hillsboro suit was pending in the Circuit Court of the Fourth Judicial Circuit in Montgomery County, Illinois, and the Macoupin suit was pending in Macoupin County, Illinois. We received a payment of $25 million from Foresight Energy in full settlement of the Hillsboro litigation. In addition, we and Hillsboro Energy amended the coal mining lease with respect to the Deer Run mine to change the $30 million recoupable annual minimum payments to $11 million non-recoupable annual minimum payments effective January 1, 2019 and extended the current lease term through the end of 2033. Furthermore, Foresight Energy forfeited its recoupable balances under the Macoupin and Hillsboro leases totaling approximately $37.4 million. All claims were dismissed in both the Hillsboro and Macoupin lawsuits.

Anadarko Contingent Consideration Payment Dispute

In January 2013, we acquired a non-controlling 48.51% general partner interest in OCI Wyoming, L.P. ("OCI LP") and all of the preferred stock and a portion of the common stock of OCI Wyoming Co. ("OCI Co") (which in turn owned a 1% limited partner interest in OCI LP) from Anadarko Holding Company and its subsidiary, Big Island Trona Company (together, "Anadarko"). The remaining general partner interest in OCI LP and common stock of OCI Co were owned by subsidiaries of OCI Chemical Corporation.

The acquisition agreement provided for additional contingent consideration of up to $50 million to be paid by us if certain performance criteria were met at OCI LP as defined in the purchase and sale agreement in any of the years 2013, 2014 or 2015. For those years, we paid an aggregate of $11.5 million to Anadarko in full satisfaction of these contingent consideration payment obligations.

In July 2013, pursuant to a series of transactions in connection with an initial public offering by a subsidiary of OCI Chemical Corporation, the ownership structure in OCI LP was simplified. In connection with such reorganization, we exchanged the stock of OCI Co for a limited partner interest in OCI LP. Following the reorganization, our interest in OCI LP increased to 49%, consisting of both limited and general partner interests. The restructuring did not have any impact on the operations, revenues, management or control of OCI LP.

In July 2017, Anadarko filed a lawsuit against Opco and NRP Trona LLC in the District Court of Harris County, Texas, 157th Judicial District. The complaint alleged that the transactions conducted in 2013 triggered an acceleration of NRP's obligation under the purchase agreement with Anadarko to pay additional contingent consideration in full and demanded immediate payment of such amount, together with interest, court costs and attorneys' fees. We do not believe the reorganization transactions triggered an obligation to pay any additional contingent consideration and we are vigorously defending this lawsuit. However, the ultimate outcome cannot be predicted with certainty and we estimate a possible range of loss between $0, if we prevail, and approximately $40 million, plus interest, court costs and attorneys' fees if Anadarko prevails and is awarded the full damages it seeks.

ITEM 4. MINE SAFETY DISCLOSURES

The information concerning mine safety violations or other regulatory matters required by SEC regulations for our construction aggregates business sold on December 11, 2018 is included in Exhibit 95.1 to this Annual Report on Form 10-K.

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PART II

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

NRP Common Units

Our common units are listed and traded on the NYSE under the symbol "NRP". As of February 5, 2019, there were approximately 15,890 beneficial and registered holders of our common units. The computation of the approximate number of unitholders is based upon a broker survey.

Securities Authorized for Issuance under Equity Compensation Plans

The following table shows the securities authorized for issuance under our 2017 Long-Term Incentive Plan at December 31, 2018. The initial number of common units authorized for issuance pursuant to awards under the plan was 800,000.

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for issuance under equity compensation plans (excluding securities reflected in column (a))
Plan Category	(a)	(b)	(c)
Equity compensation plans approved by security holders	—	—	727,208 (1)
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	—	—	727,208

(1) As of December 31, 2018, 55,329 unvested phantom units were outstanding under the plan. The phantom units convert into common units upon vesting on a one-for-one basis.

ITEM 6. SELECTED FINANCIAL DATA

The following table shows selected historical financial data for Natural Resource Partners L.P. for the periods and as of the dates indicated. We derived the information in the following tables from, and the information should be read together with and is qualified in its entirety by reference to, the historical financial statements and the accompanying notes included in "Item 8. Financial Statements and Supplementary Data" in this and previously filed Annual Reports on Form 10-K. These tables should be read together with "Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations."

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	For the Years Ended December 31,				
(In thousands, except per unit data)	2018 (1) (2)	2017 (2)	2016 (2)	2015 (2)	2014 (2)
Total revenues and other income	$278,512	$246,325	$279,244	$300,635	$308,867
Asset impairments	$18,280	$2,967	$15,861	$378,327	$26,209
Income (loss) from operations	$192,538	$176,559	$181,157	$(170,699)	$176,108
Net income (loss) from continuing operations	$122,360	$82,485	$90,626	$(260,443)	$96,681
Net income from continuing operations excluding impairments	$140,640	$85,452	$106,487	$117,884	$122,890
Net income (loss) from discontinued operations	$17,687	$6,182	$6,266	$(311,277)	$12,149
Net income (loss)	$140,047	$88,667	$96,892	$(571,720)	$108,830
Per common unit amounts (basic)					
Net income (loss) from continuing operations	$7.35	$4.57	$7.28	$(20.80)	$8.37
Net income (loss) from discontinued operations	$1.42	$0.50	$0.50	$(24.94)	$1.05
Net income (loss)	$8.77	$5.06	$7.78	$(45.75)	$9.42
Per common unit amounts (diluted)					
Net income (loss) from continuing operations	$5.90	$3.68	$7.28	$(20.80)	$8.37
Net income (loss) from discontinued operations	$0.86	$0.28	$0.50	$(24.94)	$1.05
Net income (loss)	$6.76	$3.96	$7.78	$(45.75)	$9.42
Distributions paid per common unit	$1.80	$1.80	$1.80	$2.70	$14.00
Average number of common units outstanding - basic	12,244	12,232	12,232	12,232	11,326
Average number of common units outstanding - diluted	20,234	21,950	12,232	12,232	11,326
Net cash provided by (used in)					
Operating activities of continuing operations	$178,282	$112,151	$80,243	$144,907	$189,418
Investing activities of continuing operations	$7,607	$9,807	$65,057	$15,805	$1,566
Financing activities of continuing operations	$(6,839)	$(134,149)	$(146,373)	$(166,443)	$(237,314)
Distributable cash flow (3)	$383,980	$121,958	$255,172	$157,815	$195,045
Free cash flow (3)	$183,440	$121,324	$75,970	$144,210	$193,665
Adjusted EBITDA (3)	$230,241	$211,483	$235,273	$240,553	$260,447
Cash, cash equivalents and restricted cash	$206,030	$26,980	$39,171	$40,244	$45,975
Total assets	$1,341,647	$1,389,164	$1,448,649	$1,674,865	$2,431,549
Current portion of long-term debt, net	$115,184	$79,740	$140,037	$80,745	$80,745
Long-term debt, net	$557,574	$729,608	$990,234	$1,130,696	$1,190,558
Class A Convertible Preferred Units	$164,587	$173,431	$—	$—	$—
Partners’ capital	$423,481	$265,211	$151,530	$76,336	$720,155

(1) On January 1, 2018, NRP adopted Accounting Standards Codification (ASC) 606, Revenue from Contracts with Customers, and all the related amendments (the “new revenue standard” and "ASC 606") to all open contracts using the modified retrospective method. NRP recognized a $70.5 million cumulative effect of adoption adjustment in the opening balance of partners' capital on January 1, 2018. Comparative information has not been restated and continues to be reported under the standards in effect for those periods. Refer to "Item 8. Financial Statements and Supplementary Schedules—Note 2. Summary of Significant Accounting Policies" and "Item 8. Financial Statements and Supplementary Schedules—Note 3. Revenue from Contracts with Customers" in this Annual Report on Form 10-K for more information.

(2)

In December 2018, we sold our construction aggregates materials business and have classified the assets and liabilities, operating results and cash flows of the construction aggregates business as discontinued operations for all periods presented. Refer to "Item 8. Financial Statements and Supplementary Schedules—Note 4. Discontinued Operations" in this Annual Report on Form 10-K for more information.

(3) See "—Non-GAAP Financial Measures" below.

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Non-GAAP Financial Measures

Distributable Cash Flow

Distributable cash flow ("DCF") represents net cash provided by (used in) operating activities of continuing operations plus distributions from unconsolidated investment in excess of cumulative earnings, proceeds from sales of assets, including sales of discontinued operations, and return of long-term contract receivables (including affiliate); less maintenance capital expenditures and distributions to non-controlling interest. DCF is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities. DCF may not be calculated the same for us as for other companies. In addition, DCF presented below is not calculated or presented on the same basis as Distributable cash flow as defined in our partnership agreement, which is used as a metric to determine whether we are able to increase quarterly distributions to our common unitholders. DCF is a supplemental liquidity measure used by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others to asses our ability to make cash distributions and repay debt.

Free Cash Flow

Free cash flow ("FCF") represents net cash provided by (used in) operating activities of continuing operations plus distributions from unconsolidated investment in excess of cumulative earnings and return of long-term contract receivables (including affiliate); less maintenance and expansion capital expenditures, cash flow used in acquisition costs classified as financing activities and distributions to non-controlling interest. FCF is calculated before mandatory debt repayments. FCF is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities. FCF may not be calculated the same for us as for other companies. FCF is a supplemental liquidity measure used by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others to assess our ability to make cash distributions and repay debt.

The following table reconciles net cash provided by operating activities of continuing operations (the most comparable GAAP financial measure) to DCF and FCF for the years ended December 31, 2018, 2017, 2016, 2015, and 2014:

	Year Ended December 31,				
(In thousands)	2018	2017	2016	2015	2014
Net cash provided by operating activities of continuing operations	$178,282	$112,151	$80,243	$144,907	$189,418
Add: distributions from unconsolidated investment in excess of cumulative earnings	2,097	5,646	—	—	3,633
Add: proceeds from sale of assets	2,449	1,151	62,117	13,605	1,380
Add: proceeds from sale of discontinued operations	198,091	—	109,872	—	—
Add: return of long-term contract receivables (including affiliates)	3,061	3,010	2,968	2,463	1,904
Less: maintenance capital expenditures	—	—	(28)	(416)	(316)
Less: distributions to non-controlling interest	—	—	—	(2,744)	(974)
Distributable cash flow	$383,980	$121,958	$255,172	$157,815	$195,045
Less: proceeds from sale of assets	(2,449)	(1,151)	(62,117)	(13,605)	(1,380)
Less: proceeds from sale of discontinued operations	(198,091)	—	(109,872)	—	—
Less: acquisition costs classified as financing activities	—	517	(7,213)	—	—
Free cash flow	$183,440	$121,324	$75,970	$144,210	$193,665

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Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income (loss) from continuing operations less equity earnings from unconsolidated investment, net income attributable to non-controlling interest and gain on reserve swap; plus total distributions from unconsolidated investment, interest expense, net, debt modification expense, loss on extinguishment of debt, depreciation, depletion and amortization and asset impairments. Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or loss, net income or loss attributable to partners, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance, liquidity or ability to service debt obligations. There are significant limitations to using Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring items that materially affect our net income (loss), the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDA reported by different companies. In addition, Adjusted EBITDA presented below is not calculated or presented on the same basis as Consolidated EBITDA as defined in our partnership agreement or Consolidated EBITDDA as defined in Opco's debt agreements. See "Item 8. Financial Statements and Supplementary Data—Note 13. Debt, Net" included elsewhere in this Annual Report on Form 10-K for a description of Opco’s debt agreements. Adjusted EBITDA is a supplemental performance measure used by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others to assess the financial performance of our assets without regard to financing methods, capital structure or historical cost basis.

The following table reconciles net income (loss) from continuing operations (the most comparable GAAP financial measure) to Adjusted EBITDA for the years ended December 31, 2018, 2017, 2016, 2015, and 2014:

	Year Ended December 31,				
(In thousands)	2018	2017	2016	2015	2014
Net income (loss) from continuing operations	$122,360	$82,485	$90,626	$(260,443)	$96,681
Less: equity earnings from unconsolidated investment	(48,306)	(40,457)	(40,061)	(49,918)	(41,416)
Less: net income attributable to non-controlling interest	(510)	—	—	—	—
Less: gain on reverse swap	—	—	—	(9,290)	(5,690)
Add: total distributions from unconsolidated investment	46,550	49,000	46,550	46,795	46,638
Add: interest expense, net	70,178	82,028	90,531	89,744	79,427
Add: debt modification expense	—	7,939	—	—	—
Add: loss on extinguishment of debt	—	4,107	—	—	—
Add: depreciation, depletion and amortization	21,689	23,414	31,766	45,338	58,598
Add: asset impairments	18,280	2,967	15,861	378,327	26,209
Adjusted EBITDA	$230,241	$211,483	$235,273	$240,553	$260,447

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

Introduction

The following discussion and analysis presents management’s view of our business, financial condition and overall performance and should be read in conjunction with our consolidated financial statements and footnotes included elsewhere in this filing. Our discussion and analysis consists of the following subjects:
- Executive Overview
- Results of Operations
- Liquidity and Capital Resources
- Off-Balance Sheet Transactions
- Inflation
- Environmental Regulation
- Related Party Transactions
- Summary of Critical Accounting Estimates
- Recent Accounting Standards

As used in this Item 7, unless the context otherwise requires: "we," "our," "us" and the "Partnership" refer to Natural Resource Partners L.P. and, where the context requires, our subsidiaries. References to "NRP" and "Natural Resource Partners" refer to Natural Resource Partners L.P. only, and not to NRP (Operating) LLC or any of Natural Resource Partners L.P.’s subsidiaries. References to "Opco" refer to NRP (Operating) LLC, a wholly owned subsidiary of NRP, and its subsidiaries. NRP Finance Corporation ("NRP Finance") is a wholly owned subsidiary of NRP and a co-issuer with NRP on the 10.50% senior notes due 2022 (the "2022 Notes").

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Executive Overview

We are a diversified natural resource company engaged principally in the business of owning, managing and leasing a diversified portfolio of mineral properties in the United States, including interests in coal, trona and soda ash and other natural resources. Our common units trade on the New York Stock Exchange under the symbol "NRP".

Our business is organized into two operating segments:

Coal Royalty and Other—consists primarily of coal royalty properties and coal-related transportation and processing assets. Other assets include industrial mineral royalty properties, aggregates royalty properties, oil and gas royalty properties and timber. Our coal reserves are primarily located in Appalachia, the Illinois Basin and in the Northern Powder River Basin in the United States. Our industrial minerals and aggregates properties are located in a number of states across the United States. Our oil and gas royalty assets are primarily located in Louisiana.

Soda Ash—consists of our 49% non-controlling equity interest in a trona ore mining operation and soda ash refinery in the Green River Basin, Wyoming. Ciner Resources LP, our operating partner, mines the trona, processes it into soda ash, and distributes the soda ash both domestically and internationally into the glass and chemicals industries.

In December 2018, we sold our construction aggregates business for $205 million, before customary purchase price adjustments and transaction expenses, and recorded a gain of $13.1 million. Our exit from the construction aggregates business enabled us to further reduce debt, focus on our Coal Royalty and Other and Soda Ash business segments and represented a strategic shift as we exited the operations of our construction aggregates business. As a result, we have classified the assets and liabilities, operating results and cash flows of the construction aggregates business as discontinued operations in the consolidated financial statements for all periods presented. See "Item 8. Financial Statements and Supplementary Data—Note 4. Discontinued Operations" to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for additional information. Our debt agreements stipulated that 75% of the asset sale proceeds be used to pay down the Opco Revolving Credit Facility and 25% be offered to the holders of the Opco Senior Notes on a pro-rata basis. The outstanding balance on the Opco Revolving Credit Facility was repaid in December 2018, $49 million was offered to the holders of the Opco Senior Notes in December 2018 and paid in January 2019, and we intend to use the remaining $55 million of net proceeds to repay the Opco Senior Notes as they amortize in 2019.

Corporate and Financing includes functional corporate departments that do not earn revenues. Costs incurred by these departments include interest and financing, corporate headquarters and overhead, centralized treasury and accounting and other corporate-level activity not specifically allocated to a segment.

Our 2018 financial results by business segment for the year ended December 31, 2018 are as follows:

(In thousands)	Operating Segments Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
Revenues and other income	$230,206	$48,306	$—	$278,512
Net income (loss) from continuing operations	$160,728	$48,306	$(86,674)	$122,360
Adjusted EBITDA (1)	$200,187	$46,550	$(16,496)	$230,241

Cash flow provided by (used in) continuing operations				
Operating activities	$212,394	$44,453	$(78,565)	$178,282
Investing activities	$5,510	$2,097	$—	$7,607
Financing activities	$—	$—	$(6,839)	$(6,839)
Distributable cash flow (1)	$217,904	$46,550	$(78,565)	$383,980
Free cash flow (1)	$215,455	$46,550	$(78,565)	$183,440

(1) See "Item 6. Selected Financial Data" for additional information regarding non-GAAP financial measures and reconciliations to the most comparable GAAP financial measures.

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Current Results/Market Commentary

Coal Royalty and Other Business Segment

Results in 2018 were driven by continued strength in both metallurgical and thermal coal markets. Metallurgical coal prices of all grades were driven higher from 2017 levels due to worldwide steel production growth along with a muted supply response from metallurgical coal producers due to various constraints. Benefiting from higher metallurgical coal prices, we derived approximately 65% of our coal royalty revenues and approximately 55% of our coal royalty production from metallurgical coal during the year. Looking ahead into 2019, we expect metallurgical coal prices to remain relatively stable due to supportive steel industry fundamentals combined with logistical and operational supply constraints across the industry. Macro concerns including slowing GDP growth and trade issues could negatively impact the met market.

The domestic market for thermal coal has benefited from increased export demand from Asia, principally India, and northern Europe resulting in higher year over year prices in Central and Northern Appalachia, as well as the Illinois Basin. In addition, the domestic market benefited from higher natural gas prices that increased domestic thermal coal's competitiveness. However, export thermal coal prices and domestic natural gas prices are currently down from the highs of 2018 and thermal coal pricing may be affected accordingly.

Soda Ash Business Segment

Ciner Wyoming's results are primarily affected by the global supply of and demand for soda ash, which in turn directly impacts the prices Ciner Wyoming and other producers charge for its products. Demand for soda ash in the United States is driven in a large part by economic growth and activity levels in the end-markets that the glass-making industry serve, such as the automotive and construction industries. Because the United States is a well-developed market for soda ash, we expect that domestic demand will remain stable for the near future. Because future United States capacity growth is expected to come from the four major producers in the Green River Basin, we also expect that U.S. supply levels will remain relatively stable in the near term.

Soda ash demand in international markets has continued to grow in conjunction with GDP. We expect that future global economic growth will positively influence global demand, which will likely result in increased exports, primarily from the United States, Turkey and to a limited extent, from China, the largest suppliers of soda ash to international markets.

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Results of Operations

Year Ended December 31, 2018 and 2017 Compared

Revenues and Other Income

The following table includes our revenues and other income by operating segment:

Operating Segment (In thousands)	For the Year Ended December 31, 2018	2017	Increase (Decrease)	Percentage Change
Coal Royalty and Other	$230,206	$205,868	$ 24,338	12 %
Soda Ash	48,306	40,457	7,849	19 %
Total	$278,512	$246,325	$ 32,187	13 %

The changes in revenues and other income is discussed for each of the operating segments below:

Coal Royalty and Other

The following table presents coal production, coal royalty revenue per ton and coal royalty revenues by major coal producing region, the significant categories of other revenues and other income:

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(In thousands, except per ton data)	For the Year Ended December 31, 2018	2017	Increase (Decrease)	Percentage Change
Coal production (tons)				
Appalachia				
Northern	3,187	2,136	1,051	49 %
Central	14,997	14,735	262	2 %
Southern	1,710	2,256	(546)	(24)%
Total Appalachia	19,894	19,127	767	4 %
Illinois Basin	2,739	4,373	(1,634)	(37)%
Northern Powder River Basin	4,313	4,386	(73)	(2)%
Total coal production	26,946	27,886	(940)	(3)%
Coal royalty revenue per ton				
Appalachia				
Northern	$2.74	$1.53	$1.21	79 %
Central	5.62	5.12	0.50	10 %
Southern	7.20	5.94	1.26	21 %
Illinois Basin	4.63	3.88	0.75	19 %
Northern Powder River Basin	2.65	2.65	—	— %
Combined average coal royalty revenue per ton	4.80	4.33	0.47	11 %
Coal royalty revenues				
Appalachia				
Northern	$8,719	$3,271	$5,448	167 %
Central	84,302	75,489	8,813	12 %
Southern	12,312	13,399	(1,087)	(8)%
Total Appalachia	105,333	92,159	13,174	14 %
Illinois Basin	12,673	16,989	(4,316)	(25)%
Northern Powder River Basin	11,445	11,642	(197)	(2)%
Unadjusted coal royalty revenue	129,451	120,790	8,661	7 %
Coal royalty adjustment for minimum leases[1]	(110)	—	(110)	(100)%
Total coal royalty revenue	$129,341	$120,790	$8,551	7 %
Other revenues				
Production lease minimum revenue[1][2]	$8,207	$30,822	$(22,615)	(73)%
Minimum lease straight-line revenue[1]	2,362	—	2,362	100 %
Property tax revenue	5,422	5,124	298	6 %
Wheelage revenue	6,484	4,734	1,750	37 %
Coal overriding royalty revenue	13,878	9,836	4,042	41 %
Lease modification fees[1]	—	1,000	(1,000)	(100)%
Aggregates royalty revenues	4,739	4,241	498	12 %
Oil and gas royalty revenues	6,608	4,225	2,383	56 %
Other	1,837	1,029	808	79 %
Total other revenues	$49,537	$61,011	$(11,474)	(19)%
Total Coal Royalty and Other revenues	$178,878	$181,801	$(2,923)	(2)%
Transportation and processing services	23,887	20,522	3,365	16 %
Total Coal Royalty and Other segment revenues	$202,765	$202,323	$442	0.2 %
Gain on litigation settlement	25,000	—	25,000	100 %

Gain on asset sales, net	2,441	3,545	(1,104)	(31)%
Total Coal Royalty and Other segment revenues and other income	$230,206	$205,868	$24,338	12 %

(1) These line items were impacted by the adoption of the new revenue recognition standard effective January 1, 2018. The total impact of the adoption of this standard in the year ended December 31, 2018 was a net decrease of $55.6 million in Coal Royalty and Other revenues. For more information on the overall impact of adoption of the new revenue recognition standard and changes to our revenue recognition policies as a result of this adoption, refer to "Item 8. Financial Statements and Supplementary Data—Note 2. Summary of Significant Accounting Policies to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

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(2) Production lease minimum revenue was $30.8 million in 2017 and included any expiration or forfeiture of minimums on all of our leases under ASC 605. Production lease minimum revenue was $8.2 million in 2018, including expired or forfeited minimums and breakage as a result of ASC 606. The $22.6 million decrease is primarily due to minimums expiring in 2018 that were included as breakage in the ASC 606 cumulative effect entry to Partners' capital on January 1, 2018, rather than to production lease minimum revenue.

Coal Royalty Revenue

Coal royalty revenues increased $8.6 million from 2017 to 2018 primarily driven by the following:

- Appalachia: Coal royalty revenue increased $13.2 million as a result of higher metallurgical and thermal coal prices and higher metallurgical coal production as a result of increased demand primarily in Central and Northern Appalachia, partially offset by lower thermal coal production as a result of capital constraints and declining overall coal demand for certain of our lessees which limit their ability to increase production.
- Illinois Basin: A 37% decrease in production due to the temporary relocation of certain production off of NRP's coal reserves more than offset the 19% increase in coal royalty price per ton on thermal coal and resulted in a $4.3 million decrease in coal royalty revenue. The decrease in coal royalty revenue was partially offset by a $4.2 million increase in overriding royalty revenue and wheelage primarily associated with the production of non-NRP coal.

Other Revenues

Total other revenues decreased $11.5 million from 2017 to 2018 primarily as a result of the impact of the new revenue recognition standard as discussed above. This decrease was partially offset by increased Coal overriding royalty revenue and Wheelage revenue from the production of non-NRP coal as described above in addition to the increased performance of our natural gas royalty properties.

Transportation and Processing Services

Transportation and processing services revenue increased $3.4 million from 2017 to 2018 primarily driven by the increase in tons transported and processed using our assets at the Williamson and Sugar Camp mines and a higher per ton rate at the Macoupin mine.

Gain on Litigation Settlement

Gain on litigation settlement in the year ended December 31, 2018 related to a one-time payment of $25.0 million we received from Foresight Energy to settle the Hillsboro lawsuit.

Gain on Asset Sales, Net

Gain on asset sales, net for the segment decreased $1.1 million from 2017 to 2018. Gains on asset sales during the year ended December 31, 2018 primarily related to the sale of aggregates and other royalty properties and gains on asset sales during the year ended December 31, 2017 included sales of aggregates royalty properties and condemnation payments.

Soda Ash

Revenues and other income related to our Soda Ash segment increased $7.8 million from 2017 to 2018 primarily as a result of Ciner Wyoming's litigation settlement of a royalty dispute that resulted in $12.7 million of income. This increase was partially offset by a $4.9 million decrease in income primarily due to lower production and sales resulting from unexpected equipment repairs needed, which were resolved during the second quarter of 2018, lower production volume in the third quarter of 2018 primarily due to ore grade degradation, a decrease in international sales prices driven by the absence of international sales to Turkey and higher selling, general and administrative expenses related to ANSAC, higher employee compensation expense and higher fees related to Ciner Wyoming's Enterprise Resource Planning project. These decreases were partially offset by lower costs of products sold as a result of a decrease in freight costs driven by no export volumes to Turkey.

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Operating and Other Expenses

The table below presents the significant categories of our consolidated operating and other expenses:

(In thousands)	For the Year Ended December 31, 2018	2017	Increase (Decrease)	Percentage Change
Operating expenses				
Operating and maintenance expenses (including affiliates)	$29,509	$24,883	$4,626	19 %
Depreciation, depletion and amortization (including affiliates)	21,689	23,414	(1,725)	(7)%
General and administrative (including affiliates)	16,496	18,502	(2,006)	(11)%
Asset impairments	18,280	2,967	15,313	516 %
Total operating expenses	$85,974	$69,766	$16,208	23 %
Other expense, net				
Interest expense, net	$70,178	$82,028	$(11,850)	(14)%
Debt modification expense	—	7,939	(7,939)	(100)%
Loss on extinguishment of debt	—	4,107	(4,107)	(100)%
Total other expense, net	$70,178	$94,074	$(23,896)	(25)%

Total operating expenses increased by $16.2 million from 2017 to 2018. The primary reasons for this fluctuation are as follows:

- Operating and maintenance expenses include costs to manage the Coal Royalty and Other segment and primarily consist of taxes, royalty, employee related and legal costs. These costs increased $4.6 million primarily due to increased overriding royalty interest fees, legal costs and property taxes, partially offset by lower bad debt expense.
- Depreciation, depletion and amortization ("DD&A") expense decreased $1.7 million primarily due to a $3.0 million decrease in depletion expense as a result of lower coal production in the Illinois Basin, partially offset by a $1.3 million increase on amortization of intangible assets.
- General and administrative ("G&A") expense decreased $2.0 million primarily due to lower employee-related costs year-over-year.
- Asset impairments increased $15.3 million. Asset impairments in the year ended December 31, 2018 primarily related to a $13.0 million impairment of an aggregates property that we own and lease to our former construction aggregates business, which mines, produces and sells the aggregates, in addition to $5.3 million of impairments related to certain of our coal properties. Asset impairments in the year ended December 31, 2017 primarily consisted of certain coal, aggregates and timber properties.

Total other expense, net decreased $23.9 million from 2017 to 2018. The primary reasons for this fluctuation are as follows:

- Interest expense, net decreased $11.9 million primarily due to lower debt balances in 2018 as a result of repayments of debt.
- Debt modification expense was $7.9 million for the year ended December 31, 2017 and related to costs incurred as a result of the exchange of $241 million of our 2018 Senior Notes for 2022 Senior Notes in March 2017.
- Loss on extinguishment of debt was $4.1 million for the year ended December 31, 2017 and related to the 4.563% premium paid to redeem the 2018 Senior Notes in April 2017.

Income from Discontinued Operations

Income from discontinued operations increased $11.5 million primarily as a result of the $13.1 million gain on sale of our construction aggregates business in the year ended December 31, 2018. This increase was partially offset by decreased net income from the operations of the construction aggregates business as our construction aggregates business' $5.7 million increase in operating expenses more than offset its $3.1 million increase in revenues.

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Adjusted EBITDA (Non-GAAP Financial Measure)

The following table reconciles net income (loss) from continuing operations (the most comparable GAAP financial measure) to Adjusted EBITDA by business segment:

	Operating Segments			
For the Year Ended (In thousands)	Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
December 31, 2018				
Net income (loss) from continuing operations	$160,728	$48,306	$(86,674)	$122,360
Less: equity earnings from unconsolidated investment	—	(48,306)	—	(48,306)
Less: net income attributable to non-controlling interest	(510)	—	—	(510)
Add: total distributions from unconsolidated investment	—	46,550	—	46,550
Add: interest expense, net	—	—	70,178	70,178
Add: depreciation, depletion and amortization	21,689	—	—	21,689
Add: asset impairments	18,280	—	—	18,280
Adjusted EBITDA	$200,187	$46,550	$(16,496)	$230,241
December 31, 2017				
Net income (loss) from continuing operations	$154,604	$40,457	$(112,576)	$82,485
Less: equity earnings from unconsolidated investment	—	(40,457)	—	(40,457)
Add: total distributions from unconsolidated investment	—	49,000	—	49,000
Add: interest expense, net	—	—	82,028	82,028
Add: debt modification expense	—	—	7,939	7,939
Add: loss on extinguishment of debt	—	—	4,107	4,107
Add: depreciation, depletion and amortization	23,414	—	—	23,414
Add: asset impairments	2,967	—	—	2,967
Adjusted EBITDA	$180,985	$49,000	$(18,502)	$211,483

Adjusted EBITDA increased $18.8 million from 2017 to 2018. The primary reasons for this fluctuation are as follows:

- Coal Royalty and Other segment Adjusted EBITDA increased $19.2 million primarily as a result of the increase in revenues and other income as discussed above, partially offset by increased operating and maintenance expenses as discussed above.
- Soda Ash segment Adjusted EBITDA decreased $2.5 million as a result of lower cash distributions received from Ciner Wyoming during the year ended December 31, 2018.
- Corporate and financing Adjusted EBITDA increased $2.0 million as a result of the decrease in G&A costs as discussed above.

See "Item 6. Selected Financial Data—Non-GAAP Financial Measures" for an explanation of Adjusted EBITDA.

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Distributable Cash Flow ("DCF") and Free Cash Flow ("FCF") (Non-GAAP Financial Measures)

The following table presents the three major categories of the statement of cash flows by business segment:

For the Year Ended (In thousands)	Operating Segments Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
December 31, 2018				
Cash flow provided by (used in) continuing operations				
Operating activities	$212,394	$44,453	$(78,565)	$178,282
Investing activities	5,510	2,097	—	7,607
Financing activities	—	—	(6,839)	(6,839)
December 31, 2017				
Cash flow provided by (used in) continuing operations				
Operating activities	$166,138	$43,354	$(97,341)	$112,151
Investing activities	4,161	5,646	—	9,807
Financing activities	517	—	(134,666)	(134,149)

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The following table reconciles net cash provided by operating activities (the most comparable GAAP financial measure) by business segment to DCF and FCF:

For the Year Ended (In thousands)	Operating Segments Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
December 31, 2018				
Net cash provided by (used in) operating activities of continuing operations	$212,394	$44,453	$(78,565)	$178,282
Add: distributions from unconsolidated investment in excess of cumulative earnings	—	2,097	—	2,097
Add: proceeds from sale of assets	2,449	—	—	2,449
Add: proceeds from sale of discontinued operations	—	—	—	198,091
Add: return of long-term contract receivables	3,061	—	—	3,061
Distributable cash flow	$217,904	$46,550	$(78,565)	$383,980
Less: proceeds from sale of assets	(2,449)	—	—	(2,449)
Less: proceeds from sale of discontinued operations	—	—	—	(198,091)
Free cash flow	$215,455	$46,550	$(78,565)	$183,440
December 31, 2017				
Net cash provided by (used in) operating activities of continuing operations	$166,138	$43,354	$(97,341)	$112,151
Add: distributions from unconsolidated investment in excess of cumulative earnings	—	5,646	—	5,646
Add: proceeds from sale of assets	1,151	—	—	1,151
Add: return of long-term contract receivables (including affiliates)	3,010	—	—	3,010
Distributable cash flow	$170,299	$49,000	$(97,341)	$121,958
Less: proceeds from sale of assets	(1,151)	—	—	(1,151)
Less: acquisition costs classified as financing activities	517	—	—	517
Free cash flow	$169,665	$49,000	$(97,341)	$121,324

DCF and FCF increased $262.0 million and $62.1 million, respectively, from 2017 to 2018. The primary reasons for these fluctuations are as follows:

- Coal Royalty and Other segment DCF and FCF increased $47.6 million and $45.8 million, respectively, primarily due to a one-time $25 million payment we received from Foresight Energy to settle the Hillsboro lawsuit in addition to increased cash from coal royalties as a result of higher metallurgical prices and production and increased cash from other revenues.
- Soda Ash segment DCF and FCF decreased $2.5 million as a result of lower cash distributions received from Ciner Wyoming during the year ended December 31, 2018.
- Corporate and Financing DCF and FCF increased $18.8 million primarily as a result of lower performance-based award payments and lower cash paid for interest year-over-year.

Total DCF was also impacted by the $198.1 million proceeds from the sale of our construction aggregates business in the year ended December 31, 2018.

See "Item 6. Selected Financial Data—Non-GAAP Financial Measures" for an explanation of Distributable cash flow and Free cash flow.

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Results of Operations

Year Ended December 31, 2017 and 2016 Compared

Revenues and Other Income

The following table includes our revenues and other income by operating segment:

	For the Year Ended December 31,			
Operating Segment (In thousands)	2017	2016	Increase (Decrease)	Percentage Change
Coal Royalty and Other	$205,868	$239,183	$(33,315)	(14)%
Soda Ash	40,457	40,061	396	1%
Total	$246,325	$279,244	$(32,919)	(12)%

The changes in revenues and other income is discussed for each of the operating segments below:

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Coal Royalty and Other

The table below presents coal production, coal royalty revenue per ton and coal royalty revenues by major coal producing region, the significant categories of other revenues and other income:

(In thousands, except per ton data)	For the Year Ended December 31, 2017	2016	Increase (Decrease)	Percentage Change
Coal production (tons)				
Appalachia				
Northern	2,136	2,312	(176)	(8)%
Central	14,735	13,222	1,513	11 %
Southern	2,256	2,776	(520)	(19)%
Total Appalachia	19,127	18,310	817	4 %
Illinois Basin	4,373	8,116	(3,743)	(46)%
Northern Powder River Basin	4,386	3,781	605	16 %
Gulf Coast	—	0.4	(0.4)	(100)%
Total coal production	27,886	30,207	(2,321)	(8)%
Coal royalty revenue per ton				
Appalachia				
Northern	$1.53	$1.15	$0.38	33 %
Central	5.12	3.64	1.48	41 %
Southern	5.94	3.84	2.10	55 %
Illinois Basin	3.88	3.66	0.22	6 %
Northern Powder River Basin	2.65	2.81	(0.16)	(6)%
Gulf Coast	—	3.28	(3.28)	(100)%
Combined average coal royalty revenue per ton	4.33	3.37	0.96	28 %
Coal royalty revenues				
Appalachia				
Northern	$3,271	$2,667	$604	23 %
Central	75,489	48,119	27,370	57 %
Southern	13,399	10,660	2,739	26 %
Total Appalachia	92,159	61,446	30,713	50 %
Illinois Basin	16,989	29,680	(12,691)	(43)%
Northern Powder River Basin	11,642	10,637	1,005	9 %
Gulf Coast	—	1	(1)	(100)%
Total coal royalty revenue	$120,790	$101,764	$19,026	19 %
Other revenues				
Minimums recognized as revenue	$30,822	$64,591	$(33,769)	(52)%
Property tax revenue	5,124	10,457	(5,333)	(51)%
Wheelage revenue	4,734	2,374	2,360	99 %
Coal overriding royalty revenue	9,836	2,281	7,555	331 %
Lease modification fees	1,000	—	1,000	100 %
Aggregates royalty revenues	4,241	3,163	1,078	34 %

Oil and gas royalty revenues	4,225	3,537	688	19 %
Other	1,029	2,612	(1,583)	(61)%
Total other revenues	$61,011	$89,015	$(28,004)	(31)%
Coal Royalty and Other revenues	$181,801	$190,779	$(8,978)	(5)%
Transportation and processing services	20,522	19,336	1,186	6 %
Total Coal Royalty and Other segment revenues	$202,323	$210,115	$(7,792)	(4)%
Gain on asset sales, net	3,545	29,068	(25,523)	(88)%
Total Coal Royalty and Other segment revenues and other income	$205,868	$239,183	$(33,315)	(14)%

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Coal Royalty Revenue

Coal royalty revenues increased $19.0 million from 2016 to 2017 primarily driven by the following:

- Appalachia: Coal royalty revenue increased $30.7 million as a result of increased metallurgical prices and production.
- Illinois basin: Lower production partially offset by higher royalty revenue per ton led to a $12.7 million decrease in coal royalty revenue. The decreased production was primarily as a result of the temporary relocation of certain production off NRP's coal reserves, which resulted in a $7.5 million increase in coal overriding royalty revenue and wheelage associated with the production of non-NRP coal.

Other Revenues

Total other revenues decreased $28.0 million primarily as a result of a $33.8 million decrease in minimums recognized as revenue due to certain lease modifications and terminations in the second quarter of 2016 and a $5.3 million decrease in property tax reimbursements. The decrease in property tax revenue was fully offset by lower property tax expenses as described in operating and maintenance expenses below. These decreases were partially offset by an increase in coal override revenue and wheelage as discussed above.

Transportation and Processing Services

Transportation and processing services revenue increased $1.2 million from 2016 to 2017 primarily driven by the increase in tons transported and processed using our assets at the Williamson mine.

Gain on Asset Sales, Net

Gain on asset sales, net decreased $25.5 million from 2016 to 2017 primarily as a result of numerous asset sales completed during the year ended December 30, 2016, including an $18.6 million gain on the sale of oil and gas royalty and overriding royalty interests in the Appalachian Basin.

Operating and Other Expenses

The table below presents the significant categories of our consolidated operating and other expenses:

(In thousands)	For the Year Ended December 31, 2017	2016	Increase (Decrease)	Percentage Change
Operating expenses				
Operating and maintenance expenses (including affiliates)	$24,883	$29,890	$(5,007)	(17)%
Depreciation, depletion and amortization (including affiliates)	23,414	31,766	(8,352)	(26)%
General and administrative (including affiliates)	18,502	20,570	(2,068)	(10)%
Asset impairments	2,967	15,861	(12,894)	(81)%
Total operating expenses	$69,766	$98,087	$(28,321)	(29)%
Other expense, net				
Interest expense, net (including affiliates)	$82,028	$90,531	$(8,503)	(9)%
Debt modification expense	7,939	—	7,939	100 %
Loss on extinguishment of debt	4,107	—	4,107	100 %
Total other expense, net	$94,074	$90,531	$3,543	4 %

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Total operating expenses decreased $28.3 million from 2016 to 2017. The primary reasons for these fluctuations are as follows:

- Operating and maintenance expenses decreased $5.0 million primarily due to $5.8 million lower property tax expense as a result of lower property tax rates and property tax values primarily in Kentucky and West Virginia and lower employee related costs.
- DD&A expense decreased $8.4 million driven primarily by lower coal production in the Illinois Basin.
- G&A expense decreased $2.1 million primarily due to decreased legal, consulting and advisory fees incurred in 2016 as a result of the recapitalization transactions completed in March 2017.
- Asset impairments decreased $12.9 million. Asset impairments in the year ended December 31, 2017 primarily consisted of certain coal, aggregates and timber properties and asset impairments in the year ended December 31, 2016 primarily consisted of certain coal and aggregates properties.

Total other expense, net increased $3.5 million from 2016 to 2017. The primary reasons for these fluctuations are as follows:

- Interest expense, net decreased $8.5 million primarily related to lower debt balances during 2017 as a result of the recapitalization transactions entered into in March 2017.
- Debt modification expense was $7.9 million for the year ended December 31, 2017 and related to costs incurred as a result of the exchange of $241 million of our 2018 Senior Notes for 2022 Senior Notes in March 2017.
- Loss on extinguishment of debt was $4.1 million for the year ended December 31, 2017 and related to the 4.563% premium paid to redeem the 2018 Senior Notes in April 2017.

Income from Discontinued Operations

Income from discontinued operations was essentially flat from 2016 to 2017. Income related to our non-operated oil and gas working interest assets decreased $2.2 million as a result of the sale of these assets in July 2016 while income related to our construction aggregates business increased $2.1 million as a result of increased crushed stone, sand and gravel sales volumes year-over-year.

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Adjusted EBITDA (Non-GAAP Financial Measure)

The following table reconciles net income (loss) from continuing operations (the most comparable GAAP financial measure) to Adjusted EBITDA by business segment:

For the Year Ended (In thousands)	Operating Segments Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
December 31, 2017				
Net income (loss) from continuing operations	$154,604	$40,457	$(112,576)	$82,485
Less: equity earnings from unconsolidated investment	—	(40,457)	—	(40,457)
Add: total distributions from unconsolidated investment	—	49,000	—	49,000
Add: interest expense, net	—	—	82,028	82,028
Add: debt modification expense	—	—	7,939	7,939
Add: loss on extinguishment of debt	—	—	4,107	4,107
Add: depreciation, depletion and amortization	23,414	—	—	23,414
Add: asset impairments	2,967	—	—	2,967
Adjusted EBITDA	$180,985	$49,000	$(18,502)	$211,483
December 31, 2016				
Net income (loss) from continuing operations	$161,666	$40,061	$(111,101)	$90,626
Less: equity earnings from unconsolidated investment	—	(40,061)	—	(40,061)
Add: total distributions from unconsolidated investment	—	46,550	—	46,550
Add: interest expense, net	—	—	90,531	90,531
Add: depreciation, depletion and amortization	31,766	—	—	31,766
Add: asset impairments	15,861	—	—	15,861
Adjusted EBITDA	$209,293	$46,550	$(20,570)	$235,273

Adjusted EBITDA decreased $23.8 million from 2016 to 2017. The primary reasons for these fluctuations are as follows:

- Coal Royalty and Other segment Adjusted EBITDA decreased $28.3 million. While performance of our coal-related assets improved as described above, the prior year amount included $40.5 million of revenue resulting from one-time lease modifications and $25.5 million higher gains on asset sales, net.
- Soda Ash segment Adjusted EBITDA increased $2.5 million as a result of increased cash distributions received in the year ended December 31, 2017.
- Corporate and financing Adjusted EBITDA increased $2.1 million primarily due to legal and consulting fees related to the recapitalization activities incurred in 2016.

See "Item 6. Selected Financial Data—Non-GAAP Financial Measures" for an explanation of Adjusted EBITDA.

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Distributable Cash Flow ("DCF") and Free Cash Flow ("FCF") (Non-GAAP Financial Measures)

The following table presents the three major categories of the statement of cash flows by business segment:

For the Year Ended (In thousands)	Operating Segments Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
December 31, 2017				
Cash flow provided by (used in) continuing operations				
Operating activities	$166,138	$43,354	$(97,341)	$112,151
Investing activities	4,161	5,646	—	9,807
Financing activities	517	—	(134,666)	(134,149)
December 31, 2016				
Cash flow provided by (used in) continuing operations				
Operating activities	$134,490	$46,550	$(100,797)	$80,243
Investing activities	65,057	—	—	65,057
Financing activities	16	(7,229)	(139,160)	(146,373)

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The following table reconciles net cash provided by operating activities (the most comparable GAAP financial measure) by business segment to DCF and FCF:

For the Year Ended (In thousands)	Operating Segments Coal Royalty and Other	Soda Ash	Corporate and Financing	Total
December 31, 2017				
Net cash provided by (used in) operating activities of continuing operations	$166,138	$43,354	$(97,341)	$112,151
Add: distributions from unconsolidated investment in excess of cumulative earnings	—	5,646	—	5,646
Add: proceeds from sale of assets	1,151	—	—	1,151
Add: return of long-term contract receivables (including affiliates)	3,010	—	—	3,010
Distributable cash flow	$170,299	$49,000	$(97,341)	$121,958
Less: proceeds from sale of assets	(1,151)	—	—	(1,151)
Less: acquisition costs classified as financing activities	517	—	—	517
Free cash flow	$169,665	$49,000	$(97,341)	$121,324
December 31, 2016				
Net cash provided by (used in) operating activities of continuing operations	$134,490	$46,550	$(100,797)	$80,243
Add: proceeds from sale of assets	62,117	—	—	62,117
Add: proceeds from sale of discontinued operations	—	—	—	109,872
Add: return of long-term contract receivables—affiliate	2,968	—	—	