NATURAL RESOURCE PARTNERS LP
Form 10-K
March 11, 2016

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, 2015 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 partnership 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 or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

¨ Large Accelerated Filer x Accelerated Filer ¨ Non-accelerated Filer

¨

Smaller Reporting Company

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 was approximately $295.0 million on June 30, 2015 based on a price of $37.90 per unit, which was the closing price of the common units as reported on the New York Stock Exchange (after giving effect to the one-for-ten reverse unit split effective on February 17, 2016).

As of March 1, 2016, there were 12.2 million common units outstanding. Documents incorporated by reference: None.

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CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING STATEMENTS

Statements included in this Annual Report on Form 10-K may constitute forward-looking statements. All statements, other than statements of historical facts, included herein or incorporated herein by reference are "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, construction aggregates, crude oil and natural gas, frac sand and other natural resources;
- estimated revenues, expenses and results of operations;
- the amount, nature and timing of capital expenditures;
- our ability to make acquisitions and integrate the acquisitions we do make;
- projected production levels by our lessees, VantaCore Partners LLC ("VantaCore"), and the operators of our oil and gas working interests;
- 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 therefore 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.

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. References to NRP Oil and Gas refer to NRP Oil and Gas LLC, a wholly owned subsidiary of NRP. NRP Finance Corporation ("NRP Finance") is a wholly owned subsidiary of NRP and a co-issuer with NRP on the 9.125% senior 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, operate, manage and lease a diversified portfolio of mineral properties in the United States, including interests in coal, trona and soda ash, construction aggregates, crude oil and natural gas, frac sand and other natural resources. Our business is organized into four operating segments:

Coal, Hard Mineral Royalty and Other—consists primarily of coal royalty, coal related transportation and processing assets, aggregate and industrial minerals royalty assets and timber. Our coal reserves are primarily located in Appalachia, the Illinois Basin and the Western United States. Our aggregates and industrial minerals are located in a number of states across the United States.

Soda Ash—consists of the Partnership's 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. We receive regular quarterly distributions from this business.

VantaCore—consists of our construction materials business acquired in October 2014 that operates hard rock quarries, an underground limestone mine, sand and gravel plants, asphalt plants and marine terminals. VantaCore operates in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

Oil and Gas—consists of our non-operated working interests, royalty interests and overriding royalty interests in oil and natural gas properties. Our primary interests in oil and natural gas producing properties are non-operated working interests located in the Williston Basin in North Dakota and Montana. We also own fee mineral, royalty or overriding royalty interests in oil and gas properties in several other regions, including the Appalachian Basin, Oklahoma and Louisiana.

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

Effective for the quarter ended December 31, 2015, we changed the organizational structure of the internal financial information reviewed by our Chief Executive Officer and President and Chief Operating Officer from a single segment to the four operating segments and corporate segment described above as a result of the acquisitions that have diversified our natural resource asset base. The new segment alignment is presented for the period ending December 31, 2015, with prior periods recast for comparability.

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We conduct our business through two wholly owned operating companies: Opco and NRP Oil and Gas. NRP Oil and Gas holds our non-operated oil and gas working interests in the Williston Basin. All of our other operations, including other oil and gas assets, are held by Opco. 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 Investor Rights Agreement with Adena Minerals, LLC ("Adena Minerals"), Mr. Robertson is entitled to nominate ten directors to the Board of Directors of GP Natural Resource Partners LLC. Mr. Robertson has delegated the right to nominate two of the directors, one of whom must be independent, to Adena Minerals.

The senior executives and other officers who manage NRP are employees of Western Pocahontas Properties Limited Partnership and Quintana Minerals Corporation, companies controlled by Mr. Robertson, and they 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.

Segment and Geographic Information

The amount of total revenue for each of our operating segments in the last three years is shown below (dollars in thousands). For additional operating segment information, please see "Note 3. Segment Information" in the Notes to Consolidated Financial Statements under Item 8 in this Annual Report on Form 10-K and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations" under Item 7 in this Annual Report on Form 10-K, which are both incorporated herein by reference.

	Coal, Hard Mineral Royalty and Other		Soda Ash		VantaCore		Oil and Gas		Total
2015									
Revenues	$246,353		$49,918		$139,013		$53,565		$488,849
Percentage of total	51	%	10	%	28	%	11	%	
2014									
Revenues	$256,719		$41,416		$42,051		$59,566		$399,752
Percentage of total	64	%	10	%	11	%	15	%	
2013									
Revenues	$306,851		$34,186		$—		$17,080		$358,117
Percentage of total	85	%	10	%	—	%	5	%	

Coal, Hard Mineral Royalty and Other Segment

We do not operate any coal mines, but lease our reserves to experienced mine operators under long-term leases that grant the operators the right to mine and sell our reserves in exchange for royalty payments. A typical lease has a five- to ten-year base term, with the lessee having an option to extend the lease for additional terms. Leases may include the right to renegotiate rents and royalties for the extended term. We also own and manage coal related infrastructure assets that generate additional revenues, primarily in the Illinois Basin. In addition, we own or lease aggregates and industrial mineral reserves located in a number of states across the country. We derive a small percentage of our aggregates and industrial mineral revenues by leasing our owned reserves to third party operators who mine and sell the reserves in exchange for royalty payments.

Under our standard lease, 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 pre-established minimum monthly, quarterly or annual payments. These minimum rentals reflect amounts we are entitled to receive even if no mining activity occurred during the period. Minimum rentals are usually credited against future royalties that are earned as minerals are produced.

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. As operators, our lessees 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 legacy costs, black lung benefits and workers' compensation costs associated with operating the mines on our coal and aggregates properties. We typically pay property taxes on our properties, which are then reimbursed by the coal lessee pursuant to the terms of the lease.

Coal Production and Reserve Information

The following table presents coal production for the year ended December 31, 2015 and coal reserve information as of December 31, 2015 for the properties that we owned by major coal region:

	Production	Proven and Probable Reserves (1)		
		Underground	Surface	Total
	(Tons in thousands)			
Appalachia:				
Northern	9,562	353,565	—	353,565
Central	16,862	773,987	229,899	1,003,886
Southern	3,803	78,864	12,819	91,683
Total Appalachia	30,227	1,206,416	242,718	1,449,134
Illinois Basin	11,173	327,293	5,309	332,602
Northern Powder River Basin	4,905	—	38,519	38,519
Gulf Coast	739	—	1,958	1,958
Total	47,044	1,533,709	288,504	1,822,213

(1) In excess of 90% of the reserves presented in this table are currently leased to third parties.

The following table presents the sulfur content, the typical quality of our coal reserves and the type of coal by major coal region as of December 31, 2015:

	Sulfur Content					Typical Quality (1)		Type of Coal	
	Compliance Coal (2)	Low (<1.0%)	Medium (1.0% to 1.5%)	High (>1.5%)	Total	Heat Content (Btu per pound)	Sulfur (%)	Steam	Met (3)
	(Tons in thousands)							(Tons in thousands)	
Appalachia									
Northern	33,204	33,204	905	319,456	353,565	12,784	2.89	353,565	—
Central	515,001	727,362	228,480	48,044	1,003,886	13,266	0.89	618,829	385,057
Southern	64,715	70,586	16,928	4,169	91,683	13,397	0.83	67,078	24,605
Total Appalachia	612,920	831,152	246,313	371,669	1,449,134	13,157	1.37	1,039,472	409,662
Illinois Basin	—	—	2,157	330,445	332,602	11,493	3.28	332,602	—
Northern Powder River Basin	—	38,519	—	—	38,519	8,800	0.65	38,519	—
Gulf Coast	82	1,958	—	—	1,958	6,964	0.69	1,876	82
Total	613,002	871,629	248,470	702,114	1,822,213			1,412,469	409,744

(1) Unless otherwise indicated, we present the quality of the coal throughout this Annual Report on Form 10-K on an as-received basis, which assumes 6% moisture for Appalachian reserves, 12% moisture for Illinois Basin reserves

and 25% moisture for Northern Powder River Basin reserves.

(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.

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

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in the metallurgical category can also be used as steam coal. In 2015, approximately 30% of the production and 38% of the coal royalty revenues from our properties were from metallurgical 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 engineers. The technologies and economic data used by our internal reserve engineers in the estimation of our proved 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."

Major Coal Producing Properties

The following is a summary of our major coal producing properties in each region:

Appalachia—Northern Appalachia

Area F. Area F is located in Randolph and Upshur Counties, West Virginia. In 2015, approximately 0.5 million tons were produced from this property. We lease this property to Carter Roag Coal Company, a subsidiary of United Coal Company, LLC (owned by Metinvest). Production comes from the Pleasant Hill Sewell Seam deep mine and is trucked to Carter Roag's preparation plant situated at Star Bridge, WV. The coal produced from this lease is a medium to high volatile metallurgical product and shipped via the CSX railroad to Baltimore and then by ocean vessel to Metinvest's steel mills situated in Ukraine.

Hibbs Run. The Hibbs Run property is located in Marion County, West Virginia. In 2015, approximately 8.5 million tons were produced from the property by Consolidation Coal Company, a subsidiary of Murray Energy Corporation. Coal from this property is produced from longwall mines. The royalty rate for this property is a low fixed rate per ton and has a significant effect on the per ton revenue for the region. Coal is shipped by rail to utility customers.

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

Appalachia—Central Appalachia

VICC/Alpha. The VICC/Alpha property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. In 2015, approximately 3.7 million tons were produced from this property. We primarily lease this property to a subsidiary of Alpha Natural Resources, Inc. Production comes from both underground and surface mines and is trucked to one of four preparation plants. Coal is shipped via both the CSX and Norfolk Southern railroads to utility and metallurgical customers.

Dingess-Rum. The Dingess-Rum property is located in Logan, Clay and Nicholas Counties, West Virginia. This property is leased to subsidiaries of Alpha Natural Resources, Inc. and Blackhawk Mining, LLC. In 2015, approximately 2.4 million tons were produced from the property. Both steam and metallurgical coal are produced from underground and surface mines and has been historically transported by belt or truck to preparation plants on the property. Coal is shipped via the CSX railroad to utility customers and to various export metallurgical customers.

Pinnacle. The Pinnacle property is located in Wyoming and McDowell Counties, West Virginia. In 2015, approximately 2.4 million tons of metallurgical coal were produced from our reserves on this property. We also own an overriding royalty interest on coal produced from the reserves that we do not own at this property, from which we derive additional revenues. We lease the property to a subsidiary of ERP Compliant Fuels, LLC, Seneca Resources, LLC (formerly leased to a subsidiary of Cliffs Natural Resources, Inc). Production comes from a longwall mine and is transported by beltline to a preparation plant and is then shipped via railroad and barge to both domestic and export customers.

Lynch. The Lynch property is located in Harlan and Letcher Counties, Kentucky. In 2015, approximately 2.2 million tons were produced from this property. This property was formerly leased to a subsidiary of Alpha Natural Resources but was sold to a subsidiary of Revelation Energy, LLC during 2015. Production comes from both underground and surface mines. This property has the ability to ship coal on both the CSX and Norfolk Southern railroads.

Lone Mountain. The Lone Mountain property is located in Harlan County, Kentucky. In 2015, approximately 1.6 million tons were produced from this property. We lease the property to a subsidiary of Arch Coal, Inc. Production comes from underground mines and is transported primarily by beltline to a preparation plant on adjacent property and shipped on the Norfolk Southern or CSX railroads to both utilities and steel producers.

VICC/Kentucky Land. The VICC/Kentucky Land property is located primarily in Perry, Leslie and Pike Counties, Kentucky. In 2015, approximately 1.1 million tons were produced from this property. Coal is produced from a number of lessees, including subsidiaries of Cambrian Coal and Blackhawk Mining, from both underground and surface mines. Coal is shipped primarily by truck but also on the CSX and Norfolk Southern railroads to utility customers.
The map below shows the location of our major properties in Central Appalachia:

Appalachia—Southern Appalachia

Oak Grove. The Oak Grove property is located in Jefferson County, Alabama. In 2015, approximately 2.4 million tons were produced from this property. We lease the property to a subsidiary of ERP Compliant Fuels, LLC, Seneca Coal Resources, LLC (formerly leased to a subsidiary of Cliffs Natural Resources, Inc.). Production comes from an underground longwall mine and is transported primarily by beltline to a preparation plant. The metallurgical coal is then shipped via railroad and barge to both domestic and export customers.

BLC Properties. The BLC properties are located in Kentucky and Tennessee. In 2015, approximately 1.5 million tons were produced from these properties. We lease these properties to a number of operators including Middlesboro Mining Properties, Inc., Revelation Energy, LLC and Corsa Coal Corp. Production comes from both underground and surface mines and is trucked to preparation plants and loading facilities operated by our lessees. Coal is transported by truck and is shipped via both CSX and Norfolk Southern railroads to utility and industrial customers. The map below shows the location of our major properties in Southern Appalachia:

Illinois Basin

Williamson Development. The Williamson property is located in Franklin and Williamson Counties, Illinois. The property is under lease to a subsidiary of Foresight Energy, and in 2015, approximately 5.2 million tons were mined on the property. This production is from a longwall mine and is shipped primarily via the Canadian National railroad to domestic utility customers and to various export customers.

Hillsboro/Deer Run. The Hillsboro property is located in Montgomery and Bond Counties, Illinois. The property is under lease to a subsidiary of Foresight Energy, and in 2015, approximately 2.6 million tons were shipped from the property. When active, production at the Deer Run mine on our Hillsboro property is from an underground longwall mine and is shipped via either the Union Pacific, Norfolk Southern or Canadian National railroads or by barges to domestic utilities or export customers. The Deer Run mine has been idled since March 2015 as a result of elevated carbon monoxide levels in the mine. In July 2015, we received a notice from Foresight Energy declaring a force majeure event at the mine as a result of the elevated carbon monoxide levels. While we are disputing Foresight Energy’s claim and have filed a lawsuit in connection therewith, the effect of a valid force majeure declaration would relieve Foresight Energy of its obligation to pay us minimum deficiency payments of $7.5 million per quarter, or $30.0 million per year. For more information on the idling of the Deer Run mine, see "Item 1A. Risk Factors—Risks Related to Our Business—Foresight Energy's Deer Run Mine is currently idled as a result of elevated carbon monoxide levels at the mine. If the mine remains idled for an extended period or does not resume operations, our financial condition and results of operations could be aversely affected," included elsewhere in this Annual Report on Form 10-K.

Macoupin. The Macoupin property is located in Macoupin County, Illinois. The property is under lease to a subsidiary of Foresight Energy, and in 2015, approximately 2.4 million tons were shipped from the property. Production is from an underground mine and is shipped via the Norfolk Southern or Union Pacific railroads or by barge to utility customers such or loaded into barges for shipment to export customers.

Sahara. The Sahara property is located in Saline, Hamilton and Williamson Counties in Illinois. The property is under lease to a subsidiary of Peabody Energy Corporation and approximately 0.6 million tons were mined on the property during 2015. Production is currently from an underground mine and is shipped via barge primarily to utility customers.

In addition to these properties, we own loadout and other transportation assets at the Williamson and Macoupin mines and at the Sugar Camp mine, which is another mine operated by Foresight Energy. See "—Coal Transportation and Processing Assets." The map below shows the location of our major properties in the Illinois Basin:

Northern Powder River Basin

Western Energy. The Western Energy property is located in Rosebud and Treasure Counties, Montana. In 2015, approximately 4.9 million tons were produced from our property. A subsidiary of Westmoreland Coal Company has two coal leases on the property. Coal is produced by surface dragline mining, and the coal is transported by either truck or beltline to the four-unit 2,200-megawatt Colstrip generation station located at the mine mouth. The map below shows the location of our property in the Northern Powder River Basin:

Coal Transportation and Processing Assets

We own transportation and processing infrastructure related to certain of our coal and aggregates properties. We own loadout and other transportation assets at Foresight Energy's Williamson and Macoupin mines in the Illinois Basin. 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. We typically lease this infrastructure to third parties and collect throughput fees; however, at the loadout facility at the Williamson mine in Illinois, we operate the coal handling and transportation infrastructure and have subcontracted out that responsibility to a third party.

Hard Mineral Royalty and Other Assets

As of December 31, 2015, we owned an estimated 500 million tons of aggregates reserves located in a number of states across the country. We lease a portion of these reserves to third parties in exchange for royalty payments. We also lease approximately

120 million tons of these reserves to the Grand Rivers operation in the VantaCore segment. The structure of these leases is similar to our coal leases, and these leases typically also require minimum rental payments in addition to royalties. During 2015, our aggregates lessees produced 2.2 million tons of aggregates from these properties and we received $8.1 million in aggregates royalty revenues, including overriding royalty revenues. In February 2016, we sold the aggregates reserves and related royalty rights at three aggregates operations located in Texas, Georgia and Tennessee, which comprised approximately 27%, or 139 million tons, of our aggregates reserves as of December 31, 2015, for $10.0 million in cash. The properties sold generated approximately $0.9 million in aggregates royalty reserves during 2015. The effective date of the sale was February 1, 2016.

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. While the vast majority of the 10 million acres remain largely undeveloped, BRP currently holds eight active mineral leases and has an ongoing program to identify additional opportunities to lease its minerals to operating parties. BRP’s hard mineral royalty and other assets include nearly 95,000 net mineral acres of coal rights (primarily lignite and some bituminous coal) in the Gulf Coast region, of which approximately 4,800 acres are leased in Louisiana, Alabama and Texas. In addition, BRP owns copper rights in Michigan’s Upper Peninsula that are subject to a development agreement with a copper development company. BRP also holds various other mineral rights including coalbed methane, metals, aggregates, water and geothermal, in several states throughout the United States.

Soda Ash Segment

We own a 49% non-controlling equity interest in Ciner Wyoming, which 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 six large continuous mining machines and ten 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. 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 seven 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 over 50 years.

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. Ciner Wyoming’s deca rehydration process enables

Ciner Wyoming to reduce waste storage needs and convert what is typically a waste product into a usable raw material. As a result of this process, Ciner Wyoming has been able to reduce the amount of short tons of trona ore it takes to produce one short ton of soda ash.

The soda ash produced is shipped by rail or truck from the Green River Basin facility. For the year ended December 31, 2015, Ciner Wyoming shipped approximately 96% of its soda ash to customers initially via rail under a contract with Union Pacific that expires on December 31, 2017, and the plant receives rail service exclusively from Union Pacific. Ciner Wyoming 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") provides logistics and support services for all of Ciner Wyoming’s export sales. For domestic sales, Ciner Resources Corporation provides similar services.

Ciner Wyoming’s largest customer is ANSAC, which buys soda ash (through Ciner Wyoming’s sales agent) and other of its member companies for further export to its customers. 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.

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. Under the license with Rock Springs, the applicable royalty rate may vary based on a most favored nation clause in the license which is currently the subject of litigation in Wyoming.

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.

VantaCore Segment

VantaCore is a construction materials company that we acquired on October 1, 2014. VantaCore operates four limestone quarries, one underground limestone mine, six sand and gravel plants, two asphalt plants and two marine terminals. VantaCore is headquartered in Philadelphia, Pennsylvania, and its operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana. As of December 31, 2015, VantaCore controlled approximately 400 million tons of estimated aggregates reserves, including approximately 120 million tons of reserves leased at the Grand Rivers operation from the Coal, Hard Mineral Royalty and Other segment. The reserve estimates for each of VantaCore’s properties were prepared internally and audited by an independent third party advisor. For the year ended

December 31, 2015, VantaCore sold approximately 6.0 million tons of crushed stone and gravel, including brokered stone, 1.1 million tons of sand and 0.2 million tons of asphalt. VantaCore's four operating businesses are Laurel Aggregates, located in Lake Lynn, Pennsylvania, Winn Materials/McIntosh Construction, located in Clarksville, Tennessee, Grand Rivers, located in Grand Rivers, Kentucky and Southern Aggregates, located near Baton Rouge, Louisiana. VantaCore's business is seasonal, with production typically lower in the first quarter of each year due to winter weather. The following map shows the locations of each of VantaCore's operations.

Laurel Aggregates

Laurel Aggregates is a limestone mining company located in Lake Lynn, Pennsylvania. Its operations consist of a surface and underground mines and use conventional drilling, blasting and crushing methods. The surface mine is located on approximately 100 acres of owned property, and the underground reserves are located on approximately 670 acres of leased property. Laurel pays royalties for material mined and sold from its leased property. Laurel also brokers stone for third party quarries located in Ohio and Pennsylvania. Crushed stone is loaded into third party trucks for delivery to customers located in southwestern Pennsylvania, northeastern West Virginia and eastern Ohio. Laurel’s customers consist of oilfield service companies, natural gas exploration and production companies and construction and contracting companies.

Winn Materials/McIntosh Construction

Winn Materials’ operations consist of two crushed stone quarries and a river terminal, while McIntosh is a complementary asphalt producer and paving company. Together, the two companies function as a vertically integrated unit. The operations of Winn/McIntosh are located in Clarksville, Tennessee, which is located approximately 45 miles northwest of Nashville and is Tennessee’s fifth largest city.

Winn mines and produces hard rock limestone using conventional drilling, blasting and crushing methods. Winn primarily leases its properties at its two quarries located in Clarksville and in Trenton, Kentucky and pays royalties for material produced and sold from the leased properties. Winn’s marine terminal business is located on the Cumberland River, adjacent to Winn’s Clarksville quarry. Its dock transloads various materials by barge. Through the river terminal, Winn loads out crushed stone and also imports products such as river and granite sand, fertilizer and agricultural products for the local and regional markets. The river terminal is currently being expanded to meet growing demand for additional imported product into these markets. Crushed stone produced at Winn’s quarries and products imported from the river terminal are loaded onto third party trucks for delivery to Winn’s customers.

McIntosh sells asphalt to third parties and also operates its own paving business. Winn supplies most of McIntosh’s crushed stone and sand used for both its asphalt production and construction needs. The Winn/McIntosh businesses sell to and provide services for residential, commercial and industrial customers. These businesses also supply and provide construction services for infrastructure and highway construction projects primarily within Montgomery County, Tennessee, including for Fort Campbell, one of the largest Army bases in the United States.

Grand Rivers

VantaCore purchased this 514 acre hard rock quarry operation located on the Tennessee River near Grand Rivers, Kentucky from one of NRP's aggregates lessees that had previously idled the operation. Under VantaCore's ownership, this operation continues to lease reserves from NRP and sells its limestone aggregates in both the local market loaded onto third party trucks and to river-based markets through a barge load out terminal.

The Grand Rivers quarry produces various grades of crushed limestone products mined through its open pit using conventional drilling, blasting and crushing methods performed by a third party mining contractor. Grand Rivers pays royalties for material produced and sold from the leased property to a subsidiary of NRP. Crushed stone is loaded into third party trucks to customers in Kentucky and barges for delivery to customers along the Mississippi River Basin and related waterways. Grand Rivers customers currently consist primarily of ready mix concrete companies and construction and contracting companies.

Southern Aggregates

Southern Aggregates is a sand and gravel mining company based in Denham Springs, Louisiana approximately 25 miles northeast of Baton Rouge, Louisiana. Southern operates six sand and gravel operations. Suction dredges extract sand and gravel, and the mined material is processed at plants generally located at each site. The plants separate gravel and saleable sand from waste sand and clays, with the waste returned to mined-out sections of pits. The saleable sand and gravel material is loaded onto third party trucks for delivery to Southern's customers. Southern leases its mineral reserves and pays royalties for material produced and sold from the leased properties. Southern's markets extend approximately 100 miles west and south from its operating locations, including to the cities of Baton Rouge, Lafayette and New Orleans. Southern's customers consist primarily of ready mix concrete companies, asphalt producers and contractors.

Oil and Gas Segment

We own various interests in oil and gas properties that are located in the Williston Basin, the Appalachian Basin, Louisiana and Oklahoma. Our interests in the Appalachian Basin, Louisiana and Oklahoma are minerals and royalty interests, while in the Williston Basin we own non-operated working interests. Our Williston Basin non-operated working interest properties include the properties acquired in the Sanish Field from an affiliate of Kaiser-Francis Oil Company in November 2014. Subsequent to December 31, 2015, we sold certain of our oil and gas royalty interests in the Appalachian Basin.

We generate oil and gas revenues from non-operated working interests, royalty interests and overriding royalty interests in producing oil and gas wells. Our primary interests in oil and natural gas producing properties are our non-operated working interests located in the Williston Basin, but we also own fee mineral, royalty or overriding royalty interests in oil and gas properties in several other areas, including the Appalachian Basin, the Mississippian Lime formation and northern Louisiana.

Revenues related to our non-operated working interests in oil and gas assets are recognized on the basis of our net revenue interests in hydrocarbons produced. We also incur capital expenditures and operating expenses associated with the non-operated working interests. Oil and gas royalty revenues include production payments as well as bonus payments and are recognized on the basis of hydrocarbons sold by lessees and the corresponding revenues from those sales. Generally, the lessees make payments based on a percentage of the selling price. Some leases are subject to minimum annual payments or delay rentals. Our revenues fluctuate based on changes in the market prices for oil and natural gas, the decline in production from producing wells, and other factors affecting the third-party oil and natural gas exploration and production companies that operate our wells, including the cost of development and production.

Our non-operated working interests are all located in the Williston Basin in North Dakota and Montana. As of December 31, 2015, we had non-operated working interests in 21,832 net acres in the basin, all of which are held by production. These assets include 6,086 net acres in the Sanish Field in Mountrail County, North Dakota that we acquired in November 2014 from an affiliate of Kaiser-Francis Oil Company. The interests acquired in that acquisition are all operated by Whiting Petroleum Corporation and include an estimated average working interest of 14% in approximately 210 wells that were producing as of December 31, 2015.

We own royalty interests where we have leased certain portions of our owned mineral interests to third parties primarily located in the southern portion of the Appalachian Basin and in the Mississippian Lime in Oklahoma. We also own overriding royalty interests primarily located in the Appalachian Basin in West Virginia and Pennsylvania, including in the Marcellus Shale, and in the Haynesville Shale in Louisiana. In February 2016, we sold royalty and overriding royalty interests in several producing properties located in the Appalachian Basin, including our overriding royalty interests in the Marcellus Shale, for $36.6 million in cash. The sale included royalty and overriding royalty interests in approximately 765 gross producing wells as of December 31, 2015 and approximately 10% of our estimated proved reserves as of December 31, 2015, or 1,094 MBoe. The effective date of the sale was January 1, 2016.

Through our 51% ownership of BRP as described above, we also own approximately 300,000 gross acres of oil and gas mineral rights in Louisiana, of which over 53,000 acres were leased as of December 31, 2015. In addition to the leased mineral acreage, BRP holds a 1% overriding royalty interest on approximately 25,000 mineral acres in Louisiana.

Estimated Proved Oil and Gas Reserves

Proved reserves are those quantities of crude oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain. In connection with the estimation of proved reserves, the term "reasonable certainty" implies a high degree of confidence that the quantities of crude oil, natural gas liquids and/or natural gas actually recovered will equal or exceed the estimate.

Reserves Presentation

The following table presents our estimated proved oil and gas reserves and related standardized measure of discounted cash flows as of December 31, 2015 as estimated by Netherland, Sewell & Associates, Inc., our independent reserve engineer:

	Estimated Proved Reserves (4)					
	Crude Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total Proved Reserves (MBoe) (1)		Standardized Measure of Discounted Cash Flows (2) (in thousands)
Proved Developed Producing	7,636	1,177	13,015	10,982		$ 111,783
Proved Developed Non-Producing	226	19	142	269		3,869
Proved Undeveloped	212	27	167	267		701
Total	8,074	1,223	13,324	11,518	(3)	$ 116,353

(1) Natural gas is converted on the basis of six Mcf of gas per one Bbl of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency.

(2) Standardized measure of discounted cash flows represents the present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue.

(3) Includes 10,063 MBoe of estimated proved reserves attributable to our non-operated working interests in oil and natural gas properties in the Williston Basin, approximately 3% of which were proved undeveloped reserves as of December 31, 2015.

(4) Approximately 10% of our estimated proved reserves as of December 31, 2015, or 1,094 MBoe, (all located in the Appalachian Basin) were sold in February 2016.

Our estimates of proved developed reserves, proved undeveloped reserves, and total proved reserves at December 31, 2015 and 2014 and changes in proved reserves during the last year are presented in the Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited) under Item 8. of this Form 10-K. Also presented in the Supplemental Information are the Partnership's estimates of future net cash flows and discounted future net cash flows from proved reserves. See Critical Accounting Estimates under Item 7 of this Form 10-K for additional information on the Partnership’s proved reserves.

Technologies Used in Proved Reserves Estimation

Our estimated proved reserves as of December 31, 2015, were prepared by Netherland, Sewell & Associates, Inc. ("Netherland Sewell"), our independent reserve engineer. To achieve reasonable certainty, Netherland Sewell employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps including isopach and structure maps, analogy and statistical analysis, and available downhole and production data and well test data. A copy of Netherland Sewell's summary report is included as Exhibit 99.2 to this Annual Report on Form 10-K. For additional information on our estimated proved reserves, see "Supplemental Information on Oil and Gas Exploration and Production Activities" to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

Estimated Proved Undeveloped Reserves

During 2015, we participated in 29 wells in the Williston Basin and incurred $29.1 million of related capital expenditures that resulted in the conversion of 286 MBoe of estimated proved undeveloped reserves to estimated proved developed reserves. As of December 31, 2015, we had no estimated proved undeveloped reserves that have remained undeveloped for more than five years, and we expect all estimated proved undeveloped reserves reported herein will be developed within the next two years.

Internal Controls Over Reserves Estimation Process

Netherland Sewell, our independent reserve engineering firm, estimated, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the Securities and Exchange Commission, 100% of our proved reserves as of December 31, 2015. The Netherland Sewell technical personnel responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. See Exhibit 99.2 included as an exhibit to this Annual Report on Form 10-K for further discussion of the qualifications of Netherland Sewell personnel.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to Netherland Sewell in their reserves estimation process. In the fourth quarter, our technical team was in contact regularly with representatives of Netherland Sewell to review properties and discuss methods and assumptions used in Netherland Sewell's preparation of the year-end reserves estimates. A copy of the Netherland Sewell reserve report was reviewed by our internal technical staff prior to the inclusion of such report in this Annual Report on Form 10-K.

Our Director—Engineering and Reserves is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering from the University of Texas at Austin and is a member of the Society of Petroleum Engineers. Prior to joining NRP, he spent nine years at DeGolyer and MacNaughton as a reservoir engineer working on multiple aspects of reserve evaluation and appraisals. The Director—Engineering and Reserves reports directly to our Vice President, Oil and Gas.

Drilling and Development Activities

We do not operate any wells or conduct any drilling activities. The following table sets forth information with respect to the number of net wells drilled and completed on our properties during the years ended December 31, 2015 and 2014. Well information for the year ended December 31, 2013 is not included, as our oil and natural gas producing activities were not material to our results of operations for that year. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return. Net wells represent the total of our fractional working interests or royalty interests, as applicable, owned in gross wells.

	Productive		Dry		Total	
	Gross	Net	Gross	Net	Gross	Net
2015						
Development	53	2.7	—	—	53	2.7
Exploratory	—	—	—	—	—	—
Total	53	2.7	—	—	53	2.7
2014						
Development	123	4.4	—	—	123	4.4
Exploratory	—	—	—	—	—	—
Total	123	4.4	—	—	123	4.4

Producing Oil and Natural Gas Wells

The following table sets forth the gross and net producing oil and natural gas wells in which we held working interests and royalty or overriding royalty interests as of December 31, 2015. Gross wells represent the number of wells in which we own an interest. Net wells represent the total of our fractional working interests or royalty interests, as applicable, owned in gross wells.

	Working Interest Wells(1)				Royalty and Overriding Royalty Interest Wells(2)			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	486	48	—	—	61	0.1	—	—
Other	—	—	—	—	98	4.7	1,005	73
Total	486	48	—	—	159	4.8	1,005	73

(1) As of December 31, 2015, we also owned non-operated working interests in 19 gross oil wells in various stages of development in the Williston Basin.

(2) 67 gross (1.4 net) natural gas and oil wells are attributable to our overriding royalty interest in the Marcellus Shale acquired in 2012. The remaining wells consist primarily of conventional oil and gas wells or coal bed methane that are located in the southern portion of the Appalachian Basin. In February 2016, we sold royalty and overriding royalty interests in approximately 765 gross producing wells in the Appalachian Basin as of December 31, 2015. The effective date of the sale was January 1, 2016.

Undeveloped Acreage Summary

The following table contains a summary of the undeveloped gross and net acres in which we had interests as of December 31, 2015:

	Undeveloped Acres			
	Acres Leased to NRP (1)		Net ORRI and Fee Mineral Acres	
	Gross	Net	ORRI (2)	Fee Mineral (3)
Williston Basin	610	384	—	—
Other	—	—	3,167	25,323
Total	610	384	3,167	25,323

(1) Represents mineral acres leased by third parties to NRP.

(2) Represents net acres in which we have an overriding royalty interest in the Marcellus Shale acquired in December 2012. Certain of the leases subject to the overriding royalty interest originally acquired have expired but may be renewed. To the extent those leases are renewed, our overriding royalty interest in those properties will continue. In February 2016, we sold 3,167 net ORRI acres. The effective date of the sale was January 1, 2016.

(3) Represents net fee mineral acres owned by NRP and BRP LLC and leased to third parties. No leased undeveloped fee mineral acres were sold in the February 2016 sale.

Developed Acreage Summary

The following table contains a summary of the developed gross and net acres in which we had interests as of December 31, 2015:

	Developed Acres			
	Acres Leased to NRP (1)		Net ORRI and Fee Mineral Acres	
	Gross	Net	ORRI (2)	Fee Mineral (3)
Williston Basin	120,016	21,066	—	—
Other	—	—	20,862	117,365
Total	120,016	21,066	20,862	117,365

(1) Represents mineral acres leased by third parties to NRP.

(2) Represents net acres in which we have an overriding royalty interest in the Marcellus Shale acquired in December 2012. In February 2016, we sold 20,862 net ORRI acres. The effective date of the sale was January 1, 2016.

(3) Represents net fee mineral acres owned by NRP Southern Appalachia, Grant County and BRP LLC and leased to third parties. In February 2016, we sold 93,916 net fee mineral acres. The effective date of the sale was January 1, 2016.

Significant Customers

We have a significant concentration of revenues with Foresight Energy and its subsidiaries, with total revenues of $86.6 million in 2015. The exposure is spread out over four different mining operations. We are currently in a dispute with and have filed a lawsuit against Foresight Energy's subsidiary, Hillsboro Energy, for breach of contract due to wrongful declaration of force majeure at the Deer Run mine. For additional information, see Note 15. "Major Lessees" in the Notes to Consolidated Financial Statements under "Item 8. Financial Statements and Supplementary Data" and "Item 1A. Risk Factors—Risks Related to Our Business—Foresight Energy's Deer Run Mine is currently idled as a result of elevated carbon monoxide levels at the mine. If the mine remains idled for an extended period or does not resume operations, our financial condition and results of operations could be aversely affected," included elsewhere in this Annual Report on Form 10-K.

Prior to 2015 we derived more than 10% of our total revenues from Alpha Natural Resources ("Alpha"), our second largest lessee after Foresight Energy. Revenue from Alpha declined from $48.8 million in 2014 to $34.4 million in 2015 primarily due to Alpha's idling of mines throughout the year and Alpha's August 2015 bankruptcy filing. While Alpha has recently filed a plan of reorganization with the bankruptcy court, we do not yet have certainty as to which, if any, of our leases will be accepted or assigned in the bankruptcy. To the extent our leases are rejected, Alpha’s operations on those leases will cease.

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 and hydroelectric power.

The construction aggregates industry that VantaCore operates in is highly competitive and fragmented with a large number of independent local producers in operating in VantaCore’s local markets. Additionally, VantaCore also competes against large private and public companies, some of which are significantly vertically integrated. Therefore, there is intense competition in a number of markets in which VantaCore operates. This significant competition could lead to lower prices and lower sales volumes in some markets, negatively affecting our earnings and cash flows.

Our trona mining and soda ash refinery business in the Green River Basin, Wyoming, 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.

The oil and natural gas industry is intensely competitive, and we compete with other companies in that industry who have greater resources than we do. These companies may be able to pay more for productive oil and natural gas properties and may be able to expend greater resources to evaluate properties and attract and maintain industry personnel. In addition, these companies may have a greater ability to make acquisitions in times of low commodity prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Title to Property

We owned a significant percentage of our coal and aggregates reserves in fee as of December 31, 2015. We lease the remainder from unaffiliated third parties, including leasing aggregates reserves for VantaCore's construction materials business. Ciner Wyoming also leases or licenses its trona reserves. As of December 31, 2015, we owned certain of our oil and gas reserves in fee and leased our non-operated working interests in the Williston Basin from third parties. 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 operations 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.

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 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 steam 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 exploration and development activities associated with our interests in crude oil and natural gas properties and to the aggregates and industrial mineral mining operations in which we hold interests, including VantaCore's construction aggregates mining and production operations and 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.

The emission of air pollutants from the exploration and development of crude oil and natural gas is also subject to the Clean Air Act and comparable state laws. In 2012, EPA published final New Source Performance Standards for volatile organic compounds and sulfur dioxide and National Emissions Standards for Hazardous Air Pollutants associated with oil and gas facilities. In January 2013, EPA granted petitions asking the agency to reconsider and revise parts of this rule. Accordingly, in September 2013, EPA issued updates to the New Source Performance Standards for the emission of volatile organic compounds from storage vessels used in crude oil and natural gas production. Similarly, in December 2014, EPA finalized rules related to emissions from gas and liquids during well completion. These rules could have an adverse effect on revenues from our interests in oil and natural gas properties.

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 has begun 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 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. The rule will 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. This rule is expected to have a material adverse effect on the demand for coal by electric power generators and is being challenged by 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 Clean Power Plan Rule pending a decision by the District of Columbia Circuit as well as any subsequent review by the Supreme Court.

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.

President Obama also announced an emission reduction deal 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.

EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including coal-fired electric power plants, on an annual basis, as well as certain oil and natural gas production facilities, on an annual basis.

In August 2015, EPA proposed new regulations to reduce emissions of methane from crude oil and natural gas production and transportation activities such as wells, pipelines, and valves levels by up to 45 percent by 2025 (compared to 2012 levels). A final rule is expected in 2016.

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 our VantaCore construction aggregates and Ciner Wyoming soda ash businesses and in connection with our non-operated working interests in oil and gas properties, to the extent of our proportionate interest therein.

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 has been challenged by a number of states and private parties and was stayed on a nationwide basis by the Sixth Circuit Court of Appeals in October 2015. 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 EPA’s review of permits, it has 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 suit group lawsuits have been filed against mine operators for allegedly violating conditions in their 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. Most of these cases were resolved prior to any appeal and it is difficult to predict whether such suits will continue to be successful. However, 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. NRP has been named as a defendant in one of these lawsuits. 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. While it is too early to determine the merits or predict the outcome of any of these lawsuits, 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.

Drilling and development activities associated with our oil and natural gas business generate produced water. Produced water is often disposed of in underground injection control ("UIC") wells that receive permits from EPA or from state agencies that have been granted authority to issue UIC issue permits by EPA. Failures or delays in getting such permits could negatively impact exploration and production activities and, in turn, adversely affect our oil and natural gas business.

Other Regulations Affecting the Mining Industry

Mine Health and Safety Laws

The operations of our lessees, VantaCore 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. Regulatory authorities or individual citizens who bring civil actions under SMCRA may attempt to assign the liabilities of our coal lessees to us if any of these lessees are not financially capable of fulfilling those obligations.

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.

Regulations under SMCRA include a "stream buffer zone" rule that prohibits certain mining activities near streams. In 2008, the federal Office of Surface Mining (OSM), which implements SMCRA, revised the stream buffer zone rule, making it more clear that valley fills are not prohibited by the rule. Environmental groups challenged the revision to the buffer zone rule in federal court. In February 2014, the federal court vacated the 2008 rule and in December 2014, OSM reinstated the previous version of the rule, without clarifying whether the previous version of the rule impacts the ability to construct excess fills. OSM has stated that it is considering future revisions to the buffer zone rule. Any revision or interpretation of the rule limiting or prohibiting valley fills could restrict our lessees’ ability to develop new mines, or could require our lessees to modify existing operations, which could have an adverse effect on our coal-related revenues.

In April 2013, in Mingo Logan Coal Company v. EPA, the D.C. Circuit Court ruled that EPA has the authority under the Clean Water Act to retroactively veto a Section 404 dredge and fill permit issued at a coal mine by the U.S. Army Corps of Engineers. The decision creates uncertainties for all companies operating with Clean Water Act fill permits and their business partners. While the specific facts of this case relate to ongoing fill activities, the broadly written language of the decision could have sweeping implications in other areas and result in increased regulatory activity by EPA that is adverse to the mining industry.

Other Regulations Affecting the Crude Oil and Natural Gas Industry

Hydraulic Fracturing

The exploration and production companies that operate the crude oil and natural gas properties in which we have interests use hydraulic fracturing to recover oil and natural gas from tight rock formations. Hydraulic fracturing is a process customary to the oil and gas industry in which water, sand and other additives are pumped under high pressure into tight rock formations in a manner that creates or expands fractures in the rock to facilitate oil and gas recovery. While hydraulic fracturing has been used to recover oil and natural gas for decades, the practice has recently received increased scrutiny from various federal, state and local agencies, some of which have prohibited the practice or called for further study of its effects. Future requirements that limit or more strictly regulate the permitting or use of hydraulic fracturing could impact revenues from our oil and natural gas properties.

Permitting

Additionally, state agencies are generally charged with issuing permits governing the location and construction of drilling sites. Delays or failures to obtain such permits due to local land use or environmental concerns could negatively impact revenues from our oil and gas operations.

Transportation

Our revenues could be negatively impacted if the Federal Energy Regulatory Commission, which approves interstate pipelines and certain gathering lines, fails to timely approve pipelines that transport oil or natural gas produced from the properties in which we own interests. Additionally, our oil and natural gas revenues could be negatively impacted by rules proposed in July 2014 by the United States Department of Transportation governing the transportation of crude oil by rail. As proposed, the rules would require thousands of railroad tank cars to be upgraded or phased out by 2017. Railroad tank car shortages resulting from the proposed rule could delay or increase the costs of transportation of crude oil from our Williston Basin non-operated working interests and negatively impact revenues from those properties.

Employees and Labor Relations

We historically have not had any employees. To carry out our operations, affiliates of our general partner employ 88 people who directly support our operations. None of these employees are subject to a collective bargaining agreement. As a result of our acquisition of VantaCore in the fourth quarter of 2014, we employ 225 people who support VantaCore’s construction aggregates mining and production operations. None of these employees are subject to a collective bargaining agreement.

Website Access to Company 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. Also included on our website are 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. 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.

ITEM 1A. RISK FACTORS

Risks Related to Our Business

To the extent our board of directors deems appropriate, it may determine to further decrease the amount of our quarterly distribution or suspend or eliminate the distribution altogether.

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. The actual amount of cash we have to distribute each quarter is reduced by payments in respect of debt service and other contractual obligations, fixed charges, maintenance capital expenditures and reserves for future operating or capital needs that the board of directors may determine are appropriate. 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. During 2015, given the downturns in the coal and oil and gas markets, together with our high leverage and debt service requirements, our board of directors reduced the distribution by over 87%. To the extent our board of directors deems appropriate, it may determine to further decrease the amount of the quarterly distribution or suspend or eliminate the distribution altogether. In addition, because our unitholders are required to pay income taxes on their respective shares of our taxable income, you may be required to pay taxes in excess of any future distributions we make. See"—Tax Risks to Common Unitholders—You are required to pay taxes on your share of our income even if you do not receive any cash distributions from us." Your share of our portfolio income may be taxable to you even though you receive other losses from our activities.

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

As of December 31, 2015, we and our subsidiaries had approximately $1.4 billion of total indebtedness. The terms and conditions governing our indebtedness, including NRP's 9.125% senior notes, Opco's revolving credit facility and senior notes, and NRP Oil and Gas's revolving credit facility:

- 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. 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. We are required to make substantial principal repayments each year in connection with Opco's senior notes, with approximately $81 million due thereunder each year through 2018. In addition, Opco's revolving credit facility matures in 2017, and NRP's 9.125% senior notes mature in 2018. We will be required to repay or refinance the amounts coming due in 2017 and 2018 prior to their respective maturities. We may not be able to refinance these amounts on terms acceptable to us, if at all, or the borrowing capacity under Opco's revolving credit facility may be substantially reduced. 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.

The borrowing base under NRP Oil and Gas's revolving credit facility is based on the value of our proved reserves and is redetermined on a semi-annual basis in May and October of each year. The current oil price environment or future declines in prices or reduced production from or development of our properties could result in a determination to lower the borrowing base by significant amounts. We expect that due to the current oil price environment, limited development will occur on our properties, which will result in a decline in our reserves. In such event, we may not be able to access funding under the facility necessary to operate our business and we could be required to repay any indebtedness in excess of the redetermined borrowing base.

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.

Due to the relatively high level of our indebtedness, we are pursuing or analyzing various alternatives to reduce the level of our long-term debt and lower our future debt obligations, including the application of proceeds from asset sales, further reductions in amount of cash distributed to our unitholders, possible debt repurchases, exchanges of existing debt securities for new debt securities and exchanges or conversions of existing debt securities for new equity securities, among other options. We may pursue any or all of these options without the approval of our unitholders or other stakeholders.

We may not be able to execute on an asset sale strategy in furtherance of our strategic plan, which could have a material adverse effect on our ability to service or refinance our debt obligations.

As part of our deleveraging strategy, we intend to execute on strategic asset sales in order to pay down debt. However, we may not be able to sell assets at attractive prices, or at all. If we are unable to do so, our ability to execute on our strategic plan and deleverage may be adversely affected. In addition, our revenues will decline as our reserves are depleted and our asset base is reduced in connection with any asset sales.

We do not currently have the ability to raise capital from traditional sources, which may have a material adverse effect on our business and our ability to service and refinance our debt obligations.

Traditionally, we have accessed the debt and equity capital markets on a regular basis and have relied on bank credit facilities to finance our business activities. However, due to the current commodity price environment and the state of the coal markets in particular, we believe we do not currently have the ability to access either the debt or equity capital markets. In addition, the volatility in the energy industry combined with recent bankruptcies and additional perceived credit risks of companies with coal and/or oil and gas exposure has resulted in traditional bank lenders seeking to reduce or eliminate their lending exposure to these companies. Accordingly, we will be required over the near term to run our business and service our debt through cash from operations or asset sales. In addition, we may be required to seek financing from non-traditional sources at unfavorable pricing or with unfavorable terms to run our business or to refinance or restructure our 2017 and 2018 debt maturities.

Foresight Energy’s Deer Run mine is currently idled as a result of elevated carbon monoxide levels at the mine. If the mine remains idled for an extended period or does not resume operations, our financial condition and results of operations could be adversely affected.

In late March 2015, elevated carbon monoxide readings were detected at Foresight Energy’s Deer Run mine, which we also refer to as our Hillsboro property, and coal production at the mine was idled. In July 2015, we received a notice from Foresight Energy declaring a force majeure event at the mine as a result of the elevated carbon monoxide levels. While we are disputing Foresight Energy’s claim and have filed a lawsuit in connection therewith, the effect of a valid force majeure declaration would relieve Foresight Energy of its obligation to pay us minimum deficiency payments of $7.5 million per quarter, or $30.0 million per year. Foresight Energy's failure to make the deficiency payment with respect to the second, third and fourth quarters of 2015 resulted in a $16.2 million cash impact to us. Such amount will increase for each quarter during which mining operations continue to be idled. We do not currently have an estimate as to when the mine will resume coal production. If the mine remains idled for an extended period or if the mine is permanently closed, our financial condition could be adversely affected. See Item 3. "Legal Proceedings" included elsewhere in this Annual Report on Form 10-K for more information on our lawsuit against Foresight Energy.

Coal prices continue to be severely depressed, which has negatively affected our coal-related revenues and the value of our coal reserves. Further declines or a continued low price environment could have an additional adverse effect on our coal-related revenues and the value of our coal reserves.

Prices for both steam and metallurgical coal have declined substantially in recent years and remain at levels close to or below the level of operating costs for a number of our lessees. 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 and the demand for steel;
- the proximity to and capacity of transportation facilities;
- weather conditions; and
- the effect of worldwide energy conservation measures.

Natural gas is the primary fuel that competes with steam coal for power generation. Relatively low natural gas prices have resulted in a number of utilities switching from steam coal to natural gas to the extent that it is practical to do so. This switching has resulted in a decline in steam coal prices, and to the extent that natural gas prices remain low, steam coal prices will also remain low. The closure of coal-fired power plants as a result of increased governmental regulations or the inability to comply with such regulations has also resulted in a decrease in the demand for steam coal.

Prices for metallurgical coal are also at multi-year lows due to global economic conditions. Our lessees produce a significant amount of the metallurgical coal that is used in both the U.S. and foreign steel industries. Since the amount of steel that is produced is tied to global economic conditions, a continuation of current conditions or a further decline in those conditions could result in the decline of steel, coke and metallurgical coal production. In addition, rising exports of metallurgical coal from Australia and a strong U.S. dollar continue to have a negative effect on prices received for metallurgical coal produced in the United States. Since metallurgical coal is priced higher than steam 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.

Lower prices have reduced the quantity of coal that may be economically produced from our properties, which has in turn reduced our coal-related revenues and the value of our coal reserves. Further declines or a continued low price environment could have an additional adverse effect on our coal-related revenues or the value of our reserves. 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. For the year ended December 31, 2015, we recorded an impairment charge of $257.5 million relating to certain of our coal related properties. With the continued weakness in the coal markets, we intend to continue to closely monitor our coal assets impairment risk. Future impairment analyses could result in additional downward adjustments to the carrying value of our assets.

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 have filed for protection under U.S. bankruptcy laws in the past, including several of our coal lessees, such as Alpha, Patriot Coal Corporation and Arch Coal, Inc. Alpha, which is our second largest lessee after Foresight Energy, filed for bankruptcy in August 2015. While Alpha has recently filed a plan of reorganization with the bankruptcy court, we do not yet have certainty as to which, if any, of our leases will be accepted or assigned in the bankruptcy. 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, Alpha’s operations on those leases will cease, and we will be unlikely to recover the full amount of our rejection damages claims. In addition, Foresight Energy is currently in default under certain of its debt obligations and is in negotiations with its creditors to avoid acceleration of its debts. If Foresight Energy is unable to come to an agreement with its creditors, it may also seek bankruptcy protection, which could have a material adverse effect on our business. 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.

As a result of consolidation in the coal industry and our partnership with Foresight Energy, we derive a large percentage of our revenues and other income from a small number of coal lessees.

In 2015, we derived 18% and 7% of our total revenues and other income from Foresight Energy and Alpha, respectively. As a result, we have significant concentration of revenues with these lessees. Alpha is currently in bankruptcy, and we do not know which of our leases might be assumed or rejected in the bankruptcy process. See "—Bankruptcies in the coal industry could have a material adverse effect on our business and results of operations." In addition, the idling of Foresight Energy’s Deer Run mine on our Hillsboro property has resulted in a significant cash impact to us. See "—Foresight Energy’s Deer Run mine is currently idled as a result of elevated carbon monoxide levels at the mine. If the mine remains idled for an extended period or does not resume operations, our financial condition and results of operations could be adversely affected." In addition to the extent our lessees merge, sell assets or otherwise consolidate, then our revenues could become more dependent on fewer mining companies.

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 the production from our properties would reduce our revenues. The level of production is subject to operating conditions or events beyond our or our lessees’ control including:

- the inability to acquire necessary permits or mining or surface rights;
- changes or variations in geologic conditions, such as the thickness of the mineral deposits and, in the case of coal, the amount of rock embedded in or overlying the coal 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 facilities and interruptions due to transportation delays;
- adverse weather and natural disasters, such as heavy rains and flooding;
- labor-related interruptions; and

- unexpected mine safety accidents, including fires and explosions.

As a result of recent judicial decisions and the increased involvement of the Obama Administration and EPA in the permitting process, there is substantial uncertainty relating to the ability of our coal lessees to be issued permits necessary to conduct mining operations. The non-issuance of permits has limited the ability of our coal lessees to open new operations, expand existing operations, and may preclude new acquisitions in which we might otherwise be involved. We and our lessees may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from our or their operations. If we or our lessees are pursued for these sanctions, costs and liabilities, mining operations and, as a result, our revenues could be adversely affected.

VantaCore currently operates four hard rock quarries, one underground limestone mine, six sand and gravel plants, two asphalt plants and two marine terminals. As an operator of these assets, we are exposed to risks that we have not historically been exposed to in our mineral rights and royalties business. Such risks include, but are not limited to, prices and demand for construction aggregates, capital and operating expenses necessary to maintain VantaCore’s operations, production levels, general economic conditions, conditions in the local markets that VantaCore serves, inclement or hazardous weather conditions and typically lower production levels in the winter months, permitting risk, fire, explosions or other accidents, and unanticipated geologic conditions. Any of these risks could result in damage to, or destruction of, VantaCore’s mining properties or production facilities, personal injury, environmental damage, delays in mining or processing, reduced revenue or losses or possible legal liability. In addition, not all of these risks are reasonably insurable, and our insurance coverage contains limits, deductibles, exclusions and endorsements. Our insurance coverage may not be sufficient to meet our needs in the event of loss. Any prolonged downtime or shutdowns at VantaCore’s mining properties or production facilities or material loss could have an adverse effect on our results of operations.

Changes in fuel consumption patterns by electric power generators resulting in a decrease in the use of coal have resulted in and will continue to result in lower coal production by our lessees and reduced coal-related revenues.

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 proposed rules promulgated by the EPA on greenhouse 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 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.

The adoption of climate change legislation or regulations restricting emissions of "greenhouse gases" and other hazardous air pollutants have resulted in and will continue to result in reduced demand for our coal, oil and natural gas.

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 has begun 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 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. The rule will 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. This rule is being challenged by industry participants and other parties. In February, 2016, the Supreme Court of the United States stayed the Clean Power Plan Rule pending a decision by the District of Columbia Circuit as well as any subsequent review by the Supreme Court. To the extent the Clean Power Plan is upheld, it is expected to have a material adverse effect on the demand for coal by electric power generators.

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.

In addition to EPA's GHG 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.

The emission of air pollutants from the exploration and development of crude oil and natural gas and related facilities is also subject to the Clean Air Act and comparable state laws. In 2012, EPA published final New Source Performance Standards for volatile organic compounds and sulfur dioxide and National Emissions Standards for Hazardous Air Pollutants associated with oil and gas facilities. In January 2013, EPA granted petitions asking the agency to reconsider and revise parts of this rule. Accordingly, in September 2013, EPA issued updates to the New Source Performance Standards for the emission of volatile organic compounds from storage vessels used in crude oil and natural gas production. Similarly, in December 2014, EPA finalized rules related to emissions from gas and liquids during well completion. These rules could have an adverse effect on revenues from our interests in oil and natural gas properties.

In August 2015, EPA proposed new regulations to reduce emissions of methane from crude oil and natural gas production and transportation activities such as wells, pipelines, and valves levels by up to 45 percent by 2025 (compared to 2012 levels). A final rule is expected in 2016.

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, VantaCore 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. The oil and gas industry is also subject to numerous laws and regulations. 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 the mining and oil and gas 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.

In addition to governmental regulation, private citizens’ groups have continued to be active in bringing lawsuits against coal mine operators and landowners. Since 2012, several citizen suit group lawsuits have been filed against mine operators and landowners for alleged violations of water quality standards resulting from ongoing discharges of pollutants from reclaimed mining operations, including selenium and conductivity. NRP has been named as a defendant in one of these lawsuits. The citizen suit groups have sought penalties as well as injunctive relief that would limit future discharges of these pollutants, which would result in significant expenses for our lessees. While it is too early to determine the merits or measure the impact of these lawsuits, 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.

Prices for crude oil and natural gas are extremely volatile. An extended decline or further declines in crude oil and natural gas prices could have an adverse effect on our results of operations

Crude oil and natural gas prices are subject to wide fluctuations in response to relatively minor changes in supply and demand and on numerous other factors beyond our control, including:

- domestic and foreign supply of oil and natural gas;
- the level of prices and expectations about future prices of oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the price and quantity of foreign imports;
- political and economic conditions in oil producing countries, including the Middle East, Africa, South America and Russia;
- the actions of the Organization of Petroleum Exporting Countries with respect to oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;

- the level of consumer product demand;
- weather conditions and other natural disasters;
- risks associated with drilling and completion operations;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxes;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- the proximity, cost, availability and capacity of oil and natural gas pipelines and other transportation facilities and the resulting differentials to market index prices;
- the price and availability of alternative fuels; and
- overall domestic and global economic conditions, including the relative value of the U.S. dollar to other currencies.

Due to global oversupply of crude oil in part due to increasing U.S. production and a strong U.S. dollar, crude oil prices have been at multi-year lows since late 2014. In addition, natural gas prices have also fallen to low levels due to record high levels of production and robust storage inventories. These markets will likely continue to be volatile in the future, and any extended period of low prices could have a material adverse effect on our results of operations from our oil and gas business. For the year ended December 31, 2015, we recorded an impairment charge of $367.6 million relating to certain of our oil and gas properties. With the continued weakness in the oil and gas markets, we intend to continue to closely monitor our oil and gas assets impairment risk. Future impairment analyses could result in additional downward adjustments to the carrying value of our assets.

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.

VantaCore operates in a highly competitive and fragmented industry, which may negatively impact prices, volumes and costs. In addition, both commercial and residential construction are dependent upon the overall U.S. economy.

The construction aggregates industry is highly fragmented with a large number of independent local producers in operating in VantaCore's local markets. Additionally, VantaCore also competes against large private and public companies, some of which are significantly vertically integrated. Therefore, there is intense competition in a number of markets in which VantaCore operates. This significant competition could lead to lower prices and lower sales volumes in some markets, negatively affecting our earnings and cash flows.

In addition, commercial and residential construction levels generally move with economic cycles. When the economy is strong, construction levels rise and when the economy is weak, construction levels fall. The U.S. economy is recovering from the 2008-2009 recession, but the pace of recovery is slow. Since construction activity generally lags the recovery after down cycles, construction projects have not returned to their pre-recession levels.

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 of mining;
- processing and blending minerals;
- 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 have limited control over the activities on our properties that we do not operate and are exposed to operating risks that we do not experience in the royalty business.

We do not have control over the operations of Ciner Wyoming or our non-operated oil and gas working interest properties. 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 would result in decreased distributions to NRP. The oil and gas properties in which we own working interests are operated by third-party operators and involve third-party working interest owners. We have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures required to fund such properties. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs and materially adversely affect our financial condition and results of operations. In addition, we are ultimately responsible for operating the transportation infrastructure at Foresight'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.

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In the current oil price environment, we do not expect to expend significant capital to develop our oil reserves, which will lead to a decline in the value of our properties and a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive, with significant development capital required to be expended to offset natural production declines. In the current oil price environment, we do not expect to expend significant development capital, which will lead to a decline in the value of our properties and our oil and gas reserves. Such declines will likely result in adjustments to the borrowing base under NRP Oil and Gas's revolving credit facility. To the extent the borrowing base is redetermined to an amount less than the amount we have outstanding under that facility, we will be required to repay the facility down to the new borrowing base. For more information on the NRP Oil and Gas revolving credit facility, see "—Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects.

To the extent the operators of our properties determine to continue drilling in the current environment, we would be required to fund our proportionate share on any wells in which we own working interests in order to participate in those wells. Our share of capital expenditures relating to our working interests could exceed our revenues from those interests. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. Our operations and other capital resources may not provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our actual capital expenditures could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital, which may include additional reserve based borrowings, debt financing, joint venture partnerships, production payment financings, sales of assets, offerings of debt or equity securities or other means. If we are unable to fund our capital requirements, we may be required to decline to participate in wells, which in turn could lead to a decline in the value of our assets or a decline in our oil and natural gas reserves.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce the production of coal, oil and gas, 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 other events could temporarily impair the ability of our lessees to supply minerals to their customers. Our lessees' transportation providers may face difficulties in the future that may 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. During 2015, Ciner Wyoming shipped substantially all of its soda ash by rail and Ciner Wyoming relies on the rail line to service its facilities under a contract that expires in 2017. 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.

The marketability of our crude oil and natural gas production depends in part on the availability, proximity and capacity of pipeline and rail systems owned by third parties. The lack or unavailability of capacity on these systems and facilities could result in the shut-in of producing wells or the delay, or discontinuance of, development plans for properties in which we own oil and gas interests. In addition, as a result of pipeline constraints in the Williston Basin, a significant amount of crude oil production from the region is transported by rail. Train derailments in the U.S. and Canada have resulted in increased regulatory scrutiny of the transportation of crude oil by rail. Any resulting regulations could result in increased transportation costs, which would negatively affect our profitability from our Williston Basin assets.

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, and oil and natural gas reserve engineering requires subjective estimates of underground accumulations of coal, aggregates and industrial minerals, and oil and natural gas and assumptions and are by nature imprecise. Our reserve estimates may vary substantially from the actual amounts of coal, aggregates and industrial minerals, or oil and natural gas 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, you should not place undue reliance on our reserve data that is included in this report.

We may incur losses and be subject to liability claims as a result of our ownership of working interests in oil and natural gas operations. Additionally, our insurance may be inadequate to protect us against these risks.

As an owner of working interests in oil and natural gas operations, we are responsible for our proportionate share of any losses and liabilities arising from uninsured and underinsured events, which could adversely affect our business, financial condition or results of operations. We are subject to all of the risks associated with drilling for and producing crude oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, and toxic gas or other pollutants into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- spillage or mishandling of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by third party service providers.

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

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;

- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

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.

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 units (including units held by our general partner and its affiliates). Because the owners of our general partner, along with directors and executive officers and their affiliates, own a significant percentage of our outstanding common units, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates.

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 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.

We may issue additional common units without 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 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 without unitholder approval (subject to applicable NYSE rules). 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;
- 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.

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.

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

These conflicts may include the following:

- Excluding our VantaCore business, 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;
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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.

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 revolving credit agreement. During the continuance of an event of default under our revolving credit agreement, 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. A change of control also may trigger payment obligations under various compensation arrangements with our officers.

Tax Risks to Common 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 IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to you would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for 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, 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, which is currently a maximum of 35% and would likely be liable for state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you. Because tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common 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 you.

You are required to pay taxes on your share of our income even if you do not receive any cash distributions from us. Your share of our portfolio income may be taxable to you even though you 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, you are required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax due from you with respect to that income.

For unitholders subject to the passive loss rules, our current operations include portfolio activities (such as our coal and mineral royalties business) and passive activities (such as our soda ash, aggregates and oil and gas working interests businesses). 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 royalties business, (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, your share of our portfolio income may be subject to federal income tax, regardless of other losses you 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 unitholders, and income tax liabilities arising therefrom may exceed any distributions made with respect to your units.

In response to current market conditions, we anticipate engaging 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, you 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. Unitholders may be allocated income and gain from these transactions, and income tax liabilities arising therefrom may exceed any distributions we make to you. 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. 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. Unitholders are encouraged to consult their tax advisors with respect to the consequences to them.

The tax treatment of publicly traded partnerships or an investment in our common 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 common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such 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. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Any modification to 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 a partnership for U.S. federal income tax purposes.

In addition, the Internal Revenue Service, on May 5, 2015, issued proposed regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. The proposed regulations provide an exclusive list of industry-specific rules regarding the qualifying income exception, including whether an activity constitutes the exploration, development, production and marketing of natural resources. Income earned from a royalty interest is not specifically enumerated as a qualifying income activity in the proposed regulations. However, notwithstanding the proposed regulations, our counsel has advised us that royalty income is qualifying income for purposes of Section 7704 of the Internal Revenue Code since it is "derived" from the exploration, development, production and marketing of natural resources. The U.S. Treasury Department and the IRS may clarify that royalty income is qualifying income for purposes of Section 7704 of the Internal Revenue Code; however, there are no assurances that the proposed regulations, when published as final regulations, will not take a

position that
is contrary to our interpretation of Section 7704 of the Internal Revenue Code. Finalized regulations could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to you. Recently enacted legislation alters the procedures for assessing and collecting taxes due for taxable years beginning after December 31, 2017, in a manner that could substantially reduce cash available for distribution to you.

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 common 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.

Recently enacted legislation applicable to us for taxable years beginning after December 31, 2017 alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting taxes due (including applicable penalties and interest) as a result of an audit. Unless we are eligible to (and choose to) elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed under the new rules. If we are required to pay taxes, penalties and interest as the result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

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

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income result in a decrease in your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the common
units you sell will, in effect, become taxable income to you if you sell such common units at a price greater than your tax basis in
those common units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depletion and depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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

Investments in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raise issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Allocations and/or distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest applicable effective tax rate applicable to non-U.S.

persons, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

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 you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

We 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, instead of on the basis of the date a particular unit is transferred. The U.S. Department of the Treasury recently adopted final Treasury Regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such regulations do not specifically authorize the use of the proration method we have adopted for prior taxable years and may not specifically authorize all aspects of our proration method thereafter. 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.

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

Because there are no specific rules governing the U.S. federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered as having disposed of the loaned common units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common 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 common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their common units are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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

We will be considered to have terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in our filing two tax returns for one calendar year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than the calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in taxable income for the unitholder’s taxable year that includes our termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for U.S. federal income tax purposes following the termination. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the two short tax periods included in the year in which the termination occurs.

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, (iii) repealing the percentage depletion allowance with respect to coal properties, and (iv) excluding from the definition of domestic production gross receipts all gross receipts derived from the sale, exchange, or other disposition of coal, other hard mineral fossil fuels, or primary products thereof. 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 common units.

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

In addition to federal income taxes, you 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 you do not live in any of those jurisdictions. You 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, you 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 your responsibility to file all U.S. federal, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

We are 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, we believe these claims will not have a material effect on our financial position, liquidity or operations.

On November 24, 2015, we filed a lawsuit against Foresight Energy’s subsidiary, Hillsboro Energy LLC ("Hillsboro"), in the Circuit Court of the Fourth Judicial Circuit in Montgomery County, Illinois. The lawsuit alleges, among other items, breach of contract by Hillsboro resulting from a wrongful declaration of force majeure at Hillsboro’s Deer Run mine in July 2015. In late March 2015, elevated carbon monoxide readings were detected at the Deer Run mine, and coal production at the mine was idled. In July 2015, we received the notice declaring a force majeure event at the mine as a result of the elevated carbon monoxide levels. The effect of a valid force majeure declaration would relieve Foresight Energy of its obligation to pay us minimum deficiency payments of $7.5 million per quarter, or $30.0 million per year. Foresight Energy's failure to make the deficiency payment with respect to the second, third and fourth quarters of 2015 resulted in a $16.2 million cash impact to us. Such amount will increase for each quarter during which mining operations continue to be idled. We do not currently have an estimate as to when the mine will resume coal production. If the mine remains idled for an extended period or if the mine is permanently closed, our financial condition could be adversely affected.

For more information regarding certain other legal proceedings involving NRP, see "Note 14. Commitments and Contingencies" included in the Notes to Consolidated Financial Statements in "Item 8. Financial Statements and Supplementary Data" included elsewhere in this Annual Report on Form 10-K.

ITEM 4. MINE SAFETY DISCLOSURES

The information concerning mine safety violations or other regulatory matters required by SEC regulations is included in Exhibit 95.1 to this Annual Report on Form 10-K.

PART II

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

NRP Common Units and Cash Distributions

Our common units are listed and traded on the NYSE under the symbol "NRP". As of February 1, 2016, there were approximately 34,100 beneficial and registered holders of our common units. The computation of the approximate number of unitholders is based upon a broker survey.

The following table sets forth the high and low sales prices per common unit, as reported on the NYSE Composite Transaction Tape from January 1, 2014 to December 31, 2015, and the quarterly cash distribution declared and paid with respect to each quarter per common unit. The information presented in the tables below have been adjusted to give retroactive effect to the one-for-ten reverse unit split that was effective on February 17, 2016.

	Price Range		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2014					
First Quarter	$207.20	$148.00	$3.50	5/5/2014	5/14/2014
Second Quarter	$165.70	$127.80	$3.50	8/5/2014	8/14/2014
Third Quarter	$169.10	$125.60	$3.50	11/5/2014	11/14/2014
Fourth Quarter	$138.30	$79.70	$3.50	2/5/2015	2/13/2015
2015					
First Quarter	$98.10	$63.80	$0.90	5/5/2015	5/14/2015
Second Quarter	$74.50	$36.10	$0.90	8/5/2015	8/14/2015
Third Quarter	$38.00	$22.10	$0.45	11/5/2015	11/13/2015
Fourth Quarter	$29.90	$10.00	$0.45	2/5/2016	2/12/2016

Cash Distributions to Partners

	General Partner (1)	Limited Partners (2)	Total Distributions
	(in thousands)		
2014 Distributions	$3,241	$158,801	$162,042
2015 Distributions	$1,434	$70,324	$71,758

(1) Represents distributions on our general partner’s 2% general partner interest in us.
(2) Includes distributions on 156,000 common units held by our general partner.

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." The information presented below gives pro forma effect to the one-for-ten reverse unit split that was effective on February 17, 2016.

	For the Years Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands, except per unit data)				
Total revenues and other income	$488,849	$399,752	$358,117	$379,147	$377,683
Asset impairments	$681,594	$26,209	$734	$2,568	$161,336
Income (loss) from operations	$(477,911)	$188,919	$236,236	$267,165	$104,135
Net income (loss)	$(571,720)	$108,830	$172,078	$213,355	$54,026
Net income excluding impairments (1)	$109,874	$135,039	$172,812	$215,923	$215,362
Basic and diluted net income (loss) per limited partner unit	$(45.75)	$9.42	$15.39	$19.70	$5.00
Distributions paid ($ per unit)	$2.70	$14.00	$22.00	$22.00	$21.70
Weighted average number of common units outstanding	12,230	11,326	10,958	10,603	10,603
Cash from operations	$203,424	$210,755	$247,074	$271,408	$305,574
Distributable Cash Flow(1)	$196,981	$208,366	$306,873	$296,106	$311,122
Adjusted EBITDA (1)	$292,116	$294,632	$332,196	$328,116	$326,670
Balance sheet data:					
Cash and cash equivalents	$51,773	$50,076	$92,513	$149,424	$214,922
Total assets	$1,684,075	$2,444,724	$1,991,856	$1,764,672	$1,665,649
Long-term debt	1,304,013	$1,394,240	$1,084,226	$897,039	$836,268
Partners' capital	$72,942	$720,155	$616,789	$617,447	$644,915

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

Non-GAAP Financial Measures

Distributable Cash Flow

Our Distributable Cash Flow represents net cash provided by operating activities, plus returns of unconsolidated equity investments, proceeds from sales of assets, and returns of long-term contract receivables—affiliate, less maintenance capital expenditures and distributions to non-controlling interest. Although Distributable Cash Flow is a non-GAAP financial measure, we believe it is a useful adjunct to net cash provided by operating activities under GAAP. Distributable Cash Flow 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. Distributable Cash Flow may not be calculated the same for us as for other companies. The following table (in thousands) reconciles net cash provided by operating activities (the most comparable GAAP financial measure) to Distributable Cash Flow for the years ended

December 31, 2015, 2014, 2013, 2012 and 2011:

	Year Ended December 31,				
	2015	2014	2013	2012	2011
Net cash provided by operating activities	$203,424	$210,755	$247,074	$271,408	$305,574
Add: proceeds from sale of plant and equipment and other	11,024	1,006	—	11,277	3,870
Add: proceeds from sale of mineral rights	7,096	412	10,929	13,545	1,730
Add: return of long-term contract receivables—affiliate	2,463	1,904	2,558	2,669	—
Add: return of unconsolidated equity investment	—	3,633	48,833	—	—
Less: maintenance capital expenditures (1)	(24,282)	(8,370)	—	—	—
Less: distributions to non-controlling interest	(2,744)	(974)	(2,521)	(2,793)	(52)
Distributable Cash Flow	$196,981	$208,366	$306,873	$296,106	$311,122

(1) Maintenance capital expenditures primarily consist of costs to maintain the long-term productive capacity of our oil and gas non-operating working interest business and VantaCore.

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income (loss) less equity earnings from unconsolidated investment, gain on reserve swaps and income to non-controlling interest; plus distributions from equity earnings in unconsolidated investment, interest expense, depreciation, depletion and amortization and asset impairments. Adjusted EBITDA, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. Adjusted EBITDA should not be considered in isolation or as a substitute for operating income (loss), net income (loss), cash flows provided by operating, investing and financial activities, or other income or cash flow statement data prepared in accordance with GAAP. Adjusted EBITDA provides no information regarding a partnership's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax positions. Adjusted EBITDA does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital and other commitments and obligations. Our management team believes Adjusted EBITDA is a useful measure because it is widely used by financial analysts, investors and rating agencies for comparative purposes. Adjusted EBITDA is also a financial measure widely used by investors in the high-yield bond market. 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. The following table (in thousands) reconciles net income (loss) (the most comparable GAAP financial measure) to Adjusted EBITDA for the years ended December 31, 2015, 2014, 2013, 2012 and 2011:

	Year Ended December 31,				
	2015	2014	2013	2012	2011
Net income (loss)	$(571,720)	$108,830	$172,078	$213,355	$54,026
	(49,918)	(41,416)	(34,186)	—	—

Less: equity earnings from unconsolidated investment					
Less: gain on reserve swaps	(9,290)	(5,690)	(8,149)	—	(2,990)
Add: asset impairments	681,594	26,209	734	2,568	161,336
Add: depreciation, depletion and amortization	100,828	79,876	64,377	58,221	65,118
Add: interest expense	93,827	80,185	64,396	53,972	49,180
Add: distributions from equity earnings in unconsolidated investment	46,795	46,638	72,946	—	—
Adjusted EBITDA	$292,116	$294,632	$332,196	$328,116	$326,670

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Adjusted EBITDA presented in the table above differs from the EBITDDA definitions contained in Opco's debt agreements. See Note 9. "Debt and Debt—Affiliate" included in the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data" included elsewhere in this Annual Report on Form 10-K for a description of Opco's debt agreements.

Net Income Excluding Impairments

Net income excluding impairments is a non-GAAP financial measure that we define as net income (loss) plus asset impairments. Net income excluding impairments, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. Net income excluding impairments should not be considered in isolation or as a substitute for operating income (loss), net income (loss), cash flows provided by operating, investing and financial activities, or other income or cash flow statement data prepared in accordance with GAAP. Our management team believes net income excluding impairments is useful in evaluating our financial performance because asset impairments are irregular non-cash charges and excluding these from net income allows us to better compare results period-over-period.The following table (in thousands) reconciles net income (loss) (the most comparable GAAP financial measure) to net income excluding impairment for the years ended December 31, 2015, 2014, 2013, 2012 and 2011:

	Year Ended December 31,				
	2015	2014	2013	2012	2011
Net income (loss)	$(571,720)	$108,830	$172,078	$213,355	$54,026
Add: asset impairments	681,594	26,209	734	2,568	161,336
Net income excluding impairments	$109,874	$135,039	$172,812	$215,923	$215,362

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINACNIAL 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
•Unrestricted Subsidiary Information
•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. References to NRP Oil and Gas refer to NRP Oil and Gas LLC, a wholly owned subsidiary of NRP. NRP Finance Corporation ("NRP Finance") is a wholly owned subsidiary of NRP and a co-issuer with NRP on the 9.125% senior notes.

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, crude oil and natural gas, construction aggregates, frac sand and other natural resources. Our common units trade on the New York Stock Exchange under the symbol "NRP". The information presented in Item 7. reflects the one-for-ten reverse unit split that was effective on February 17, 2016.

For the year ended December 31, 2015, we recorded revenues and other income of $488.8 million, and a net loss of $571.7 million. During 2015, Adjusted EBITDA and Distributable Cash Flow, which we consider to be the critical measures in evaluating our operating performance, met or exceeded the guidance issued to the public markets in February 2015, as revised in August 2015. Despite the rapidly deteriorating coal and oil and gas markets in 2015, we recorded Adjusted EBITDA in 2015 of $292.1 million, which was essentially flat compared to our Adjusted EBITDA in 2014, and Distributable Cash Flow of $197.0 million, which exceeded expectations and was down only 5% compared to 2014. Adjusted EBITDA and Distributable Cash Flow are non-GAAP financial measures. For a reconciliation of Adjusted EBITDA to net income, see "Item 6. Selected Financial Data—Non-GAAP Financial Measures—Adjusted EBITDA." For a reconciliation of Distributable Cash Flow to net cash provided by operating activities see "Item 6. Selected Financial Data—Non-GAAP Financial Measures—Distributable Cash Flow." Management believes that the presentation of Adjusted EBITDA and Distributable Cash Flow provide information useful in assessing our segment financial condition and results of operations. Adjusted EBITDA and Distributable Cash Flow as defined by us may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income (loss) and cash provided by (used in) operating activities, respectively.

Our business is organized into four operating segments:

Coal, Hard Mineral Royalty and Other—consists primarily of coal royalty, coal related transportation and processing assets, aggregate and industrial minerals royalty assets and timber. Our coal reserves are primarily located in Appalachia, the Illinois Basin and the Western United States. Our aggregates and industrial minerals are located in a number of states across the United States.

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. We receive regular quarterly distributions from this business.

VantaCore—consists of our construction materials business acquired in October 2014 that operates hard rock quarries, an underground limestone mine, sand and gravel plants, asphalt plants and marine terminals. VantaCore operates in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

Oil and Gas—consists of our non-operated working interests, royalty interests and overriding royalty interests in oil and natural gas properties. Our primary interests in oil and natural gas producing properties are non-operated working interests located in the Williston Basin in North Dakota and Montana. We also own fee mineral, royalty or overriding royalty interests in oil and gas properties in several other regions, including the Appalachian Basin, Oklahoma and Louisiana.

Current Liquidity Position

As of December 31, 2015, we had $64.8 million of liquidity that consisted of $51.8 million in cash and $13.0 million in combined borrowing capacity under our revolving credit facilities. During the year ended December 31, 2015, we reduced our debt by a net amount of $91.0 million. Opco's $300.0 million revolving credit facility matures in October 2017, and as of December 31, 2015, we had $290.0 million outstanding thereunder. We borrowed $75.0 million under Opco's revolving credit facility in September 2015 in order to repay Opco's term loan in full. In October 2015, the borrowing base under the NRP Oil and Gas revolving credit facility was redetermined to $88.0 million, and we repaid $15.0 million under that credit facility, reducing our outstanding borrowings thereunder to $85.0 million. As of the date of this report, the combined borrowing capacity under our two revolving credit facilities is $13.0 million.

In February 2016, we sold the aggregates reserves and related royalty rights at three aggregates operations located in Texas, Georgia and Tennessee, which comprised approximately 27%, or 139 million tons, of our hard mineral reserves as of December 31, 2015 for $10.0 million in cash. The effective date of the sale was February 1, 2016. In February 2016, we sold royalty and overriding royalty interests in several producing properties located in the Appalachian Basin, including our overriding royalty interests in the Marcellus Shale, for $37.5 million in cash. The sale included royalty and overriding royalty interests in approximately 765 gross producing wells as of December 31, 2015 and approximately 10% of our estimated proved reserves, or 1,094 MBoe, as of December 31, 2015, or 1,094 MBoe. The effective date of the sale was January 1, 2016. We intend to use the net proceeds from these asset sales to repay debt.

We have significant debt service requirements, including $80.8 million in principal payments on Opco's senior notes each year through 2018, and our operating results continue to be impacted by the adverse conditions in the commodity markets. In April 2015, we announced a long-term plan to strengthen our balance sheet, reduce debt and enhance liquidity in order to reposition the partnership for future growth. As part of that plan, we reduced our cash distributions with respect to the first and second quarters of 2015 to $0.90 per common unit (giving effect to the one-for-ten reverse unit split effective on February 17, 2016), a 75% decrease from the distribution paid with respect to fourth quarter of 2014. In October 2015, the Board further reduced the distribution to $0.45 per common unit (giving effect to the one-for-ten reverse unit split effective on February 17, 2016) with respect to the third quarter of 2015, representing an additional 50% reduction in the distribution paid with respect to the second quarter of 2015. The cash savings resulting from the distribution reductions are being used primarily to repay debt. We have also taken steps to reduce general and administrative and other overhead costs in connection with these efforts. However, we have determined that the cash savings from the distribution cuts and our cost reduction efforts will not be sufficient to meet our deleveraging objectives and have determined to sell certain assets to help meet these objectives. While we have closed two asset sale transactions, if we are unable to complete additional asset sales and conditions in the commodity markets continue to deteriorate, our liquidity and our ability to comply with the financial and other restrictive covenants contained in our debt agreements will be adversely affected.

Current Results/Market Outlook

Coal, Hard Minerals Royalty and Other Business Segment

For the year ended December 31, 2015, our Coal, Hard Minerals Royalty and Other business segment contributed revenues and other income of $246.4 million, Adjusted EBITDA of $204.6 million, and Distributable Cash Flow of $212.2 million. Our revenues and other income from the Coal, Hard Mineral Royalty and Other segment represented 51% of our total revenues and other income in 2015, as compared to 64% of total revenues and other income in 2014, in part due to revenues reported for a full year of ownership of VantaCore. Although our total revenues and other income for 2015 increased over 2014, our Coal, Hard Mineral Royalty and Other revenues were down 4% compared to the same period. The majority of this decrease was due to lower coal prices in each of the Appalachian regions during the period and in the Illinois Basin as a result primarily of lower coal production during the period. This decrease in coal royalty revenues was partially offset by an increase in other coal related revenues, which increased 82% over the 2014 period, due to increased minimums recognized as revenue, increases in gains recognized on coal reserve swaps, condemnation payments and the receipt of lease assignment fees.

Both the thermal and metallurgical coal markets remain severely challenged, and we do not anticipate that either market will recover in the near term. We expect that coal producers will continue to cut production and idle additional mines in response to market conditions, but we do not know to what extent our properties may be affected. A number of coal producers have filed petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code, and additional producers may file for bankruptcy. Historically, our leases have generally been assumed and all pre-petition bankruptcy amounts have been cured in full in our lessees’ bankruptcy processes, but we have no assurance this will continue in the future. In October 2015, Patriot Coal Corporation completed the sale of its assets in accordance with its bankruptcy plan. All of our leases were assumed and assigned in the sale process, and we received full pre-petition cure payments. Alpha Natural Resources ("Alpha"), which is our second largest lessee, filed for Chapter 11 bankruptcy protection in August 2015. Alpha has continued operating and paying royalties to us following the bankruptcy filing. However, Alpha has reduced production and idled certain mines, and we expect that Alpha will continue to reduce production and/or idle mines during its bankruptcy process. Production cuts and mine idlings by Alpha have resulted in and would continue to result in decreased royalty payments to us to the extent such production cuts or idlings are on our properties. We estimate that Alpha owes us approximately $3.2 million in pre-petition royalties and minimum payments, and we expect to receive pre-petition amounts due to us with respect to any leases that are assumed in the bankruptcy process. Arch Coal, Inc. filed for Chapter 11 bankruptcy protection in January 2016. While we do not yet know whether our leases will be assumed or rejected in Arch’s bankruptcy process, our overall exposure to Arch is immaterial.

While producers of Central Appalachian thermal coal have struggled for an extended period due to the high cost nature of their operations, production from our Illinois Basin properties also decreased by 15% in 2015 as compared to 2014. Part of the decrease in production from our Illinois Basin properties is attributable to the idling of Foresight Energy's ("Foresight Energy") Deer Run mine (which we also refer to as our Hillsboro property) as a result of elevated carbon monoxide levels at the mine beginning in March 2015. In July 2015, we received a notice from Foresight Energy declaring a resulting force majeure event at the Deer Run mine. While we have filed a lawsuit disputing Foresight Energy’s claim of force majeure, the effect of a valid force majeure declaration would relieve Foresight Energy of its obligation to pay us quarterly minimum deficiency payments with respect to the Deer Run mine until mining resumes. Under the lease for the Deer Run mine, Foresight Energy is required to make minimum deficiency payments to us of $7.5 million per quarter, or $30.0 million per year. The amount payable to us as the minimum deficiency payment with respect to any quarter is reduced by the amount of coal royalties actually paid to us for tonnage sold at the mine with respect to that quarter. We received royalty payments on tonnage sold from coal stockpiles at the Deer Run mine during the second and third quarters of 2015, but royalty payments from tonnage sold with respect to the fourth quarter of 2015 significantly declined and we expect that the stockpiles will be depleted early in the first quarter of 2016. Foresight Energy’s failure to make the deficiency payments with respect to the second, third and fourth quarters of 2015 resulted in a negative cash impact to us of $16.2 million. Such amount will increase for each quarter during which mining operations continue to be idled. We do not know when, or if, mining activities at the Deer Run mine will recommence.

The metallurgical coal markets continued to deteriorate during 2015, and the metallurgical coal benchmark price for the first quarter of 2016 was set at a new multi-year low. We derived approximately 38% of our coal royalty revenues and 30% of the related production from metallurgical coal during 2015. The global metallurgical coal market continues to suffer from oversupply driven in part by reduced demand from China. Domestic coal producers are also burdened by the effects of the relatively strong U.S. dollar, which increases the production cost of domestic coal producers relative to foreign producers.

Soda Ash Business Segment

For the year ended December 31, 2015, our Soda Ash business segment contributed revenues and other income of $49.9 million, Adjusted EBITDA of $46.8 million, and Distributable Cash Flow of $43.0 million. Our trona mining and soda ash refinery investment performed in line with our expectations in 2015 with record soda ash production volumes. During 2015, the international market for soda ash weakened somewhat due to softer pricing, but Ciner Wyoming's international sales were consistent with expectations. Domestic sales volumes, which are typically sold at higher prices than soda ash sold internationally, have remained relatively stable. The cash we receive from Ciner Wyoming is in part determined by the quarterly distributions declared by Ciner Resources LP. In February 2016, Ciner Resources LP paid a quarterly distribution of $0.5575 per common unit with respect to the fourth quarter of 2015, an increase of 1% over the distribution paid with respect to the third quarter of 2015 and an increase of 5% over the distribution paid with respect to the fourth quarter of 2014.

VantaCore Business Segment

For the year ended December 31, 2015, our VantaCore business segment contributed revenues and other income of $139.0 million, Adjusted EBITDA of $22.1 million, and Distributable Cash Flow of $18.8 million.

VantaCore's construction aggregates mining and production business is largely dependent on the strength of the local markets that it serves and is also seasonal, with lower production and sales expected during the first quarter of each year due to winter weather. VantaCore's Laurel Aggregates operation in southwestern Pennsylvania serves producers and oilfield service companies operating in the Marcellus and Utica Shales and was impacted during 2015 by the slowing pace of exploration and development of natural gas in those areas due to low natural gas prices. Increased local construction activity partially offset these declines during 2015, but we expect that Laurel's business will continue to be impacted by decreased natural gas development activities. VantaCore's operations based in Clarksville, Tennessee and Baton Rouge, Louisiana depend on the pace of commercial and residential construction in those areas. The Clarksville operation performed above expectations during 2015, while the Baton Rouge operation volumes were lower than expected. In June 2015, VantaCore purchased a hard rock quarry operation located on the Tennessee River near Grand Rivers, Kentucky from one of NRP's aggregates lessees that had previously idled the operation. This operation continues to lease reserves from NRP and sells its produced limestone aggregates in both the local market and downstream to river-based markets.

Oil and Gas Business Segment

For the year ended December 31, 2015, our Oil and Gas business segment contributed revenues and other income of $53.6 million, Adjusted EBITDA of $31.0 million, and Distributable Cash Flow of $24.6 million. Revenues in our Oil and Gas business segment decreased year-over year primarily due to a decline in oil prices, partially offset by increased production volumes.

Global oil prices continued to decline in 2015 and remained significantly lower than 2014, and prices have continued to decline in the first quarter of 2016. Although domestic crude oil production has shown signs of decline, inventories remain above the five-year average indicating continued excessive supply. Production of crude is estimated to continue to decline as a result of reduced development drilling activities. Natural gas prices have also shown recent declines due to reduced demand and increased inventories. Our oil and gas revenues will continue to fluctuate with changes in prices for oil and natural gas and are expected to decrease over time due to natural production declines in producing wells and significantly decreased drilling activity. As of the date of this filing, we have not hedged any of our future oil or natural gas production.

Management’s Forecast and Strategic Plan

Opco’s revolving credit facility matures in October 2017 and NRP’s 9.125% Senior Notes mature in October 2018. We believe we need to significantly improve our leverage ratios prior to the maturity thereof in order to be able to refinance or restructure such debt. We remain committed to our strategic plan announced in April 2015 to improve our balance sheet and reduce leverage, and intend to take all necessary steps to execute on that plan, including through asset sales and other means. Through February 2016, we completed asset sales for $47.5 million in gross proceeds. However, we believe the deterioration in the commodity markets will continue to have a negative impact on our results of operations, which in turn may prevent us from achieving our leverage ratio goals. Traditionally, we have accessed the debt and equity capital markets on a regular basis and have relied on bank credit facilities to finance our business activities. However, due to the current commodity price environment and the state of the coal markets in particular, we believe we do not currently have the ability to access either the debt or equity capital markets. In addition, the volatility in the energy industry combined with recent bankruptcies and additional perceived credit risks of companies with coal and/or oil and gas exposure has resulted in traditional bank lenders seeking to reduce or eliminate their lending exposure to these companies. Accordingly, we will be required over the near term to run our business and service our debt through cash from operations or asset sales. In addition, we may be required to seek financing from non-traditional sources at unfavorable pricing or with unfavorable terms to run our business or to refinance or restructure our 2017 and 2018 debt maturities.

While NRP has a diversified portfolio of assets and a history and continued forecast of profitable operations with positive operating cash flows, its operating results and credit metrics continue to be impacted by demand challenges for coal and excess worldwide supply of oil and gas. In particular, as described in "Note 10. Debt and Debt—Affiliate" in the Consolidated Financial Statements included elsewhere in this Annual Report on Form 10-K, the agreements governing the outstanding debt of NRP Oil and Gas and Opco contain customary financial covenants, including maintenance covenants, and other restrictive covenants. In addition, NRP has issued $425 million of 9.125% Senior Notes, that are governed by an indenture ("the Indenture") containing customary incurrence-based financial covenants and other covenants, but not maintenance covenants. The following discussion presents management’s outlook and strategic plan to address its debt covenant compliance.

Opco and NRP

As of December 31, 2015, Opco had $290.0 million of indebtedness outstanding under its revolving credit facility due October 2017 (the "Opco Credit Facility") and $585.9 million outstanding under several series of Private Placement Notes (the "Opco Private Placement Notes") (collectively referred to as the "Opco Debt agreements"). The maximum leverage ratio under the Opco Debt agreements is required to be below 4.0x through March 31, 2016. Commencing with respect to the period ended June 30, 2016, the maximum leverage ratio reduces to 3.75x and reduces again to 3.5x commencing with respect to the period ended June 30, 2017. In addition, the Opco Debt agreements contain certain additional customary negative covenants that, among other items, restrict Opco’s ability to incur additional debt, grant liens on its assets, make investments, sell assets and engage in business combinations.

As of December 31, 2015, Opco was in compliance with and we forecast that Opco will continue to remain in compliance through December 31, 2016 with the covenants contained in its debt agreements. In addition, we believe Opco has sufficient liquidity to make all regularly scheduled principal and interest payments through December 31, 2016. We are currently pursuing or considering a number of actions including (i) dispositions of assets, (ii) actively managing our debt capital structure through a number of potential alternatives, including exchange offers and non-traditional debt financing, (iii) minimizing our capital expenditures, (iv) obtaining waivers or amendments from our lenders, (v) effectively managing our working capital and (vi) improving our cash flows from operations. While we forecast that we will be in compliance with all of the covenants under the Opco Debt agreements through December 31, 2016, our forecast is sensitive to commodity pricing and counterparty risk. Accordingly, we intend to pursue one or more of the alternatives discussed above in order to mitigate the effects of further commodity price and market deterioration which could otherwise cause us to breach financial covenants under the Opco Debt agreements. Breaches of the Opco Debt agreement covenants that are not waived or cured, to the extent possible, would result in an event of default under the Opco Debt agreements, and if such debt is accelerated by the lenders thereunder, such acceleration would also result in a cross-default under the Indenture.

NRP Oil and Gas

NRP Oil and Gas had $85.0 million outstanding under its senior secured, reserve-based revolving credit facility (the "RBL Facility") as of December 31, 2015. The facility is secured by a first priority lien on substantially all of NRP Oil and Gas’s assets and is not guaranteed by NRP or any other subsidiary of NRP. Due to the significant and sustained decline in oil prices since the end of 2014, we forecast that NRP Oil and Gas may not be able to remain in compliance with the 3.5x leverage ratio as required in the RBL Facility during the next 12 months. In addition, we expect that, due to current oil and gas prices, the next borrowing base redetermination under the RBL Facility that is scheduled to occur in May 2016 may result in a reduction of the borrowing base by an amount that would exceed NRP Oil and Gas’s ability to repay principal within the required time-frame following such redetermination. In addition, the RBL Facility requires the entity to provide annual financial statements that include a report from its independent registered public accounting firm with an opinion that does not contain "a "going concern" or like qualification or exception." Any of these events would qualify as an event of default and would provide the RBL Facility lenders with the ability to accelerate the debt outstanding under the RBL Facility to the extent not waived or cured. While we are attempting to take appropriate mitigating actions, there is no assurance that any particular actions with respect to amending, refinancing, extending the maturity or curing potential defaults in the RBL Facility will be sufficient, and we may be required to sell some or all of the assets of NRP Oil and Gas, raise new equity capital at NRP Oil and Gas or pursue restructuring alternatives. As a result, we believe there is substantial doubt about the ability of NRP Oil and Gas to continue as a going concern through December 31, 2016. As we were in compliance with all covenants contained in the RBL Facility throughout 2015 and at December 31, 2015, we have classified this debt as non-current in accordance with its terms.

An event of default under the RBL facility and subsequent acceleration of that debt by the lenders thereunder would not result in a cross-default under the Indenture. NRP Oil and Gas is designated as an "Unrestricted Subsidiary" for purposes of the Indenture, which prevents an event of default under the RBL Facility and subsequent acceleration of that debt from triggering an event of default under the Indenture. In addition, there are no cross-defaults under the Opco Debt agreements as a result of defaults under the RBL Facility. As a result, there would be no default or acceleration of indebtedness under the Indenture or under the Opco Debt agreements in the event NRP Oil and Gas is in default under its RBL Facility.

Results of Operations

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Adjusted EBITDA (Non-GAAP Financial Measure)

Adjusted EBITDA decreased $2.5 million, or 1%, from $294.6 million in 2014 to $292.1 million in 2015. The decrease is mainly related to declines in our Coal, Hard Mineral Royalty and Other and Oil and Gas business segments year-over-year, partially offset by higher income from our VantaCore business that was acquired in October 2014. Adjusted EBITDA is a non-GAAP financial measure. See "Item 6. Selected Financial Data—Non-GAAP Financial Measures—Adjusted EBITDA" for an explanation of Adjusted EBITDA and see below for our Adjusted EBITDA by business segment and a reconciliation to net income (loss) (in thousands):

	Operating Segments					
For the Year Ended	Coal, Hard Mineral Royalty and Other	Soda Ash	VantaCore	Oil and Gas	Corporate and Financing	Total
December 31, 2015						
Net income (loss)	$(138,388)	$49,918	$272	$(377,365)	$(106,157)	$(571,720)
Less: equity earnings from unconsolidated investment	—	(49,918)	—	—	—	(49,918)
Less: gain on reserve swap	(9,290)	—	—	—	—	(9,290)
Add: distributions from unconsolidated investment	—	46,795	—	—	—	46,795
Add: depreciation, depletion and amortization	44,478	—	15,578	40,772	—	100,828
Add: asset impairment	307,800	—	6,218	367,576	—	681,594
Add: interest expense	—	—	—	—	93,827	93,827
Adjusted EBITDA	$204,600	$46,795	$22,068	$30,983	$(12,330)	$292,116
December 31, 2014						
Net income (loss)	$143,678	$41,416	$32	$14,338	$(90,634)	$108,830
Less: equity earnings from unconsolidated investment	—	(41,416)	—	—	—	(41,416)
Less: gain on reserve swap	(5,690)	—	—	—	—	(5,690)
Add: distributions from unconsolidated investment	—	46,638	—	—	—	46,638
Add: depreciation, depletion and amortization	52,645	—	3,296	23,935	—	79,876
Add: asset impairment	26,209	—	—	—	—	26,209
Add: interest expense	—	—	—	—	80,185	80,185
Adjusted EBITDA	$216,842	$46,638	$3,328	$38,273	$(10,449)	$294,632

Distributable Cash Flow (Non-GAAP Financial Measure)

Distributable Cash Flow for 2015 decreased $11.4 million, or 5%, from $208.4 million in 2014 to $197.0 million in 2015. This decrease is due primarily to a reduction in cash provided by our coal operations, partially offset by our VantaCore business that was acquired in October 2014. Distributable Cash Flow is a non-GAAP financial measure. See "Item 6. Selected Financial Data—Non-GAAP Financial Measures—Distributable Cash Flow" for an explanation of Distributable Cash Flow and see below for Distributable Cash Flow by business segment a reconciliation to net cash provided by (used in) operating activities (in thousands):

	Operating Segments					
For the Year Ended	Coal, Hard Mineral Royalty and Other	Soda Ash	VantaCore	Oil and Gas	Corporate and Financing	Total
December 31, 2015						
Net cash provided by (used in) operating activities	$197,913	$43,029	$23,605	$40,536	$(101,659)	$203,424
Add: return on long-term contract receivables—affiliate	2,463	—	—	—	—	2,463
Add: proceeds from sale of PP&E	10,100	—	924	—	—	11,024
Add: proceeds from sale of mineral rights	3,505	—	—	3,591	—	7,096
Less: maintenance capital expenditures	(416)	—	(5,727)	(18,139)	—	(24,282)
Less: distributions to non-controlling interest	(1,372)	—	—	(1,372)	—	(2,744)
Distributable Cash Flow	$212,193	$43,029	$18,802	$24,616	$(101,659)	$196,981
December 31, 2014						
Net cash provided by (used in) operating activities	$232,484	$42,516	$2,746	$24,671	$(91,662)	$210,755
Add: return on long-term contract receivables—affiliate	1,904	—	—	—	—	1,904
Add: return of unconsolidated equity investment	—	3,633	—	—	—	3,633
Add: proceeds from sale of PP&E	968	—	38	—	—	1,006
Add: proceeds from sale of mineral rights	412	—	—	—	—	412
Less: maintenance capital expenditures	(316)	—	(900)	(7,154)	—	(8,370)
Less: distributions to non-controlling interest	(487)	—	—	(487)	—	(974)
Distributable Cash Flow	$234,965	$46,149	$1,884	$17,030	$(91,662)	$208,366

Revenues and Other Income

The following table shows our diversified sources of revenues and other income by business segment for the years ended December 31, 2015 and 2014 (in thousands except for percentages):

	Coal, Hard Mineral Royalty and Other	Soda Ash	VantaCore	Oil and Gas	Total
2015					
Revenues	246,353	49,918	139,013	53,565	488,849
Percentage of total	51 %	10 %	28 %	11 %	
2014					
Revenues	256,719	41,416	42,051	59,566	399,752
Percentage of total	64 %	10 %	11 %	15 %	

Revenues and other income increased $89.0 million, or 22%, from $399.8 million in 2014 to $488.8 million in 2015. This increase is primarily due to the inclusion of a full year of VantaCore revenues and an increase in Soda Ash revenues during the year. These increases were partially offset by a reduction of revenues in both our Oil and Gas and Coal, Hard Mineral Royalty and Other business segments.

Coal, Hard Mineral Royalty and Other

Revenues and other income related to our Coal, Hard Mineral Royalty and Other segment decreased $10.4 million, or 4%, from $256.7 million in 2014 to $246.4 million in 2015. The table below presents coal royalty production and revenues derived from our major coal producing regions, hard mineral royalty income and the significant categories of other revenues:

	For the Years Ended December 31, 2015	2014	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data) (Unaudited)			
Coal royalty production (tons)				
Appalachia				
Northern	9,562	9,339	223	2 %
Central	16,862	20,092	(3,230)	(16)%
Southern	3,803	3,914	(111)	(3)%
Total Appalachia	30,227	33,345	(3,118)	(9)%
Illinois Basin	11,173	13,177	(2,004)	(15)%
Northern Powder River Basin	4,905	2,844	2,061	72 %
Gulf Coast	740	1,093	(353)	(32)%
Total coal royalty production	47,045	50,459	(3,414)	(7)%
Average coal royalty revenue per ton				
Appalachia				
Northern	$0.28	$0.92	$(0.64)	(70)%
Central	3.85	4.46	(0.61)	(14)%
Southern	4.57	5.18	(0.61)	(12)%
Total Appalachia	2.81	3.55	(0.74)	(21)%
Illinois Basin	3.94	4.10	(0.16)	(4)%
Northern Powder River Basin	2.54	2.74	(0.20)	(7)%
Gulf Coast	3.47	3.47	—	— %
Combined average coal royalty revenue per ton	$3.06	$3.65	$(0.59)	(16)%
Coal royalty revenues				
Appalachia				
Northern	$2,672	$8,621	$(5,949)	(69)%
Central	64,877	89,627	(24,750)	(28)%
Southern	17,390	20,292	(2,902)	(14)%
Total Appalachia	84,939	118,540	(33,601)	(28)%
Illinois Basin	44,063	54,049	(9,986)	(18)%
Northern Powder River Basin	12,443	7,804	4,639	59 %
Gulf Coast	2,570	3,793	(1,223)	(32)%
Total coal royalty revenue	$144,015	$184,186	$(40,171)	(22)%
Other coal related revenues				
Override revenue	$2,920	$4,601	$(1,681)	(37)%
Transportation and processing fees	22,033	22,048	(15)	— %
Minimums recognized as revenue	15,489	6,659	8,830	133 %
Lease assignment fees	21,000	—	21,000	100 %

Condemnation related revenues	3,669	—	3,669	100%
Coal bonus related revenues	—	98	(98)	(100)%
Reserve swap	9,290	5,690	3,600	63%
Wheelage	3,166	3,442	(276)	(8)%
Total other coal related revenues	$77,567	$42,538	$35,029	82%
Total coal related revenues and coal related revenues—affiliates	$221,582	$226,724	$(5,142)	(2)%
Hard mineral royalty revenues	$8,090	$12,073	$(3,983)	(33)%
Property tax revenue	$11,258	$13,609	$(2,351)	(17)%
Other	$5,423	$4,313	$1,110	26%
Total coal, hard mineral royalty and other revenue	$246,353	$256,719	$(10,366)	(4)%

Total coal production decreased 3.4 million tons, or 7%, from 50.4 million tons in 2014 to 47.0 million tons in 2015. Total coal royalty revenues decreased $40.2 million, or 22%, from $184.2 million in 2014 to $144.0 million in 2015. Coal prices continue to be depressed, which has negatively affected our coal related revenues. Further declines or a continued low price environment could have an additional adverse effect on our coal related revenues. During the year ended December 31, 2015 as compared to 2014, total coal production and total coal royalty revenues were down in Appalachia, the Illinois Basin and the Gulf Coast, while we saw a significant increase in the Northern Powder River Basin. All Appalachian regions saw a decrease in coal royalty revenues during the year with coal royalty revenues in Northern Appalachia down 69% despite a 2% increase in production from that area. We saw a decrease in the average coal revenue per ton throughout all of our regions, with the exception of the Gulf Coast whose average coal revenue per ton remained flat, for the year ended December 31, 2015 when compared to the year ended December 31, 2014.

Other coal related revenues increased $35.0 million, or 82%, from $42.5 million in 2014 to $77.6 million in 2015. This increase is primarily a result of two lease assignment fee payments received in 2015 totaling $21.0 million, an $8.8 million increase in minimums recognized as revenue, $3.7 million public roadway condemnation payments and a $3.6 million increase in reserve swap gains year-over-year. These increases were partially offset by decreased overriding royalty revenue in 2015.

Hard mineral royalty revenues decreased $4.0 million, or 33%, from $12.1 million in 2014 to $8.1 million in 2015. This decrease is due primarily to a decrease in minimums recognized as revenues and aggregate royalty revenues.

Soda Ash

Revenues and other income related to our Soda Ash segment increased $8.5 million, or 21%, from $41.4 million in 2014 to $49.9 million in 2015. This increase is primarily related to our allocated percentage of Ciner Wyoming's $15.0 million increase in income year-over-year. For the year ended December 31, 2015, we received $46.8 million in cash distributions from Ciner Wyoming and for the year ended December 31, 2014, we received $46.6 million in cash distributions.

VantaCore

Tonnage sold by the VantaCore segment increased 5.1 million tons from 2.3 million tons in 2014 to 7.4 million tons in 2015. Revenues and other income related to our VantaCore segment increased $96.9 million, or 231%, from $42.1 million in 2014 to $139.0 million in 2015. This increase is due to the fact that VantaCore was acquired in the fourth quarter of 2014.

Oil and Gas

Revenues and other income related to our Oil and Gas segment decreased $6.0 million, or 10%, from $59.6 million in 2014 to $53.6 million in 2015. This decrease is due to lower commodity prices during the year, partially offset by increased production, primarily as a result of the acquisition of non-operated working interests in the Williston Basin in November 2014. The table below presents oil and gas production and revenues derived from our major oil and gas producing regions and the significant categories of oil and gas revenues:

	For the Years Ended December 31, 2015	2014	Increase (Decrease)	Percentage Change
	(Dollars in thousands, except per unit data) (Unaudited)			
Williston Basin non-operated working interests:				
Production volumes:				
Oil (MBbl)	1,108	578	530	92 %
Natural gas (Mcf)	810	408	402	99 %
NGL (MBbl)	138	53	85	160 %
Total production (MBoe)	1,381	699	682	98 %
Average sales price per unit:				
Oil (Bbl)	$41.19	77.85	(36.66)	(47)%
Natural gas (Mcf)	2.28	5.04	(2.76)	(55)%
NGL (Bbl)	9.20	33.64	(24.44)	(73)%
Revenues:				
Oil	$45,635	44,995	640	1 %
Natural gas	1,847	2,056	(209)	(10)%
NGL	1,269	1,783	(514)	(29)%
Non- production	450	—	450	100 %
Total revenues	$49,201	$48,834	$367	1 %
Royalty and overriding royalty revenues	$4,364	10,732	(6,368)	(59)%
Total oil and gas revenues	$53,565	$59,566	$(6,001)	(10)%

Operating and Maintenance Expenses (including affiliates)

Operating and maintenance expenses (including affiliates) increased $77.8 million, or 83%, from $94.2 million in 2014 to $172.0 million in 2015. This increase is primarily related to the inclusion of a full year of VantaCore operating expenses in 2015.

Coal, Hard Mineral Royalty and Other

Operating and maintenance expenses in our Coal, Hard Mineral Royalty and Other segment decreased $1.7 million, or 5%, from $34.2 million in 2014 to $32.5 million in 2015. This decrease is primarily related to decreased overhead expenses allocated to the segment, specifically a decrease in LTIP expense as a result of the decline in unit price year-over-year.

VantaCore

Operating and maintenance expenses in our VantaCore segment increased $78.2 million from $38.7 million in 2014 to $116.9 million in 2015. This increase is due to the fact that 2014 results only include three months of VantaCore activity as compared to twelve months in 2015.

Oil and Gas

Operating and maintenance expenses in our Oil and Gas segment increased $1.3 million, or 6%, from $21.3 million in 2014 to $22.6 million in 2015. This increase is primarily due to a full year of operating expenses related to the fourth quarter 2014 Sanish Field acquisition, partially offset by decreased overhead as a result of the 2014 consulting expenses related to the acquisition. The average production cost per unit decreased $3.88 per unit, or 30%, from $13.08 per unit in 2014 to $9.20 per unit in 2015.

Depreciation, Depletion and Amortization ("DD&A") Expense

DD&A expense increased $20.9 million, or 26%, from $79.9 million in 2014 to $100.8 million in 2015. This increase is primarily related to a full year of DD&A expense on our VantaCore and Sanish Field assets acquired during the fourth quarter of 2014, partially offset by decreased DD&A expense as a result of the reduction in our assets basis due to the 2015 asset impairments described below.

Coal, Hard Mineral Royalty and Other

DD&A expense for our Coal, Hard Mineral Royalty and Other segment decreased $8.1 million, or 15%, from $52.6 million in 2014 to $44.5 million in 2015. This decrease was primarily the result of the reduction in depletion expense on the assets that were impaired during the third and fourth quarters of 2015.

VantaCore

DD&A expense for our VantaCore segment increased $12.3 million from $3.3 million in 2014 to $15.6 million in 2015. This increase was due to the fact that 2014 results only include three months of activity as compared to a full year in 2015.

Oil and Gas

DD&A expense for our Oil and Gas segment increased $16.9 million, or 70%, from $23.9 million in 2014 to $40.8 million in 2015. This increase was primarily due to increased production as a result of a full year of expense on the assets acquired in the fourth quarter 2014 Sanish Field acquisition, partially offset by the impact of the reduction in asset basis on the assets impaired in the third and fourth quarters of 2015.

General and Administrative (including affiliates) ("G&A") Expense

Corporate and financing G&A expense includes corporate headquarters, financing and centralized treasury and accounting. These costs increased $1.8 million, or 17%, from $10.5 million in 2014 to $12.3 million in 2015. This increase was primarily due to an increase in salaries, bonus and benefits, consulting, rent and legal fees. This increase was partially offset by a decrease in LTIP expense as a result of the decline in unit price year-over-year.

Asset Impairment

Asset impairment expense increased $655.4 million from $26.2 million in 2014 to $681.6 million in 2015. We recorded the following asset impairments during the years ended December 31, 2015 and 2014 (in thousands):

	For the Year Ended December 31,	
Impaired Assets	2015	2014
Mineral Rights		
Coal, hard mineral royalty and other	$300,870	$19,806
Oil and gas	367,576	—
Total Mineral Rights Impairment	$668,446	$19,806
Plant and Equipment		
Coal, hard mineral royalty and other	$6,930	$779
VantaCore	692	—
Total Plant and Equipment Impairment	$7,622	$779
Intangible Assets		
Coal, hard mineral royalty and other	$—	$5,624
Goodwill		
VantaCore	$5,526	$—
Total impairment	$681,594	$26,209

Coal, Hard Mineral Royalty and Other

Asset impairment expense related to our Coal, Hard Mineral and Other segment increased $281.6 million from $26.2 million in 2014 to $307.8 million in 2015. This increase was primarily due to the significant impairment expense taken in the third quarter 2015. Coal property impairments primarily resulted from idled operations in Appalachia combined with the continued deterioration in the coal markets and expectations of further reductions in global and domestic coal demand due to reduced global steel demand, low natural gas prices, and continued regulatory pressure on the electric power generation industry. Hard mineral royalty property impairments primarily resulted from greenfield development projects that have not performed as projected, leading to recent lease concessions on minimums and royalties combined with the continued regional market decline for certain properties. During the fourth quarter of 2015, we recognized an additional $8.2 million impairment expense on our coal properties as a result of continued market declines and $4.7 million impairment expense related to coal processing and transportation assets as well as obsolete equipment at our Logan office. During the second quarter of 2015 we recorded a $2.3 million impairment expense related to a coal preparation plant. With continued weakness in the commodity markets, we will continue to closely monitor our assets for impairment. It is reasonably possible that our estimate of future net cash flows could change in the near term. If conditions in coal markets continue to deteriorate, it is likely that additional non-cash write-downs of properties would occur in the future.

VantaCore

Asset impairment expense related to our VantaCore segment increased from $0.0 million in 2014 to $6.2 million in 2015. The 2015 impairment expense was primarily related to the $5.5 million write off of goodwill as well as a $0.7 million impairment related to obsolete plant and equipment.

Oil and Gas

Asset impairment expense related to our Oil and Gas segment increased from $0.0 million in 2014 to $367.6 million in 2015. The 2015 impairment expense in our Oil and Gas segment primarily resulted from declines in future expected realized commodity prices and reduced expected drilling activity on our acreage.

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of future net cash flows from our oil and natural gas reserves could continue to change in the near term. If oil and natural gas prices decline from the prices used in our impairment analysis, it is likely that additional non-cash write-downs of oil and gas properties will occur in the future. If future capital expenditures are greater than expected or if we have significant declines in our oil and natural gas reserve volumes, our estimate of future net cash flows from oil and natural gas reserves would decrease and non-cash write-downs of our oil and natural gas properties may occur in the future. In order to test the sensitivity of the fair value of our oil and gas properties to changes in oil and gas prices, management modeled a 10% change in the forward price curve across the full term of expected future cash flows from our oil and gas properties. This 10% change in oil and gas prices resulted in zero additional non-cash write-downs and an immaterial decline in our oil and natural gas reserve volumes.

Interest Expense

Interest expense increased $13.6 million, or 17%, from $80.2 million in 2014 to $93.8 million in 2015. This increase was primarily the result of additional debt incurred to complete acquisitions in the fourth quarter of 2014.

Results of Operations

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Adjusted EBITDA (Non-GAAP Financial Measure)

Adjusted EBITDA decreased $37.6 million, or 11%, from $332.2 million in 2013 to $294.6 million in 2014. This decrease is mainly related to the special distribution of $44.8 million received in 2013 from Ciner Wyoming as well as lower coal related revenues offset by higher earnings from our VantaCore and Oil and Gas business segments. Adjusted EBITDA is a non-GAAP financial measure. See "Item 6. Selected Financial Data—Non-GAAP Financial Measures—Adjusted EBITDA" for an explanation of Adjusted EBITDA and see below for Adjusted EBITDA by business segment and a reconciliation of to net income (loss) (in thousands):

	Operating Segments					
For the Year Ended	Coal, Hard Mineral Royalty and Other	Soda Ash	VantaCore	Oil and Gas	Corporate and Financing	Total
December 31, 2014						
Net income (loss)	$143,678	$41,416	$32	$14,338	$(90,634)	$108,830
Less: equity earnings from unconsolidated investment	—	(41,416)	—	—	—	(41,416)
Less: gain on reserve swap	(5,690)	—	—	—	—	(5,690)
Add: distributions from unconsolidated investment	—	46,638	—	—	—	46,638
Add: depreciation, depletion and amortization	52,645	—	3,296	23,935	—	79,876
Add: asset impairment	26,209	—	—	—	—	26,209
Add: interest expense	—	—	—	—	80,185	80,185
Adjusted EBITDA	$216,842	$46,638	$3,328	$38,273	$(10,449)	$294,632
December 31, 2013						
Net income (loss)	$211,590	$34,186	$—	$5,198	$(78,896)	$172,078
Less: equity earnings from unconsolidated investment	—	(34,186)	—	—	—	(34,186)
Less: gain on reserve swap	(8,149)	—	—	—	—	(8,149)
Add: distributions from unconsolidated investment	—	72,946	—	—	—	72,946
Add: depreciation, depletion and amortization	58,502	—	—	5,875	—	64,377
Add: asset impairment	734	—	—	—	—	734
Add: interest expense	—	—	—	—	64,396	64,396
Adjusted EBITDA	$262,677	$72,946	$—	$11,073	$(14,500)	$332,196

Distributable Cash Flow (Non-GAAP Financial Measure)

Distributable Cash Flow for 2014 decreased by $98.5 million, or 32%, from $306.9 million in 2013 to $208.4 million in 2014. This decrease was due primarily to a $44.8 million special distribution received from Ciner Wyoming in 2013, declines in the coal business, and an additional $21.0 million of interest paid in 2014 that resulted in a $36.3 million decrease in net cash provided by operations relative to 2013 and also a $9.5 million difference in proceeds from the sale of assets. Distributable Cash Flow is a non-GAAP financial measure. See "Item 6. Selected Financial Data—Non-GAAP Financial Measures—Distributable Cash Flow" for an explanation of Distributable Cash Flow and see below for Distributable Cash Flow by business segment and a reconciliation to net cash provided by (used in) operating activities (in thousands):

	Operating Segments					
For the Year Ended	Coal, Hard Mineral Royalty and Other	Soda Ash	VantaCore	Oil and Gas	Corporate and Financing	Total
December 31, 2014						
Net cash provided by (used in) operating activities	$232,484	$42,516	$2,746	$24,671	$(91,662)	$210,755
Add: return on long-term contract receivables—affiliate	1,904	—	—	—	—	1,904
Add: return of unconsolidated equity investment	—	3,633	—	—	—	3,633
Add: proceeds from sale of PP&E	968	—	38	—	—	1,006
Add: proceeds from sale of mineral rights	412	—	—	—	—	412
Less: maintenance capital expenditures	(316)	—	(900)	(7,154)	—	(8,370)
Less: distributions to non-controlling interest	(487)	—	—	(487)	—	(974)
Distributable Cash Flow	$234,965	$46,149	$1,884	$17,030	$(91,662)	$208,366
December 31, 2013						
Net cash provided by (used in) operating activities	$285,524	$24,113	$—	$9,292	$(71,855)	$247,074
Add: return on long-term contract receivables—affiliate	2,558	—	—	—	—	2,558
Add: return of unconsolidated equity investment	—	48,833	—	—	—	48,833
Add: proceeds from sale of PP&E	—	—	—	—	—	—
Add: proceeds from sale of mineral rights	10,929	—	—	—	—	10,929
Less: maintenance capital expenditures	—	—	—	—	—	—
Less: distributions to non-controlling interest	(1,261)	—	—	(1,260)	—	(2,521)
Distributable Cash Flow	$297,750	$72,946	$—	$8,032	$(71,855)	$306,873

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Revenues and Other Income

The following table shows our diversified sources of revenues and other income by business segment for the years ended December 31, 2014 and 2013 (in thousands except for percentages):

	Coal, Hard Mineral Royalty and Other	Soda Ash	VantaCore	Oil and Gas	Total
2014					
Revenues	256,719	41,416	42,051	59,566	399,752
Percentage of total	64 %	10 %	11 %	15 %	
2013					
Revenues	306,851	34,186	—	17,080	358,117
Percentage of total	86 %	9 %	— %	5 %	

Revenues and other income increased $41.7 million, or 12%, from $358.1 million in 2013 to $399.8 million in 2014. This increase was mainly due to the fourth quarter 2014 acquisition of VantaCore and Sanish Field, partially offset by a $50.2 million reduction in Coal, Hard Mineral Royalty and Other segment revenues.

Coal, Hard Mineral Royalty and Other

Revenues and other income related to our Coal, Hard Mineral Royalty and Other segment decreased $50.2 million, or 16%, from $306.9 million in 2013 to $256.7 million in 2014. The table below presents coal royalty production and revenues derived from our major coal producing regions, hard mineral royalty income and the significant categories of other revenues:

	For the Years Ended December 31, 2014	2013	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data) (Unaudited)			
Coal royalty production (tons)				
Appalachia				
Northern	9,339	11,505	(2,166)	(19)%
Central	20,092	20,801	(709)	(3)%
Southern	3,914	4,151	(237)	(6)%
Total Appalachia	33,345	36,457	(3,112)	(9)%
Illinois Basin	13,177	13,087	90	1%
Northern Powder River Basin	2,844	2,778	66	2%
Gulf Coast	1,093	970	123	13%
Total coal royalty production	50,459	53,292	(2,833)	(5)%
Average coal royalty revenue per ton				
Appalachia				
Northern	$0.92	$1.27	$(0.35)	(27)%
Central	4.46	5.05	(0.59)	(12)%
Southern	5.18	6.30	(1.12)	(18)%
Total Appalachia	3.55	4.00	(0.44)	(11)%
Illinois Basin	4.10	4.28	(0.18)	(4)%
Northern Powder River Basin	2.74	2.72	0.02	1%
Gulf Coast	3.47	3.39	0.08	2%
Combined average coal royalty revenue per ton	$3.65	$3.99	$(0.34)	(9)%
Coal royalty revenues				
Appalachia				
Northern	$8,621	$14,643	$(6,022)	(41)%
Central	89,627	105,004	(15,377)	(15)%
Southern	20,292	26,156	(5,864)	(22)%
Total Appalachia	118,540	145,803	(27,263)	(19)%
Illinois Basin	54,049	56,001	(1,952)	(3)%
Northern Powder River Basin	7,804	7,569	235	3%
Gulf Coast	3,793	3,290	503	15%
Total coal royalty revenue	$184,186	$212,663	$(28,477)	(13)%
Other coal related revenues				
Override revenue	$4,601	$10,372	$(5,771)	(56)%
Transportation and processing fees	22,048	22,519	(471)	(2)%
Minimums recognized as revenue	6,659	6,528	131	2%
Condemnation related revenues	—	10,370	(10,370)	100%

Coal bonus related revenues	98	—	98		100	%
Reserve swap	5,690	8,149	(2,459	)	(30	)%
Wheelage	3,442	3,593	(151	)	(4	)%
Total other coal related revenues	$42,538	$61,531	$(18,993	)	(31	)%
Total coal related revenues and coal related revenues—affiliates	$226,724	$274,194	$(47,470	)	(17	)%
Hard mineral royalty revenues	$12,073	$13,479	$(1,406	)	(10	)%
Property taxes	$13,609	$15,416	$(1,807	)	(12	)%
Other	$4,313	$3,762	$551		15	%
Total coal, hard mineral royalty and other revenue	$256,719	$306,851	$(50,132	)	(16	)%

Total coal production decreased 2.8 million tons, or 5%, from 53.3 million tons in 2013 50.5 million tons in 2014. Total coal royalty revenues decreased $28.5 million, or 13%, from $212.7 million in 2013 to $184.2 million in 2014. During the year ended December 31, 2014 as compared to the same period in 2013, total coal production, total coal royalty revenues and average coal royalty revenue per ton were down in all Appalachia regions. Production in the Illinois Basin remained relatively flat year-over-year; however, total royalty revenues decreased $2.0 million due to a 4% decrease in average royalty revenue per ton. Total coal production, total coal royalty revenues and average royalty revenue per ton remained relatively flat in both the Northern Powder River Basin and the Gulf Coast.

Other coal related revenues decreased $19.0 million, or 31%, from $61.5 million in 2013 to $42.5 million in 2014. The decrease is primarily a result of a $10.4 million condemnation payment received in 2013 in addition to a $5.8 million decrease in override revenues and a $2.5 million decrease in reserve swap gains year-over-year

Hard mineral royalty revenues decreased $1.4 million, or 10%, from $13.5 million in 2013 to $12.1 million in 2014. This decrease is primarily due to one of our lessees moving from property on which we receive royalty revenue to property on which we receive overriding royalty revenue and another lessee temporarily idling its operation in early 2014. This decrease was offset by an increase in override revenues of approximately $2.0 million in our overriding royalty revenues from frac sand properties, the remaining increase is due to override revenues increasing on our Washington aggregates property due to a lessee moving from our owned property to an area subject to an override.

Soda Ash

Revenues and other income related to our Soda Ash segment increased $7.2 million, or 21%, from $34.2 million in 2013 to $41.4 million in 2014. This increase was due to improved earnings at Ciner Wyoming in 2014 over 2013. For the year ended December 31, 2014, we received $46.6 million in cash distributions and for the year ended December 31, 2014 we received $72.9 million in cash, which included a one-time special distribution of $44.8 million.

VantaCore

Tonnage sold by the VanataCore segment was 2.3 million tons for the year ended December 31, 2014. Revenues and other income related to our VantaCore segment was $42.1 million in 2014. We acquired VantaCore in October 2014.

Oil and Gas

Revenues and other income related to our Oil and Gas segment increased $42.5 million from $17.1 million in 2013 to $59.6 million in 2014. This increase is due to a full year of revenues from our non-operated working interests in the Williston Basin that were acquired the second half of 2013. In addition, our 2014 results include revenues attributable to our Sanish Field properties acquired in November 2014.

Operating and Maintenance Expenses (including affiliates)

Operating and maintenance expenses (including affiliates) increased $52.2 million from $42.0 million in 2013 to $94.2 million in 2014. This increase was primarily the result of expenses related to VantaCore and our Sanish Field operations, which were both acquired in the fourth quarter of 2014.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased $15.5 million, or 24%, from $64.4 million in 2013 to $79.9 million in 2014. This increase was due to a full year depletion on the oil and gas assets acquired in the second half of 2013 as well as the depreciation, depletion and amortization expense on the VantaCore and Sanish Field assets acquired during the fourth quarter of 2014.

General and Administrative (including affiliates)

Corporate and financing G&A expenses include corporate headquarters, financing and centralized treasury and accounting. These costs decreased $4.2 million, or 28%, from $14.7 million in 2013 to $10.5 million in 2014. This decrease was primarily related to a decrease in LTIP expense as a result of the decline in our unit price.

Asset Impairment

Asset impairment expense increased $25.5 million from $0.7 million in 2013 to $26.2 million in 2014. This increase is due to the Coal, Hard Mineral Royalty and Other segment's impairment of $19.8 million related to its mineral rights, $5.6 million related to its intangible assets and $0.8 million related to its plant and equipment in 2014. The Coal, Hard Mineral Royalty and Other segment recorded a $0.7 million impairment related to its mineral rights in 2013.

Interest Expense

Interest expense increased $15.8 million, or 25%, from $64.4 million in 2013 to $80.2 million in 2014. Interest expense increased due to additional debt incurred in 2014 and 2013 to fund acquisitions as well as a refinancing of our credit facility and payment on our term loan with 9.125% high yield notes.

Liquidity and Capital Resources

Overview

As of December 31, 2015, we had $64.8 million of liquidity that consisted of $51.8 million in cash and $13.0 million in combined borrowing capacity under our revolving credit facilities. During the year ended December 31, 2015, we reduced our debt by a net amount of $91.0 million. Opco's $300.0 million revolving credit facility matures in October 2017, and as of December 31, 2015, we had $290.0 million outstanding thereunder. We borrowed $75.0 million under Opco's revolving credit facility in September 2015 in order to repay Opco's term loan in full. In October, 2015, the borrowing base under the NRP Oil and Gas revolving credit facility was redetermined to $88.0 million, and we repaid $15.0 million under that facility, reducing our outstanding borrowings under that facility to $85.0 million. As of the date of this report, the combined borrowing capacity under our revolving credit facilities is $13.0 million.

In February 2016, we sold the aggregates reserves and related royalty rights at three aggregates operations located in Texas, Georgia and Tennessee, which comprised approximately 27%, or 139 million tons, of our hard mineral reserves as of December 31, 2015 for $10.0 million in cash. The effective date of the sale was February 1, 2016. In February 2016, we sold royalty and overriding royalty interests in several producing properties located in the Appalachian Basin, including our overriding royalty interests in the Marcellus Shale, for $37.5 million in cash. The sale included royalty and overriding royalty interests in approximately 765 gross producing wells as of December 31, 2015 and approximately 10% of our estimated proved reserves, or 1,094 MBoe, as of December 31, 2015, or 1,094 MBoe. The effective date of the sale was January 1, 2016. We intend to use the net proceeds from these asset sales to repay debt. While we believe we have sufficient liquidity to meet our current financial needs, we have significant debt service requirements, including $80.8 million in principal payments on Opco's senior notes each year through 2018, and our operating results continue to be impacted by the adverse conditions in the commodity markets. In April 2015, we announced a long-term plan to strengthen our balance sheet, reduce debt and enhance liquidity in order to reposition the partnership for future growth. As part of that plan, we reduced our cash distributions during 2015 by over 87%. The cash savings resulting from the distribution reductions are being used primarily to repay debt. We have also taken steps to reduce general and administrative and other overhead costs in connection with these efforts. However, we have determined that the cash savings from the distribution cuts and our cost reduction efforts will not be sufficient to meet our delevraging objectives and have determined to sell certain assets to help meet these objectives. While we have closed two asset sale transactions, if we are unable to complete additional asset sales and conditions in the commodity markets continue to deteriorate, our liquidity and our ability to comply with the financial and other restrictive covenants contained in our debt agreements will be adversely affected. For a more complete discussion of factors that will affect our liquidity, see "Item 1A. Risk Factors—Risks Related to Our Business."

Opco’s revolving credit facility matures in October 2017 and NRP’s 9.125% Senior Notes mature in October 2018. We believe we need to significantly improve our leverage ratios prior to the maturity thereof in order to be able to refinance or restructure such debt. We remain committed to our strategic plan announced in April 2015 to improve our balance sheet and reduce leverage, and intend to take all necessary steps to execute on that plan, including through asset sales and other means. Through February 2016, we completed asset sales for $47.5 million in gross proceeds.

However, we believe the deterioration in the commodity markets will continue to have a negative impact on our results of operations, which in turn may prevent us from achieving our leverage ratio goals. Traditionally, we have accessed the debt and equity capital markets on a regular basis and have relied on bank credit facilities to finance our business activities. However, due to the current commodity price environment and the state of the coal markets in particular, we believe we do not currently have the ability to access either the debt or equity capital markets. In addition, the volatility in the energy industry combined with recent bankruptcies and additional perceived credit risks of companies with coal and/or oil and gas exposure has resulted in traditional bank lenders seeking to reduce or eliminate their lending exposure to these companies. Accordingly, we will be required over the near term to run our business and service our debt through cash from operations or asset sales. In addition, we may be required to seek financing from non-traditional sources at unfavorable pricing or with unfavorable terms to run our business or to refinance or restructure our 2017 and 2018 debt maturities.

Generally, we satisfy our working capital requirements with cash generated from operations. Our current liabilities exceeded our current assets by approximately $15.5 million as of December 31, 2015, primarily due to $80.8 million in principal payments on Opco's senior notes due over the next year. Excluding these principal payments, our current assets exceeded our current liabilities by approximately $65.5 million as of December 31, 2015.

Capital Expenditures

Our capital expenditures, other than for acquisitions, have historically been minimal. However, as a result of our Sanish Field oil and gas and VantaCore aggregates acquisitions in the fourth quarter of 2014, our operating capital expenditures have been higher in 2015. In response to the significant decline in oil price, we expect our oil and gas capital expenditures to decline significantly in 2016 as compared to 2015. A portion of the capital expenditures associated with both our oil and gas working interest business and VantaCore are maintenance capital expenditures, which are capital expenditures made to maintain the long-term production capacity of those businesses. We deduct maintenance capital expenditures when calculating distributable cash flow. Total capital expenditures for NRP Oil and Gas for the year ended December 31, 2015 were $30.5 million. We continue to monitor the development programs of the operators of these properties and manage the capital expenditures associated with those properties by only participating in wells that are expected to provide acceptable economic returns. VantaCore's capital expenditures for the year ended December 31, 2015 were $14.0 million.

Cash Flows

Net cash provided by operating activities for the years ended December 31, 2015, 2014 and 2013 was $203.4 million, $210.8 million and $247.1 million, respectively. The majority of our cash provided by operations is generated from coal royalty revenues, our equity interest in Ciner Wyoming as well as VantaCore and oil and gas revenues.

Net cash used in investing activities for the years ended December 31, 2015, 2014 and 2013 was $30.3 million, $520.5 million and $302.8 million, respectively. During 2015 our investing activities primarily consisted of well participation costs within our Oil and Gas segment and plant and equipment acquisitions within our VantaCore segment. These 2015 investing cash outflows were partially offset by various asset sales including an aggregate preparation plant, cell phone tower lease contracts and condemnation payments within our Coal, Hard Mineral Royalty and Other segment as well as sales of mineral rights within our Oil and Gas segment. Our 2014 investing activities consisted of our Sanish Field and VantaCore acquisitions, the $5.0 million Illinois Basin coal acquisition completed in June 2014, as well as additional capital expenditures related to the participation in new wells in connection with our Williston Basin non-operated oil and gas working interest properties. Our 2013 investing activities consisted of the acquisitions of the interest in Ciner Wyoming and two acquisitions of non-operated working interests in oil and gas properties located in the Williston Basin.

Net cash flows used in financing activities for the year ended December 31, 2015 was $171.5 million and net cash flows provided by financing activities for the year ended December 31, 2014 was $267.3 million. Net cash flows used in financing activities for the year ended December 31, 2013 was $1.2 million. During 2015, 2014 and 2013 we had proceeds from loans of $100.0 million, $637.4 million and $567.0 million, respectively. During 2015, 2014 and 2013, these proceeds were offset by repayment of debt of $191.0 million, $328.0 million and $386.2 million, respectively. Also during 2015, 2014 and 2013 we paid cash distributions to our unitholders of $71.8 million, $162.0 million and $246.5 million, respectively. During 2014, we had net proceeds from an issuance of common units of $122.8 million, together with a capital contribution from our general partner of $3.2 million. During 2013, we had net proceeds from an issuance of common units of $74.7 million, together with a capital contribution from our general partner of $1.5 million.

Capital Resources and Obligations

Indebtedness

As of December 31, 2015 and 2014, we had the following indebtedness (in thousands):

	December 31, 2015	December 31, 2014
Current portion of long-term debt, net	$80,983	$80,983
Long-term debt and debt—affiliate, net	1,304,013	1,394,240
Total debt and debt—affiliate, net	$1,384,996	$1,475,223

We were and continue to be in compliance with the terms of the financial covenants contained in our debt agreements. Adjusted EBITDA as defined in "Item 6. Selected Financial Data—Non-GAAP Financial Measures—Adjusted EBITDA" differs from the EBITDDA definitions contained in our debt agreements. For additional information regarding our debt and the agreements governing our debt, including the covenants contained therein, see "Item 8. Financial Statements and Supplementary Data—Note 10. Debt and Debt—Affiliate" in this Annual Report on Form 10-K.

Long-Term Contractual Obligations

The following table reflects our long-term non-cancelable contractual obligations as of December 31, 2015 (in millions):

	Payments Due by Period						
Contractual Obligations	Total	2016	2017	2018	2019	2020	Thereafter
NRP:							
Long-term debt principal payments (including current maturities) (1)	$425.0	$—	$—	$425.0	$—	$—	$—
Long-term debt interest payments (1)	116.4	38.8	38.8	38.8	—	—	—
NRP Oil and Gas:							
Long-term debt principal payments (2)	85.0	—	—	—	85.0	—	—
Opco:							
Long-term debt principal payments (including current maturities) (3)	877.1	81.0	371.0	81.0	76.4	54.9	212.8
Long-term debt interest payments (4)	148.5	33.3	28.2	23.2	18.2	14.2	31.4
Rental leases (5)	2.0	0.7	0.7	0.6	—	—	—
Total	$1,654.0	$153.8	$438.7	$568.6	$179.6	$69.1	$244.2

(1) The amounts indicated in the table include principal and interest due on NRP’s 9.125% senior notes.
(2) Does not consider the impact of any repayments required as a result of reductions in the borrowing base of the facility.
(3) The amounts indicated in the table include principal due on Opco’s senior notes, credit facility and utility local improvement obligation.
(4) The amounts indicated in the table include interest due on Opco’s senior notes and utility local improvement obligation.
(5) On January 1, 2009, Opco entered into a ten-year lease agreement for the rental of office space from Western Pocahontas Properties Limited Partnership for $0.6 million per year. In addition, BRP LLC ("BRP") leases office space for approximately $0.1 million per year through 2017. These rental obligations are included in the table above.

Anadarko Contingent Consideration Payment Claim

The purchase agreement for the acquisition of our interest in Ciner Wyoming, formerly OCI Wyoming, requires us to pay additional contingent consideration to Anadarko to the extent certain performance criteria described in the purchase agreement are met at Ciner Wyoming in any of the years 2013, 2014 or 2015. We paid $0.5 million and $3.8 million of consideration in the first quarter of 2014 and 2015, respectively, in satisfaction of our obligations under this agreement with respect to 2013 and 2014. As of December 31, 2015, we estimate, and have recorded $7.2 million as the amount that will be payable in the first quarter of 2016 with respect to 2015. We have no obligation to pay contingent consideration with respect to any period after 2015.
In March 2014, Anadarko gave us written notice that it believed certain reorganization transactions conducted in 2013 within the OCI organization triggered an acceleration of our obligation to pay the additional contingent consideration

in full and demanded immediate payment of such amount. We disagreed with Anadarko's position in a written response provided to Anadarko in April 2014. In April 2015, Anadarko sent a written request for additional information regarding the OCI reorganization and indicated that they are still considering this claim against us. We do not believe the reorganization transactions triggered an obligation to pay the additional contingent consideration. We responded in writing in May 2015, and we will continue to engage in discussions with Anadarko to resolve the issue if necessary. However, if Anadarko were to pursue and prevail on such a claim, we would be required to pay an amount to Anadarko in excess of the amounts already paid, together with the $7.2 million accrual described above, up to the maximum amount of the additional contingent consideration, minus a deductible. Under the purchase agreement, the maximum cumulative amount of additional contingent consideration is an amount equal to the net present value of $50.0 million. Any additional amount paid by us would be considered to be additional acquisition consideration and added to Equity and other unconsolidated investments and would reduce our liquidity.

Shelf Registration Statement

In September 2015, we filed a registration statement on Form S-3 with the SEC that is available for registered offerings of common units.

Unrestricted Subsidiary Information

In February 2016, NRP designated NRP Oil and Gas as an Unrestricted Subsidiary for purposes of the Indenture. In addition, BRP LLC and its wholly owned subsidiary, Coval Leasing Company, LLC, are also Unrestricted Subsidiaries for purposes of the Indenture. For more information regarding the financial condition and results of operations of NRP and its Restricted Subsidiaries for purposes of the Indenture separate from NRP’s Unrestricted Subsidiaries for purposes of the Indenture, see "Note 17. Supplementary Unrestricted Subsidiary Information" under the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

Off-Balance Sheet Transactions

We do not have any off-balance sheet arrangements with unconsolidated entities or related parties and accordingly, there are no off-balance sheet risks to our liquidity and capital resources from unconsolidated entities.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on operations for the years ended December 31, 2015, 2014 and 2013.

Environmental Regulation

For additional information on environmental regulation that may have a material impact on our business, see "—Executive Overview—Political, Legal and Regulatory Environment Affecting Our Coal Business" and "Item 1. Business—Regulation and Environmental Matters."

Related Party Transactions

The information required by this Item is included under "Item 8. Financial Statements and Supplementary Data—Note 12. Related Party Transactions" and "Item 13. Certain Relationships and Related Transactions, and Director Independence" in this Annual Report on Form 10-K and is incorporated by reference herein.

Summary of Critical Accounting Estimates

Preparation of the accompanying financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in the accompanying Consolidated Balance Sheets and the reported amounts of revenues and expenses in the accompanying Consolidated Statements of Comprehensive Income during the reporting period. See "Note 2. Summary of Significant Accounting Policies" to the audited consolidated financial statements under Item 8 of this Form 10-K for discussion of the Partnership's significant accounting policies. The following critical accounting policies are affected by estimates and assumptions used in the preparation of Consolidated Financial Statements.

Revenues

Coal, Hard Mineral Royalty and Other Revenues. Coal and hard mineral royalty revenues are recognized on the basis of tons of mineral sold by our lessees and the corresponding revenue from those sales. Generally, the lessees make payments to us based on the greater of a percentage of the gross sales price or a fixed price per ton of mineral they sell. Processing fees are recognized on the basis of tons of material processed through the facilities by our lessees and the corresponding revenue from those sales. Generally, the lessees of the processing facilities make payments to us based on the greater of a percentage of the gross sales price or a fixed price per ton of material that is processed and sold from the facilities. The processing leases are structured in a manner so that the lessees are responsible for operating and maintenance expenses associated with the facilities. Other revenues include transportation and processing fees. Transportation fees are recognized on the basis of tons of material transported over the beltlines. Under the terms of the transportation contracts, we receive a fixed price per ton for all material transported on the beltlines.

Soda Ash Revenues. We account for non-marketable investments using the equity method of accounting if the investment gives us the ability to exercise significant influence over, but not control of, an investee. Significant influence generally exists if we have an ownership interest representing between 20% and 50% of the voting stock of the investee. We account for our investment in Ciner Wyoming using this method.

Under the equity method of accounting, investments are stated at initial cost and are adjusted for subsequent additional investments and the proportionate share of earnings or losses and distributions. The basis difference between the investment and the proportional share of the fair value of the underlying net assets of equity method investees is hypothetically allocated first to identified tangible assets and liabilities, then to finite-lived intangibles or indefinite-lived intangibles and the remaining balance is attributed to goodwill. The portion of the basis difference attributed to net tangible assets and finite-lived intangibles is amortized over its estimated useful life while indefinite-lived intangibles, if any, and goodwill are not amortized. The amortization of the basis difference is recorded as a reduction of earnings from the equity investment in the Consolidated Statements of Comprehensive Income.

Our carrying value in an equity method investee company is reflected in the caption "Equity and other unconsolidated investments" in our Consolidated Balance Sheets. Our adjusted share of the earnings or losses of the investee company is reflected in the Consolidated Statements of Comprehensive Income as revenues and other income under the caption ‘‘Equity and other unconsolidated investment income." These earnings are generated from natural resources, which are considered part of our core business activities consistent with its directly owned revenue generating activities. Investee earnings are adjusted to reflect the amortization of any difference between the cost basis of the equity investment and the proportionate share of the investee’s book value, which has been allocated to the fair value of net identified tangible and finite-lived intangible assets and amortized over the estimated lives of those assets.

VantaCore Revenues. Revenues from the sale of aggregates, gravel, sand and asphalt are recorded based upon the transfer of product at delivery to customers, which generally occurs at the quarries or asphalt plants. Revenues from long-term construction contracts are recognized on the percentage-of-completion method, measured by the percentage of total costs incurred to date to the estimated total costs for each contract. That method is used since we consider total cost to be the best available measure of progress on the contracts. Provisions for estimated losses on uncompleted contracts are made in the period in which such losses are determined. Changes in job performance, job conditions and estimated profitability, including those arising from final contract settlements, which result in revisions to job costs and profits are recognized in the period in which the revisions are determined. Contract costs include all direct job costs and those indirect costs related to contract performance, such as indirect labor, supplies, insurance, equipment maintenance and depreciation. General and administrative costs are charged to expense as incurred.

Oil and Gas Revenues. Oil and gas related revenues consist of revenues from our non-operated working interests, royalties and overriding royalties. Revenues related to our non-operated working interests in oil and gas assets are recognized on the basis of our net revenue interests in hydrocarbons produced. We also have capital expenditure and operating expenditure obligations associated with the non-operated working interests. Our revenues fluctuate based on changes in the market prices for oil and natural gas, the decline in production from producing wells, and other factors affecting the third-party oil and natural gas exploration and production companies that operate our wells, including the cost of development and production. Oil and gas royalty revenues are recognized on the basis of volume of hydrocarbons sold by lessees and the corresponding revenue from those sales. Also, included within oil and gas royalties are lease bonus payments, which are generally paid upon the execution of a lease.

Deferred Revenue

Most of our coal and aggregates lessees must make minimum annual or quarterly payments which are generally recoupable over certain time periods. These minimum payments are recorded as deferred revenue when received. The deferred revenue attributable to the minimum payment is recognized as revenue when the lessee recoups the minimum payment through production or in the period immediately following the expiration of the lessee's ability to recoup the payments.

Lessee Audits and Inspections

We periodically audit lessee information by examining certain records and internal reports of our lessees. Our regional managers also perform periodic mine inspections to verify that the information that has been reported to us is accurate. The 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. Audits and inspections, however, are in periods subsequent to when the revenue is reported and any adjustment identified by these processes might be in a reporting period different from when the revenue was initially recorded. Typically there are no material adjustments from this process.

Share-Based Payment

We account for awards relating to our Long-Term Incentive Plan using the fair value method, which requires us to estimate the fair value of the grant, and charge or credit the estimated fair value to expense over the service or vesting period of the grant based on fluctuations in our common unit price. In addition, estimated forfeitures are included in the periodic computation of the fair value of the liability and the fair value is recalculated at each reporting date over the service or vesting period of the grant.

Asset Impairment

We have developed procedures to periodically evaluate our long-lived assets for possible impairment. These procedures are performed throughout the year and are based on historic, current and future performance and are designed to be early warning tests. If an asset fails one of the early warning tests, additional evaluation is performed for that asset that considers both quantitative and qualitative information. A long-lived asset is deemed impaired when the future expected undiscounted cash flows from its use and disposition is less than the assets' carrying value. Impairment is measured based on the estimated fair value, which is usually determined based upon the present value of the projected future cash flow compared to the assets' carrying value. We believe our estimates of cash flows and discount rates are consistent with those of principal market participants. In addition to the evaluations discussed above, specific events such as a reduction in economically recoverable reserves or production ceasing on a property for an extended period may require a separate impairment evaluation be completed on a significant property. As a result of the continued weakness in the coal markets and the potential for further declines in oil and natural gas prices, we intend to closely monitor our coal and oil and gas assets, and the impairment evaluation process may be completed more frequently if deemed necessary. Future impairment analyses could result in downward adjustments to the carrying value of our assets. During 2015, we recorded impairment expense of $676.1 million on certain of our mineral rights within our Coal, Hard Mineral Royalty and Other and Oil and Gas segments as well as plant and equipment within our Coal, Hard Mineral Royalty and Other and VantaCore segments. For further discussion relating to our 2015 impairments see "Item 8. Financial Statements and Supplementary Data—Note 8. Minerals Rights" and "Item 8. Financial Statements and Supplementary Data—Note 7. Plant and Equipment" to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

We evaluate our equity investments for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such investment may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized in the financial statements as an impairment loss. The fair value of the impaired investment is based on quoted market prices, or upon the present value of expected cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate.

In accordance with FASB accounting and disclosure guidance for goodwill, we test our recorded goodwill for impairment annually or more often if indicators of potential impairment exist, by determining if the carrying value of a reporting unit exceeds its estimated fair value. Factors that could trigger an interim impairment test include, but are not limited to, underperformance relative to historical or projected future operating results or significant changes in our overall business, industry, or economic trends. We recorded a $5.5 million impairment loss related to the VantaCore reporting unit for the year ended December 31, 2015.

Business Combinations

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

Proved Oil and Gas Reserves

The Partnership utilizes Netherland Sewell, an independent reserve engineering firm, to estimate its proved oil and gas reserves according to the definition of proved reserves provided by the Securities and Exchange Commission and the Financial Accounting Standards Board (FASB). This definition includes oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods, government regulations, etc. (at prices and costs as of the date the estimates are made). Prices are calculated using the unweighted average of the first-day-of-the-month pricing and then adjusted for transportation and other costs. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to Netherland Sewell in their reserves estimation process.

The Partnership's estimates of proved reserves are made using available geological and reservoir data, as well as production performance data. These estimates are reviewed annually by Netherland Sewell and our internal staff of petroleum engineers and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions, and governmental restrictions, as well as changes in the expected recovery associated with infill drilling. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits at an earlier projected date. The quantities of estimated proved oil and gas reserves are a significant component of DD&A. A material adverse change in the estimated volumes of proved reserves could have a negative impact on DD&A and could result in property impairments.

Recent Accounting Standards

For a discussion of recent accounting pronouncements, see the applicable section of "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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, which includes adverse changes in commodity prices and interest rates as discussed below:

Commodity Price Risk

We are dependent upon the effective marketing of the coal mined by our lessees. Our lessees sell the coal under various long-term and short-term contracts as well as on the spot market. We estimate that over 65% of our coal is currently sold by our lessees under coal supply contracts that have terms of one year or more. Current conditions in the coal industry may make it difficult for our lessees to extend existing contracts or enter into supply contracts with terms of one year or more. Our lessees' failure to negotiate long-term contracts could adversely affect the stability and profitability of our lessees' operations and adversely affect our coal royalty revenues. If more coal is sold on the spot market, coal royalty revenues may become more volatile due to fluctuations in spot coal prices.

We have market risk related to the prices for oil and natural gas, NGLs and condensate. Management expects energy prices to remain unpredictable and potentially volatile. As energy prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, a non-cash write-down of the Partnership's oil and gas properties may be required if commodity prices experience a significant decline.

We have market risk related to prices for our aggregates products. Aggregates prices are primarily driven by economic conditions in the local markets in which the products are sold.

The market price of soda ash directly affects the profitability of Ciner Wyoming’s 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.

Interest Rate Risk

Our exposure to changes in interest rates results from our borrowings under our revolving credit facility and term loan, which are subject to variable interest rates based upon LIBOR. At December 31, 2015, we had $375.0 million outstanding in variable interest rate debt. If interest rates were to increase by 1%, annual interest expense would increase approximately $3.8 million, assuming the same principal amount remained outstanding during the year.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners of Natural Resource Partners L.P.

We have audited the accompanying consolidated balance sheets of Natural Resource Partners L.P. as of December 31, 2015 and 2014, and the related consolidated statements of comprehensive income (loss), partners' capital and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of Ciner Wyoming LLC (Ciner Wyoming), a Limited Liability Company in which Natural Resource Partners L.P. owns a 49% interest. In the consolidated financial statements Natural Resource Partners L.P.'s investment in Ciner Wyoming is stated at $262 million and $264 million as of December 31, 2015 and 2014, respectively, and Natural Resource Partners L.P.'s equity in the net income of Ciner Wyoming is stated at $50 million, $41 million and $34 million for the three years in the period ended December 31, 2015, respectively. Those statements were audited by other auditors whose report has been furnished to us. Our opinion, insofar as it relates to the amounts included for Natural Resource Partners L.P., is based on the report of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Natural Resource Partners L.P. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

The condensed consolidating balance sheets and statements of comprehensive income (loss) appearing in Note 17 of the consolidated financial statements have been subjected to audit procedures performed in conjunction with the audit of Natural Resource Partners L.P.'s consolidated financial statements. Such information is the responsibility of the Partnership's management. Our audit procedures included determining whether the information reconciles to the financial statements or the underlying accounting and other records, as applicable, and performing procedures to test the completeness and accuracy of the information. In our opinion, the information is fairly stated, in all material respects, in relation to the financial statements as a whole.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Natural Resource Partners L.P.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated March 11, 2016, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
March 11, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Managers and Members of
Ciner Wyoming LLC
Atlanta, Georgia

We have audited the accompanying balance sheets of Ciner Wyoming LLC (the "Company") as of December 31, 2015 and 2014 and the related statements of operations and comprehensive income, members’ equity, and cash flows for each of the three years in the period ended December 31, 2015, and the related notes to the financial statements. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Atlanta, Georgia
March 11, 2016

NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$51,773	$50,076
Accounts receivable, net	50,167	66,455
Accounts receivable—affiliates	6,864	9,494
Inventory	7,835	5,814
Prepaid expenses and other	4,490	4,279
Total current assets	121,129	136,118
Land	25,022	25,243
Plant and equipment, net	61,239	60,093
Mineral rights, net	1,094,027	1,781,852
Intangible assets, net	56,927	60,733
Equity in unconsolidated investment	261,942	264,020
Long-term contracts receivable—affiliate	47,359	50,008
Goodwill	—	52,012
Other assets	15,306	14,645
Other assets—affiliate	1,124	—
Total assets	$1,684,075	$2,444,724
LIABILITIES AND CAPITAL		
Current liabilities:		
Accounts payable	$8,465	$22,465
Accounts payable—affiliates	1,464	950
Accrued liabilities	45,735	43,533
Current portion of long-term debt, net	80,983	80,983
Total current liabilities	136,647	147,931
Deferred revenue	80,812	73,207
Deferred revenue—affiliates	82,853	87,053
Long-term debt, net	1,284,083	1,374,336
Long-term debt, net—affiliate	19,930	19,904
Other non-current liabilities	6,808	22,138
Commitments and contingencies (see Note 14)		
Partners' capital:		
Common unitholders' interest (12.2 million units outstanding)	79,094	709,019
General partner's interest	(606)	12,245
Accumulated other comprehensive loss	(2,152)	(459)
Total partners' capital	76,336	720,805
Non-controlling interest	(3,394)	(650)
Total capital	72,942	720,155
Total liabilities and capital	$1,684,075	$2,444,724

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

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NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands, except per unit data)

	For the Years Ended December 31,		
	2015	2014	2013
Revenues and other income:			
Coal, hard mineral royalty and other	$156,638	$172,160	$213,825
Coal, hard mineral royalty and other—affiliates	89,715	84,559	93,026
VantaCore	139,013	42,051	—
Oil and gas	53,565	59,566	17,080
Equity in earnings of Ciner Wyoming	49,918	41,416	34,186
Total revenues and other income	488,849	399,752	358,117
Operating expenses:			
Operating and maintenance expenses	155,959	83,433	33,211
Operating and maintenance expenses—affiliates, net	16,031	10,770	8,821
Depreciation, depletion and amortization	100,828	79,876	64,377
General and administrative	7,036	7,287	11,452
General and administrative—affiliates	5,312	3,258	3,286
Asset impairments	681,594	26,209	734
Total operating expenses	966,760	210,833	121,881
Income (loss) from operations	(477,911)	188,919	236,236
Other income (expense)			
Interest expense	(93,827)	(80,185)	(64,396)
Interest income	18	96	238
Other expense, net	(93,809)	(80,089)	(64,158)
Net income (loss)	$(571,720)	$108,830	$172,078
Net income (loss) attributable to partners:			
Limited partners	(559,492)	106,653	168,636
General partner	(12,228)	2,177	3,442
Basic and diluted net income (loss) per common unit	$(45.75)	$9.42	$15.39
Weighted average number of common units outstanding	12,230	11,326	10,958
Net income (loss)	$(571,720)	$108,830	$172,078
Add: comprehensive income (loss) from unconsolidated investment and other	(1,693)	(81)	65
Comprehensive income (loss)	$(573,413)	$108,749	$172,143

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

NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(In thousands)

	Common Unitholders		General Partner	Accumulated Other Comprehensive Income (Loss)	Partners' Capital Excluding Non-Controlling Interest	Non-Controlling Interest	Total Capital
	Units	Amounts					
Balance at December 31, 2012	10,603	$605,019	$10,026	$(443)	$ 614,602	$ 2,845	$617,447
Issuance of common units	378	75,000	—	—	75,000	—	75,000
Capital contribution	—	—	1,531	—	1,531	—	1,531
Cost associated with equity transactions	—	(293)	—	—	(293)	—	(293)
Distributions to unitholders	—	(241,588)	(4,930)	—	(246,518)	—	(246,518)
Distributions to non-controlling interests	—	—	—	—	—	(2,521)	(2,521)
Net income	—	168,636	3,442	—	172,078	—	172,078
Comprehensive income from unconsolidated investment and other	—	—	—	65	65	—	65
Balance at December 31, 2013	10,981	$606,774	$10,069	$(378)	$ 616,465	$ 324	$616,789
Issuance of common units	1,006	127,202	—	—	127,202	—	127,202
Issuance of common units for acquisitions	243	31,604	—	—	31,604	—	31,604
Capital contribution	—	—	3,240	—	3,240	—	3,240
Cost associated with equity transactions	—	(4,413)	—	—	(4,413)	—	(4,413)
Distributions to unitholders	—	(158,801)	(3,241)	—	(162,042)	—	(162,042)
Distributions to non-controlling interests	—	—	—	—	—	(974)	(974)
Net income	—	106,653	2,177	—	108,830	—	108,830
Comprehensive loss from unconsolidated investment and other	—	—	—	(81)	(81)	—	(81)
Balance at December 31, 2014	12,230	$709,019	$12,245	$(459)	$ 720,805	$ (650)	$720,155
Cost associated with equity transactions	—	(109)	—	—	(109)	—	(109)
Distributions to unitholders	—	(70,324)	(1,434)	—	(71,758)	—	(71,758)
Distributions to non-controlling interests	—	—	—	—	—	(2,744)	(2,744)

Net loss	—	(559,492)	(12,228)