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

FORM 10-K

☒ **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 ☒

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

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

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

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

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

☐ Large Accelerated Filer ☒ Accelerated Filer ☐ Non-accelerated Filer ☐ Smaller Reporting Company

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

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:

		Proven and Probable Reserves (1)		
	Production	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

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

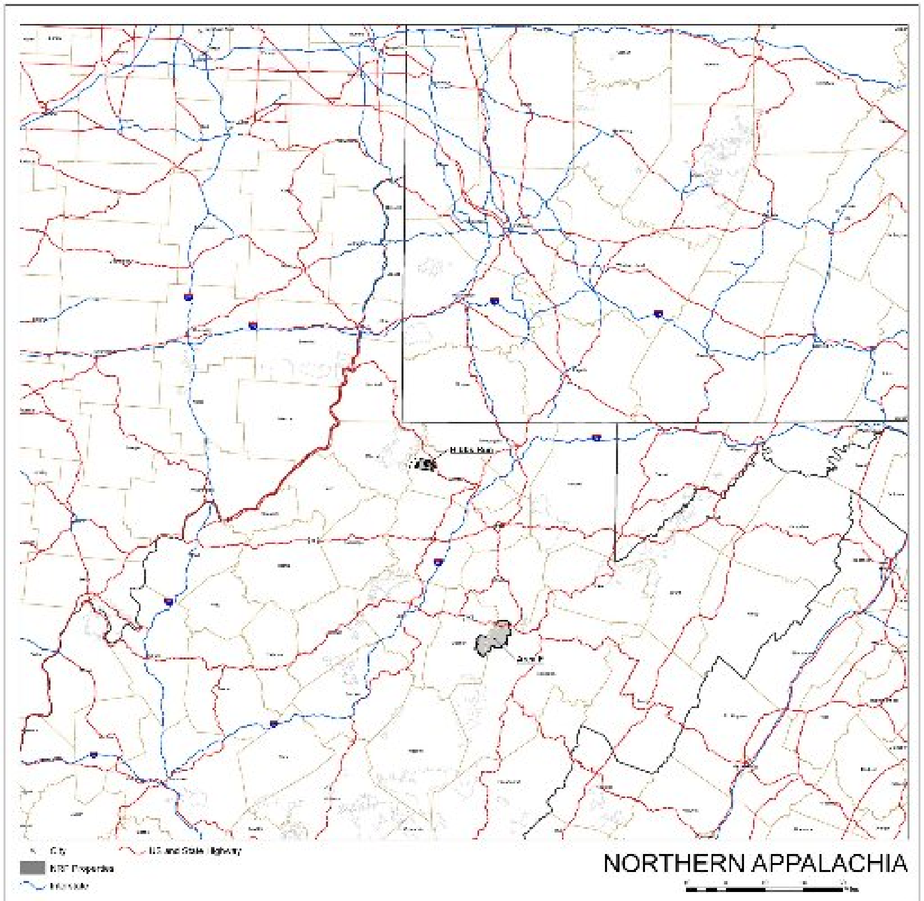
The following is a summary of our major coal producing properties in each region:

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.

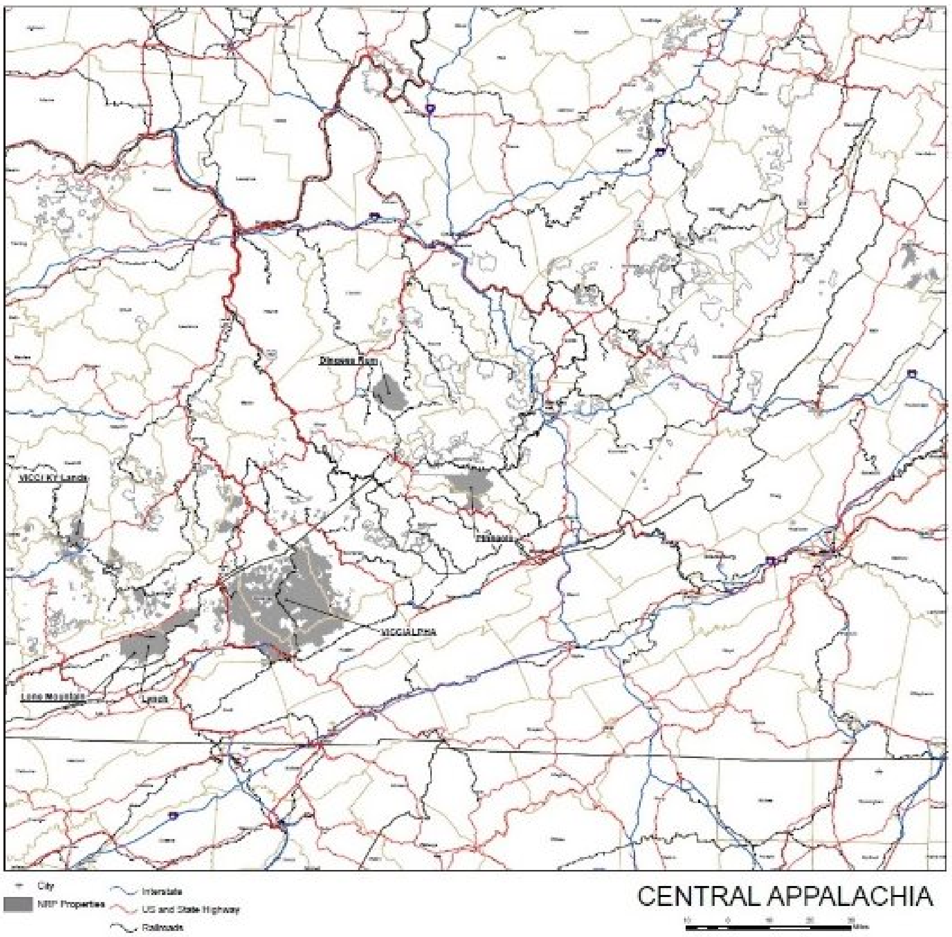
Dingess-Rum. The Dingess-Rum property is located in Logan, Clay and Nicholas Counties, West Virginia. This property is leased to subsidiaries of Alpha Natural Resources, Inc. and Blackhawk Mining, LLC. In 2015, approximately 2.4 million tons were produced from the property. Both steam and metallurgical 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.

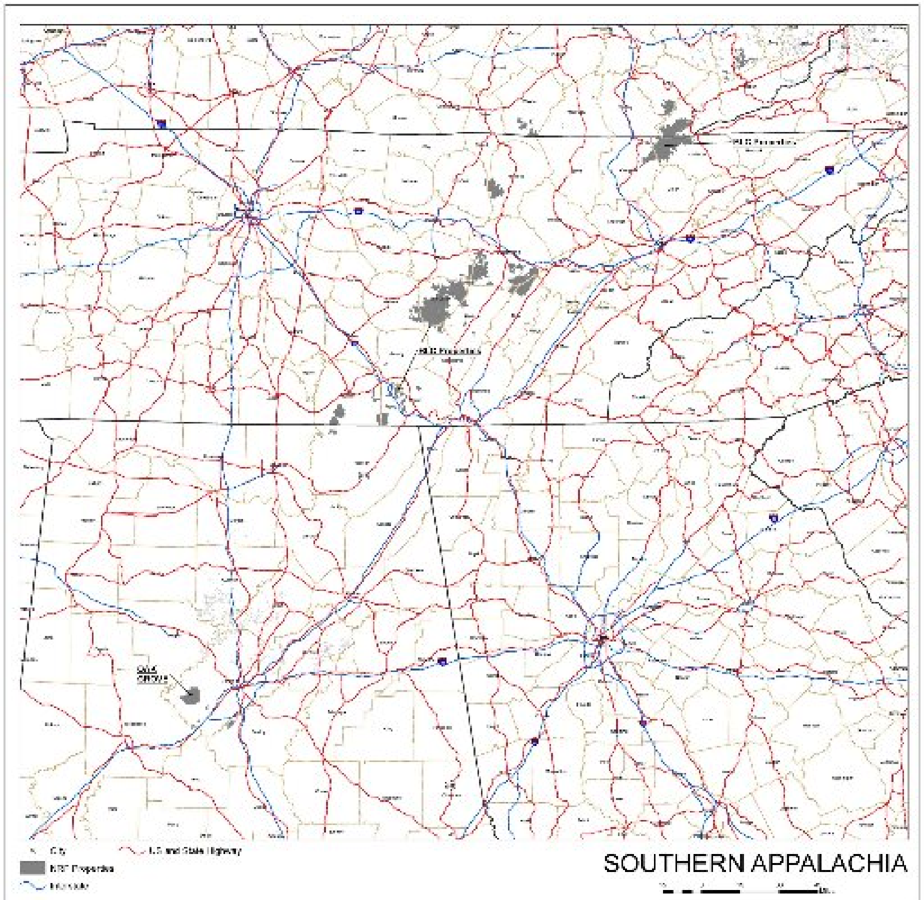
VICC/Kentucky Land. The VICC/Kentucky Land property is located primarily in Perry, Leslie and Pike Counties, Kentucky. In 2015, approximately 1.1 million tons were produced from this property. Coal is produced from a number of lessees, including subsidiaries of Cambrian Coal and Blackhawk Mining, from 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

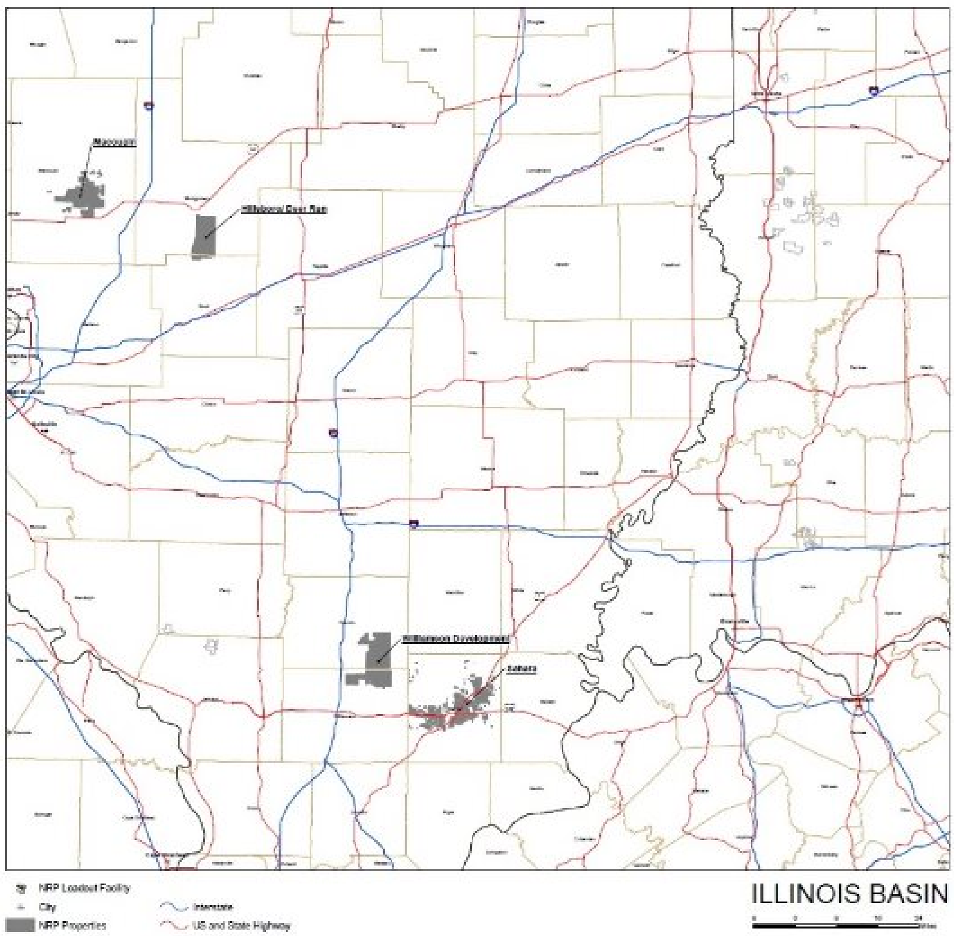
Williamson Development. The Williamson property is located in Franklin and Williamson Counties, Illinois. The property is under lease to a subsidiary of Foresight Energy, and in 2015, approximately 5.2 million tons were mined on the property. This production is from a longwall mine and is shipped primarily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

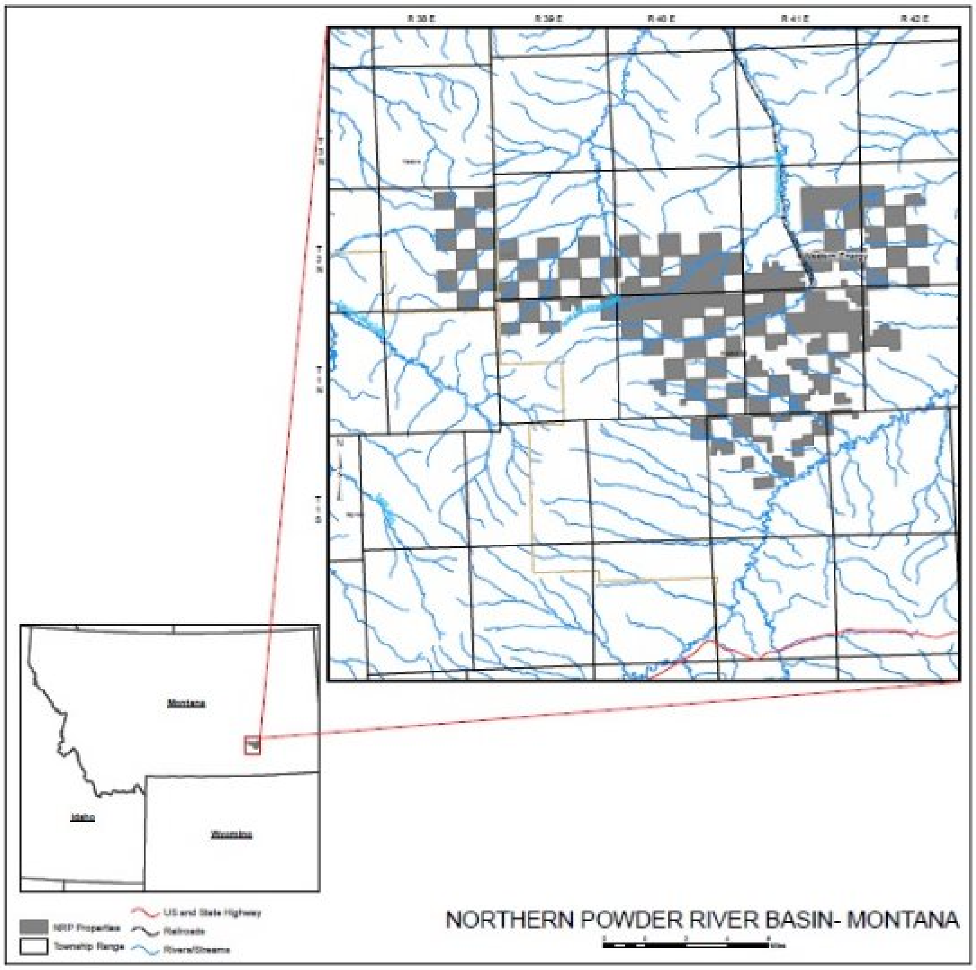
Sahara. The Sahara property is located in Saline, Hamilton and Williamson Counties in Illinois. The property is under lease to a subsidiary of Peabody Energy Corporation and approximately 0.6 million tons were mined on the property during 2015. Production is currently from an underground mine and is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

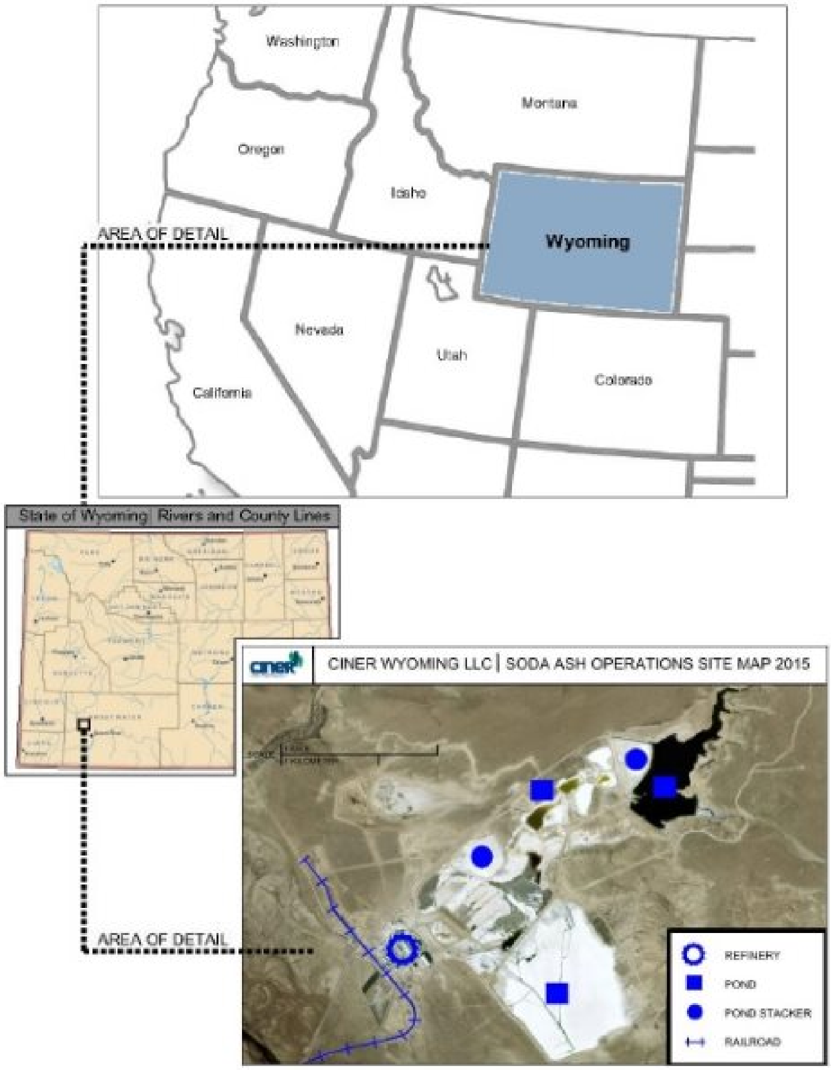
120 million tons of these reserves to the Grand Rivers operation in the VantaCore segment. The structure of these leases is similar to our coal leases, and these leases typically also require minimum rental payments in addition to royalties. During 2015, our aggregates lessees produced 2.2 million tons 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.

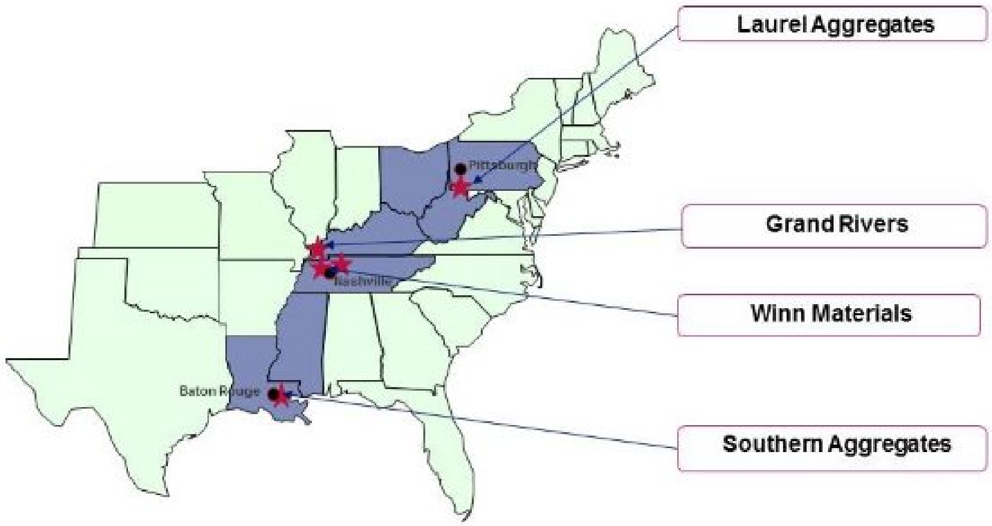
Ciner Wyoming's largest customer is ANSAC, which buys soda ash (through Ciner Wyoming's sales agent) and other of its member companies for further export to its customers. ANSAC takes soda ash orders directly from its overseas customers and then purchases soda ash for resale from its member companies 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

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(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.

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;
- 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
Less: equity earnings from unconsolidated investment	(49,918)	(41,416)	(34,186)	—	—
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

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

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	For the Years Ended December 31, 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	For the Years Ended December 31, 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):

Impaired Assets	For the Year Ended December 31, 2015	For the Year Ended December 31, 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

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	For the Years Ended December 31, 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.

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)	—	(571,720)	—	(571,720)
Non-cash contributions	—	—	811	—	811	—	811
Comprehensive loss from unconsolidated investment and other	—	—	—	(1,693)	(1,693)	—	(1,693)
Balance at December 31, 2015	12,230	$ 79,094	$ (606)	$ (2,152)	$ 76,336	$ (3,394)	$ 72,942

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

NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Years Ended December 31,		
	2015	2014	2013
Cash flows from operating activities:			
Net income (loss)	$ (571,720)	$ 108,830	$ 172,078
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Asset impairment	681,594	26,209	734
Depreciation, depletion and amortization	100,828	79,876	64,377
Distributions from equity earnings from unconsolidated investments	46,795	43,005	24,113
Equity earnings from unconsolidated investment	(49,918)	(41,416)	(34,186)
Gain on reserve swap	(9,290)	(5,690)	(8,149)
Other, net	(1,295)	1,942	(8,721)
Other, net—affiliates	(287)	—	—
Change in operating assets and liabilities:			
Accounts receivable	16,486	(8,685)	2,593
Accounts receivable—affiliates	2,630	(1,828)	2,947
Accounts payable	(3,775)	(2,408)	1,633
Accounts payable—affiliates	514	559	(566)
Accrued liabilities	(4,676)	(1,821)	7,927
Deferred revenue	7,605	2,056	4,164
Deferred revenue—affiliates	(4,200)	15,618	15,076
Accrued incentive plan expenses	(7,023)	(5,265)	2,284
Other items, net	(1,030)	(47)	(516)
Other items, net—affiliates	186	(180)	1,286
Net cash provided by operating activities	203,424	210,755	247,074
Cash flows from investing activities:			
Acquisition of mineral rights	(40,679)	(356,026)	(72,000)
Acquisition of plant and equipment and other	(10,175)	(2,454)	—
Proceeds from sale of plant and equipment and other	11,024	1,006	—
Proceeds from sale of mineral rights	7,096	412	10,929
Acquisition of equity interests	—	—	(293,085)
Acquisition of aggregates business	—	(168,978)	—
Return of equity and other unconsolidated investments	—	3,633	48,833
Return of long-term contract receivables—affiliate	2,463	1,904	2,558
Net cash used in investing activities	(30,271)	(520,503)	(302,765)
Cash flows from financing activities:			
Proceeds from loans	100,000	617,471	567,020
Proceeds from loans—affiliate	—	19,904	—
Proceeds from issuance of common units	—	127,202	75,000
Capital contribution by general partner	—	3,240	1,531
Repayments of loans	(190,983)	(327,983)	(386,230)
Distributions to partners	(71,758)	(162,042)	(246,518)
Distributions to non-controlling interest	(2,744)	(974)	(2,521)
Debt issue costs and other	(5,971)	(9,507)	(9,502)
Net cash provided by (used in) financing activities	(171,456)	267,311	(1,220)
Net increase (decrease) in cash and cash equivalents	1,697	(42,437)	(56,911)
Cash and cash equivalents at beginning of period	50,076	92,513	149,424
Cash and cash equivalents at end of period	$ 51,773	$ 50,076	$ 92,513
Supplemental cash flow information:			
Cash paid during the period for interest	$ 88,493	$ 76,155	$ 55,191
Non-cash investing activities:			

Plant, equipment and mineral rights funded with accounts payable or accrued liabilities	$	5,949	$	11,879	$	3,019
Units issued for acquisition of aggregate operations		—		31,604		—
Non-cash contingent consideration on equity investments		—		—		15,000

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

NATURAL RESOURCE PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Nature of Operations

Natural Resource Partners L.P. (the "Partnership"), a Delaware limited partnership, was formed in April 2002. The general partner of the Partnership is NRP (GP) LP ("NRP GP"), a Delaware limited partnership, whose general partner is GP Natural Resource Partners LLC, a Delaware limited liability company. The Partnership engages principally in the business of owning, operating, managing and leasing a diversified portfolio of mineral properties in the United States, including interests in coal, trona and soda ash, oil and gas, construction aggregates, frac sand and other natural resources. As used in these Notes to Consolidated Financial Statements, the terms "NRP," "we," "us" and "our" refer to Natural Resource Partners L.P. and its subsidiaries, unless otherwise stated or indicated by context.

The Partnership's coal reserves are located in the three major U.S. coal-producing regions: Appalachia, the Illinois Basin and the Western United States, as well as lignite reserves in the Gulf Coast region. The Partnership does not operate any coal mines, but leases its coal reserves to experienced mine operators under long-term leases that grant the operators the right to mine and sell its reserves in exchange for royalty payments. The Partnership also owns and manages infrastructure assets that generate additional revenues, primarily in the Illinois Basin.

The Partnership owns or leases aggregates and industrial minerals located in a number of states across the country. The Partnership derives a small percentage of its aggregates and industrial mineral revenues by leasing its owned reserves to third party operators who mine and sell the reserves in exchange for royalty payments. However, the majority of the Partnership's aggregates revenues come through its ownership of VantaCore Partners LLC ("VantaCore"), which was acquired in October 2014. VantaCore specializes in the construction materials industry and operates four hard rock quarries, six sand and gravel plants, two asphalt plants and two marine terminals. VantaCore's current operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

The Partnership owns a 49% non-controlling equity interest in Ciner Wyoming LLC ("Ciner Wyoming"), a trona ore mining operation and soda ash refinery in the Green River Basin, Wyoming. Ciner Resources LP, the Partnership's 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. The Partnership receives regular quarterly distributions from this business, and records income in accordance with the equity method of accounting.

The Partnership also owns various interests in oil and gas properties that are located in the Williston Basin, the Appalachian Basin, Louisiana and Oklahoma. The Partnership's interests in the Appalachian Basin, Louisiana and Oklahoma are minerals and royalty interests, while in the Williston Basin the Partnership owns non-operated working interests.

The Partnership's operations are conducted through, and its operating assets are owned by, its subsidiaries. The Partnership owns its subsidiaries through two wholly owned operating companies: NRP (Operating) LLC ("NRP Opco") and NRP Oil and Gas LLC ("NRP Oil and Gas"). NRP Oil and Gas holds the Partnership's non operated oil and gas working interests in the Williston Basin. All other operations of the Partnership, including other oil and gas assets, are held by NRP Opco. NRP GP has sole responsibility for conducting the Partnership's business and for managing its operations. Because NRP GP 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 makes decisions on its 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. Mr. Robertson is entitled to nominate all ten of the 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, LLC, an affiliate of Christopher Cline.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying Consolidated Financial Statements of the Partnership have been prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP"). The consolidated financial statements include the accounts of Natural Resource Partners L.P. and its wholly owned subsidiaries, as well as BRP LLC ("BRP"), a joint venture with International Paper Company controlled by the Partnership. The Partnership has an equity investment through which it is able to exercise significant influence over but does not control the investee and is not the primary beneficiary of the investee's activities which is accounted for using the equity method. Intercompany transactions and balances have been eliminated.

Management's Forecast, Strategic Plan and Going Concern Analysis

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 , NRP Oil and Gas and NRP Opco have debt agreements that contain customary financial covenants, including maintenance covenants, and other 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 going concern analysis in light of management's outlook and strategic plan to address its debt covenant compliance and maturities.

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 4.0 x through March 31, 2016. Commencing with respect to the period ended June 30, 2016, the maximum leverage ratio reduces to 3.75 x and reduces again to 3.5 x 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, management intends 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, management forecasts that NRP Oil and Gas may not be able to remain in compliance with the 3.5 x leverage ratio as required in the RBL Facility during the next 12 months. In addition, management expects 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 a default 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.

Recasting of Certain Prior Period Information

Due to the acquisitions that diversified our natural resource asset base, effective for the quarter ended December 31, 2015, management revised the Partnership's operating segments to align with its management structure and organizational responsibilities and revised the information that its chief operating decision maker regularly reviews for purposes of allocating resources and assessing performance. As a result, effective for the quarter ended December 31, 2015, we report our financial performance based on new segments as described in "Note 3. Segment Information". We recast certain prior period amounts to conform to the way we internally manage and monitor segment performance. This change had no impact on the Partnership's consolidated financial position, net income (loss) or cash flows. In addition, certain reclassifications have been made to prior period amounts to conform to the current period financial statement presentation. Prior year general and administrative charges that were allocated to the operating segments have been reclassified to Operating and maintenance expenses and Operating and maintenance expenses—affiliates on the Consolidated Statements of Comprehensive Income. In our opinion, all adjustments, consisting only of normal recurring adjustments necessary for a fair presentation, have been included.

Reverse Unit Split

On January 26, 2016, the board of directors of our general partner approved a 1-for-10 reverse split on our common units, effective following market close on February 17, 2016. Pursuant to the authorization provided, the Partnership completed the 1-for-10 reverse unit split and its common units began trading on a reverse unit split-adjusted basis on the New York Stock Exchange on February 18, 2016. As a result of the reverse unit split, every 10 outstanding common units were combined into one common unit. The reverse unit split reduced the number of common units outstanding from 122.3 million units to approximately 12.2 million units. All units and per unit data included in these consolidated financial statements have been retroactively restated to reflect the reverse unit split.

Use of 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. Actual results could differ from those estimates.

Business Combinations

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

Out-of-Period Adjustment

In March 2015, the Partnership recorded an out-of-period adjustment to correct an error in depletion expense related to its oil and gas royalty interests owned by BRP, in which the Partnership owns a 51% interest. Depletion expense for the year ended December 31, 2015 includes a credit of $3.8 million to adjust the impact of depletion expense recorded in prior periods. After evaluating the quantitative and qualitative aspects of the error and the out-of-period adjustment to the Partnership’s financial results, management determined the misstatement and the out-of-period adjustment are not material to the prior period financial statements.

Fair Value

The Partnership discloses certain assets and liabilities using fair value as defined by authoritative guidance. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. See "Note 11. Fair Value Measurements."

There are three levels of inputs that may be used to measure fair value:

- Level 1—Quoted prices in active markets for identical assets or liabilities.
- Level 2—Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.
- Level 3—Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. Level 3 assets and liabilities include financial instruments whose value is determined using pricing models, discounted cash flow methodologies, or similar techniques, as well as instruments for which the determination of fair value requires significant management judgment or estimation.

Cash and Cash Equivalents

The Partnership considers all highly liquid short-term investments with an original maturity of three months or less to be cash equivalents.

Accounts Receivable

Accounts receivable from the Partnership’s lessees and customers do not bear interest. Receivables are recorded net of the allowance for doubtful accounts in the accompanying Consolidated Balance Sheets. The Partnership evaluates the collectability of its accounts receivable based on a combination of factors. The Partnership regularly analyzes its accounts receivable and when it becomes aware of a specific lessee’s or customer’s inability to meet its financial obligations to the Partnership, such as in the case of bankruptcy filings or deterioration in the lessee’s or customer’s operating results or financial position, the Partnership records a specific reserve for bad debt to reduce the related receivable to the amount it reasonably believes is collectible. The reserve is recognized as a reduction in the accounts receivable and an increase in operating and maintenance expenses or operating and maintenance expenses—affiliates. Accounts are charged off when collection efforts are complete and future recovery is doubtful. The allowance for doubtful accounts included in the Partnership's net accounts receivable balance (including affiliates) was $5.3 million and $0.7 million at December 31, 2015 and December 31, 2014, respectively. A significant amount of the change to the Partnership's allowance for doubtful accounts during 2015 relates to new allowances for doubtful coal-related receivables.

Inventory

Inventories are stated at the lower of cost or market. The cost of aggregates and asphalt components such as stone, sand, and recycled and liquid asphalt is determined by the first-in, first-out (FIFO) method. Cost includes all direct materials, direct labor and related production overheads based on normal operating capacity. The cost of supplies inventory is determined by the average cost method and includes operating and maintenance supplies to be used in the Partnership’s aggregates operations.

Plant and Equipment

Plant and equipment is recorded at its original cost of construction or, upon acquisition, at fair value of the asset acquired and consists of coal preparation plants, related coal handling facilities, and other coal and aggregate processing and transportation infrastructure. Expenditures for new facilities and expenditures that substantially increase the useful life of property, including interest during construction, are capitalized and reported in the Consolidated Statements of Cash Flows. These assets are recorded at cost and are depreciated on a straight-line basis over their useful lives generally as follows:

	Years
Buildings and improvements	20 to 40
Machinery and equipment	5 to 12
Leasehold improvements	Life of Lease

The Partnership begins capitalizing mine development costs at its aggregates operations at a point when reserves are determined to be proven or probable, economically mineable and when demand supports investment in the market. Capitalization of these costs ceases when production commences. Mine development costs are amortized based on production over the estimated life of mineral reserves and amortization is included as a component of depreciation expense.

Mineral Rights

Mineral rights owned and leased are recorded at its original cost of construction or, upon acquisition, at fair value of the assets acquired. Coal and aggregate mineral rights are depleted on a unit-of-production basis by lease, based upon minerals mined in relation to the net cost of the mineral properties and estimated proven and probable tonnage therein. The Partnership owns royalty and non-operated working interests in oil and natural gas reserves, all of which are located in the U.S. The Partnership does not determine whether or when to develop reserves. The Partnership uses the successful efforts method to account for its working interest in oil and gas properties. Oil and gas non-operated working interests are depleted on a unit-of-production basis. The depletion rate is adjusted annually based upon the amount of remaining reserves as determined by independent third party petroleum engineers. Oil and gas royalty interests are depleted on a straight-line basis over 30 years or the life of the asset, whichever is shorter.

Intangible Assets

The Partnership’s intangible assets consist primarily of contracts that at acquisition were more favorable for the Partnership than prevailing market rates, known as above-market contracts. The estimated fair values of the above-market rate contracts are determined based on the present value of future cash flow projections related to the underlying assets acquired. Intangible assets are amortized on a unit-of-production basis except that a minimum amortization is calculated on a straight-line basis for temporarily idled assets.

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.

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.

Revenue Recognition

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.

Most of the Partnership's 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 based upon the underlying mineral lease 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.

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 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 Ciner Wyoming is reflected in the caption "Equity in unconsolidated investments" in our Consolidated Balance Sheets. Our adjusted share of the earnings or losses of Ciner Wyoming is reflected in the Consolidated Statements of Comprehensive Income as revenues and other income under the caption ''Equity in earnings of Ciner Wyoming." 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. 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.

Property Taxes

The Partnership is responsible for paying property taxes on the properties it owns. Typically, the lessees are contractually responsible for reimbursing the Partnership for property taxes on the leased properties. The payment of and reimbursement of property taxes is included in Coal, Hard Mineral Royalty and Other revenues and in Operating and maintenance expenses, respectively, in the Consolidated Statements of Comprehensive Income.

Transportation Revenue and Expense

The Company records transportation revenue and pays transportation costs to a Foresight affiliate to operate equipment on behalf of the Company. The revenue and expenses related to these transactions are recorded as Coal, Hard Mineral Royalty and Other—affiliates revenues and Operating and maintenance expenses—affiliates in the Consolidated Statements of Comprehensive Income. Shipping and handling costs invoiced to aggregate customers and paid to third-party carriers are recorded as Coal, Hard Mineral Royalty and Other revenues and Operating and maintenance expenses in the Consolidated Statements of Comprehensive Income.

Asset Retirement Costs and Obligations

The Partnership accrues for mine closure, reclamation as well as plugging and abandonment of its oil and gas non-operated working interests in accordance with authoritative guidance related to accounting for asset retirement costs and obligations. This guidance requires the fair value of an obligation be recognized in the period it is incurred, if the fair value can be reasonably estimated. The Partnership recognizes an asset and liability related to the present value of future estimated costs. Depreciation or depletion of the capitalized asset retirement cost is determined based upon the underlying asset being retired in the future. Accretion of the asset retirement obligation is recognized over time and will increase as the obligation becomes more near term. It is reasonably possible that the estimates related to asset retirement and environmental obligations may change in the future. See "Note 13. Asset Retirement Obligations."

Unit-Based Compensation

We have awarded unit-based compensation in the form of phantom units that are more fully described in Note 16. Long-Term Incentive Plans." A summary of our accounting policy for unit-based awards follows.

The Partnership accounts for awards relating to its Long-Term Incentive Plan using the fair value method, which requires the Partnership to estimate the fair value of the grant, and charge or credit the estimated fair value to expense over the requisite service period of the grant based on fluctuations in the Partnership's 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. See "Note 16. Long-Term Incentive Plans."

Deferred Financing Costs

Deferred financing costs consist of legal and other costs related to the issuance of the Partnership's long-term debt. These costs are amortized over the term of the debt. Deferred financing costs are included in Other Assets on the Partnership's Consolidated Balance Sheets.

Income Taxes

No provision for income taxes related to the operations of the Partnership has been included in the accompanying financial statements because, as a partnership, it is not subject to federal or material state income taxes and the tax effect of its activities accrues to the unitholders. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities. In the event of an examination of the Partnership’s tax return, the tax liability of the partners could be changed if an adjustment in the Partnership’s income is ultimately sustained by the taxing authorities.

Lessee Audits and Inspections

The Partnership periodically audits lessee information by examining certain records and internal reports of its lessees. The Partnership’s regional managers also perform periodic mine inspections to verify that the information that has been reported to the Partnership 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 the Partnership 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.

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") amended its guidance on revenue recognition. The core principle of this amendment is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This guidance is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. Early adoption is permitted for reporting periods beginning after December 15, 2016, including interim reporting periods within that period. This guidance can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. The Partnership is currently evaluating the impact of the provisions of this guidance on its consolidated financial position, results of operations and cash flows.

In August 2014, the FASB issued guidance on management’s responsibility to evaluate whether there is substantial doubt about an entity’s ability to continue as a going concern and to provide related footnote disclosures. The guidance is effective for interim and annual periods ending after December 15, 2016 and early adoption is permitted. The new guidance will require a formal assessment of going concern by management based on criteria prescribed in the new guidance, but will not impact the Partnership's financial position or results of operations. The Partnership is reviewing its policies and processes to ensure compliance with this new guidance.

In April 2015, the FASB issued authoritative guidance which intended to simplify the presentation of debt issuance costs in financial statements. This guidance requires an entity to present such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. Amortization of the costs will continue to be reported as interest expense. This guidance is effective for annual reporting periods beginning after December 15, 2016. Early adoption is permitted. This guidance will be applied retrospectively to each prior period presented. The Partnership is currently evaluating the impact of the provisions of this guidance on its consolidated balance sheets.

In July 2015, the FASB issued authoritative guidance which intended to simplify the measurement of inventory. This guidance requires an entity to measure inventory at the lower of cost or net realizable value. The amendments do not apply to inventory that is measured using last-in, first-out or the retail inventory method. This guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, with early adoption permitted. This guidance should be applied on a prospective basis. The Partnership is currently evaluating the impact of the provisions of this guidance on its consolidated financial position, results of operations and cash flows.

In February 2016, FASB issued authoritative lease guidance that establishes a right-of-use ("ROU") model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. The main difference between the current requirement under GAAP and the ROU model is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases. The new standard is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. A modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Partnership is currently evaluating the impact of the provisions of this guidance on its consolidated financial position, results of operations and cash flows.

3. Segment Information

The Partnership's segments are strategic business units that offer products and services to different customer segments in different geographies within the U.S. and that are managed accordingly. NRP has the following 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.

Direct segment costs and certain costs incurred at a corporate level that are identifiable and that benefit the Partnership's segments are allocated to the operating segments. These allocated costs include costs of: taxes, legal, information technology and shared facilities services and are included in Operating and maintenance expenses and Operating and maintenance expenses—affiliates on the Consolidated Statements of Comprehensive Income. Prior year general and administrative charges that are allocated to the operating segments have been reclassified to operating and maintenance expenses. Intersegment sales are at prices that approximate market.

In reconciling items to consolidated operating income, Corporate and Financing 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.

The following table summarizes certain financial information for each of the Partnership's operating segments (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						
Revenues (including affiliates)	$ 246,353	$ 49,918	$ 139,013	$ 53,565	$ —	$ 488,849
Intersegment revenues (expenses)	21	—	(21)	—	—	—
Depreciation, depletion and amortization	44,478	—	15,578	40,772	—	100,828
Asset impairment	307,800	—	6,218	367,576	—	681,594
Interest expense, net	—	—	—	—	(93,809)	(93,809)
Net income (loss)	(138,388)	49,918	272	(377,365)	(106,157)	(571,720)
Capital expenditures	428	—	14,039	30,457	—	44,924
Total assets at December 31, 2015	1,047,922	261,942	200,348	158,862	15,001	1,684,075
December 31, 2014						
Revenues (including affiliates)	$ 256,719	$ 41,416	$ 42,051	$ 59,566	$ —	$ 399,752
Depreciation, depletion and amortization	52,645	—	3,296	23,935	—	79,876
Asset impairment	26,209	—	—	—	—	26,209
Interest expense, net	—	—	—	—	(80,089)	(80,089)
Net income (loss)	143,678	41,416	32	14,338	(90,634)	108,830
Capital expenditures	5,351	—	171,116	359,851	—	536,318
Total assets at December 31, 2014	1,403,762	264,020	219,658	540,713	16,571	2,444,724
December 31, 2013						
Revenues (including affiliates)	$ 306,851	$ 34,186	$ —	$ 17,080	$ —	$ 358,117
Depreciation, depletion and amortization	58,502	—	—	5,875	—	64,377
Asset impairment	734	—	—	—	—	734
Interest expense, net	—	—	—	—	(64,158)	(64,158)
Net income (loss)	211,590	34,186	—	5,198	(78,896)	172,078
Capital expenditures	—	293,085	—	75,019	—	368,104
Total assets at December 31, 2013	1,520,428	269,338	—	189,211	12,879	1,991,856

4. Acquisitions

VantaCore Acquisition

On October 1, 2014, the Partnership continued its effort to own a more diversified portfolio of natural resources by completing its acquisition of VantaCore for $200.6 million in cash and common units. At the time of acquisition, VantaCore operated three hard rock quarries, six sand and gravel plants, two asphalt plants, one underground limestone mine and one marine terminal. VantaCore is headquartered in Philadelphia, Pennsylvania and its current operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana. This acquisition aligned the Partnership's effort to own a more diversified portfolio of natural resources.

The Partnership accounted for the transaction as a business combination under the acquisition method of accounting. Accordingly, the Partnership conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated fair values on the acquisition date, while transaction and integration costs associated with the acquisitions were expensed as incurred. The fair value of these assets and liabilities was estimated using a discounted cash flow technique with significant inputs including future production volumes, aggregate sales prices, reserves and operating costs that are not observable in the market and thus represents a Level 3 fair value measurement. The results of operations of the acquisition have been included in our consolidated financial statements since the acquisition date.

In the first quarter 2015, the purchase price allocation was adjusted as more detailed analysis was completed and additional information was obtained about the facts and circumstances for various items of VantaCore's plant and equipment that existed as of acquisition date. As a result of this adjustment, plant and equipment was increased by $22.5 million with a corresponding decrease to goodwill. In the second quarter 2015, the purchase price allocation was adjusted as more detailed analysis was completed and additional information was obtained about the facts and circumstances for VantaCore's right to mine and intangible assets that existed as of the acquisition date. As a result of this adjustment, Mineral rights, net and Intangible assets, net were increased by $24.7 million with a corresponding decrease to Goodwill. The purchase price allocation was further adjusted as more detailed analysis was completed for VantaCore's asset retirement obligations that existed as of acquisition date. As a result of this adjustment, asset retirement obligations were decreased by $2.3 million with a corresponding decrease to the asset retirement cost that was capitalized as part of the related land, property and equipment. The accounting for the VantaCore acquisition was completed in the second quarter of 2015 with the exception of this asset retirement obligation adjustment that was recoded in the fourth quarter of 2015. Measurement-period adjustments were not material to prior period financial statements and were recorded during the period in which the amount of the adjustment was determined. The accounting for the VantaCore acquisition is summarized as follows (in thousands):

	October 1, 2014
Consideration	
Cash	$ 168,978
NRP common units	31,604
Total consideration given	$ 200,582
Allocation of Purchase Price	
Current assets	$ 37,222
Land, property and equipment	59,946
Mineral rights	111,500
Other assets	4,347
Current liabilities	(16,953)
Asset retirement obligation	(1,005)
Goodwill	5,525
Fair value of net assets acquired	$ 200,582

Included in the Consolidated Statements of Comprehensive Income was revenue of $42.1 million and operating income of $0.1 million for the year ended December 31, 2014. Transaction costs through December 31, 2014 associated with this acquisition were $2.9 million and were expensed as incurred. These expenses are reflected in Operating and maintenance expenses on the Consolidated Statements of Comprehensive Income.

Sanish Field Acquisition

On November 12, 2014, the Partnership continued its effort to own a more diversified portfolio of natural resources by completing its acquisition of non-operated oil and gas working interests in the Sanish Field of the Williston Basin from an affiliate of Kaiser-Francis Oil Company for $339.1 million .

The Partnership accounted for the transaction as a business combination under the acquisition method of accounting. Accordingly, the Partnership conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated fair values on the acquisition date, while transaction and integration costs associated with the acquisitions were expensed as incurred. The fair value of these assets and liabilities was estimated using a discounted cash flow technique with significant inputs that are not observable in the market and thus represents a Level 3 fair value measurement. Significant inputs used to determine the fair value include estimates of: (i) reserves, including estimated oil and natural gas reserves and risk-adjusted probable reserves; (ii) future commodity prices; (iii) production costs, (iv) capital expenditures, (v) production and (vi) discount rates. The results of operations of the acquisition have been included in our consolidated financial statements since the acquisition date. The accounting for the Sanish Field acquisition was completed in the second quarter of 2015 without significant changes during the measurement period and is summarized as follows (in thousands):

		November 12, 2014
Consideration		
Cash	$	339,093
Allocation of Purchase Price		
Mineral rights - proven oil and gas properties		298,293
Mineral rights - probable and possible oil and gas resources		40,800
Fair value of net assets acquired	$	339,093

Included in the Consolidated Statements of Comprehensive Income was revenue of $12.8 million and operating income of $3.7 million for the year ended December 31, 2014. The transaction costs incurred in connection with this acquisition were $1.8 million through December 31, 2014, and were expensed as incurred. These expenses are reflected in Operating and maintenance expenses on the Consolidated Statements of Comprehensive Income.

Pro Forma Financial Information (unaudited)

The following unaudited pro forma financial information (in thousands) presents a summary of the Partnership's consolidated revenues, net income and net income per common unit for the twelve months ended December 31, 2014 and 2013 assuming the VantaCore and Sanish Field acquisitions had been completed as of January 1, 2013, including adjustments to reflect the values assigned to the net assets acquired:

	For the Years ended December 31,			
	2014		2013	
Total revenues and other income	$	533,517	$	579,933
Net income	$	122,319	$	197,164
Basic and diluted net income per common unit	$	9.90	$	16.00

Other Oil and Gas Aquisitions

During the year ended December 31, 2013, the Partnership also completed two smaller acquisitions of oil and natural gas properties located in the Williston Basin as described below:

Sundance Acquisition

In December, 2013, the Partnership completed the acquisition of non-operated working interests in oil and gas properties in the Williston Basin of North Dakota from Sundance Energy, Inc. for $29.4 million , following post-closing purchase price adjustments. The Partnership accounted for the transaction in accordance with the authoritative guidance for business combinations. During the third quarter of 2014, the Partnership finalized the determination of the fair value of the assets acquired and liabilities assumed in the acquisition, with no material adjustments. The assets acquired are included in Mineral rights in the accompanying Consolidated Balance Sheets.

Abraxas Acquisition

In August, 2013, the Partnership completed the acquisition of non-operated working interests in oil and gas properties in the Williston Basin of North Dakota and Montana from Abraxas Petroleum for $38.0 million , following post-closing purchase price adjustments. The Partnership accounted for the transaction in accordance with the authoritative guidance for business combinations. During the second quarter of 2014, the Partnership finalized the determination of the fair values of the assets acquired and liabilities assumed in the acquisition, with no material adjustments. The assets acquired are included in Mineral rights on the accompanying Consolidated Balance Sheets.

With respect to the Abraxas and Sundance acquisitions, revenues of $5.4 million and operating income of $2.5 million were included in the Consolidated Statements of Comprehensive Income and Consolidated Balance Sheet for the year ended December 31, 2013.

5. Equity Investment

We account for our 49% investment in Ciner Wyoming LLC ("Ciner Wyoming", and formerly "OCI Wyoming LLC") using the equity method of accounting. Ciner Wyoming distributed $46.8 million , $46.6 million and $72.9 million to us in the year ended December 31, 2015, 2014 and 2013, respectively.

The difference between the amount at which the investment in Ciner Wyoming is carried and the amount of underlying equity in Ciner Wyoming's net assets was $154.8 million and $162.7 million as of December 31, 2015 and 2014, respectively. This excess basis relates to plant, property and equipment and right to mine assets. The excess basis difference that relates to property, plant and equipment is being amortized into income using the straight-line method over a weighted average of 28 years . The excess basis difference that relates to right to mine assets is being amortized into income using the units of production method.

Our equity in the earnings of Ciner Wyoming is summarized as follows (in thousands):

	For the Year Ended December 31,		
	2015	2014	2013
Income allocation to NRP's equity interests	$ 54,709	$ 47,354	$ 37,036
Amortization of basis difference	(4,791)	(5,938)	(2,850)
Equity in earnings of unconsolidated investment	$ 49,918	$ 41,416	$ 34,186

The results of Ciner Wyoming's operations are summarized as follows (in thousands):

	For the Year Ended December 31,		
	2015	2014	2013
Sales	$ 486,393	$ 465,032	$ 442,132
Gross profit	131,493	118,439	94,299
Net Income	111,650	96,640	79,655

The financial position of Ciner Wyoming is summarized as follows (in thousands):

	For the Year Ended December 31,	
	2015	2014
Current assets	$ 144,695	$ 179,851
Noncurrent assets	233,845	223,053
Current liabilities	43,018	47,704
Noncurrent liabilities	116,808	149,192

6. Inventory

The components of inventories at December 31, 2015 and 2014 are as follows (in thousands):

	December 31, 2015	December 31, 2014
Aggregates	$ 7,056	$ 4,596
Supplies and parts	779	1,218
Total inventory	$ 7,835	$ 5,814

7. Plant and Equipment

The Partnership's plant and equipment consist of the following (in thousands):

	December 31, 2015	December 31, 2014
Plant and equipment at cost	$ 92,203	$ 89,759
Construction in process	1,074	457
Less accumulated depreciation	(32,038)	(30,123)
Total plant and equipment, net	$ 61,239	$ 60,093

Depreciation expense related to the Partnership's plant and equipment totaled $15.9 million , $7.6 million and $6.0 million for the year ended December 31, 2015, 2014 and 2013, respectively. During the second quarter of 2015 the Partnership recorded a $2.3 million impairment expense related to a coal preparation plant and during the fourth quarter of 2015 the Partnership recorded a $4.7 million impairment expense related to coal processing and transportation assets as well as obsolete equipment at our Logan office. The fair value measurement of these impaired assets recorded at fair value were $0.0 million at the end of the reporting period. The Partnership also recorded a $0.7 million impairment expense related to obsolete plant and equipment at VantaCore. During the fourth quarter of 2014, the Partnership recorded $0.8 million in impairment expense related to a coal preparation plant. These impairment charges are included in Asset impairments in the Consolidated Statements of Comprehensive Income for the year ending December 31, 2015 and December 31, 2014, respectively.

8. Mineral Rights

The Partnership's mineral rights consist of the following (in thousands):

	For the Year Ended December 31, 2015		
	Carrying Value	Accumulated Depletion	Net Book Value
Coal, Hard Mineral Royalty and Other	$ 1,278,274	$ (432,260)	$ 846,014
VantaCore	112,700	(3,082)	109,618
Oil and Gas	155,293	(16,898)	138,395
Total	$ 1,546,267	$ (452,240)	$ 1,094,027

	For the Year Ended December 31, 2014		
	Carrying Value	Accumulated Depletion	Net Book Value
Coal, Hard Mineral Royalty and Other	$ 1,680,169	$ (505,582)	$ 1,174,587
VantaCore	87,907	(482)	87,425
Oil and Gas	560,395	(40,555)	519,840
Total	$ 2,328,471	$ (546,619)	$ 1,781,852

Depletion expense related to the Partnership's mineral rights totaled $80.3 million , $68.6 million and $54.6 million for the year ended December 31, 2015, 2014 and 2013, respectively.

Impairment of Mineral Rights

The Partnership has developed procedures to periodically evaluate its long-lived assets for possible impairment. These procedures are performed throughout the year and consider both quantitative and qualitative information based on historic, current and future performance and are designed to identify impairment indicators. If an impairment indicator is identified, 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 primarily 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. The inputs used by management for fair value measurements include significant inputs that are not observable in the market and thus represent a Level 3 fair value measurement for these types of assets. 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 that a separate impairment evaluation be completed on a significant property.

During the years ended December 31, 2015, 2014 and 2013, the Partnership identified facts and circumstances that indicated that the carrying value of certain of its mineral rights exceed future cash flows from those assets and recorded non-cash impairment expense as follows (in thousands):

	For the years ended December 31,								
Impaired Asset Description	**2015**			**2014**			**2013**		
Oil and gas properties	$	367,576	(1)	$	—		$	—	
Coal properties		257,468	(2)		16,793	(4)		734	
Hard mineral royalty properties		43,402	(3)		3,013	(4)			
Total	$	668,446		$	19,806		$	734	

(1) We recorded $335.7 million of oil and gas property impairment during the third quarter 2015 and $31.9 million during the fourth quarter of 2015. The fair value measurement of these impaired assets recorded at fair value were $108.0 million at the end of the reporting period. These impairments primarily resulted from declines in future expected realized commodity prices and reduced expected drilling activity on our acreage. NRP compared net capitalized costs of its oil and natural gas properties to estimated undiscounted future net cash flows. If the net capitalized cost exceeded the undiscounted future net cash flows, NRP recorded an impairment for the excess of net capitalized cost over fair value. A discounted cash flow method was used to estimate fair value. Significant inputs used to determine the fair value include estimates of: (i) oil and natural gas reserves and risk-adjusted probable and possible reserves; (ii) future commodity prices; (iii) production costs, (iv) capital expenditures, (v) production and (vi) discount rates. The underlying commodity prices embedded in the Partnership's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing as of the measurement date, adjusted for estimated location and quality differentials.

(2) We recorded $1.5 million of coal property impairment during the second quarter of 2015, $247.8 million of coal property impairment during the third quarter of 2015 and $8.2 million during the fourth quarter of 2015. The fair value measurement of these impaired assets recorded at fair value were $0.4 million at the end of the reporting period. These impairments primarily resulted from the continued deterioration and expectations of further reductions in global and domestic coal demand due to reduced global steel demand, sustained low natural gas prices, and continued regulatory pressure on the electric power generation industry. NRP compared net capitalized costs of its coal properties to estimated undiscounted future net cash flows. If the net capitalized cost exceeded the undiscounted future cash flows, NRP recorded an impairment for the excess of net capitalized cost over fair value. Significant inputs used to determine fair value include estimates of future cash flow, discount rate and useful economic life. Estimated cash flows are the product of a process that began with current realized pricing as of the measurement date and included an adjustment for risk related to the future realization of cash flows.

(3) We recorded $43.4 million of aggregates property impairment during the third quarter of 2015. The fair value measurement of these impaired assets recorded at fair value was $0.0 million at the end of the reporting period. This impairment 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. NRP compared net capitalized costs of its aggregates properties to estimated undiscounted future net cash flows. If the net capitalized cost exceeded the undiscounted cash flows, NRP recorded an impairment for the excess of net capitalized cost over fair value. A discounted cash flow model was used to estimate fair value. Significant inputs used to determine fair value include estimates of future cash flow, discount rate and useful economic life. Estimated cash flows are the product of a process that began with current realized pricing as of the measurement date and included an adjustment for risk related to the future realization of cash flows.

(4) We recorded $16.8 million of coal property impairment and $3.0 million impairment of our aggregates properties during the fourth quarter of 2014. Management concluded certain unleased properties were impaired due primarily to the ongoing regulatory environment and continued depressed coal markets with little indications of improvement in the near term. The fair values for those unleased properties were determined for the associated reserves using Level 2 market approaches based upon recent comparable sales and Level 3 expected cash flows.

9. Goodwill and Intangible Assets

The Partnership's intangible assets consist of the following (in thousands):

		December 31, 2015		December 31, 2014
Contract intangibles	$	81,109	$	82,972
Other intangibles		5,076		3,004
Less accumulated amortization		(29,258)		(25,243)
Total intangible assets, net	$	56,927	$	60,733

Amortization expense related to the Partnership's intangible assets totaled $4.6 million , $3.6 million and $3.8 million for the years ended December 31, 2015, 2014 and 2013, respectively.

During the second quarter of 2014, the Partnership and a lessee amended an aggregates lease in its Coal, Hard Mineral Royalty and Other segment, which led the Partnership to conclude an impairment triggering event had occurred. Fair value of the lease agreement was determined using Level 3 expected cash flows. The resulting impairment expense of $5.6 million is included in Asset impairments on the Consolidated Statements of Comprehensive Income.

The estimates of amortization expense for the periods as indicated below are based on current mining plans and are subject to revision as those plans change in future periods.

For the Year Ended December 31,		Estimated Amortization Expense
		(in thousands)
2016	$	3,544
2017		3,095
2018		3,108
2019		3,108
2020		3,108

The weighted average remaining amortization period for contract intangibles and other intangibles was 14 years and 31 years , respectively.

During the fourth quarter of 2014, $52.0 million of goodwill was added relating to the VantaCore acquisition. This amount represented the preliminary residual value. During 2015, the purchase price allocation was adjusted as more detailed analysis was completed and additional information was obtained about the facts and circumstances for VantaCore’s property, plant and equipment, right to mine assets and asset retirement obligations that existed as of the acquisition date. These adjustments decreased goodwill by $46.5 million and resulted in an acquisition date goodwill of $5.5 million .

During the fourth quarter of 2015, we evaluated goodwill for impairment and compared the estimated fair value of the VantaCore reporting unit to its carrying amount. The carrying amount exceeded fair value and we recorded a $5.5 million goodwill impairment expense. The lower fair value was primarily a result of the deterioration in certain regional markets in which VantaCore operates causing a decline in future performance levels compared to levels estimated during the purchase price allocation process. A discounted cash flow model was used to estimate fair value. Significant inputs used to determine fair value include estimates of future cash flow, discount rate and useful economic life. These estimates were based on current conditions and historical experience applied to develop projections of future operating performance.

10. Debt and Debt—Affiliate

As used in this Note 10, references to "NRP LP" refer to Natural Resource Partners L.P. only, and not to NRP (Operating) LLC, or NRP Oil and Gas LLC, wholly owned subsidiaries of NRP LP, or any of Natural Resource Partners L.P.’s subsidiaries. References to "Opco" refer to NRP (Operating) LLC and its subsidiaries. References to NRP Oil and Gas refer to NRP Oil and Gas LLC, a wholly owned subsidiary of NRP LP. NRP Finance Corporation ("NRP Finance") is a wholly owned subsidiary of NRP LP and a co-issuer with NRP LP on the 9.125% senior notes described below. See discussion of Management's Forecast, Strategic Plan and Going Concern Analysis and certain matters involving the Partnership's debt in Note 2.

As of December 31, 2015 and 2014, Debt and debt—affiliate consisted of the following (in thousands):

	December 31, 2015	December 31, 2014
NRP LP Debt:		
$425 million 9.125% senior notes, with semi-annual interest payments in April and October, due October 2018, $300 million issued at 99.007% and $125 million issued at 99.5%	$ 422,923	$ 422,167
Opco Debt:		
$300 million floating rate revolving credit facility, due October 2017	290,000	—
$300 million floating rate revolving credit facility, due August 2016	—	200,000
$200 million floating rate term loan, due January 2016	—	75,000
4.91% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, due June 2018	13,850	18,467
8.38% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, due March 2019	85,714	107,143
5.05% senior notes, with semi-annual interest payments in January and July, with annual principal payments in July, due July 2020	38,462	46,154
5.31% utility local improvement obligation, with annual principal and interest payments in February, due March 2021	1,153	1,345
5.55% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, due June 2023	21,600	24,300
4.73% senior notes, with semi-annual interest payments in June and December, with annual principal payments in December, due December 2023	60,000	67,500
5.82% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, due March 2024	135,000	150,000
8.92% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, due March 2024	40,909	45,455
5.03% senior notes, with semi-annual interest payments in June and December, with annual principal payments in December, due December 2026	148,077	161,538
5.18% senior notes, with semi-annual interest payments in June and December, with annual principal payments in December, due December 2026	42,308	46,154
NRP Oil and Gas Debt:		
Reserve-based revolving credit facility due November 2019	85,000	110,000
Total debt and debt—affiliate	1,384,996	1,475,223
Less: current portion of long-term debt, net	(80,983)	(80,983)
Total long-term debt and debt—affiliate	$ 1,304,013	$ 1,394,240

NRP LP Debt

Senior Notes

In September 2013, NRP LP, together with NRP Finance as co-issuer, issued $300.0 million of 9.125% Senior Notes due 2018 at an offering price of 99.007% of par. Net proceeds after expenses from the issuance of the senior notes were approximately $289.0 million . The senior notes call for semi-annual interest payments on April 1 and October 1 of each year, and will mature on October 1, 2018.

In October 2014, NRP LP, together with NRP Finance as co-issuer, issued an additional $125.0 million of its 9.125% Senior Notes due 2018 at an offering price of 99.5% of par. The notes constitute the same series of securities as the existing $300.0 million 9.125% senior notes due 2018 issued in September 2013. Net proceeds of $122.6 million from the additional issuance of the Senior Notes were used to fund a portion of the purchase price of NRP's acquisition of non-operated working interests in oil and gas assets located in the Williston Basin in North Dakota. The notes call for semi-annual interest payments on April 1 and October 1 of each year and will mature on October 1, 2018.

NRP and NRP Finance have the option to redeem the NRP Senior Notes, in whole or in part, at any time on or after April 1, 2016, at fixed redemption prices specified in the indenture governing the NRP Senior Notes (the "NRP Senior Notes Indenture"). Before April 1, 2016, NRP and NRP Finance may redeem all or part of the NRP Senior Notes at a redemption price equal to the sum of the principal plus a make whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. Furthermore, before April 1, 2016, NRP and NRP Finance may on any one or more occasions redeem up to 35% of the aggregate principal amount of the notes with the net proceeds of certain public or private equity offerings at a redemption price of 109.125% of the principal amount of notes, plus any accrued and unpaid interest, if any, to the date of redemption, if at least 65% of the aggregate principal amount of the notes issued under the indenture remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering. In the event of a change of control, as defined in the indenture, the holders of the notes may require NRP and NRP Finance to purchase their notes at a purchase price equal to 101% of the principal amount of the notes, plus accrued and unpaid interest, if any.

The indenture governing the $425.0 million of senior notes issued by NRP LP (the "Indenture") contains covenants that, among other things, limit the ability of NRP LP and certain of its subsidiaries to incur or guarantee additional indebtedness. Under the Indenture, NRP LP and certain of its subsidiaries generally are not permitted to incur additional indebtedness unless, on a consolidated basis, the fixed charge coverage ratio (as defined in the indenture) is at least 2.0 to 1.0 for the four preceding full fiscal quarters. The ability of NRP LP and certain of its subsidiaries to incur additional indebtedness is further limited in the event the amount of indebtedness of NRP LP and certain of its subsidiaries that is senior to NRP LP’s unsecured indebtedness exceeds certain thresholds. As of December 31, 2015 and December 31, 2014, NRP was in compliance with the terms of the financial covenants contained in its debt agreements.

Opco Debt

All of Opco’s debt is guaranteed by its wholly owned subsidiaries and is secured by certain of the assets of Opco and its wholly owned subsidiaries other than NRP Trona LLC, as further described below. As of December 31, 2015 and December 31, 2014, Opco was in compliance with the terms of the financial covenants contained in its debt agreements.

Revolving Credit Facility

In June 2015, Opco entered into a $300.0 million Third Amended and Restated Credit Agreement (the "A&R Revolving Credit Facility"), which amended and restated Opco’s $300.0 million Second Amended and Restated Credit Agreement due August 2016. The A&R Revolving Credit Facility matures on October 2, 2017 , is guaranteed by all of Opco’s wholly owned subsidiaries, and is secured by liens on certain of the assets of Opco and its subsidiaries, as further described below.

Initially, indebtedness under the A&R Revolving Credit Facility bears interest, at Opco's option, at a rate of either:

- the higher of (i) the prime rate as announced by the agent bank; (ii) the federal funds rate plus 0.50% ; or (iii) LIBOR plus 1% , in each case plus 2.375% ; or
- a rate equal to LIBOR plus 3.375%

Borrowings under the A&R Revolving Credit Facility will bear interest at such rate until the time that Opco delivers quarterly financial statements for the year ended December 31, 2015 to the lenders thereunder. Following such delivery date, indebtedness under the A&R Revolving Credit Facility will bear interest, at Opco's option, at a rate of either:

- the higher of (i) the prime rate as announced by the agent bank; (ii) the federal funds rate plus 0.50% ; or (iii) LIBOR plus 1% , in each case plus an applicable margin ranging from 1.50% to 2.50% or
- a rate equal to LIBOR plus an applicable margin ranging from 2.50% to 3.50%

The weighted average interest rates for the borrowings outstanding under the A&R Revolving Credit Facility for the twelve months ended December 31, 2015 and year ended December 31, 2014 were 2.91% and 1.98% , respectively.

Opco will incur a commitment fee on the unused portion of the revolving credit facility at a rate of 0.50% per annum. Opco may prepay all amounts outstanding under the A&R Revolving Credit Facility at any time without penalty.

The A&R Revolving Credit Facility contains financial covenants requiring Opco to maintain:

- a leverage ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the A&R Revolving Credit Facility) not to exceed:
    - 4.0 to 1.0 for each fiscal quarter ending on or before March 31, 2016;
    - 3.75 to 1.0 for each subsequent fiscal quarter ending on or before March 31, 2017; and
    - 3.5 to 1.0 for each fiscal quarter ending on or after June 30, 2017; and
- a ratio of consolidated EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated lease expense) of not less than 3.5 to 1.0.

The A&R Revolving Credit Facility contains 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. Included in the investment covenant are restrictions upon Opco’s ability to acquire assets where Opco does not maintain certain levels of liquidity. The A&R Revolving Credit Facility also contains customary events of default, including cross-defaults under Opco’s senior notes (as described below).

The A&R Revolving Credit Facility is collateralized and secured by liens on certain of Opco’s assets with a carrying value of $709.9 million classified as Land, Mineral rights and Plant and equipment on the Partnership’s Consolidated Balance Sheet as of December 31, 2015. The collateral includes (1) the equity interests in all of Opco’s wholly owned subsidiaries, other than NRP Trona LLC (which owns a 49% non-controlling equity interest in Ciner Wyoming), (2) the personal property and fixtures owned by Opco’s wholly owned subsidiaries, other than NRP Trona LLC, (3) Opco’s material coal royalty revenue producing properties, (4) real property associated with certain of VantaCore’s construction aggregates mining operations, and (5) certain of Opco’s coal-related infrastructure assets.

Term Loan

During 2013, Opco entered into a $200.0 million Term Loan facility (the "Term Loan") with a maturity date of January 23, 2016. The weighted average interest rates for the debt outstanding under the term loan for the twelve months ended December 31, 2015 and 2014 were 2.19% and 2.22% respectively.

Opco repaid $101.0 million in principal under the Term Loan during the third quarter of 2013, and repaid an additional $24.0 million during the fourth quarter of 2014. In September 2015, Opco repaid the remaining $75.0 million on the term loan using borrowings under the A&R Revolving Credit Facility.

Senior Notes

Opco made principal payments of $80.8 million on its senior notes during the year ended December 31, 2015. The Note Purchase Agreements relating to Opco’s senior notes contain covenants requiring Opco to:

- Maintain a ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the note purchase agreement) of no more than 4.0 to 1.0 for the four most recent quarters;
- not permit debt secured by certain liens and debt of subsidiaries to exceed 10% of consolidated net tangible assets (as defined in the note purchase agreement); and
- maintain the ratio of consolidated EBITDDA (as defined in the note purchase agreement) to consolidated fixed charges (consisting of consolidated interest expense and consolidated operating lease expense) at not less than 3.5 to 1.0.

The 8.38% and 8.92% senior notes also provide that in the event that Opco’s leverage ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the note purchase agreement) exceeds 3.75 to 1.00 at the end of any fiscal quarter, then in addition to all other interest accruing on these notes, additional interest in the amount of 2.00% per annum shall accrue on the notes for the two succeeding quarters and for as long thereafter as the leverage ratio remains above 3.75 to 1.00.

In connection with the entry into the A&R Revolving Credit Facility in June 2015, Opco entered into the Third Amendment to the Note Purchase Agreements (the "NPA Amendment") that provides for the security of the senior notes by the same collateral package pledged by Opco and its subsidiaries to secure the A&R Revolving Credit Facility, as described above. In addition, the

NPA Amendment includes a covenant that provides that, in the event Opco or any of its subsidiaries is subject to any additional or more restrictive covenants under the agreements governing its material indebtedness (including the A&R Revolving Credit Facility, and all renewals, amendments or restatements thereof), such covenants shall be deemed to be incorporated by reference in the senior notes and the holders of the senior notes shall receive the benefit of such additional or more restrictive covenants to the same extent as the lenders under such material indebtedness agreement.

NRP Oil and Gas Debt

Revolving Credit Facility

In August 2013, NRP Oil and Gas entered into a 5 -year, $100.0 million senior secured, reserve-based revolving credit facility in order to fund capital expenditure requirements related to the development of the oil and gas assets in which it owns non-operated working interests. In connection with the closing of the Sanish Field acquisition in November 2014, the credit facility was amended to increase its size to $500.0 million with an initial borrowing base of $137.0 million , and the maturity date thereof was extended to November 2019 .

The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in May and November of each year, based on the value of the proved oil and natural gas reserves of NRP Oil and Gas, in accordance with the lenders' customary procedures and practices. NRP Oil and Gas and the lenders each have a right to one additional redetermination each year. In April 2015, the lenders completed their semi-annual redetermination of the borrowing base under the NRP Oil and Gas revolving credit facility and the $137.0 million borrowing base under that facility was redetermined to $105.0 million . In October 2015, the lenders under the NRP Oil and Gas revolving credit facility completed their semi-annual redetermination of the borrowing base under the NRP Oil and Gas revolving credit facility and the $105.0 million borrowing base was redetermined to $88.0 million . The Partnership repaid $25.0 million of outstanding borrowings under the NRP Oil and Gas revolving credit facility during the year ended December 31, 2015. At December 31, 2015 and 2014, there was $85.0 million and $110.0 million respectively, outstanding under the NRP Oil and Gas revolving credit facility.

The credit facility is secured by a first priority lien and security interest in substantially all of the assets of NRP Oil and Gas. NRP Oil and Gas is the sole obligor under its revolving credit facility, and neither the Partnership nor any of its other subsidiaries is a guarantor of such facility. The weighted average interest rate for the debt outstanding under the credit facility for the twelve months ended December 31, 2015 and, 2014 was 2.50% and 2.37% , respectively.

Indebtedness under the NRP Oil and Gas credit facility bears interest, at the option of NRP Oil and Gas, at either:

- the higher of (i) the prime rate as announced by the agent bank; (ii) the federal funds rate plus 0.50%; or (iii) LIBOR plus 1%, in each case plus an applicable margin ranging from 0.50% to 1.50%; or
- a rate equal to LIBOR, plus an applicable margin ranging from 1.50% to 2.50%.

NRP Oil and Gas incurs a commitment fee on the unused portion of the borrowing base under the credit facility at a rate ranging from 0.375% to 0.50% per annum.

The NRP Oil and Gas credit facility contains certain covenants, which, among other things, require the maintenance of:

- a total leverage ratio (defined as the ratio of the total debt of NRP Oil and Gas to its EBITDAX) of not more than 3.5 to 1.0; and
- a minimum current ratio of 1.0 to 1.0.

As of December 31, 2015 and 2014, NRP Oil and Gas was in compliance with the terms of the financial covenants contained in its credit facility.

Consolidated Principal Payments

The consolidated principal payments due are set forth below (in thousands):

	NRP LP		Opco		NRP Oil and Gas	
	Senior Notes		Senior Notes	Credit Facility	Credit Facility	Total
2016	$ —		$ 80,983	$ —	$ —	$ 80,983
2017	—		80,983	290,000	—	370,983
2018	425,000	(1)	80,983	—	—	505,983
2019	—		76,366	—	85,000	161,366
2020	—		54,938	—	—	54,938
Thereafter	—		212,820	—	—	212,820
	$ 425,000		$ 587,073	$ 290,000	$ 85,000	$ 1,387,073

(1) The 9.125% senior notes due 2018 were issued at a discount and as of December 31, 2015 were carried at $422.9 million .

11. Fair Value Measurements

The Partnership's financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and long-term debt. The carrying amounts reported on our Consolidated Balance Sheets for cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to their short-term nature. The following table (in thousands) shows the carrying amount and estimated fair value of our other financial instruments:

	December 31, 2015		December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Assets				
Contracts receivable—affiliate, current and long-term (1)	$ 4,891	$ 4,158	$ 4,870	$ 5,162
Debt and debt—affiliate				
NRP LP senior notes (2)	$ 422,923	$ 277,313	$ 422,167	$ 423,780
Opco senior notes and utility local improvement obligation (1)	$ 587,073	$ 383,065	$ 668,056	$ 672,740
Opco revolving credit facility and term loan facility (3)	$ 290,000	$ 290,000	$ 275,000	$ 275,000
NRP Oil and Gas revolving credit facility (3)	$ 85,000	$ 85,000	$ 110,000	$ 110,000

(1) The Level 3 fair value is estimated by management using quotations obtained for comparable instruments on the closing trading prices near year end.

(2) The Level 1 fair value is based upon quotations obtained for identical instruments on the closing trading prices near year end.

(3) The Level 3 fair value approximates the carrying amount because the interest rates are variable and reflective of market rates and the terms of the credit facility allow the Partnership to repay this debt at any time without penalty.

12. Related Party Transactions

Reimbursements to Affiliates of our General Partner

The Partnership's general partner does not receive any management fee or other compensation for its management of Natural Resource Partners L.P. However, in accordance with the partnership agreement, the general partner and its affiliates are reimbursed for expenses incurred on the Partnership's behalf. Direct general and administrative expenses are charged to the Partnership as incurred. The Partnership also reimburses indirect general and administrative costs, including certain legal, accounting, treasury, information technology, insurance, administration of employee benefits and other corporate services incurred by the Partnership's general partner and its affiliates, Quintana Minerals Corporation and Western Pocahontas Properties Limited Partnership ("WPPLP"). In addition, the Partnership receives non-cash equity contributions from its general partner related to compensation paid directly by the general partner and not reimbursed by the Partnership. These amounts are presented as non-cash equity contributions on the Partnership's Consolidated Statements of Partners' Capital.

The Partnership had Accounts payable—affiliates to Quintana Minerals Corporation of $1.1 million and $0.6 million at December 31, 2015 and 2014, respectively, for services provided by Quintana Minerals Corporation to the Partnership. The Partnership had Accounts payable—affiliates to WPPLP of $0.3 million and $0.4 million at December 31, 2015 and 2014, respectively.

Direct general and administrative expenses charged to the Partnership by its general partner for services performed by WPPLP and Quintana Minerals Corporation are as follows (in thousands):

	For the Year Ended December 31,		
	2015	2014	2013
Operating and maintenance expenses—affiliates, net	16,031	10,770	8,821
General and administrative—affiliates	5,312	3,258	3,286

The Partnership also leases an office building in Huntington, West Virginia from WPPLP and pays $0.6 million in lease payments each year through December 31, 2018.

Cline Affiliates

Various companies controlled by Chris Cline, including Foresight Energy LP, lease coal reserves from the Partnership, and the Partnership also leases coal transportation assets to them for a fee. Mr. Cline, both individually and through another affiliate, Adena Minerals, LLC, owns a 31% interest (unaudited) in the NRP's general partner, as well as approximately 0.5 million of NRP's common units (unaudited) at December 31, 2015. Coal related revenues from Foresight Energy totaled $86.6 million , $81.5 million and $88.4 million for the years ended December 31, 2015, 2014 and 2013, respectively.

As of December 31, 2015 and 2014, the Partnership had Accounts receivable—affiliates from Foresight Energy of $6.4 million and $9.2 million , respectively. As of December 31, 2015, the Partnership had received $82.6 million in minimum royalty payments to date that have been recorded as Deferred revenue—affiliates since they have not been recouped by Foresight Energy.

The Partnership owns and leases rail load out and associated facilities to Foresight Energy at Foresight Energy's Sugar Camp mine. The lease agreement is accounted for as a direct financing lease. Total projected remaining payments under the lease at December 31, 2015 were $81.2 million with unearned income of $35.4 million , and the net amount receivable was $45.9 million , of which $2.0 million is included in Accounts receivable—affiliates while the remaining is included in Long-term contracts receivable—affiliate on the accompanying Consolidated Balance Sheets. Minimum lease payments are $5.0 million per year for the next five years and represent a $1.25 million per quarter in deficiency payment.

Total projected remaining payments under the lease at December 31, 2014 were $86.3 million with unearned income of $39.0 million and the net amount receivable was $47.3 million , of which $1.8 million is included in Accounts receivable—affiliates while the remaining is included in Long-term contracts receivable—affiliates on the accompanying Consolidated Balance Sheets.

The Partnership holds a contractual overriding royalty interest from a subsidiary of Foresight Energy that provides for payments based upon production from specific tons at Foresight Energy's Sugar Camp operations. This overriding royalty was accounted for as a financing arrangement and is reflected as an affiliate receivable. The net amount receivable under the agreement as of December 31, 2015 was $4.9 million , of which $1.5 million is included in Accounts receivable—affiliates while the remaining is included in Long-term contracts receivable—affiliate. The net amount receivable under the agreement as of December 31, 2014 was $5.6 million , of which $1.1 million is included in Accounts receivable—affiliates while the remaining is included in Long-term contracts receivable—affiliate on the accompanying Consolidated Balance Sheets.

During the years ended December 31, 2015, 2014 and 2013, the Partnership recognized a gain of $9.3 million , $5.7 million and $8.1 million , respectively on a reserve swap at Foresight Energy's Williamson mine. The gain is included in Coal, hard mineral royalty and other—affiliates revenues on the Consolidated Statements of Comprehensive Income. The Level 3 fair value of the reserves was estimated using a discounted cash flow model. The expected cash flows were developed using estimated annual sales tons, forecasted sales prices and anticipated market royalty rates.

Long-Term Debt—Affiliate

Donald R. Holcomb, one of the Partnership’s directors, is a manager of Cline Trust Company, LLC, which owns approximately 0.54 million of the Partnership’s common units and $20.0 million in principal amount of the Partnership’s 9.125% Senior Notes due 2018. The members of the Cline Trust Company are four trusts for the benefit of the children of Chris Cline, each of which owns an approximately equal membership interest in the Cline Trust Company. Mr. Holcomb also serves as trustee of each of the four trusts. Cline Trust Company, LLC purchased the $20.0 million of the Partnership’s 9.125% Senior Notes due 2018 in the Partnership’s offering of $125.0 million additional principal amount of such notes in October 2014 at the same price as the other purchasers in that offering. The balance on this portion of the Partnership’s 9.125% Senior Notes due 2018 was $19.9 million as of December 31, 2015 and 2014 and is included in Long-term debt, net—affiliate on the accompanying Consolidated Balance Sheet.

Quintana Capital Group GP, Ltd.

Corbin J. Robertson, Jr. is a principal in Quintana Capital Group GP, Ltd. ("Quintana Capital"), which controls several private equity funds focused on investments in the energy business. In connection with the formation of Quintana Capital, the Partnership adopted a formal conflicts policy that establishes the opportunities that will be pursued by the Partnership and those that will be pursued by Quintana Capital. The governance documents of Quintana Capital’s affiliated investment funds reflect the guidelines set forth in the Partnership's conflicts policy.

At December 31, 2015, a fund controlled by Quintana Capital owned a majority interest in Corsa Coal Corp ("Corsa")., a coal mining company traded on the TSX Venture Exchange that is one of the Partnership’s lessees in Tennessee. Corbin J. Robertson III, one of the Partnership’s directors, is Chairman of the Board of Corsa. Coal related revenues from Corsa totaled $3.1 million , $3.0 million and $4.6 million for the years ended December 31, 2015, 2014 and 2013, respectively.

As of December 31, 2015, the Partnership had recorded $0.3 million in minimum royalty payments to date as Deferred revenue—affiliates since they have not been recouped by Corsa. The Partnership also had Accounts receivable—affiliates totaling $0.2 million and $0.3 million from Corsa at December 31, 2015 and 2014, respectively.

A fund controlled by Quintana Capital owned a significant membership interest in Taggart Global USA, LLC, including the right to nominate two members of Taggart’s 5-person board of directors. In 2013, Taggart was sold to Forge Group, and Quintana no longer retains an interest in Taggart or Forge. The Partnership owns and leases preparation plants to Forge, which operates the plants. The lease payments were based on the sales price for the coal that was processed through the facilities. The revenues from Taggart prior to the sale to Forge were $1.8 million for the year ended December 31, 2013.

WPPLP Production Royalty and Overriding Royalty

For the year ended December 31, 2015, the Partnership recorded $0.4 million in operating and maintenance expenses—affiliates related to a non-participating production royalty payable to WPPLP pursuant to a conveyance agreement entered into in 2007. These charges were zero for the years ended December 31, 2014 and 2013. The Partnership had Other assets—affiliate from WPPLP of $1.1 million and $0.0 million at December 31, 2015 and December 31, 2014, respectively related to a non-production royalty receivable from WPPLP for overriding royalty interest on a mine.

13. Asset Retirement Obligations

The Partnership accrues a liability for legal asset retirement obligations based on an estimate of the timing and amount of settlement. The Partnership accrues for costs involving the ultimate closure of certain of its aggregate mining operations in accordance with its operating permits. These charges include costs of land reclamation, water drainage, and incremental direct administration cost of closing the operations. The Partnership also accrues for estimated costs relating to plugging wells in which it has a non-operation working interest. Upon initial recognition of an asset retirement obligation the Partnership increases the carrying amount of the long-lived asset by the same amount as the liability. Over time, the liabilities are accreted for the change in their present value, through charges to depreciation, depletion, and amortization and the initial costs are depleted over the useful lives of the related assets.

The following table presents a reconciliation (in thousands) of the beginning and ending carrying amounts of the Partnership's asset retirement obligations. The short-term balance of $0.0 million and $0.1 million at December 31, 2015 and 2014, respectively, is included in Accrued liabilities and the remaining balance is included in Other non-current liabilities in the Consolidated Balance Sheets. The Partnership does not have any assets that are legally restricted for purposes of settling these obligations.

	For the Years Ended December 31,	
	2015	2014
Balance, January 1	$ 4,973	$ 39
Liabilities incurred in current period, including aquisitions	5	4,697
Accretion expense	284	237
Acquisition related purchase price adjustments	(2,280)	—
Balance, December 31	$ 2,982	$ 4,973

14. Commitments and Contingencies

Legal

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

The purchase agreement for the acquisition of the Partnership's interest in Ciner Wyoming, formerly OCI Wyoming, requires the Partnership 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. During the first quarters of 2014 and 2015, the Partnership paid $0.5 million and $3.8 million , respectively, in contingent consideration to Anadarko. As of December 31, 2015, the Partnership has estimated and recorded $7.2 million as an accrued liability on its consolidated Balance Sheet, payable in the first quarter of 2016 with respect to 2015. The Partnership has no obligation to pay contingent consideration with respect to any period after 2015.

In March 2014, Anadarko gave the Partnership written notice that it believed certain reorganization transactions conducted in 2013 within the OCI organization triggered an acceleration of the Partnership's obligation under the purchase agreement with Anadarko to pay the additional contingent consideration in full and demanded immediate payment of such amount. The Partnership disagreed with Anadarko's position in a written response provided to them in April 2014. In April 2015, Anadarko sent a written request for additional information regarding the OCI reorganization and indicated that they were still considering this claim against the Partnership. The Partnership responded in writing in May 2015 and does not believe the reorganization transactions triggered an obligation to pay the additional contingent consideration. The Partnership will continue to engage in discussions with Anadarko to resolve the issue to the extent necessary. However, if Anadarko were to pursue and prevail on such a claim, the Partnership 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 the Partnership would be considered to be additional acquisition consideration and added to Equity and other unconsolidated investments.

Since 2013, several citizen group lawsuits have been filed against landowners alleging ongoing discharges of pollutants, including selenium and conductivity, from valley fills located at reclaimed mountaintop removal mining sites in West Virginia. In each case, the mine on the subject property had been closed, the property had been reclaimed, and the state reclamation bond had been released. Any determination that a landowner or lessee has liability for discharges from a previously reclaimed mine site could result in substantial compliance costs or fines and would result in uncertainty as to continuing liability for completed and reclaimed coal mine operations. A subsidiary of the Partnership has been named as a defendant in one of these lawsuits. Given the early stage of this ongoing litigation, the Partnership currently cannot reasonably estimate a range of potential loss, if any, related to this matter.

Hillsboro/Deer Run

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.

Environmental Compliance

The operations the Partnership's lessees' conduct on its properties, as well as the aggregates/industrial minerals and oil and gas operations in which the Partnership has interests, are subject to federal and state environmental laws and regulations. See "Item 1. Business—Regulation and Environmental Matters." As an owner of surface interests in some properties, the Partnership may be liable for certain environmental conditions occurring on the surface properties. The terms of substantially all of the Partnership's coal leases require the lessee to comply with all applicable laws and regulations, including environmental laws and regulations. Lessees post reclamation bonds assuring that reclamation will be completed as required by the relevant permit, and substantially all of the leases require the lessee to indemnify the Partnership against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. The Partnership makes regular visits to the mines to ensure compliance with lease terms, but the duty to comply with all regulations rests with the lessees. The Partnership believes that its lessees will be able to comply with existing regulations and does not expect that any lessee's failure to comply with environmental laws and regulations to have a material impact on the Partnership's financial condition or results of operations. The Partnership has neither incurred, nor is aware of, any material environmental charges imposed on the Partnership related to its properties for the period ended December 31, 2015. The Partnership is not associated with any environmental contamination that may require remediation costs. However, the Partnership's lessees do conduct reclamation work on the properties under lease to them. Because the Partnership is not the permittee of the mines being reclaimed, the Partnership is not responsible for the costs associated with these reclamation operations. As an owner of working interests in oil and natural gas operations, the Partnership is responsible for its proportionate share of any losses and liabilities, including environmental liabilities, arising from uninsured and underinsured events. The Partnership is also responsible for losses and liabilities, including environmental liabilities that may arise from uninsured and underinsured events at its VantaCore operations.

15. Major Lessees

Revenues from lessees that exceeded ten percent of total revenues and other income for any of the periods presented below are as follows (in thousands except for percentages):

	For the Years Ended December 31,					
	2015		2014		2013	
	Revenues	Percent	Revenues	Percent	Revenues	Percent
Foresight Energy	$ 86,614	17.7%	$ 81,546	20.4%	$ 88,432	24.7%
Alpha Natural Resources	$ 34,364	7.0%	$ 48,783	12.2%	$ 55,147	15.4%

All of the revenue related to the customers above is included in revenues of the Coal, Hard Mineral Royalty and Other segment.

The Partnership had a significant concentration of revenues with Foresight Energy and Alpha Natural Resources. The exposure is currently spread out over a number of different mining operations and leases. During the year ended December 31, 2015, total revenues and other income from Alpha Natural Resources included a $6.0 million non-recurring lease assignment fee.

16. Long-Term Incentive Plans

GP Natural Resource Partners LLC adopted the Natural Resource Partners Long-Term Incentive Plan (the "Long-Term Incentive Plan") for directors of GP Natural Resource Partners LLC and employees of its affiliates who perform services for the Partnership. The compensation committee of GP Natural Resource Partners LLC's board of directors administers the Long-Term Incentive Plan. Subject to the rules of the exchange upon which the common units are listed at the time, the board of directors and the compensation committee of the board of directors have the right to alter or amend the Long-Term Incentive Plan or any part of the Long-Term Incentive Plan from time to time. Except upon the occurrence of unusual or nonrecurring events, no change in any outstanding grant may be made that would materially reduce the benefit intended to be made available to a participant without the consent of the participant.

Phantom units are incentive based equity awards issued to employees over a vesting period that entitle the grantee to receive the cash equivalent to the value of a unit of our common units upon each vesting. The Partnership records compensation cost equal to the fair value of the award at the measurement date, which is determined to be the earlier of the performance commitment date or the service completion date. In addition, compensation cost for unvested phantom unit awards is adjusted quarterly for any changes in the Partnership's unit price. Under the plan a grantee will receive the market value of a common unit in cash upon vesting. Market value is defined as the average closing price over the 20 trading days prior to the vesting date. The compensation committee may make grants under the Long-Term Incentive Plan to employees and directors containing such terms as it determines, including the vesting period. Outstanding grants vest upon a change in control of the Partnership, the general partner, or GP Natural Resource Partners LLC. If a grantee's employment or membership on the board of directors terminates for any reason, outstanding grants will be automatically forfeited unless and to the extent the compensation committee provides otherwise.

In connection with the phantom unit awards, the Compensation, Nominating and Governance Committee also granted tandem Distribution Equivalent Rights ("DERs"), which entitle the holders to receive distributions equal to the distributions paid on the Partnership's common units between the date the units are granted and the vesting date. The DERs are payable in cash upon vesting but may be subject to forfeiture if the grantee ceases employment prior to vesting.

A summary of activity in the outstanding grants during 2015 is as follows (in thousands):

	Phantom Units
Outstanding grants at January 1, 2015	115
Grants during the period	52
Grants vested and paid during the period	(29)
Forfeitures during the period	(12)
Outstanding grants at December 31, 2015	126

Grants typically vest at the end of a four -year period and are paid in cash upon vesting. The Partnership recorded a credit to general and administrative expenses related to its Long-Term Incentive Plan of $3.4 million for the year ended December 31, 2015, due to the decline in the market price of the Partnership's common units during 2015. For the years ended December 31, 2014 and 2013 the Partnership recorded G&A expenses of $1.0 million and $9.6 million , respectively.

In connection with the Long-Term Incentive Plans, payments are typically made during the first quarter of the year. Payments of $4.4 million , $6.5 million and $7.0 million were made during the years ended December 31, 2015, 2014, and 2013, respectively. The grant date fair value was $4.2 million , $6.6 million and $7.8 million for awards in 2015, 2014 and 2013, respectively. The unaccrued cost associated with unvested outstanding grants and related DERs at December 31, 2015 and December 31, 2014, was $0.7 million and $5.2 million , respectively.

17. Supplementary Unrestricted Subsidiary Information

The following is presented as supplementary data as required by the Indenture governing the NRP Senior Notes due 2018 (the "Indenture"). As described in Note 2. Summary of Significant Accounting Policies, in February 2016, the Partnership designated NRP Oil and Gas, a wholly owned subsidiary of NRP, as an Unrestricted Subsidiary for purposes of the Indenture. In addition, the Partnership has designated BRP LLC, a joint venture in which the Partnership owns a 51% interest, and Coval Leasing Company, LLC, a wholly owned subsidiary of BRP LLC, as Unrestricted Subsidiaries for purposes of the Indenture. The information below may not necessarily be indicative of the results of operations, or financial position had the subsidiaries operated as independent entities. There were no transactions between the Partnership and its Restricted Subsidiaries and its Unrestricted Subsidiaries. In accordance with the requirements of the Indenture, the following condensed consolidating financial information presents the financial condition and results of operations of the Partnership and its Restricted Subsidiaries and its Unrestricted Subsidiaries:

CONDENSED CONSOLIDATING BALANCE SHEETS
(in thousands)

	December 31, 2015		
	Unrestricted Subsidiaries of NRP	NRP and its Restricted Subsidiaries	Total
ASSETS			
Current assets (including affiliates)	$ 21,540	$ 99,589	$ 121,129
Mineral rights, net	134,445	959,582	1,094,027
Equity in unconsolidated investment	—	261,942	261,942
Other non-current assets (including affiliates)	2,287	204,690	206,977
Total assets	$ 158,272	$ 1,525,803	$ 1,684,075
LIABILITIES AND CAPITAL			
Current portion of long-term debt, net	—	80,983	80,983
Other current liabilities (including affiliates)	7,351	48,313	55,664
Long-term debt, net (including affiliate)	85,000	1,219,013	1,304,013
Other non-current liabilities (including affiliates)	4,703	165,770	170,473
Partners' capital	64,663	11,673	76,336
Non-controlling interest	(3,445)	51	(3,394)
Total liabilities and capital	$ 158,272	$ 1,525,803	$ 1,684,075

	December 31, 2014		
	Unrestricted Subsidiaries of NRP	NRP and its Restricted Subsidiaries	Total
ASSETS			
Current assets (including affiliates)	$ 23,842	$ 112,276	$ 136,118
Mineral rights, net	446,938	1,334,914	1,781,852
Equity in unconsolidated investment	—	264,020	264,020
Other non-current assets (including affiliates)	4,156	258,578	262,734
Total assets	$ 474,936	$ 1,969,788	$ 2,444,724
LIABILITIES AND CAPITAL			
Current portion of long-term debt, net	—	80,983	80,983
Other current liabilities (including affiliates)	16,212	50,736	66,948
Long-term debt, net (including affiliate)	110,000	1,284,240	1,394,240
Other non-current liabilities (including affiliates)	5,193	177,205	182,398
Partners' capital	344,232	376,573	720,805
Non-controlling interest	(701)	51	(650)
Total liabilities and capital	$ 474,936	$ 1,969,788	$ 2,444,724

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year Ended December 31, 2015		
	Unrestricted Subsidiaries of NRP	NRP and its Restricted Subsidiaries	Total
Revenues	$ 56,091	$ 432,758	$ 488,849
Operating expenses	361,166	605,594	966,760
Loss from operations	(305,075)	(172,836)	(477,911)
Other expense	4,065	89,744	93,809
Net loss	(309,140)	(262,580)	(571,720)
Add: comprehensive loss from unconsolidated investment and other	—	(1,693)	(1,693)
Comprehensive loss	$ (309,140)	$ (264,273)	$ (573,413)

	Year Ended December 31, 2014		
	Unrestricted Subsidiaries of NRP	NRP and its Restricted Subsidiaries	Total
Revenues	$ 56,840	$ 342,912	$ 399,752
Operating expenses	41,754	169,079	210,833
Income from operations	15,086	173,833	188,919
Other expense	662	79,427	80,089
Net income	14,424	94,406	108,830
Add: comprehensive loss from unconsolidated investment and other	—	(81)	(81)
Comprehensive income	$ 14,424	$ 94,325	$ 108,749

	Year Ended December 31, 2013		
	Unrestricted Subsidiaries of NRP	NRP and its Restricted Subsidiaries	Total
Revenues	$ 14,386	$ 343,731	$ 358,117
Operating expenses	8,812	113,069	121,881
Income from operations	5,574	230,662	236,236
Other expense	39	64,119	64,158
Net income	5,535	166,543	172,078
Add: comprehensive income from unconsolidated investment and other	—	65	65
Comprehensive income	$ 5,535	$ 166,608	$ 172,143

18. Subsequent Events

The following represents material events that have occurred subsequent to December 31, 2015 through the time of the Partnership's filing of its Annual Report on Form 10-K with the SEC:

Distribution Declared

On February 12, 2016, the Partnership paid a distribution of $0.45 per unit to unitholders of record on February 5, 2016.

Reverse Unit Split

On January 26, 2016, the board of directors of our general partner approved a 1-for- 10 reverse split on our common units, effective following market close on February 18, 2016. Pursuant to the authorization provided, the Partnership completed the 1-for-10 reverse unit split and its common units began trading on a reverse unit split-adjusted basis on the New York Stock Exchange on February 18, 2016. As a result of the reverse unit split, every 10 units of issued and outstanding common units were combined into one issued and outstanding common unit, without any change in the par value per unit. The reverse unit split reduced the number of common units outstanding from 122.3 million units to approximately 12.2 million units. All units and per unit data included in these consolidated financial statements have been retroactively restated to reflect the reverse unit split.

Oil and Gas Royalty Properties Sale

In February 2016, the Partnership sold royalty and overriding royalty interests in several producing properties located in the Appalachian Basin for $36.6 million in net cash proceeds and recorded a gain of $20.3 million . 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.

Aggregate Royalty Properties Sale

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 estimated aggregates reserves as of December 31, 2015 for $9.8 million in net cash proceeds and recorded a gain of $1.6 million . The effective date of the sale was February 1, 2016.

NATURAL RESOURCE PARTNERS L.P.
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

The Partnership prepared the following oil and gas information in accordance with the authoritative guidance for oil and gas extractive activities.

Capitalized Costs (in thousands):

	For the Years Ended December 31, 2015	2014
Proven properties	$ 199,404	$ 392,153
Unproven properties	—	46,400
Total property, plant, and equipment	199,404	438,553
Accumulated depreciation, depletion, and amortization	(60,542)	(18,993)
Net capitalized costs	$ 138,862	$ 419,560

Costs incurred for property acquisitions, exploration, and development (in thousands):

	For the Years Ended December 31, 2015	2014
Property acquisitions		
Proven properties	$ —	$ 298,627
Unproven properties	—	40,800
Development	29,080	5,340
Total	$ 29,080	$ 344,767

Results of Operations for Producing Activities (in thousands):

	For the Years Ended December 31, 2015	2014
Production revenue	$ 49,201	$ 48,834
Royalty and overriding royalty revenue (1)	4,364	10,732
Total oil and gas related revenue	53,565	59,566
Operating costs and expense:		
Depreciation, depletion and amortization	40,772	23,936
Property, franchise and other taxes	5,210	5,529
Production costs	12,871	12,544
Impairment of oil and gas properties	367,576	—
Total operating costs and expense	426,429	42,009
Total income from operations	$ (372,864)	$ 17,557

(1) Includes $0.4 million and $1.9 million for the years ended December 31, 2015 and 2014, respectively of nonproduction revenues including lease bonus payments

Estimated Proved 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. The Partnership estimated proved reserves as of December 31, 2015 and 2014 were prepared by Netherland, Sewell & Associates, Inc., the Partnership's 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 the Partnership's 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. Netherland Sewell prepared its report covering properties representing 100% of the Partnership's estimated proved reserves as of December 31 2015 and 2014. Prices were calculated using the unweighted average of the first-day-of-the-month pricing for the twelve months ended December 31, 2015 and 2014. These prices were then adjusted for transportation and other costs. There can be no assurance that the proved reserves will be produced as estimated or that the prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reserve engineers often arrive at different estimates for the same properties. A copy of Netherland Sewell's summary report is included as Exhibit 99.2 to this Annual Report on Form 10-K.

The following tables shows our estimated domestic proved reserves and reserve additions and revisions:

	Crude Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)(2)	Total Proved Reserves (MBoe)(3)
December 31, 2014	9,983	1,229	14,370	13,607
Revisions of previous estimates	(1,451)	89	701	(1,244)
Extensions, discoveries and other additions	776	60	541	926
Sales of properties	(98)	—	(62)	(108)
Production	(1,136)	(156)	(2,226)	(1,663)
December 31, 2015 (1)	8,074	1,222	13,324	11,518
Proved developed reserves as of December 31, 2015	7,862	1,196	13,157	11,251
Proved undeveloped reserves as of December 31, 2015	212	26	167	267
Proved developed reserves as of December 31, 2014	8,930	1,098	13,161	12,221
Proved undeveloped reserves as of December 31, 2014	1,053	131	1,209	1,386

(1) Includes reserves attributable to the Partnership's 51% member interest in BRP LLC.

(2) 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.

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

The standardized measure of discounted future net cash flows from our estimated proved oil and gas reserves is as follows (in thousands):

	For the Years Ended December 31,	
	2015	2014
Future cash inflows	$ 364,352	$ 920,454
Less related future:		
Production costs	(164,649)	(312,666)
Development and abandonment costs	(7,826)	(20,072)
Future net cash flows before 10% discount	191,877	587,716
Discount to present value at a 10% annual rate	(75,524)	(282,519)
Total standardized measure of discounted net cash flows	$ 116,353	$ 305,197

NATURAL RESOURCE PARTNERS L.P.
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

The table below is a summary of the changes in the standardized measure of discounted future net cash flows for our proved oil and gas reserves during the year ended December 31, 2015 (in thousands):

Beginning of the period	$	305,197
Revisions to previous estimates:		
Changes in prices and costs		(188,946)
Changes in quantities		(11,750)
Changes in future development costs		(12,202)
Previously estimated development costs incurred during the period		29,080
Additions to proved reserves from extensions, discoveries and improved recovery, less related costs		11,928
Purchases and sales of reserves in place, net		(3,851)
Accretion of discount		31,795
Sales of oil and gas, net of production costs		(35,112)
Production timing and other		(9,786)
Net increase (decrease)		(188,844)
End of period	$	116,353

NATURAL RESOURCE PARTNERS L.P.
SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

Quarterly Financial Data

The following table summarizes quarterly financial data for 2015 and 2014 (in thousands, except per unit data):

2015	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total 2015**
Total revenues and other income	$ 109,677	$ 137,630	$ 125,479	$ 116,063	$ 488,849
Depreciation, depletion and amortization	$ 25,392	$ 30,660	$ 26,624	$ 18,152	$ 100,828
Asset impairment	$ —	$ 3,803 (1)	$ 626,838 (2)	$ 50,953 (3)	$ 681,594
Income (loss) from operations	$ 40,417	$ 55,920	$ (576,290)	$ 2,042	$ (477,911)
Net income (loss)	$ 17,489	$ 32,578	$ (600,001)	$ (21,786)	$ (571,720)
Net income (loss) per limited partner unit	$ 1.40	$ 2.50	$ (47.90)	$ (1.75)	$ (45.75)
Weighted average number of common units outstanding	12,230	12,230	12,230	12,230	12,230

2014	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total 2014**
Total revenues and other income	$ 80,309	$ 90,561	$ 91,609	$ 137,273	$ 399,752
Depreciation, depletion and amortization	$ 14,647	$ 16,350	$ 18,621	$ 30,258	$ 79,876
Asset impairment	$ —	$ 5,624 (4)	$ —	$ 20,585 (5)	26,209
Income from operations	$ 52,439	$ 50,403	$ 55,027	$ 31,050	$ 188,919
Net income	$ 32,605	$ 31,407	$ 36,173	$ 8,645	$ 108,830
Net income per limited partner unit	$ 2.90	$ 2.80	$ 3.20	$ 0.70	$ 9.42
Weighted average number of common units outstanding	10,985	11,040	11,124	12,145	11,326

(1) During the second quarter of 2015 we recorded a $2.3 million impairment expense related to a coal preparation plant and a $1.5 million impairment expense related to coal mineral rights.

(2) During the third quarter of 2015 we recorded $335.7 million of oil and gas property impairment, $247.8 million of coal property impairment and $43.4 million of aggregates property impairment.

(3) During the fourth quarter of 2015 we recorded $31.9 million of oil and gas property impairment, $8.2 million of coal property impairment, $5.5 million of goodwill impairment, $4.7 million related to coal processing and transportation assets as well as obsolete equipment at our Logan office as well as a $0.7 million impairment expense related to obsolete plant and equipment at VantaCore.

(4) During the second quarter of 2014, we recorded $5.6 million of intangible asset impairment related to an aggregates lease.

(5) During the fourth quarter of 2014, we recorded $16.8 million of coal property impairment and $3.0 million of aggregates property impairment as well as $0.8 million in impairment expense related to a coal preparation plant. that began with current realized pricing as of the measurement date and included an adjustment for risk related to the future realization of cash flows.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of December 31, 2015. This evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of GP Natural Resource Partners LLC, our managing general partner. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and procedures were effective as of December 31, 2015 at the reasonable assurance level in producing the timely recording, processing, summary and reporting of information and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosures.

Management’s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of GP Natural Resource Partners LLC, our managing general partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2015 based on the framework in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission "2013 Framework" (COSO). Based on that evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2015. No changes were made to our internal control over financial reporting during the last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Ernst & Young, LLP, the independent registered public accounting firm who audited the Partnership’s consolidated financial statements included in this Annual Report on Form 10-K, has issued a report on the Partnership’s internal control over financial reporting, which is included herein.

Report of Independent Registered Public Accounting Firm

The Partners of Natural Resource Partners L.P.

We have audited 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) (the COSO criteria). Natural Resource Partners L.P.’s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company’s internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Natural Resource Partners L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet 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 and our report dated March 11, 2016 expressed an unqualified opinion there thereon.

/s/ Ernst & Young LLP

Houston, Texas
March 11, 2016

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE MANAGING GENERAL PARTNER AND CORPORATE GOVERNANCE

As a master limited partnership we do not employ any of the people responsible for the management of our properties. Instead, we reimburse affiliates of our managing general partner, GP Natural Resource Partners LLC, for their services. The following table sets forth information concerning the directors and officers of GP Natural Resource Partners LLC as of January 31, 2016. Each officer and director is elected for their respective office or directorship on an annual basis. Unless otherwise noted below, the individuals served as officers or directors of the partnership since the initial public offering. Subject to the Investor Rights Agreement with Adena Minerals, LLC, 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.

Name	Age	Position with the General Partner
Corbin J. Robertson, Jr.	68	Chairman of the Board and Chief Executive Officer
Wyatt L. Hogan	44	President and Chief Operating Officer
Craig W. Nunez	54	Chief Financial Officer and Treasurer
Christopher J. Zolas	41	Chief Accounting Officer
Kevin J. Craig	47	Executive Vice President, Coal
David M. Hartz	42	Vice President, Oil and Gas
Kathy H. Roberts	64	Vice President, Investor Relations
Kathryn S. Wilson	41	Vice President, General Counsel and Secretary
Gregory F. Wooten	59	Vice President, Chief Engineer
Robert T. Blakely	74	Director
Russell D. Gordy	65	Director
Donald R. Holcomb	59	Director
Robert B. Karn III	74	Director
S. Reed Morian	70	Director
Richard A. Navarre	55	Director
Corbin J. Robertson, III	45	Director
Stephen P. Smith	55	Director
Leo A. Vecellio, Jr.	69	Director

Corbin J. Robertson, Jr. has served as Chief Executive Officer and Chairman of the Board of Directors of GP Natural Resource Partners LLC since 2002. Mr. Robertson has vast business experience having founded and served as a director and as an officer of multiple companies, both private and public, and has served on the boards of numerous non-profit organizations. He has served as the Chief Executive Officer and Chairman of the Board of the general partners of Western Pocahontas Properties Limited Partnership since 1986, Great Northern Properties Limited Partnership since 1992, Quintana Minerals Corporation since 1978, and as Chairman of the Board of Directors of New Gauley Coal Corporation since 1986. He also serves as a Principal with Quintana Capital Group, Chairman of the Board of the Cullen Trust for Higher Education and on the boards of the American Petroleum Institute, the National Petroleum Council, the Baylor College of Medicine and the Spirit Golf Association. In 2006, Mr. Robertson was inducted into the Texas Business Hall of Fame. Mr. Robertson is the father of Corbin J. Robertson, III.

Wyatt L. Hogan has served as President and Chief Operating Officer of GP Natural Resource Partners LLC since March 2015. From September 2014 through February 2015, Mr. Hogan served as President of GP Natural Resource Partners LLC. Mr. Hogan was Executive Vice President of GP Natural Resource Partners from December 2013 through August 2014 and Vice President, General Counsel and Secretary of GP Natural Resource Partners from May 2003 to December 2013. Mr. Hogan joined NRP in 2003 from Vinson & Elkins L.L.P., where he practiced corporate and securities law from August 2000 through April 2003. Mr. Hogan also serves as Executive Vice President of Quintana Minerals Corporation, New Gauley Coal Corporation, the general partner of Western Pocahontas Properties Limited Partnership and the general partner of Great Northern Properties Limited Partnership, and from 2003 to October 2013, Mr. Hogan served as General Counsel and Secretary of those entities. He is also a member of the Board of Directors of Quintana Minerals Corporation and represents NRP as one of its appointees to the Board of

Managers of Ciner Wyoming LLC. Mr. Hogan also serves as a member of the Board of the National Mining Association and the American Coalition for Clean Coal Electricity. Mr. Hogan has been involved in numerous charitable organizations and currently serves as Chairman of the Board of Kids' Meals, Inc. and is on the Boards of the Kinkaid Investment Foundation and the Kinkaid Alumni Association.

Craig W. Nunez has served as Chief Financial Officer and Treasurer of GP Natural Resource Partners LLC since January 2015. Prior to joining NRP, Mr. Nunez was an owner and Chief Executive Officer of Bocage Group, a private investment company specializing in energy, natural resources and master limited partnerships since March 2012. In addition, until joining NRP, he was a FINRA-registered Investment Advisor Representative with Searle & Co since July 2012 and served as an Executive Advisor to Capital One Asset Management since January 2014. From September 2011 through March 2012, Mr. Nunez served as the Executive Vice President and Chief Financial Officer of Quicksilver Resources Canada, Inc. Mr. Nunez was Senior Vice President and Treasurer of Halliburton Company from January 2007 until September 2011, and Vice President and Treasurer of Halliburton Company from February 2006 to January 2007. Prior to that, he was Treasurer of Colonial Pipeline Company from November 1995 to February 2006. Mr. Nunez has been involved in numerous charitable organizations and currently serves on the boards of Goodwill Industries of Houston and Medical Bridges, Inc.

Christopher J. Zolas has served as Chief Accounting Officer of GP Natural Resource Partners since March 2015. Prior to joining NRP, Mr. Zolas served as Director of Financial Reporting at Cheniere Energy, Inc., a publicly traded energy company, where he performed financial statement preparation and analysis, technical accounting and SEC reporting for five separate SEC registrants, including a master limited partnership. Mr. Zolas joined Cheniere Energy, Inc. in 2007 as Manager of SEC Reporting and Technical Accounting and was promoted to Director in 2009. Prior to joining Cheniere Energy, Inc., Mr. Zolas worked in public accounting with KPMG LLP from 2002 to 2007.

Kevin J. Craig has served as Executive Vice President, Coal of GP Natural Resource Partners since September 2014. Mr. Craig was the Vice President of Business Development for GP Natural Resource Partners LLC since 2005. Mr. Craig also represents NRP as one of its appointees to the Board of Managers of Ciner Wyoming LLC. Mr. Craig joined NRP in 2005 from CSX Transportation, where he served as Terminal Manager for the West Virginia Coalfields. He has extensive marketing and finance experience with CSX since 1996. Mr. Craig also served as a Delegate to the West Virginia House of Delegates having been elected in 2000 and re-elected in 2002, 2004, 2006, 2008, 2010 and 2012. Mr. Craig most recently served as Chairman of the Committee on Energy. Mr. Craig did not seek re-election in 2014 and his term ended January 2015. Prior to joining CSX, he served as a Captain in the United States Army. Mr. Craig served as the Chairman of the Huntington Regional Chamber of Commerce Board of Directors and as a Director for the West Virginia Chamber of commerce and is involved in numerous state coal associations. Mr. Craig also represents NRP as one of its appointees to the Board of Managers of Ciner Wyoming LLC.

David M. Hartz has served as Vice President, Oil and Gas of GP Natural Resource Partners LLC since December 2013. He served as Director, Oil and Gas from 2011 to December 2013. Prior to joining NRP, Mr. Hartz served as Director of Scotia Waterous, the oil and gas investment banking group within Scotia Capital from 2007 until 2011 where he was involved in oil and gas acquisition and divestiture transactions throughout the United States. Prior to investment banking, Mr. Hartz served in a variety of technical positions as a petroleum geologist for Texaco and Hess within several U.S. and international petroleum basins. He is a member of IPAA, Houston Producers Forum, as well as numerous state oil and gas associations.

Kathy H. Roberts is Vice President, Investor Relations of GP Natural Resource Partners LLC. Ms. Roberts joined NRP in July 2002. She was the Principal of IR Consulting Associates from 2001 to July 2002 and from 1980 through 2000 held various financial and investor relations positions with Santa Fe Energy Resources, most recently as Vice President-Public Affairs. She is a Certified Public Accountant. Ms. Roberts currently serves on the Board of Directors of the Master Limited Partnership Association and has served on the local board of directors of the National Investor Relations Institute. She has also served on the Executive Committee and as a National Vice President of the Institute of Management Accountants.

Kathryn S. Wilson has served as Vice President, General Counsel and Secretary of GP Natural Resource Partners LLC since December 2013. Ms. Wilson served as Associate General Counsel from March 2013 to December 2013. Since October 2013, Ms. Wilson has also served as General Counsel and Secretary of each of Quintana Minerals Corporation, New Gauley Coal Corporation, the general partner of Western Pocahontas Properties Limited Partnership, and the general partner of Great Northern Properties Limited Partnership. Ms. Wilson practiced corporate and securities law with Vinson & Elkins L.L.P. from September 2001 to February 2010 and from November 2011 to February 2013. Ms. Wilson served as General Counsel of Antero Resources Corporation from March 2010 to June 2011.

Gregory F. Wooten has served as Vice President, Chief Engineer of GP Natural Resource Partners LLC since December 2013. Mr. Wooten joined NRP in 2007, serving as Regional Manager. Prior to joining NRP, Mr. Wooten served as Vice President, COO and Chief Engineer of Dingess Rum Properties, Inc., where he managed coal, oil, gas and timber properties from 1982 until 2007. Prior to 1982, Mr. Wooten worked as a planning and production engineer in the coal industry and is a member of the American Institute of Mining, Metallurgical, and Petroleum Engineers.

Robert T. Blakely joined the Board of Directors of GP Natural Resource Partners LLC in January 2003. Mr. Blakely has extensive public company experience having served as Executive Vice President and Chief Financial Officer for several companies. From January 2006 until August 2007, he served as Executive Vice President and Chief Financial Officer of Fannie Mae, and from August 2007 to January 2008 as an Executive Vice President at Fannie Mae. From mid-2003 through January 2006, he was Executive Vice President and Chief Financial Officer of MCI, Inc. He previously served as Executive Vice President and Chief Financial Officer of Lyondell Chemical from 1999 through 2002, Executive Vice President and Chief Financial Officer of Tenneco, Inc. from 1981 until 1999 as well as a Managing Director at Morgan Stanley. He served until December 31, 2011 as a Trustee of the Financial Accounting Foundation and is a trustee emeritus of Cornell University. He has served on the Board of Westlake Chemical Corporation since August 2004. In 2009, Mr. Blakely joined the Boards of Directors of Ally Financial (formerly GMAC, Inc.), where he serves as Chairman of the Audit Committee, and Greenhill & Co.

Russell D. Gordy joined the Board of Directors of GP Natural Resource Partners in October 2013. Mr. Gordy brings extensive oil and gas industry, mineral interest and land ownership and financial experience to the Board. Mr. Gordy is currently managing partner and majority owner in SG Interests, a producer of oil and coal bed methane gas, RGGS, which controls mineral acres currently producing oil and gas, coal, iron ore, limestone, and copper, and Rock Creek Ranch. He is also President of Gordy Oil Company, an oil and gas exploration company in the Gulf Coast of Texas and Louisiana, and Gordy Gas Corporation, an oil and gas exploration company in the San Juan Basin of Colorado and New Mexico. Prior to forming SG Interests in 1989, Mr. Gordy was a founding partner of Northwind Exploration Company an exploration company created in 1981 with former Houston Oil and Minerals employees. Mr. Gordy served on the board of directors of Houston Exploration Company from 1987 until 2001.

Donald R. Holcomb joined the Board of Directors of GP Natural Resource Partners LLC in October 2013. Mr. Holcomb brings financial and coal company experience to the Board of Directors. Mr. Holcomb is currently the Chief Executive Officer of Dickinson Fuel Company, Inc., the managing general partner of Dickinson Properties Limited Partnership, a land company in West Virginia. He is also the owner and manager of Ikes Fork, LLC and Hanover Property Management LLC. From 2001 to March 31, 2013, Mr. Holcomb served as Chief Financial Officer for Foresight Reserves LP and its subsidiaries, which companies are affiliated with Christopher Cline. Mr. Holcomb also serves as trustee of various trusts affiliated with the Cline family. Prior to joining Foresight, Mr. Holcomb held a variety of executive management positions, including at Banner Coal & Land Company, Inc., Patriot Automotive Group, Atlantic Mine Supply Company, Inc., and Wind River Consulting, LLC. Mr. Holcomb is a retired Certified Public Accountant.

Robert B. Karn III joined the Board of Directors of GP Natural Resource Partners LLC in 2002. Mr. Karn brings extensive financial and coal industry experience to the Board of Directors. He currently is a consultant and serves on the Board of Directors of various entities. He was the partner in charge of the coal mining practice worldwide for Arthur Andersen from 1981 until his retirement in 1998. He retired as Managing Partner of the St. Louis office's Financial and Economic Consulting Practice. Mr. Karn is a Certified Public Accountant, Certified Fraud Examiner and has served as president of numerous organizations. He also currently serves on the Board of Directors of Peabody Energy Corporation, Kennedy Capital Management, Inc. and the Board of Trustees of numerous publicly listed closed-end, mutual and exchange traded funds of the Guggenheim family of funds.

S. Reed Morian joined the Board of Directors of GP Natural Resource Partners LLC in 2002. Mr. Morian has vast executive business experience having served as Chairman and Chief Executive Officer of several companies since the early 1980s and serving on the board of other companies. Mr. Morian has served as a member of the Board of Directors of the general partner of Western Pocahontas Properties Limited Partnership since 1986, New Gauley Coal Corporation since 1992 and the general partner of Great Northern Properties Limited Partnership since 1992. Mr. Morian worked for Dixie Chemical Company from 1971 to 2006 and served as its Chairman and Chief Executive Officer from 1981 to 2006. He has also served as Chairman, Chief Executive Officer and President of DX Holding Company since 1989. He formerly served on the Board of Directors for the Federal Reserve Bank of Dallas-Houston Branch from April 2003 until December 2008 and as a Director of Prosperity Bancshares, Inc. from March 2005 until April 2009.

Richard A. Navarre joined the Board of Directors of GP Natural Resource Partners LLC in October 2013. Mr. Navarre brings extensive financial, strategic planning, public company and coal industry experience to the Board of Directors. From 1993 until

2012, Mr. Navarre held several executive positions with Peabody Energy Corporation, including President-Americas from March 2012 to June 2012, President and Chief Commercial Officer from January 2008 to March 2012, Executive Vice President of Corporate Development and Chief Financial Officer from July 2006 to January 2008 and Chief Financial Officer from October 1999 to June 2008. Since his retirement from Peabody Energy in 2012, Mr. Navarre has provided advisory services to the coal industry and private equity firms. Mr. Navarre serves on the Board of Directors of Civeo Corporation, where he serves as Chairman of the Audit Committee. He is a member of the Hall of Fame of the College of Business and a member of the Board of Advisors of the College of Business and Administration of Southern Illinois University Carbondale. He is a member of the Board of Directors of the Foreign Policy Association and is the former Chairman of the Bituminous Coal Operators' Association and former advisor to the New York Mercantile Exchange. Mr. Navarre is a Certified Public Accountant. Mr. Navarre also has been involved in numerous charitable organizations throughout his career.

Corbin J. Robertson, III joined the Board of Directors of GP Natural Resource Partners LLC in May 2013. Mr. Robertson has experience with investments in a variety of energy businesses, having served both in management of private equity firms and having served on several boards of directors. Mr. Robertson has served as a Co-Managing Partner of LKCM Headwater Investments GP, LLC and LKCM Headwater Investments I, L.P., a private equity fund, since June 2011. He has served as the Chief Executive Officer of the general partner of Western Pocahontas Properties Limited Partnership since May 2008, and has served on the Board of Directors of Western Pocahontas since October 2012. Mr. Robertson also co-founded Quintana Energy Partners, an energy-focused private equity firm in 2006, and served as a Managing Director thereof from 2006 until December 2010. Mr. Robertson has served on the Board of Directors for Quintana Minerals Corporation since October 2007, and previously served as Vice President-Acquisitions for GP Natural Resource Partners LLC from 2003 until 2005. Mr. Robertson also serves on the Board of Directors of the general partner of Genesis Energy L.P., a publicly traded master limited partnership, as well as Corsa Coal Corp, Buckhorn Energy Services and LL&B Minerals, each of which is in the energy business. Mr. Robertson is the son of Corbin J. Robertson, Jr.

Stephen P. Smith joined the Board of Directors of GP Natural Resource Partners LLC in 2004. Mr. Smith brings extensive public company financial experience in the power and energy industries to the Board of Directors. Mr. Smith has served as Chief Financial Officer and Chief Accounting Officer of the general partner of Columbia Pipeline Partners L.P. since December 2014 and as a Director since September 2014. Mr. Smith also serves as Executive Vice President and Chief Financial Officer of Columbia Pipeline Group. Mr. Smith served as Executive Vice President and Chief Financial Officer for NiSource, Inc. from June 2008 to June 2015. Prior to joining NiSource, he held several positions with American Electric Power Company, Inc, including Senior Vice President - Shared Services from January 2008 to June 2008, Senior Vice President and Treasurer from January 2004 to December 2007, and Senior Vice President - Finance from April 2003 to December 2003. From November 2000 to January 2003, Mr. Smith served as President and Chief Operating Officer - Corporate Services for NiSource Inc. Prior to joining NiSource, Mr. Smith served as Deputy Chief Financial Officer for Columbia Energy Group from November 1999 to November 2000 and Chief Financial Officer for Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company from 1996 to 1999.

Leo A. Vecellio, Jr. joined the Board of Directors of GP Natural Resource Partners LLC in May 2007. Mr. Vecellio brings extensive experience in the aggregates and coal mine development industry to the Board of Directors. Mr. Vecellio and his family have been in the aggregates materials and construction business since the late 1930s. Since November 2002, Mr. Vecellio has served as Chairman and Chief Executive Officer of Vecellio Group, Inc, a major aggregates producer, contractor and oil terminal developer/operator in the Mid-Atlantic and Southeastern states. For nearly 30 years prior to that time Mr. Vecellio served in various capacities with Vecellio & Grogan, Inc., having most recently served as Chairman and Chief Executive Officer from April 1996 to November 2002. Mr. Vecellio is the former Chairman of the American Road and Transportation Builders and is a longtime member of the Florida Council of 100, as well as many other civic and charitable organizations.

Corporate Governance

Board Attendance and Executive Sessions

The Board met 11 times in 2015. During that period, every director attended all of the Board meetings, with the exception of Mr. Blakely, Mr. Vecellio, Mr. Gordy, Mr. Holcomb and Corbin J. Robertson, III, who each missed one meeting. During 2015, our non-management directors met in executive session several times. The presiding director was Mr. Blakely, the Chairman of our Compensation, Nominating and Governance Committee, or CNG Committee. In addition, our independent directors met one time in executive session in December 2015. Mr. Blakely was the presiding director at that meeting. Interested parties may communicate with our non-management directors by writing a letter to the Chairman of the CNG Committee, NRP Board of Directors, 1201 Louisiana Street, Suite 3400, Houston, Texas 77002.

Independence of Directors

The Board of Directors has affirmatively determined that Messrs. Blakely, Gordy, Karn, Navarre, Smith and Vecellio are independent based on all facts and circumstances considered by the Board, including the standards set forth in Section 303A.02(a) of the NYSE's listing standards. Although we had a majority of independent directors in 2015, because we are a limited partnership as defined in Section 303A of the NYSE's listing standards, we are not required to do so. The Board has an Audit Committee, a Compensation, Nominating and Governance Committee, and a Conflicts Committee, each of which is staffed solely by independent directors.

Audit Committee

Our Audit Committee is comprised of Robert B. Karn III, who serves as chairman, Robert T. Blakely, Richard A. Navarre and Stephen P. Smith. Mr. Karn, Mr. Blakely, Mr. Navarre and Mr. Smith are "Audit Committee Financial Experts" as determined pursuant to Item 407 of Regulation S-K. Mr. Blakely currently serves on four audit committees. In accordance with the rules of the NYSE, our Board of Directors has made the determination that Mr. Blakely's service on four audit committees does not impair his ability to serve effectively on our audit committee.

Report of the Audit Committee

Our Audit Committee is composed entirely of independent directors. The members of the Audit Committee meet the independence and experience requirements of the New York Stock Exchange. The Committee has adopted, and annually reviews, a charter outlining the practices it follows. The charter complies with all current regulatory requirements. The Audit Committee Charter is available on our website at *www.nrplp.com* and is available in print upon request.

During 2015, at each of its meetings, the Committee met with the senior members of our financial management team, our general counsel and our independent auditors. The Committee had private sessions at certain of its meetings with our independent auditors and the senior members of our financial management team and the general counsel at which candid discussions of financial management, accounting and internal control and legal issues took place.

The Committee approved the engagement of Ernst & Young LLP as our independent auditors for the year ended December 31, 2015 and reviewed with our financial managers and the independent auditors overall audit scopes and plans, the results of internal and external audit examinations, evaluations by the auditors of our internal controls and the quality of our financial reporting.

Management has reviewed the audited financial statements in the Annual Report with the Audit Committee, including a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant accounting judgments and estimates, and the clarity of disclosures in the financial statements. In addressing the quality of management's accounting judgments, members of the Audit Committee asked for management's representations and reviewed certifications prepared by the Chief Executive Officer and Chief Financial Officer that our unaudited quarterly and audited consolidated financial statements fairly present, in all material respects, our financial condition and results of operations, and have expressed to both management and auditors their general preference for conservative policies when a range of accounting options is available.

The Committee also discussed with the independent auditors other matters required to be discussed by the auditors with the Committee by PCAOB Auditing Standard No. 16, *Communications With Audit Committees.* The Committee received and discussed with the auditors their annual written report on their independence from the partnership and its management, which is made under Rule 3526, *Communication With Audit Committees Concerning Independence,* and considered with the auditors whether the provision of non-audit services provided by them to the partnership during 2015 was compatible with the auditors' independence.

In performing all of these functions, the Audit Committee acts only in an oversight capacity. The Committee reviews our Quarterly Reports on Form 10-Q and Annual Reports on Form 10-K prior to filing with the Securities and Exchange Commission. In 2015, the Committee also reviewed quarterly earnings announcements with management and representatives of the independent auditor in advance of their issuance. In its oversight role, the Committee relies on the work and assurances of our management, which has the primary responsibility for financial statements and reports, and of the independent auditors, who, in their report, express an opinion on the conformity of our annual financial statements with U.S. generally accepted accounting principles.

In reliance on these reviews and discussions, and the report of the independent auditors, the Audit Committee has recommended to the Board of Directors, and the Board has approved, that the audited financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2015, for filing with the Securities and Exchange Commission.

Robert B. Karn III, Chairman
Robert T. Blakely
Richard A. Navarre
Stephen P. Smith

Compensation, Nominating and Governance Committee

Executive officer compensation is administered by the CNG Committee, which is comprised of four members. Mr. Blakely, the Chairman, has served on this Committee since 2003. Mr. Karn has served on the Committee since 2002. Mr. Vecellio joined the committee in 2007, and Mr. Gordy joined the Committee in 2013. The CNG Committee has reviewed and approved the compensation arrangements described in the Compensation Discussion and Analysis section of this Annual Report on Form 10-K. Our Board of Directors appoints the CNG Committee and delegates to the CNG Committee responsibility for:

- reviewing and approving the compensation for our executive officers in light of the time that each executive officer allocates to our business;
- reviewing and recommending the annual and long-term incentive plans in which our executive officers participate; and
- reviewing and approving compensation for the Board of Directors.

Our Board of Directors has determined that each CNG Committee member is independent under the listing standards of the NYSE and the rules of the SEC.

Pursuant to its charter, the CNG Committee is authorized to obtain at NRP's expense compensation surveys, reports on the design and implementation of compensation programs for directors and executive officers and other data that the CNG Committee considers as appropriate. In addition, the CNG Committee has the sole authority to retain and terminate any outside counsel or other experts or consultants engaged to assist it in the evaluation of compensation of our directors and executive officers. The CNG Committee Charter is available on our website at *www.nrplp.com* and is available in print upon request.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires directors, officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of their equity securities. These people are also required to furnish us with copies of all Section 16(a) forms that they file. Based solely upon a review of the copies of Forms 3, 4 and 5 furnished to us, or written representations from certain reporting persons that no Forms 5 were required for transactions occurring in 2014 and except as described below, we believe that our officers and directors and persons who beneficially own more than ten percent of a registered class of our equity securities complied with all filing requirements with respect to transactions in our equity securities during 2015. On December 18, 2015, David M. Hartz filed a Form 4 reporting the sale of 1,368 common units in the open market on October 29, 2015 that had not been previously reported on a timely basis.

Partnership Agreement

Investors may view our partnership agreement and the amendments to the partnership agreement on our website at *www.nrplp.com* . The partnership agreement and the amendments are also filed with the SEC and are available in print to any unitholder that requests them.

Corporate Governance Guidelines and Code of Business Conduct and Ethics

We have adopted Corporate Governance Guidelines. We have also adopted a Code of Business Conduct and Ethics that applies to our management, and complies with Item 406 of Regulation S-K. Our Corporate Governance Guidelines and our Code of Business Conduct and Ethics are available on our website at *www.nrplp.com* and are available in print upon request.

NYSE Certification

Pursuant to Section 303A of the NYSE Listed Company Manual, in 2015, Corbin J. Robertson, Jr. certified to the NYSE that he was not aware of any violation by the Partnership of NYSE corporate governance listing standards.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Overview

As a publicly traded partnership, we have a unique employment and compensation structure that is different from that of a typical public corporation. We have no employees, other than at the VantaCore operations, and our executive officers based in Houston, Texas are employed by Quintana Minerals Corporation and our executive officers based in Huntington, West Virginia are employed by Western Pocahontas Properties Limited Partnership, both of which are our affiliates. For a more detailed description of our structure, see "Item 1. Business—Partnership Structure and Management" in this Annual Report on Form 10-K. Although our executives' salaries and bonuses are paid directly by the private companies that employ them, we reimburse those companies based on the time allocated to NRP by each executive officer. Our reimbursement for the compensation of executive officers is governed by our partnership agreement. The information presented in this Item 11. does not give effect to the one-for-ten reverse unit split that was effective on February 17, 2016.

Executive Officer Compensation Strategy and Philosophy

Under our partnership agreement, we are required to distribute all of our available cash each quarter. Historically, our primary business objective was to generate cash flows at levels that could sustain long-term quarterly cash distributions to our investors. However, given the collapse of the coal and oil markets over the past year, coupled with the closure of the debt and equity capital markets to the energy space, our current objective is to preserve long-term equity value for our unitholders by using our excess free cash flow to reduce our leverage. Our objective in determining the compensation of our executive officers is to retain qualified people to manage the business through a difficult market cycle. Although we historically have not tied our compensation to achievement of specific financial targets or fixed performance criteria, we have reevaluated that strategy in light of current market conditions. See "—2016 Cash Long-Term Incentive Plan" below.

The 2015 compensation for executive officers consisted of four primary components:

- base salaries;
- annual cash incentive awards, including cash payments made by our general partner based on the cash distributions it receives from the common units that it owns (which we refer to herein as "GP Bonus Awards");
- long-term equity incentive compensation; and
- perquisites and other benefits.

In December 2014, our CNG Committee reviewed the performance of the executive officers and the amount of time expected to be spent by each NRP officer on NRP business, and determined the salaries for each officer for 2015. All of our named executive officers, other than Corbin J. Robertson, Jr., our Chairman and Chief Executive Officer, spent 97% or more of their time on NRP matters during 2015, and NRP bears the allocated cost of their time. Mr. Robertson has historically spent approximately 50% of his time on NRP matters. Mr. Robertson does not receive a salary or an annual bonus in his capacity as Chief Executive Officer. Rather, Mr. Robertson has historically been compensated exclusively through long-term phantom unit grants awarded by the CNG Committee and through GP Bonus Awards. Mr. Robertson also directly or indirectly owns in excess of 20% of the outstanding common units of NRP, and thus his interests are directly aligned with our unitholders.

In February of each year, the CNG Committee approves the year-end bonuses for the year just ended and long-term incentive awards for the executive officers. The CNG Committee considers the performance of the partnership, the performance of the individuals and the outlook for the future in determining the amounts of the awards. In accordance with past practice, the CNG Committee met in February 2015 and approved the long-term incentive awards disclosed in the Summary Compensation Table below. Because we are a partnership, tax and accounting conventions make it more costly for us to issue additional common units or options as incentive compensation. Consequently, we have no outstanding options or restricted units and currently have no plans to issue options or restricted units in the future. Instead, we have traditionally issued phantom units, coupled with tandem distribution equivalent rights ("DERs"), to our executive officers that are paid in cash based on the average closing price of our common units for the 20-day trading period prior to vesting. The phantom units and DERs typically vest four years from the date of grant. In past years, these awards have served to align the executive officers' interests with those of our unitholders.

During 2015, given the sharp decline in NRP's unit price, the Board of Directors recognized that the value of the executive officers' phantom unit awards and the decreased GP Bonus Awards no longer provided long-term incentive or retention value to management. Accordingly, the Board authorized and directed the CNG Committee to begin a review of options for a new long-term incentive program for NRP management to be adopted in 2016. Upon the conclusion of this review, in February 2016, the CNG Committee elected not to award additional phantom units under the long-term incentive plan and instead adopted a new cash long-term incentive plan and recommended the new plan and forms of award agreements thereunder to the Board for approval. The Board approved the new plan and awards in February 2016 and approved awards to officers under the plan in March 2016. See "—2016 Cash Long-Term Incentive Plan" below.

Role of Compensation Experts

The CNG Committee did not retain any consultants to evaluate compensation of officers or directors with respect to 2015 compensation. Historically, the CNG Committee periodically has utilized consultants to get a basic sense of the market, but has considered the advice of the consultant as only one of many factors among the other items discussed in this compensation discussion and analysis. For a more detailed description of the CNG Committee and its responsibilities, see "Item 10. Directors and Executive Officers of the Managing General Partner and Corporate Governance" in this Annual Report on Form 10-K.

During 2015, at the direction of the Board, the CNG Committee retained Meridian Compensation Partners ("Meridian") to advise on a new long-term incentive strategy to be implemented in 2016 in order to incentivize and retain management in light of the significant decrease in phantom unit award value and GP Bonus Awards. See "—2016 Cash Long-Term Incentive Plan" below. In selecting Meridian as its compensation consultant, the CNG Committee assessed the independence of Meridian pursuant to SEC rules and considered, among other things, whether Meridian provides any other services to NRP, the policies of Meridian that are designed to prevent any conflict of interest between Meridian, the CNG Committee and NRP, any personal or business relationship between Meridian and a member of the CNG Committee or one of NRP's executive officers and whether Meridian owned any of NRP's common units. In addition to the foregoing, the CNG Committee received documentation from Meridian addressing the firm's independence. Meridian was engaged directly by the CNG Committee, reports exclusively to the CNG Committee and does not provide any additional services to NRP. The CNG Committee has concluded that Meridian is independent and does not have any conflicts of interest. While management did cooperate with Meridian in collecting data with respect to NRP's compensation programs, the CNG Committee determined that management had not attempted to influence Meridian's review or recommendations.

Role of Our Executive Officers in the Compensation Process

Mr. Hogan, our President and Chief Operating Officer, provided Mr. Robertson with recommendations relating to the executive officers other than himself in connection with the evaluation of the 2015 compensation programs. Mr. Robertson considered those recommendations and provided the CNG Committee with recommendations for all of the executive officers other than himself. Mr. Robertson relied on his personal experience in setting compensation over a number of years in determining the appropriate amounts for each employee, and considered each of the factors described elsewhere in this compensation discussion and analysis. Mr. Robertson and Mr. Hogan attended the CNG Committee meetings at which the Committee deliberated and approved the compensation, but were excused from the meetings when the CNG Committee discussed their compensation. No other named executive officer assumed an active role in the evaluation or design of the 2015 executive officer compensation programs.

Evaluation of 2015 Performance; Components of Compensation

2015 Performance

During 2015, NRP's Adjusted EBITDA and distributable cash flow, which the Board considers to be the critical measures in evaluating NRP's 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 market expectations and was down only 5% compared to 2014. During 2015, as part of NRP's strategic plan to pay down debt and improve its balance sheet and credit metrics, the Board reduced the cash distribution paid to unitholders by over 87%. We used the cash savings from the distribution reduction to permanently reduce our outstanding debt by approximately $91.0 million. The reduction in the distribution resulted in a significant decline in NRP's unit price, which diminished the long-term incentive and retention value of management's phantom unit awards and GP Bonus Awards.

Base Salaries

With the exception of Mr. Robertson, who, as described above, does not receive a salary for his services as Chief Executive Officer, our named executive officers are paid an annual base salary by Quintana Minerals Corporation ("Quintana") and Western Pocahontas Properties Limited Partnership ("Western Pocahontas") for services rendered to us by the executive officers during the fiscal year. We then reimburse Quintana and Western Pocahontas based on the time allocated by each executive officer to our business. The base salaries of our named executive officers are reviewed on an annual basis as well as at the time of a promotion or other material change in responsibilities. The CNG Committee reviews and approves the full salaries paid to each executive officer by Quintana and Western Pocahontas, based on both the actual time allocations to NRP in the prior year and the anticipated time allocations in the coming year. Adjustments in base salary are based on an evaluation of individual performance, our partnership's overall performance during the fiscal year and the individual's contribution to our overall performance.

In determining salaries for NRP's executive officers for 2015, at the December 2014 meeting, the CNG Committee considered the financial performance of NRP for the nine months ended September 30, 2014 as well as the projected financial performance of NRP for the fourth quarter of 2014 and for the year ending December 31, 2015. The CNG Committee also considered the individual performance of each member of the executive management team during 2014 and the changes to the management team that became effective during the year. Based on its review, the CNG Committee approved the salaries disclosed in the Summary Compensation Table below.

Annual Cash Incentive Awards

Each named executive officer participated in two cash incentive programs in 2015, with the exception of Mr. Robertson who did not participate in the cash bonus program. The first program is a discretionary cash bonus award approved in February 2016 by the CNG Committee based on similar criteria used to evaluate the annual base salaries. The bonuses awarded with respect to 2015 under this program are disclosed in the Summary Compensation Table under the Bonus column. As with the base salaries, there are no formulas or specific performance targets related to these awards. The bonuses for Mr. Hogan and Ms. Wilson were increased over the prior year in order to partially offset declines in their overall compensation due to the significant declines in phantom unit award value and GP Bonus Awards; however, in spite of the increased bonuses, total compensation earned in 2015 by our named executive officers was significantly lower than total compensation earned in 2014.

Under the second cash incentive program (the GP Bonus Award program), our general partner has set aside the cash distributions it receives on an annual basis with respect to distributions on NRP's common units held by our general partner for awards to our executive officers, including Mr. Robertson. Although Mr. Robertson has the sole discretion to determine the GP Bonus Awards allocated to each executive officer, including himself, the cash awards that our officers receive under this plan are reviewed by the CNG Committee and taken into account when making determinations with respect to salaries, bonuses and long-term incentive awards. Unlike the discretionary cash bonus award described above, the GP Bonus Awards are paid by the general partner and not reimbursed by NRP. However, because the GP Bonus Awards represent compensation to executive officers related to services provided to NRP, they are recorded by NRP as general and administrative expenses and equity contributions from the general partner. Prior to 2015, we did not record the GP Bonus Awards cash compensation paid by the general partner as an expense.

The amounts received by the named executive officers (with the exception of Mr. Nunez, who was not employed by NRP during 2014) under the GP Bonus Award program were significantly lower for 2015 as compared to 2014 due to the 87% reduction in the per unit distribution paid by NRP during the calendar year ended December 31, 2015. This decrease resulted in a decreased overall amount allocated to the executive officers.

Long-Term Incentive Compensation

At the time of our initial public offering, we adopted the Natural Resource Partners Long-Term Incentive Plan for our directors and all the employees who perform services for NRP, including the executive officers. Historically, we considered long-term equity-based incentive compensation to be the most important element of our compensation program for executive officers because we believed that these awards kept our officers focused on the growth of NRP, particularly the sustainability and long-term growth of quarterly distributions and their impact on our unit price, over an extended time horizon.

Our CNG Committee has historically approved annual awards of phantom units that vest four years from the date of grant. The amounts included in the compensation table reflect the grant date fair value of the unit awards determined in accordance with FASB stock compensation authoritative guidance. NRP bears 100% of the costs of the phantom units. We structured the phantom unit awards so that our executive officers and directors directly benefited along with our unitholders when our unit price increases, and experienced reductions in the value of their incentive awards when our unit price declined. Similarly, because the awards are forfeited by the executives upon termination of employment in most instances, the long-term vesting component of these awards encouraged our senior executives and employees to remain with NRP over an extended period of time, thereby ensuring continuity in our management team. Consistent with this approach, we included DERs as a possible award to be granted under the plan. The DERs are contingent rights, granted in tandem with phantom units, to receive upon vesting of the related phantom units an amount in cash equal to the cash distributions made by NRP with respect to the common units during the period in which the phantom units are outstanding.

As noted below, in light of current market conditions, the currently low value of NRP's common units and the strategic plan to dedicate all free cash flow towards reducing NRP's leverage, the CNG Committee determined that the phantom units and DERs awarded under the Long-Term Incentive Plan no longer held retentive value for NRP's management team. As a result, the CNG Committee recommended, and the Board approved, the 2016 Cash Long-Term Incentive Plan described below.

Perquisites and Other Personal Benefits

Both Quintana and Western Pocahontas maintain employee benefit plans that provide our executive officers and other employees with the opportunity to enroll in health, dental and life insurance plans. Each of these benefit plans require the employee to pay a portion of the health and dental premiums, with the company paying the remainder. These benefits are offered on the same basis to all employees of Quintana and Western Pocahontas, and the company costs are reimbursed by us to the extent the employee allocates time to our business.

Quintana and Western Pocahontas also maintain tax-qualified 401(k) and defined contribution retirement plans. Quintana matches 100% of the first 4.5% of the employee contributions under the 401(k) plan and Western Pocahontas matches the employee contributions at a level of 100% of the first 3% of the contribution and 50% of the next 3% of the contribution. In addition, each company contributes 1/12 of each employee's base salary to the defined contribution retirement plan on an annual basis. As with the other contributions, any amounts contributed by Quintana and Western Pocahontas are reimbursed by us based on the time allocated by the employee to our business. None of NRP, Quintana or Western Pocahontas maintains a pension plan or a defined benefit retirement plan.

2016 Cash Long-Term Incentive Plan

As discussed above, in February 2016, the CNG Committee adopted a new cash-based long-term incentive plan and recommended the new plan and awards thereunder to the non-management members of the Board for approval. The Board approved the new plan and the forms of long-term incentive award agreements in February 2016. Under the new plan, the executive officers are eligible to receive two types of cash incentive awards: (1) time vesting awards that will vest 50% in February 2017 and 50% in February 2018, and (2) performance-based awards that will generally vest 50% upon the repayment, refinancing or rollover of the Opco revolving credit facility that matures in October 2017 and 50% upon the repayment, refinancing or rollover of NRP's 9.125% Senior Notes due October 2018, in each case as determined by the Board and depending upon the continued employment of the applicable executive officer. Up to an additional 100% of the amount of the performance-based awards may be awarded to the executive officers in the sole discretion of the Board after considering additional performance criteria including, but not limited to, NRP's common unit price, projected EBITDA, and leverage ratio.

In March 2016, the Board made awards under the new plan to NRP's executive officers. The awards made in March 2016 to the named executive officers under the new cash long-term incentive plan are as follows:

2016 Cash Incentive Awards

	Performance Award Grant Amount	Time Vesting Award Grant Amount	Total Grant Amount	Total Maximum Payout Amount (1)
Corbin J. Robertson, Jr. - Chairman and Chief Executive Officer	$ 1,500,000	$ 500,000	$ 2,000,000	$ 3,500,000
Wyatt L. Hogan - President and Chief Operating Officer	750,000	250,000	1,000,000	1,750,000
Craig W. Nunez - Chief Financial Officer and Treasurer	562,500	187,500	750,000	1,312,500
Kathryn S. Wilson - Vice President, General Counsel and Secretary	450,000	150,000	600,000	1,050,000
Christopher J. Zolas - Chief Accounting Officer	150,000	150,000	300,000	450,000

(1) Assumes the Board determines to award the discretional additional 100% of the performance-based award amounts.

Unit Ownership Requirements

We do not have any policy guidelines that require specified ownership of our common units by our directors or executive officers or unit retention guidelines applicable to equity-based awards granted to directors or executive officers. As of December 31, 2015, our named executive officers held 308,725 phantom units that have been granted as compensation. In addition, Mr. Robertson directly or indirectly owns in excess of 20% of the outstanding units of NRP.

Securities Trading Policy

Our insider trading policy states that executive officers and directors may not purchase or sell puts or calls to sell or buy our common units, engage in short sales with respect to our common units, or buy our securities on margin.

Tax Implications of Executive Compensation

Because we are a partnership, Section 162(m) of the Internal Revenue Code does not apply to compensation paid to our named executive officers and accordingly, the CNG Committee did not consider its impact in determining compensation levels in 2013, 2014 or 2015. The CNG Committee has taken into account the tax implications to the partnership in its decision to limit the long-term incentive compensation to phantom units as opposed to options or restricted units.

Accounting Implications of Executive Compensation

The CNG Committee has considered the partnership accounting implications, particularly the "book-up" cost, of issuing equity as incentive compensation, and has determined that phantom units offer the best accounting treatment for the partnership while still motivating and retaining our executive officers.

Report of the Compensation, Nominating and Governance Committee

The CNG Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management. Based on the reviews and discussions referred to in the foregoing sentence, the CNG Committee recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the year ended December 31, 2015.

Robert T. Blakely, Chairman
Russell D. Gordy
Robert B. Karn III
Leo A. Vecellio, Jr.

Summary Compensation Table

The following table sets forth the amounts reimbursed to affiliates of our general partner for compensation in 2013, 2014 and 2015 based on each individual's allocation of time to Natural Resource Partners:

Name and Principal Position (1)	Year	Salary	Cash Bonus	Phantom Unit Awards (2)	All Other Compensation (3)	Total
Corbin J. Robertson, Jr. - Chief Executive	2015	$ —	$ —	$ 321,912	$ —	$ 321,912
Officer	2014	—	—	595,728	—	595,728
	2013	—	—	712,000	—	712,000
Wyatt L. Hogan - President and Chief	2015	$ 400,000	$ 400,000	$ 160,956	$ 33,783	$ 994,739
Operating Officer	2014	377,654	225,000	186,165	33,336	822,155
	2013	344,970	126,900	222,500	31,358	725,728
Craig W. Nunez - Chief Financial Officer (4)	2015	$ 375,000	$ 375,000	$ 446,575	$ 33,783	$ 1,230,358
Kathryn S. Wilson - Vice President, General	2015	$ 315,250	$ 175,000	$ 84,949	$ 33,413	$ 608,612
Counsel and Secretary (5)	2014	291,375	100,000	121,007	30,869	543,251
Christopher J. Zolas - Chief Accounting Officer (4)	2015	$ 244,932	$ 150,000	$ 239,295	$ 30,858	$ 665,085

(1) In 2015, Messrs. Robertson, Hogan, Nunez, Ms. Wilson and Mr. Zolas spent approximately 50%, 100%, 100%, 97% and 100%, respectively, of their time on NRP matters.

(2) Amounts represent the grant date fair value of phantom unit awards determined in accordance with Accounting Standards Codification Topic 718 determined without regard to forfeitures. For information regarding the assumptions used in calculating these amounts, see Note 16 to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K. Phantom unit awards granted in 2015 for Messrs. Nunez and Zolas, both of which were hired in 2015, vest in February 2016 through 2019, while phantom unit awards granted in 2015 for Messrs. Robertson and Hogan and Ms. Wilson vest in 2019.

(3) Includes portions of 401(k) matching and retirement contributions allocated to Natural Resource Partners by Quintana.

(4) Messrs. Nunez and Zolas were not a named executive officer for purposes of this Summary Compensation Table during 2014 or 2013.

(5) Ms. Wilson was not a named executive officer for purposes of this Summary Compensation Table during 2013.

The following table sets forth the GP Bonus Awards paid by the general partner and not reimbursed by NRP as described above. These GP Bonus Award amounts are not included in the summary compensation table.

Name and Principal Position	Year	Amount
Corbin J. Robertson, Jr. - Chief Executive Officer	2015	$ 160,000
	2014	180,000
	2013	456,000
Wyatt L. Hogan - President and Chief Operating Officer	2015	$ 160,000
	2014	384,000
	2013	391,000
Craig W. Nunez - Chief Financial Officer	2015	$ 160,000
Kathryn S. Wilson - Vice President, General Counsel and Secretary	2015	$ 125,000
	2014	180,000
Christopher J. Zolas - Chief Accounting Officer	2015	$ 52,000

Grants of Plan-Based Awards in 2015

The following table sets forth the grant date and fair value of phantom unit awards granted in 2015.

Named Executive Officer	Grant Date	Phantom Units (1)	Grant Date Fair Value of Unit Awards (2)
Corbin J. Robertson, Jr.	2/10/2015	36,000	$ 321,912
Wyatt L. Hogan	2/10/2015	18,000	160,956
Craig W. Nunez (3)	2/11/2015	50,000	446,575
Kathryn S. Wilson	2/10/2015	9,500	84,949
Christopher J. Zolas (4)	3/9/2015	30,000	239,295

(1) The phantom units granted in February 2015 and vest in February 2019. The unit numbers in the table above do not give effect to NRP's one-for-ten (1:10) reverse common unit split that became effective on February 17, 2016.

(2) Amounts represent the grant date fair value of phantom unit awards determined in accordance with Accounting Standards Codification Topic 718 determined without regard to forfeitures plus accumulated DERs. For information regarding the assumptions used in calculating these amounts, see Note 16 to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

(3) Mr. Nunez received 11,000 phantom units that vested in February 2016 and 12,000, 13,000 and 14,000 phantom units that vest in February 2016, 2017, 2018 and 2019, respectively.

(4) Mr. Zolas received 6,000 phantom units that vested in February 2016 and 6,500, 8,000 and 8,500 phantom units that vest in February 2016, 2017, 2018 and 2019, respectively.

None of our executive officers has an employment agreement, and the salary, bonus and phantom unit awards noted above are approved by the CNG Committee. See our disclosure under "—Compensation Discussion and Analysis" for a description of the factors that the CNG Committee considers in determining the amount of each component of compensation.

Subject to the rules of the exchange upon which the common units are listed at the time, the Board and the CNG Committee have the right to alter or amend the Long-Term Incentive Plan or any part of the Long-Term Incentive Plan from time to time. Except upon the occurrence of unusual or nonrecurring events, no change in any outstanding grant may be made that would materially reduce any award to a participant without the consent of the participant.

The CNG Committee may make grants under the Long-Term Incentive Plan to employees and directors containing such terms as it determines, including the vesting period. Outstanding grants vest upon a change in control of NRP, our general partner or GP Natural Resource Partners LLC. If a grantee's employment or membership on the Board terminates for any reason, outstanding grants will be automatically forfeited unless and to the extent the CNG Committee provides otherwise.

As stated above under "—Compensation Discussion and Analysis," we have no outstanding option grants, and do not intend to grant any options or restricted unit awards in the future. In addition, the CNG Committee determined to make cash long-term incentive awards in 2016 in lieu of phantom unit awards as described above under "—Compensation Discussion and Analysis—2016 Cash Long-Term Incentive Plan." The CNG Committee may determine to make additional awards of phantom units in the future.

Phantom Units Vested in 2015

The table below shows the phantom units that vested in 2015 with respect to each named executive officer, along with the phantom unit value realized by each individual:

Named Executive Officer	Phantom Units Vested in 2015 (1)	Value Realized on 2015 Vesting
Corbin J. Robertson, Jr.	33,000	$ 295,350
Wyatt L. Hogan	9,000	80,550
Craig W. Nunez	—	—
Kathryn S. Wilson	4,500	40,275
Christopher J. Zolas	—	—

(1) The unit numbers in the table above do not give effect to NRP's one-for-ten (1:10) reverse common unit split that became effective on February 17, 2016.

Outstanding Awards at December 31, 2015

The table below shows the total number of outstanding phantom units held by each named executive officer at December 31, 2015. The phantom units shown below have been awarded over the last four years, with a portion of the phantom units having vesting in February 2016 and the remaining portion vesting in each of 2017, 2018 and 2019.

Named Executive Officer	Unvested Phantom Units (1)		Market Value of Unvested Phantom Units (2)
Corbin J. Robertson, Jr.	133,600	(3)	$ 169,281
Wyatt L. Hogan	66,800	(4)	84,836
Craig W. Nunez	50,000	(5)	63,500
Kathryn S. Wilson	28,325	(6)	35,973
Christopher J. Zolas	30,000	(7)	38,100

(1) The unit numbers in the table above do not give effect to NRP's one-for-ten (1:10) reverse common unit split that became effective on February 17, 2016.

(2) Based on a unit price of $1.27, the closing price for the common units on December 31, 2015.

(3) Includes 32,000 phantom units vested in February 2016 and 32,000, 33,600 and 36,000 phantom units vesting in February 2017, 2018 and 2019, respectively.

(4) Includes 16,000 phantom units vested in February 2016 and 16,000, 16,800 and 18,000 phantom units vesting in February 2017, 2018 and 2019, respectively.

(5) Includes 11,000 vested in February 2016 and 12,000, 13,000 and 14,000 phantom units vesting in February 2017, 2018 and 2019, respectively.

(6) Includes 5,500 phantom units vested in February 2016, and 6,500, 6,825 and 9,500 phantom units vesting in February 2017, 2018 and 2019, respectively.

(7) Includes 6,000 phantom units vested in February 2016 and 6,500, 8,000 and 9,500 phantom units vesting in February 2017, 2018 and 2019, respectively.

Potential Payments upon Termination or Change in Control

None of our executive officers have entered into employment agreements with Natural Resource Partners or its affiliates. Consequently, there are no severance benefits payable to any executive officer upon the termination of their employment. Upon the occurrence of a change in control of NRP, our general partner or GP Natural Resource Partners LLC, the outstanding phantom unit awards held by each of our executive officers would immediately vest. The table below indicates the impact of a change in control on the outstanding equity-based awards at December 31, 2015, assuming a settlement value of $1.21 (the 20-day average of the common units as of December 31, 2015, as required pursuant to the terms of the phantom units).

Named Executive Officer	Unvested Phantom Units (1)	Market Value of Phantom Units	Accumulated DERs	Total Potential Payments	
Corbin J. Robertson, Jr.	133,600	$ 161,589	$ 365,100	$ 526,689	
Wyatt L. Hogan	66,800	80,795	182,550	263,345	
Craig W. Nunez	50,000	60,475	11,250	71,725	(2)
Kathryn S. Wilson	28,325	34,259	56,728	90,987	(3)
Christopher J. Zolas	30,000	36,285	6,750	43,035	(4)

(1) The unit numbers in the table above do not give effect to NRP's one-for-ten (1:10) reverse common unit split that became effective on February 17, 2016.

(2) Phantom units vesting in 2016, 2017, 2018 and 2019 include accrued DERs from February 11, 2015, the date of the grant of these units to Mr. Nunez.

(3) Phantom units vested in 2015 and phantom units vesting in 2016 and 2017 include accrued DERs from February 12, 2013, the date of the grant of these units to Ms. Wilson.

(4) Phantom units vesting in 2016, 2017, 2018 and 2019 include accrued DERs from March 9, 2015, the date of the grant of these units to Mr. Zolas.

Directors' Compensation for the Year Ended December 31, 2015

The table below shows the directors' compensation for the year ended December 31, 2015. As with our named executive officers, we do not grant any options or restricted units to our directors:

Name of Director	Fees Earned or Paid in Cash (1)	Phantom Unit Awards (2) (3)	Total
Robert Blakely	$ 85,000	$ 36,662	$ 121,662
Russell Gordy	65,000	36,662	101,662
Donald Holcomb	60,000	36,662	96,662
Robert Karn III	85,000	36,662	121,662
S. Reed Morian	60,000	36,662	96,662
Richard Navarre	65,000	36,662	101,662
Corbin J. Robertson, III	60,000	36,662	96,662
Stephen Smith	80,000	36,662	116,662
Leo A. Vecellio, Jr.	65,000	36,662	101,662

(1) In 2015, the annual retainer for the directors was $60,000, and the directors did not receive any additional fees for attending meetings. Each chairman of a committee received an annual fee of $10,000 for serving as chairman, and each committee member received $5,000 for serving on a committee.

(2) Amounts represent the grant date fair value of unit awards determined in accordance with Accounting Standards Codification Topic 718 determined without regard to forfeitures. For information regarding the assumptions used in calculating these amounts, see Note 16 to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

(3) As of December 31, 2015, each director held 15,385 phantom units, of which 3,700 phantom units vested in February 2016, and 3,700, 3,885 and 4,100 phantom units will vest in February 2017, 2018 and 2019, respectively. The awards amounts included in the foregoing sentence vesting in 2017, 2018 and 2019 do not give effect to NRP's one-for-ten (1:10) reverse common unit split that became effective on February 17, 2016. Phantom unit awards outstanding on the effective date of the reverse unit split were adjusted accordingly.

The table below shows the phantom units that vested in 2015 with respect to each Director, along with the value realized by each individual:

Director	**Phantom Units Vested in 2015 (1)**	**Value Realized on 2015 Vesting**
Robert Blakely	3,580	$ 59,893
Russell Gordy	3,580	40,275
Donald Holcomb	3,580	40,275
Robert Karn III	3,580	59,893
S. Reed Morian	3,580	59,893
Richard Navarre	3,580	40,275
Corbin J. Robertson, III	3,580	42,244
Stephen Smith	3,580	59,893
Leo A. Vecellio, Jr.	3,580	59,893

(1) The unit numbers in the table above do not give effect to NRP's one-for-ten (1:10) reverse common unit split that became effective on February 17, 2016.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2015, Messrs. Blakely, Gordy, Karn and Vecellio served on the CNG Committee. None of Messrs. Blakely, Gordy, Karn or Vecellio has ever been an officer or employee of NRP or GP Natural Resource Partners LLC. None of our executive officers serve as a member of the board of directors or compensation committee of any entity that has any executive officer serving as a member of our Board or CNG Committee.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth, as of February 1, 2016, the amount and percentage of our common units beneficially held by (1) each person known to us to beneficially own 5% or more of any class of our units, (2) by each of the directors and executive officers and (3) by all directors and executive officers as a group. Unless otherwise noted, each of the named persons and members of the group has sole voting and investment power with respect to the units shown. The information presented in this Item 12. does not give effect to the one-for-ten reverse unit split that was effective on February 17, 2016.

Name of Beneficial Owner	Common Units	Percentage of Common Units(1)
Corbin J. Robertson, Jr. (2)	24,346,308	19.9%
Western Pocahontas Properties Limited Parntership (3)	17,279,860	14.1%
Wyatt L. Hogan(4)	12,500	*
Craig W. Nunez	—	—
Kevin J. Craig	18,000	*
David M. Hartz	—	*
Kathy H. Roberts	20,000	*
Kathryn S. Wilson	—	—
Gregory F. Wooten	—	—
Christopher J. Zolas	—	—
Robert T. Blakely	22,500	*
Russell D. Gordy(5)	70,000	*
Donald R. Holcomb(6)	5,469,950	4.5%
Robert B. Karn III(7)	5,634	*
S. Reed Morian(8)	6,161,588	5.0%
Richard A. Navarre	10,000	*
Corbin J. Robertson III(9)	1,727,892	1.4%
Stephen P. Smith	3,552	*
Leo A. Vecellio, Jr.	20,000	*
Directors and Officers as a Group	37,887,924	31.0%

* Less than one percent.

(1) Percentages based upon 122,299,825 common units issued and outstanding as of February 1, 2016. Unless otherwise noted, beneficial ownership is less than 1%.

(2) Mr. Robertson may be deemed to beneficially own the 17,279,860 common units owned by Western Pocahontas Properties Limited Partnership, 5,627,120 common units held by Western Bridgeport, Inc., 110,206 common units held by Western Pocahontas Corporation and 56 common units held by QMP Inc. Also included are 31,540 common units held by Barbara Robertson, Mr. Robertson's spouse. Mr. Robertson's address is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002. The 5,627,120 units held by Western Bridgeport are pledged as collateral for a loan.

(3) These common units may be deemed to be beneficially owned by Mr. Robertson. The address of Western Pocahontas Properties Limited Partnership is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002.

(4) Of these common units, 500 common units are owned by the Anna Margaret Hogan 2002 Trust, 500 common units are owned by the Alice Elizabeth Hogan 2002 Trust, and 500 common units are held by the Ellen Catlett Hogan 2005 Trust. Mr. Hogan is a trustee of each of these trusts.

(5) Mr. Gordy may be deemed to beneficially own 50,000 common units owned by Minion Trail, Ltd. and 20,000 common units owned by Rock Creek Ranch 1, Ltd.

(6) Includes 5,349,816 common units held by Cline Trust Company LLC. Mr. Holcomb is a manager of Cline Trust Company and may be deemed to have voting or investment power over the common units held of record by Cline Trust Company. The members of Cline Trust Company are for trusts for the benefit of Christopher Cline, and Mr. Holcomb serves as trustee of each of those trusts. Mr. Holcomb disclaims beneficial ownership of the common units held by Cline Trust Company.

(7) Includes 317 common units held by each of two trusts for the benefit of Mr. Karn's grandchildren. Mr. Karn is the trustee of each of these trusts for his grandchildren, but disclaims beneficial ownership of these securities.

(8) Mr. Morian may be deemed to beneficially own 3,448,624 common units owned by Shadder Investments and 600,972 common units held by Mocol Properties. The 3,448,624 units owned by Shadder Investments are pledged as collateral for a loan agreement.

(9) Mr. Robertson may be deemed to beneficially own 97,828 common units held CIII Capital Management, LLC, 100,000 common units held by BHJ Investments, 50,461 common units held by The Corbin James Robertson III 2009 Family Trust and 387 common units held by his spouse, Brooke Robertson. The address for CIII Capital Management, LLC is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002, the address for BHJ Investments is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002 and the address for The Corbin James Robertson III 2009 Family Trust is 1415 Louisiana Street, Suite 2400, Houston, Texas 77002. The following common units are pledged as collateral for loans: 295,413 common units owned directly by Mr. Robertson.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Western Pocahontas Properties Limited Partnership, New Gauley Coal Corporation and Great Northern Properties Limited Partnership are three privately held companies that are primarily engaged in owning and managing mineral properties. We refer to these companies collectively as the WPP Group. Corbin J. Robertson, Jr. owns the general partner of Western Pocahontas Properties, 85% of the general partner of Great Northern Properties and is the Chairman and Chief Executive Officer of New Gauley Coal Corporation.

Omnibus Agreement

Non-competition Provisions

As part of the omnibus agreement entered into concurrently with the closing of our initial public offering, the WPP Group and any entity controlled by Corbin J. Robertson, Jr., which we refer to in this section as the GP affiliates, each agreed that neither they nor their affiliates will, directly or indirectly, engage or invest in entities that engage in the following activities (each, a "restricted business") in the specific circumstances described below:

- the entering into or holding of leases with a party other than an affiliate of the GP affiliate for any GP affiliate-owned fee coal reserves within the United States; and
- the entering into or holding of subleases with a party other than an affiliate of the GP affiliate for coal reserves within the United States controlled by a paid-up lease owned by any GP affiliate or its affiliate.

"Affiliate" means, with respect to any GP affiliate or, any other entity in which such GP affiliate owns, through one or more intermediaries, 50% or more of the then outstanding voting securities or other ownership interests of such entity. Except as described below, the WPP Group and their respective controlled affiliates will not be prohibited from engaging in activities in which they compete directly with us.

A GP affiliate may, directly or indirectly, engage in a restricted business if:

- the GP affiliate was engaged in the restricted business at the closing of the offering; provided that if the fair market value of the asset or group of related assets of the restricted business subsequently exceeds $10 million, the GP affiliate must offer the restricted business to us under the offer procedures described below.
- the asset or group of related assets of the restricted business have a fair market value of $10 million or less; provided that if the fair market value of the assets of the restricted business subsequently exceeds $10 million, the GP affiliate must offer the restricted business to us under the offer procedures described below.
- the asset or group of related assets of the restricted business have a fair market value of more than $10 million and the general partner (with the approval of the conflicts committee) has elected not to cause us to purchase these assets under the procedures described below.
- its ownership in the restricted business consists solely of a non-controlling equity interest.

For purposes of this paragraph, "fair market value" means the fair market value as determined in good faith by the relevant GP affiliate.

The total fair market value in the good faith opinion of the WPP Group of all restricted businesses engaged in by the WPP Group, other than those engaged in by the WPP Group at closing of our initial public offering, may not exceed $75 million. For purposes of this restriction, the fair market value of any entity engaging in a restricted business purchased by the WPP Group will be determined based on the fair market value of the entity as a whole, without regard for any lesser ownership interest to be acquired.

If the WPP Group desires to acquire a restricted business or an entity that engages in a restricted business with a fair market value in excess of $10 million and the restricted business constitutes greater than 50% of the value of the business to be acquired, then the WPP Group must first offer us the opportunity to purchase the restricted business. If the WPP Group desires to acquire a restricted business or an entity that engages in a restricted business with a value in excess of $10 million and the restricted business constitutes 50% or less of the value of the business to be acquired, then the GP affiliate may purchase the restricted business first and then offer us the opportunity to purchase the restricted business within six months of acquisition. For purposes of this paragraph, "restricted business" excludes a general partner interest or managing member interest, which is addressed in a separate restriction summarized below. For purposes of this paragraph only, "fair market value" means the fair market value as determined in good faith by the relevant GP affiliate.

If we want to purchase the restricted business and the GP affiliate and the general partner, with the approval of the conflicts committee, agree on the fair market value and other terms of the offer within 60 days after the general partner receives the offer from the GP affiliate, we will purchase the restricted business as soon as commercially practicable. If the GP affiliate and the general partner, with the approval of the conflicts committee, are unable to agree in good faith on the fair market value and other terms of the offer within 60 days after the general partner receives the offer, then the GP affiliate may sell the restricted business to a third party within two years for no less than the purchase price and on terms no less favorable to the GP affiliate than last offered by us. During this two-year period, the GP affiliate may operate the restricted business in competition with us, subject to the restriction on total fair market value of restricted businesses owned in the case of the WPP Group.

If, at the end of the two year period, the restricted business has not been sold to a third party and the restricted business retains a value, in the good faith opinion of the relevant GP affiliate, in excess of $10 million, then the GP affiliate must reoffer the restricted business to the general partner. If the GP affiliate and the general partner, with the approval of the conflicts committee, agree on the fair market value and other terms of the offer within 60 days after the general partner receives the second offer from the GP affiliate, we will purchase the restricted business as soon as commercially practicable. If the GP Affiliate and the general partner, with the concurrence of the conflicts committee, again fail to agree after negotiation in good faith on the fair market value of the restricted business, then the GP affiliate will be under no further obligation to us with respect to the restricted business, subject to the restriction on total fair market value of restricted businesses owned.

In addition, if during the two-year period described above, a change occurs in the restricted business that, in the good faith opinion of the GP affiliate, affects the fair market value of the restricted business by more than 10 percent and the fair market value of the restricted business remains, in the good faith opinion of the relevant GP affiliate, in excess of $10 million, the GP affiliate will be obligated to reoffer the restricted business to the general partner at the new fair market value, and the offer procedures described above will recommence.

If the restricted business to be acquired is in the form of a general partner interest in a publicly held partnership or a managing member interest in a publicly held limited liability company, the WPP Group may not acquire such restricted business even if we decline to purchase the restricted business. If the restricted business to be acquired is in the form of a general partner interest in a non-publicly held partnership or a managing member of a non-publicly held limited liability company, the WPP Group may acquire such restricted business subject to the restriction on total fair market value of restricted businesses owned and the offer procedures described above.

The omnibus agreement may be amended at any time by the general partner, with the concurrence of the conflicts committee. The respective obligations of the WPP Group under the omnibus agreement terminate when the WPP Group and its affiliates cease to participate in the control of the general partner.

Restricted Business Contribution Agreement

In connection with our partnership with Christopher Cline and his affiliates, Mr. Cline, Foresight Reserves LP and Adena (collectively, the "Cline Parties") and NRP have executed a Restricted Business Contribution Agreement. Pursuant to the terms of the Restricted Business Contribution Agreement, the Cline Parties and their affiliates are obligated to offer to NRP any business owned, operated or invested in by the Cline Parties, subject to certain exceptions, that either (a) owns, leases or invests in hard minerals or (b) owns, operates, leases or invests in transportation infrastructure relating to future mine developments by the Cline Parties in Illinois. In addition, we created an area of mutual interest (the "AMI") around certain of the properties that we have acquired from Cline affiliates. During the applicable term of the Restricted Business Contribution Agreement, the Cline Parties will be obligated to contribute any coal reserves held or acquired by the Cline Parties or their affiliates within the AMI to us. In connection with the offer of mineral properties by the Cline Parties to NRP, the parties to the Restricted Business Contribution Agreement will negotiate and agree upon an area of mutual interest around such minerals, which will supplement and become a part of the AMI.

We have made several acquisitions from Cline affiliates pursuant to the Restricted Business Contribution Agreement. For a summary of recent acquisitions and revenues that we have derived from the Cline relationship, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Significant Acquisitions" and "—Transactions with Cline Affiliates."

Mr. Holcomb, who was appointed to the Board in October 2013, previously served as Chief Financial Officer for Foresight Reserves LP and its subsidiaries. Mr. Holcomb owned a less than 1% equity interest in certain Cline affiliates until March 2013 when he fully divested from all Cline affiliates. As a result of his position as an executive officer and an equity holder of certain Cline affiliates, Mr. Holcomb may be deemed to have had an indirect material interest in the transactions with the Cline affiliates described in this Annual Report on Form 10-K.

Mr. Holcomb is a manager of Cline Trust Company, LLC, which owns approximately 0.54 million of our common units and $20 million in principal amount of our 9.125% Senior Notes due 2018. The members of the Cline Trust Company are four trusts for the benefit of the children of Christopher Cline, each of which owns an approximately equal membership interest in the Cline Trust Company. Mr. Holcomb also serves as trustee of each of the four trusts.

Investor Rights Agreement

NRP and certain affiliates and Adena executed an Investor Rights Agreement pursuant to which Adena was granted certain management rights. Specifically, Adena has the right to name two directors (one of which must be independent) to the Board of Directors of our managing general partner so long as Adena beneficially owns either 5% of our limited partnership interest or 5% of our general partner's limited partnership interest and so long as certain rights under our managing general partner's LLC Agreement have not been exercised by Adena or Mr. Robertson. Leo A. Vecellio and Donald R. Holcomb currently serve as Adena's two directors. Mr. Vecellio serves on our CNG Committee. Adena will also have the right, pursuant to the terms of the Investor Rights Agreement, to withhold its consent to the sale or other disposition of any entity or assets contributed by Cline affiliates to NRP, and any such sale or disposition will be void without Adena's consent.

Quintana Capital Group GP, Ltd.

Corbin J. Robertson, Jr. is a principal in Quintana Capital Group GP, Ltd., which controls several private equity funds focused on investments in the energy business. NRP's Board of Directors has adopted a formal conflicts policy that establishes the opportunities that will be pursued by NRP and those that will be pursued by Quintana Capital. The basic tenets of the policy are set forth below.

NRP's business strategy has historically focused on:

- The ownership of natural resource properties in North America, including, but not limited to coal, aggregates and industrial minerals, and oil and gas. NRP leases these properties to mining or operating companies that mine or produce the resources and pay NRP a royalty.
- The ownership and operation of transportation, storage and related logistics activities related to extracted hard minerals.

The businesses and investments described in this paragraph are referred to as the "NRP Businesses."

NRP’s acquisition strategy also includes:

- The ownership of non-operating working interests in oil and gas properties.
- The ownership of non-controlling equity interests in companies involved in natural resource development and extraction.
- The operation of construction aggregates mining and production businesses.

The businesses and investments described in this paragraph are referred to as the "Shared Businesses."

NRP’s business strategy does not, and is not expected to, include:

- The ownership of equity interests in companies involved in the mining or extraction of coal.
- Investments that do not generate "qualifying income" for a publicly traded partnership under U.S. tax regulations.
- Investments outside of North America.
- Midstream or refining businesses that do not involve hard extracted minerals, including the gathering, processing, fractionation, refining, storage or transportation of oil, natural gas or natural gas liquids.

In addition, although NRP’s current oil and gas strategy is focused on the acquisition of minerals, royalties and non-operated working interests, NRP may also consider the acquisition of operated interests. The businesses and investments described in this paragraph are referred to as the "Non-NRP Businesses."

It is acknowledged that neither Quintana Capital nor Mr. Robertson will have any obligation to offer investments relating to Non-NRP Businesses to NRP, and that NRP will not have any obligation to refrain from pursuing a Non-NRP Business if there is a change in its business strategy.

For so long as Corbin Robertson, Jr. remains both an affiliate of Quintana Capital and an executive officer or director of NRP or an affiliate of its general partner, before making an investment in an NRP Business, Quintana Capital has agreed to adhere to the following procedures:

- Quintana Capital will first offer such opportunity in its entirety to NRP. NRP may elect to pursue such investment wholly for its own account, to pursue the opportunity jointly with Quintana Capital or not to pursue such opportunity.
- If NRP elects not to pursue an NRP Business investment opportunity, Quintana Capital may pursue the investment for its own account on similar terms.
- NRP will undertake to advise Quintana Capital of its decision regarding a potential investment opportunity within 10 business days of the identification of such opportunity to the Conflicts Committee.

If the opportunity relates to the acquisition of a Shared Business, NRP and Quintana Capital will adhere to the following procedures:

- If the opportunity is generated by individuals other than Mr. Robertson, the opportunity will belong to the entity for which those individuals are working.
- If the opportunity is generated by Mr. Robertson and both NRP and Quintana Capital are interested in pursuing the opportunity, it is expected that the Conflicts Committee will work together with the relevant Limited Partner Advisory Committees for Quintana Capital to reach an equitable resolution of the conflict, which may involve investments by both parties.

In all cases above in which Mr. Robertson has a conflict of interest, investment decisions will be made on behalf of NRP by the Conflicts Committee and on behalf of Quintana Capital Group by the relevant Investment Committee, with Mr. Robertson abstaining.

A fund controlled by Quintana Capital owns an interest in Corsa Coal Corp, a coal mining company traded on the TSX Venture Exchange that is one of our lessees in Tennessee. Corbin J. Robertson, III, one of our directors, is Chairman of the Board of Corsa.

For more information on our relationship with Corsa Coal, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Related Party Transactions—Quintana Capital Group GP, Ltd."

Office Building in Huntington, West Virginia

We lease an office building in Huntington, West Virginia from Western Pocahontas Properties Limited Partnership. The terms of the lease, including $0.6 million per year in lease payments, were approved by our conflicts committee.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including the WPP Group, the Cline entities, and their affiliates) on the one hand, and our partnership and our limited partners, on the other hand. The directors and officers of GP Natural Resource Partners LLC have duties to manage GP Natural Resource Partners LLC and our general partner in a manner beneficial to its owners. At the same time, our general partner has a duty to manage our partnership in a manner beneficial to us and our unitholders. The Delaware Revised Uniform Limited Partnership Act, which we refer to as the Delaware Act, provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the fiduciary duties otherwise owed by a general partner to limited partners and the partnership. Pursuant to these provisions, our partnership agreement contains various provisions modifying the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing the duties of the general partner and the methods of resolving conflicts of interest. Our partnership agreement also specifically defines the remedies available to limited partners for actions taken that, without these defined liability standards, might constitute breaches of fiduciary duty under applicable Delaware law.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and our partnership or any other partner, on the other, our general partner will resolve that conflict. Our general partner may, but is not required to, seek the approval of the conflicts committee of the Board of Directors of our general partner of such resolution. The partnership agreement contains provisions that allow our general partner to take into account the interests of other parties in addition to our interests when resolving conflicts of interest.

Our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our unitholders if the resolution of the conflict is considered to be fair and reasonable to us. Any resolution is considered to be fair and reasonable to us if that resolution is:

- approved by the conflicts committee, although our general partner is not obligated to seek such approval and our general partner may adopt a resolution or course of action that has not received approval;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In resolving a conflict, our general partner, including its conflicts committee, may, unless the resolution is specifically provided for in the partnership agreement, consider:

- the relative interests of any party to such conflict and the benefits and burdens relating to such interest;
- any customary or accepted industry practices or historical dealings with a particular person or entity;
- generally accepted accounting practices or principles; and
- such additional factors it determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

Conflicts of interest could arise in the situations described below, among others.

Actions taken by our general partner may affect the amount of cash available for distribution to unitholders.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- amount and timing of asset purchases and sales;

- cash expenditures;
- borrowings;
- the issuance of additional common units; and
- the creation, reduction or increase of reserves in any quarter.

In addition, borrowings by us and our affiliates do not constitute a breach of any duty owed by our general partner to the unitholders, including borrowings that have the purpose or effect of enabling our general partner to receive distributions.

For example, in the event we have not generated sufficient cash from our operations to pay the quarterly distribution on our common units, our partnership agreement permits us to borrow funds which may enable us to make this distribution on all outstanding common units.

The partnership agreement provides that we and our subsidiaries may borrow funds from our general partner and its affiliates. Our general partner and its affiliates may not borrow funds from us or our subsidiaries.

Excluding VantaCore, we do not have any officers or employees and rely solely on officers and employees of GP Natural Resource Partners LLC and its affiliates.

Excluding our VantaCore business, we do not have any officers or employees and rely solely on officers and employees of GP Natural Resource Partners LLC and its affiliates. Affiliates of GP Natural Resource Partners LLC conduct businesses and activities of their own in which we have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition for the time and effort of the officers and employees who provide services to our general partner. The officers of GP Natural Resource Partners LLC are not required to work full time on our affairs. These officers devote significant time to the affairs of the WPP Group or its affiliates and are compensated by these affiliates for the services rendered to them.

We reimburse our general partner and its affiliates for expenses.

We reimburse our general partner and its affiliates for costs incurred in managing and operating us, including costs incurred in rendering corporate staff and support services to us. The partnership agreement provides that our general partner determines the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

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

Our general partner intends to limit its liability under contractual arrangements so that the other party has recourse only to our assets, and not against our general partner or its assets. The partnership agreement provides that any action taken by our general partner to limit its liability or our liability is not a breach of our general partner’s fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability.

Common unitholders have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us on the one hand, and our general partner and its affiliates, on the other, do not grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Contracts between us, on the one hand, and our general partner and its affiliates, on the other, are not the result of arm’s-length negotiations.

The partnership agreement allows our general partner to pay itself or its affiliates for any services rendered to us, provided these services are rendered on terms that are fair and reasonable. Our general partner may also enter into additional contractual arrangements with any of its affiliates on our behalf. Neither the partnership agreement nor any of the other agreements, contracts and arrangements between us, on the one hand, and our general partner and its affiliates, on the other, are the result of arm’s-length negotiations.

All of these transactions entered into after our initial public offerings are on terms that are fair and reasonable to us.

Our general partner and its affiliates have no obligation to permit us to use any facilities or assets of our general partner and its affiliates, except as may be provided in contracts entered into specifically dealing with that use. There is no obligation of our general partner or its affiliates to enter into any contracts of this kind.

We may not choose to retain separate counsel for ourselves or for the holders of common units.

The attorneys, independent auditors and others who have performed services for us in the past were retained by our general partner, its affiliates and us and have continued to be retained by our general partner, its affiliates and us. Attorneys, independent auditors and others who perform services for us are selected by our general partner or the conflicts committee and may also perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest arising between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict. We do not intend to do so in most cases. Delaware case law has not definitively established the limits on the ability of a partnership agreement to restrict such fiduciary duties.

Our general partner's affiliates may compete with us.

The partnership agreement provides that our general partner is restricted from engaging in any business activities other than those incidental to its ownership of interests in us. Except as provided in our partnership agreement, the Omnibus Agreement and the Restricted Business Contribution Agreement, affiliates of our general partner will not be prohibited from engaging in activities in which they compete directly with us.

The Conflicts Committee Charter is is available upon request.

Director Independence

For a discussion of the independence of the members of the Board of Directors of our managing general partner under applicable standards, see "Item 10. Directors and Executive Officers of the Managing General Partner and Corporate Governance—Corporate Governance—Independence of Directors," which is incorporated by reference into this Item 13.

Review, Approval or Ratification of Transactions with Related Persons

If a conflict or potential conflict of interest arises between our general partner and its affiliates (including the WPP Group, the Cline entities, and their affiliates) on the one hand, and our partnership and our limited partners, on the other hand, the resolution of any such conflict or potential conflict is addressed as described under "—Conflicts of Interest."

Pursuant to our Code of Business Conduct and Ethics, conflicts of interest are prohibited as a matter of policy, except under guidelines approved by the Board and as provided in the Omnibus Agreement, the Restricted Business Contribution Agreement, and our partnership agreement. For the year ended December 31, 2015, there were no transactions where such guidelines were not followed.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The Audit Committee of the Board of Directors of GP Natural Resource Partners LLC recommended and we engaged Ernst & Young LLP to audit our accounts and assist with tax work for fiscal 2015 and 2014. All of our audit, audit-related fees and tax services have been approved by the Audit Committee of our Board of Directors. The following table presents fees for professional services rendered by Ernst &Young LLP:

	2015	2014
Audit Fees(1)	$ 1,192,306	$ 1,056,542
Tax Fees(2)	773,005	738,626
All Other Fees(3)	2,400	1,910

(1) Audit fees include fees associated with the annual integrated audit of our consolidated financial statements and internal controls over financial reporting, separate audits of subsidiaries and reviews of our quarterly financial statement for inclusion in our Form 10-Q and comfort letters; consents; work related to acquisitions; assistance with and review of documents filed with the SEC.

(2) Tax fees include fees principally incurred for assistance with tax planning, compliance, tax return preparation and filing of Schedules K-1.

(3) All other fees include the subscription to EY Online research tool.

Audit and Non-Audit Services Pre-Approval Policy

I. Statement of Principles

Under the Sarbanes-Oxley Act of 2002 (the "Act"), the Audit Committee of the Board of Directors is responsible for the appointment, compensation and oversight of the work of the independent auditor. As part of this responsibility, the Audit Committee is required to pre-approve the audit and non-audit services performed by the independent auditor in order to assure that they do not impair the auditor’s independence from the Partnership. To implement these provisions of the Act, the SEC has issued rules specifying the types of services that an independent auditor may not provide to its audit client, as well as the audit committee’s administration of the engagement of the independent auditor. Accordingly, the Audit Committee has adopted, and the Board of Directors has ratified, this Audit and Non-Audit Services Pre-Approval Policy (the "Policy"), which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the independent auditor may be pre-approved.

The SEC’s rules establish two different approaches to pre-approving services, which the SEC considers to be equally valid. Proposed services may either be pre-approved without consideration of specific case-by-case services by the Audit Committee ("general pre-approval") or require the specific pre-approval of the Audit Committee ("specific pre-approval"). The Audit Committee believes that the combination of these two approaches in this Policy will result in an effective and efficient procedure to pre-approve services performed by the independent auditor. As set forth in this Policy, unless a type of service has received general pre-approval, it will require specific pre-approval by the Audit Committee if it is to be provided by the independent auditor. Any proposed services exceeding pre-approved cost levels or budgeted amounts will also require specific pre-approval by the Audit Committee.

For both types of pre-approval, the Audit Committee will consider whether such services are consistent with the SEC’s rules on auditor independence. The Audit Committee will also consider whether the independent auditor is best positioned to provide the most effective and efficient service for reasons such as its familiarity with our business, employees, culture, accounting systems, risk profile and other factors, and whether the service might enhance the Partnership’s ability to manage or control risk or improve audit quality. All such factors will be considered as a whole, and no one factor will necessarily be determinative.

The Audit Committee is also mindful of the relationship between fees for audit and non-audit services in deciding whether to pre-approve any such services and may determine, for each fiscal year, the appropriate ratio between the total amount of fees for audit, audit-related and tax services.

The appendices to this Policy describe the audit, audit-related and tax services that have the general pre-approval of the Audit Committee. The term of any general pre-approval is 12 months from the date of pre-approval, unless the Audit Committee considers a different period and states otherwise. The Audit Committee will annually review and pre-approve the services that may be provided by the independent auditor without obtaining specific pre-approval from the Audit Committee. The Audit Committee will add or subtract to the list of general pre-approved services from time to time, based on subsequent determinations.

The purpose of this Policy is to set forth the procedures by which the Audit Committee intends to fulfill its responsibilities. It does not delegate the Audit Committee’s responsibilities to pre-approve services performed by the independent auditor to management.

Ernst & Young LLP, our independent auditor has reviewed this Policy and believes that implementation of the policy will not adversely affect its independence.

II. Delegation

As provided in the Act and the SEC’s rules, the Audit Committee has delegated either type of pre-approval authority to Robert B. Karn III, the Chairman of the Audit Committee. Mr. Karn must report, for informational purposes only, any pre-approval decisions to the Audit Committee at its next scheduled meeting.

III. Audit Services

The annual Audit services engagement terms and fees will be subject to the specific pre-approval of the Audit Committee. Audit services include the annual financial statement audit (including required quarterly reviews), subsidiary audits and other procedures required to be performed by the independent auditor to be able to form an opinion on the Partnership's consolidated financial statements. These other procedures include information systems and procedural reviews and testing performed in order to understand and place reliance on the systems of internal control, and consultations relating to the audit or quarterly review. Audit services also include the attestation engagement for the independent auditor's report on management's report on internal controls for financial reporting. The Audit Committee monitors the audit services engagement as necessary, but not less than on a quarterly basis, and approves, if necessary, any changes in terms, conditions and fees resulting from changes in audit scope, partnership structure or other items.

In addition to the annual audit services engagement approved by the Audit Committee, the Audit Committee may grant general pre-approval to other audit services, which are those services that only the independent auditor reasonably can provide. Other audit services may include statutory audits or financial audits for our subsidiaries or our affiliates and services associated with SEC registration statements, periodic reports and other documents filed with the SEC or other documents issued in connection with securities offerings.

IV. Audit-related Services

Audit-related services are assurance and related services that are reasonably related to the performance of the audit or review of the Partnership's financial statements or that are traditionally performed by the independent auditor. Because the Audit Committee believes that the provision of audit-related services does not impair the independence of the auditor and is consistent with the SEC's rules on auditor independence, the Audit Committee may grant general pre-approval to audit-related services. Audit-related services include, among others, due diligence services pertaining to potential business acquisitions/dispositions; accounting consultations related to accounting, financial reporting or disclosure matters not classified as "Audit Services"; assistance with understanding and implementing new accounting and financial reporting guidance from rulemaking authorities; financial audits of employee benefit plans; agreed-upon or expanded audit procedures related to accounting and/or billing records required to respond to or comply with financial, accounting or regulatory reporting matters; and assistance with internal control reporting requirements.

V. Tax Services

The Audit Committee believes that the independent auditor can provide tax services to the Partnership such as tax compliance, tax planning and tax advice without impairing the auditor's independence, and the SEC has stated that the independent auditor may provide such services. Hence, the Audit Committee believes it may grant general pre-approval to those tax services that have historically been provided by the auditor, that the Audit Committee has reviewed and believes would not impair the independence of the auditor and that are consistent with the SEC's rules on auditor independence. The Audit Committee will not permit the retention of the independent auditor in connection with a transaction initially recommended by the independent auditor, the sole business purpose of which may be tax avoidance and the tax treatment of which may not be supported in the Internal Revenue Code and related regulations. The Audit Committee will consult with the Chief Financial Officer or outside counsel to determine that the tax planning and reporting positions are consistent with this Policy.

VI. Pre-Approval Fee Levels or Budgeted Amounts

Pre-approval fee levels or budgeted amounts for all services to be provided by the independent auditor will be established annually by the Audit Committee. Any proposed services exceeding these levels or amounts will require specific pre-approval by the Audit Committee. The Audit Committee is mindful of the overall relationship of fees for audit and non-audit services in determining whether to pre-approve any such services. For each fiscal year, the Audit Committee may determine the appropriate ratio between the total amount of fees for audit, audit-related and tax services.

VII. Procedures

All requests or applications for services to be provided by the independent auditor that do not require specific approval by the Audit Committee will be submitted to the Chief Financial Officer and must include a detailed description of the services to be rendered. The Chief Financial Officer will determine whether such services are included within the list of services that have received the general pre-approval of the Audit Committee. The Audit Committee will be informed on a timely basis of any such services rendered by the independent auditor.

Requests or applications to provide services that require specific approval by the Audit Committee will be submitted to the Audit Committee by both the independent auditor and the Chief Financial Officer, and must include a joint statement as to whether, in their view, the request or application is consistent with the SEC's rules on auditor independence.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) and (2) Financial Statements and Schedules
See "Item 8. Financial Statements and Supplementary Data."

(a)(3) Ciner Wyoming LLC Financial Statements. The financial statements of Ciner Wyoming LLC required pursuant to Rule 3-09 of Regulation S-X are included in this filing as Exhibit 99.3.

(a)(4) Exhibits

Exhibit Number		Description
2.1	—	Purchase Agreement, dated as of January 23, 2013, by and among Anadarko Holding Company, Big Island Trona Company, NRP Trona LLC and NRP (Operating) LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K filed on January 25, 2013).
2.2	—	Agreement and Plan of Merger, dated as of August 18, 2014, by and among VantaCore Partners LP, VantaCore LLC, the Holders named therein, Natural Resource Partners L.P., NRP (Operating) LLC and Rubble Merger Sub, LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K filed on August 20, 2014).
2.3	—	Interest Purchase Agreement, by and among NRP Oil and Gas LLC, Kaiser-Whiting, LLC and the Owners of Kaiser-Whiting, LLC dated as of October 5, 2014 (incorporated by reference to Current Report on Form 8-K filed on October 6, 2014).
3.1	—	Fourth Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of September 20, 2010 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed on September 21, 2010).
3.2	—	Fifth Amended and Restated Agreement of Limited Partnership of NRP (GP) LP, dated as of December 16, 2011 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed on December 16, 2011).
3.3	—	Fifth Amended and Restated Limited Liability Company Agreement of GP Natural Resource Partners LLC, dated as of October 31, 2013 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed on October 31, 2013).
3.4	—	Amended and Restated Limited Liability Company Agreement of NRP (Operating) LLC, dated as of October 17, 2002 (incorporated by reference to Exhibit 3.4 of Annual Report on Form 10-K for the year ended December 31, 2002).
3.5	—	Certificate of Limited Partnership of Natural Resource Partners L.P.(incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 filed April 19, 2002, File No. 333-86582).
4.1	—	Note Purchase Agreement dated as of June 19, 2003 among NRP (Operating) LLC and the Purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed June 23, 2003).
4.2	—	First Amendment, dated as of July 19, 2005, to Note Purchase Agreement dated as of June 19, 2003 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K filed on July 20, 2005).
4.3	—	Second Amendment, dated as of March 28, 2007, to Note Purchase Agreement dated as of June 19, 2003 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K filed on March 29, 2007).

Exhibit Number		Description
4.4	—	First Supplement to Note Purchase Agreement, dated as of July 19, 2005 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on July 20, 2005).
4.5	—	Second Supplement to Note Purchase Agreement, dated as of March 28, 2007 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 29, 2007).
4.6	—	Third Supplement to Note Purchase Agreement, dated as of March 25, 2009 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 26, 2009).
4.7	—	Fourth Supplement to Note Purchase Agreement, dated as of April 20, 2011 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on April 21, 2011).
4.8	—	Subsidiary Guarantee of Senior Notes of NRP (Operating) LLC, dated June 19, 2003 (incorporated by reference to Exhibit 4.5 to Current Report on Form 8-K filed June 23, 2003).
4.9	—	Form of Series A Note (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K filed June 23, 2003).
4.10	—	Form of Series B Note (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K filed June 23, 2003).
4.11	—	Form of Series D Note (incorporated by reference to Exhibit 4.12 to Annual Report on Form 10-K filed February 28, 2007).
4.12	—	Form of Series E Note (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K filed March 29, 2007).
4.13	—	Form of Series F Note (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q filed May 7, 2009).
4.14	—	Form of Series G Note (incorporated by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q filed May 7, 2009).
4.15	—	Form of Series H Note (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q filed May 5, 2011).
4.16	—	Form of Series I Note (incorporated by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q filed May 5, 2011).
4.17	—	Form of Series J Note (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on June 15, 2011).
4.18	—	Form of Series K Note (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on October 3, 2011).
4.19	—	Registration Rights Agreement, dated as of January 23, 2013, by and among Natural Resource Partners L.P. and the Investors named therein (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on January 25, 2013).
4.20	—	Amendment No. 1 to Fourth Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated March 6, 2012 (incorporated by reference to Exhibit 4.1 to Quarterly Report on Form 10-Q filed on August 7, 2012).

Exhibit Number		Description
4.21	—	Indenture, dated September 18, 2013, by and among Natural Resource Partners L.P. and NRP Finance Corporation, as issuers, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on September 19, 2013).
4.22	—	Form of 9.125% Senior Notes due 2018 (contained in Exhibit 1 to Exhibit 4.22).
4.23	—	9.125% Senior Note due 2018 in $20,000,000 aggregate principal amount issued by Natural Resource Partners L.P. and NRP Finance Corporation to Cline Trust Company, LLC, dated October 17, 2014 (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K filed on October 20, 2014).
4.24	—	Third Amendment, dated as of June 16, 2015, to Note Purchase Agreements, dated as of June 19, 2003, among NRP (Operating) LLC and the holders named therein (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on June 18, 2015).
10.1	—	Third Amended and Restated Credit Agreement, dated as of June 16, 2015, by and among NRP (Operating) LLC, the lenders party thereto, Citibank, N.A. as Administrative Agent and Collateral Agent, Citigroup Global Markets Inc. and Wells Fargo Securities LLC as Joint Lead Arrangers and Joint Bookrunners, and Citibank, N.A., as Syndication Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on June 18, 2015).
10.2	—	Contribution Agreement, dated as of September 20, 2010, by and among Natural Resource Partners L.P., NRP (GP) LP, Western Pocahontas Properties Limited Partnership, Great Northern Properties Limited Partnership, New Gauley Coal Corporation and NRP Investment L.P. (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on September 21, 2010).
10.3	—	Natural Resource Partners Second Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on January 17, 2008).
10.4***	—	Form of Phantom Unit Agreement (incorporated by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2007).
10.5***	—	Natural Resource Partners Annual Incentive Plan (incorporated by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2002).
10.6	—	First Amended and Restated Omnibus Agreement, dated as of April 22, 2009, by and among Western Pocahontas Properties Limited Partnership, Great Northern Properties Limited Partnership, New Gauley Coal Corporation, Robertson Coal Management LLC, GP Natural Resource Partners LLC, NRP (GP) LP, Natural Resource Partners L.P. and NRP (Operating) LLC (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed May 7, 2009).
10.7	—	Restricted Business Contribution Agreement, dated January 4, 2007, by and among Christopher Cline, Foresight Reserves LP, Adena Minerals, LLC, GP Natural Resource Partners LLC, NRP (GP) LP, Natural Resource Partners L.P. and NRP (Operating) LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on January 4, 2007).
10.8	—	Investor Rights Agreement, dated January 4, 2007, by and among NRP (GP) LP, GP Natural Resource Partners LLC, Robertson Coal Management and Adena Minerals, LLC (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed on January 4, 2007).

Exhibit Number		Description
10.9	—	Waiver Agreement, dated November 12, 2009, by and among Natural Resource Partners L.P., Great Northern Properties Limited Partnership, Western Pocahontas Properties Limited Partnership, New Gauley Coal Corporation, Robertson Coal Management LLC, GP Natural Resource Partners LLC, NRP (GP) LP, and NRP (Operating) LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on November 13, 2009).
10.10	—	Common Unit Purchase Agreement, dated January 23, 2013, by and among Natural Resource Partners, L.P. and the purchasers named therein (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on January 25, 2013).
10.11	—	Limited Liability Company Agreement of Ciner Wyoming LLC (formerly OCI Wyoming LLC), dated June 30, 2014 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed by Ciner Resources LP (formerly OCI Resources LP) on July 2, 2014).
10.12		Amendment No. 1 to the Amended and Restated Limited Liability Company Agreement of Ciner Resource Partners LLC (formerly known as OCI Resource Partners LLC), dated November 5, 2015 (incorporated by reference to Exhibit 3.4 to Current Report on Form 8-K filed by Ciner Resources LP (formerly OCI Resources LP) on November 5, 2015).
10.13	—	Credit Agreement, dated as of August 12, 2013, among NRP Oil and Gas LLC, Wells Fargo Bank, N.A., as Administrative Agent, and Wells Fargo Securities, LLC as Sole Bookrunner and Sole Lead Arranger (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on August 13, 2013).
10.14	—	First Amendment to Credit Agreement, dated effective as of December 19, 2013, among NRP Oil and Gas LLC, Wells Fargo Bank, N.A., as Administrative Agent, and Wells Fargo Securities, LLC as Sole Bookrunner and Sole Lead Arranger (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on December 20, 2013).
10.15		Second Amendment to Credit Agreement entered into effective as of November 12, 2014 among NRP Oil and Gas LLC, each of the Lenders that is a signatory thereto, and Wells Fargo Bank, N.A., as administrative agent for the Lenders (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on November 14, 2014).
10.16***		Natural Resource Partners L.P. 2016 Cash Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on February 26, 2016).
10.17***		Form of Long-Term Incentive Award Agreement (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed on February 26, 2016).
10.18***		Form of Long-Term Performance Award Agreement (incorporated by reference to Exhibit 10.3 to Current Report on Form 8-K filed on February 26, 2016).
21.1*	—	List of subsidiaries of Natural Resource Partners L.P.
23.1*	—	Consent of Ernst & Young LLP.

Exhibit Number		Description
23.2*	—	Consent of Deloitte & Touche LLP.
23.3*	—	Consent of Netherland, Sewell & Associates, Inc.
31.1*	—	Certification of Chief Executive Officer pursuant to Section 302 of Sarbanes-Oxley.
31.2*	—	Certification of Chief Financial Officer pursuant to Section 302 of Sarbanes-Oxley.
32.1**	—	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350.
32.2**	—	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350.
95.1*	—	Mine Safety Disclosure.
99.1	—	Description of certain provisions of the Fourth Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P. (incorporated by reference to Exhibit 99.1 to Current Report on Form 8-K filed on September 21, 2010).
99.2*	—	Report of Netherland, Sewell & Associates, Inc.
99.3*	—	Financial Statements of Ciner Wyoming LLC as of and for the years ended December 31, 2015, 2014 and 2013.
101.INS*	—	XBRL Instance Document
101.SCH*	—	XBRL Taxonomy Extension Schema Document
101.CAL*	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	—	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	—	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE*	—	XBRL Taxonomy Extension Presentation Linkbase Document

*	Filed herewith
**	Furnished herewith
***	Management compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NATURAL RESOURCE PARTNERS L.P.

By: NRP (GP) LP, its general partner

By: GP NATURAL RESOURCE PARTNERS LLC, its general partner

Date: March 11, 2016

By: */ s /* CORBIN J. ROBERTSON, JR.

Corbin J. Robertson, Jr.
Chairman of the Board and
Chief Executive Officer
(Principal Executive Officer)

Date: March 11, 2016

By: */ s /* CRAIG W. NUNEZ

Craig W. Nunez
Chief Financial Officer and
Treasurer
(Principal Financial Officer)

Date: March 11, 2016

By: */ s /* CHRISTOPHER J. ZOLAS

Christopher J. Zolas
Chief Accounting Officer
(Principal Accounting Officer)

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

Date: March 11, 2016

/ s / ROBERT T. BLAKELY

Robert T. Blakely
Director

Date: March 11, 2016

/ s / RUSSELL D. GORDY

Russell D. Gordy
Director

Date: March 11, 2016

/ s / DONALD R. HOLCOMB

Donald R. Holcomb
Director

Date: March 11, 2016

/ s / ROBERT B. KARN III

Robert B. Karn III
Director

Date: March 11, 2016

/ s / S. REED MORIAN

S. Reed Morian
Director

Date: March 11, 2016

/ s / RICHARD A. NAVARRE

Richard A. Navarre
Director

Date: March 11, 2016

/ s / CORBIN J. ROBERTSON III

Corbin J. Robertson III
Director

Date: March 11, 2016

/ s / STEPHEN P. SMITH

Stephen P. Smith
Director

Date: March 11, 2016

/ s / LEO A. VECELLIO, JR.

Leo A. Vecellio, Jr.
Director

Exhibit 21.1

List of Subsidiaries of Natural Resource Partners L.P.

NRP (Operating) LLC
NRP Oil and Gas LLC
NRP Finance Corporation
WPP LLC
ACIN LLC
WBRD LLC
Hod LLC
Shepard Boone Coal Company LLC
Gatling Mineral, LLC
Independence Land Company, LLC
Williamson Transport, LLC
Little River Transport, LLC
Rivervista Mining, LLC
Deepwater Transportation, LLC
NRP Trona LLC
VantaCore Partners LLC
Laurel Aggregates Terminal Services of Delaware, LLC
Laurel Aggregates of Delaware, LLC
Laurel Aggregates of PA, LLC
Utica Resources LLC
Winn Materials, LLC
Winn Materials of Kentucky, LLC
Winn Marine, LLC
McIntosh Construction Company, LLC
McAsphalt. LLC
Southern Aggregates, LLC
Lake Lynn Transportation LLC
BRP LLC (51% interest)
CoVal Leasing Company, LLC (51% interest)

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements (Form S-3 No. 333-207034, Form S-3 No. 333-183314, and Form S-3 No. 333-187883) of Natural Resource Partners L.P., and the related prospectus of our reports dated March 11, 2016, with respect to the consolidated financial statements of Natural Resource Partners L.P., and the effectiveness of internal control over financial reporting of Natural Resource Partners L.P., included in this Annual Report (Form 10-K) for the year ended December 31, 2015.

/s/ Ernst & Young LLP

Houston, Texas
March 11, 2016

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements on Form S-3 (Nos. 333-207034, 333-183314, and 333-187883) of Natural Resource Partners L.P., of our report dated March 11, 2016, relating to the financial statements of Ciner Wyoming LLC as of December 31, 2015 and 2014, and for the three years in the period ended December 31, 2015, appearing in the Annual Report on Form 10-K of Natural Resource Partners L.P. for the year ended December 31, 2015.

/s/ Deloitte & Touche LLP

Atlanta, Georgia
March 11, 2016

Exhibit 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the use by Natural Resource Partners L.P. (the “Company”) of our name and to the inclusion of information taken from our report dated February 5, 2016 included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2015, filed with the U.S. Securities and Exchange Commission on March 11, 2016, as well as to the incorporation by reference thereof into the Company's Registration Statements on Forms S-3 (Nos. 333-207034, 333-183314 and 333-187883).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
March 11, 2016

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Corbin J. Robertson, Jr., certify that:

1 I have reviewed this report on Form 10-K of Natural Resource Partners L.P.

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

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

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

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

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

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

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

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

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

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

By: /s/ Corbin J. Robertson, Jr.
Corbin J. Robertson, Jr.
Chief Executive Officer

Date: March 11, 2016

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Craig W. Nunez, certify that:

1. I have reviewed this report on Form 10-K of Natural Resource Partners L.P.

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

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

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

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

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

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

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

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

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

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

By: /s/ Craig W. Nunez
Craig W. Nunez
Chief Financial Officer

Date: March 11, 2016

Exhibit 32.1

**CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF GP NATURAL RESOURCE PARTNERS LLC
PURSUANT TO 18 U.S.C. § 1350**

In connection with the accompanying report on Form 10-K for the year ended December 31, 2015 filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Corbin J. Robertson, Jr., Chief Executive Officer of GP Natural Resource Partners LLC, the general partner of the general partner of Natural Resource Partners L.P. (the “Company”), hereby certify, to my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

By: /s/ Corbin J. Robertson, Jr.
Corbin J. Robertson, Jr.
Chief Executive Officer

Date: March 11, 2016

Exhibit 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF GP NATURAL RESOURCE PARTNERS LLC
PURSUANT TO 18 U.S.C. § 1350

In connection with the accompanying report on Form 10-K for the year ended December 31, 2015 filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Craig W. Nunez, Chief Financial Officer of GP Natural Resource Partners LLC, the general partner of the general partner of Natural Resource Partners L.P. (the “Company”), hereby certify, to my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

By: /s/ Craig W. Nunez
Craig W. Nunez
Chief Financial Officer

Date: March 11, 2016

MINE SAFETY DISCLOSURE

Our mining operations are subject to regulation by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Act"). We have disclosed below information regarding certain citations and orders issued by MSHA and related assessments and legal actions with respect to these mining operations. In evaluating the below information regarding mine safety and health, investors should take into account factors such as: (i) the number of citations and orders will vary depending on the size of a mine; (ii) the number of citations issued will vary from inspector to inspector and mine to mine; and (iii) citations and orders can be contested and appealed, and in that process are often reduced in severity and amount, and are sometimes dismissed or vacated. The tables below do not include any orders or citations issued to independent contractors at our mines.

Section 1503 of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") requires issuers to include in periodic reports filed with the Securities and Exchange Commission ("SEC") certain information relating to citations and orders for violations of standards under the Mine Act. The following tables disclose information required under the Dodd-Frank Act for the 12 month period ending December 31, 2015.

Mine Name / MSHA Identification Number	*Section 104 S&S Citations* (1)	*Section 104(b) Orders* (2)	*Section 104(d) Citations and Orders* (3)	*Section 110(b)(2) Violations* (4)	*Section 107(a) Orders* (5)	*Total Dollar Value of MSHA Assessments Proposed* (6)
Winn Materials/40-03094	10	0	2	0	1	$56,338 (7)
Grand Rivers/Winn Materials of Kentucky/15-19561	0	0	0	0	0	$0
Laurel Aggregates/36-08891	2	0	0	0	0	$5,262
Southern Aggregates/Plant 11/16-01537	2	0	0	0	0	$524
Southern Aggregates/Plant 1/16-01388	0	0	0	0	0	$300
Southern Aggregates/Plant 7/16-01519	0	0	0	0	0	$100
Southern Aggregates/Plant 6/16-00336	3	0	0	0	0	$936
Southern Aggregates/Plant 9/16-01536	2	0	0	0	0	$1,384
Southern Aggregates/Plant 12/16-01546	2	0	0	0	0	$1,068
Southern Aggregates/Plant 7.2/16-01551	2	0	0	0	0	$634
Southern Aggregates/Plant 15/16-01550	0	0	0	0	0	$200

(1) Mine Act section 104 S&S citations shown above are for alleged violations of mandatory health or safety standards that could significantly and substantially contribute to a mine health and safety hazard. It should be noted that, for purposes of this table, S&S citations that are included in another column, such as Section 104(d) citations, are not also included as Section 104 S&S citations in this column.

(2) Mine Act section 104(b) orders are for alleged failures to totally abate a citation within the time period specified in the citation.

(3) Mine Act section 104(d) citations and orders are for an alleged unwarrantable failure (*i.e.* , aggravated conduct constituting more than ordinary negligence) to comply with mandatory health or safety standards.

(4) Mine Act section 110(b)(2) violations are for an alleged "flagrant" failure (*i.e.* , reckless or repeated) to make reasonable efforts to eliminate a known violation of a mandatory safety or health standard that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury.

(5) Mine Act section 107(a) orders are for alleged conditions or practices which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated and result in orders of immediate withdrawal from the area of the mine affected by the condition.

(6) Amounts shown include assessments proposed by MSHA during the twelve-month period ending December 31, 2015 on all citations and orders, including those citations and orders that are not required to be included within the above chart.

(7) The two 104(d) citations and orders issued to Winn Materials-Clarksville represents $48,263 of the $56,338 total proposed assessment.

Mine Name / MSHA Identification Number	Total Number of Mining Related Fatalities	Received Notice of Pattern of Violations Under Section 104(e) (yes/no) [(8)]	Legal Actions Pending as of Last Day of Period	Legal Actions Initiated During Period	Legal Actions Resolved During Period
Winn Materials/40-03094	0	0	23	23	2
Grand Rivers/Winn Materials of Kentucky/15-19561	0	0	0	0	0
Laurel Aggregates/36-08891	0	0	3	5	3
Southern Aggregates/Plant 11/16-01537	0	0	5	3	0
Southern Aggregates/Plant 1/16-01388	0	0	0	0	2
Southern Aggregates/Plant 7/16-01519	0	0	0	0	2
Southern Aggregates/Plant 6/16-00336	0	0	4	4	0
Southern Aggregates/Plant 9/16-01536	0	0	3	3	0
Southern Aggregates/Plant 12/16-01546	0	0	0	1	1
Southern Aggregates/Plant 7.2/16-01551	0	0	1	1	0
Southern Aggregates/Plant 15/16-01550	0	0	1	1	0

(8) Mine Act section 104(e) written notices are for an alleged pattern of violations of mandatory health or safety standards that could significantly and substantially contribute to a mine safety or health hazard.

The number of legal actions pending before the Federal Mine Safety and Health Review Commission as of December 31, 2015 that fall into each of the following categories is as follows:

Mine Name / MSHA Identification Number	Contests of Citations and Orders	Contests of Proposed Penalties	Complaints for Compensation	Complaints of Discharge/ Discrimination/ Interference	Applications for Temporary Relief	Appeals of Judges Rulings
Winn Materials/40-03094	17	6	0	0	0	0
Grand Rivers/Winn Materials of Kentucky/15-19561	0	0	0	0	0	0
Laurel Aggregates/36-08891	0	3	0	0	0	0
Southern Aggregates/Plant 11/16-01537	2	3	0	0	0	0
Southern Aggregates/Plant 1/16-01388	0	0	0	0	0	0
Southern Aggregates/Plant 7/16-01519	0	0	0	0	0	0
Southern Aggregates/Plant 6/16-00336	2	2	0	0	0	0
Southern Aggregates/Plant 9/16-01536	1	2	0	0	0	0
Southern Aggregates/Plant 12/16-01546	0	1	0	0	0	0
Southern Aggregates/Plant 7.2/16-01551	0	1	0	0	0	0
Southern Aggregates/Plant 15/16-01550	0	1	0	0	0	0

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

February 5, 2016

Mr. Tim Chung
Natural Resource Partners L.P.
1201 Louisiana Street, Suite 3400
Houston, Texas 77002

Dear Mr. Chung:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2015, to the Natural Resource Partners L.P. (NRP LP) interest in certain oil and gas properties located in the United States. We completed our evaluation on January 21, 2016. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by NRP LP. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for NRP LP's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the NRP LP interest in these properties, as of December 31, 2015, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	7,636.6	1,176.8	13,014.9	183,344.3	111,783.1
Proved Developed Non-Producing	226.5	18.7	141.6	5,850.9	3,869.3
Proved Undeveloped	212.3	27.4	166.9	2,682.5	700.9
Total Proved	8,075.4	1,223.0	13,323.3	191,877.6	116,353.4

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

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info@nsai-petro.com
netherlandsewell.com

Gross revenue is NRP LP's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for NRP LP's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2015. For oil and NGL volumes, the average West Texas Intermediate posted price of $46.79 per barrel is adjusted by region for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.587 per MMBTU is adjusted by region for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $40.47 per barrel of oil, $8.38 per barrel of NGL, and $2.051 per MCF of gas.

Operating costs used in this report are based on operating expense records of NRP LP, where available. For other properties, we have estimated operating costs based on our knowledge of similar operations in the area. Operating costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Since all properties are nonoperated, headquarters general and administrative overhead expenses of NRP LP are not included. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by NRP LP and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are NRP LP's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the NRP LP interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on NRP LP receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by NRP LP, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from NRP LP, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical person primarily responsible for preparing the estimates presented herein meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Steven W. Jansen, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2011 and has over 4 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees II

By: C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ Steven W. Jansen

By: Steven W. Jansen, P.E. 112973
Vice President

Date Signed: February 5, 2016

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir* . Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2) : Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen* . Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate* . Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate* . The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves* . Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves - Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves - Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project* . A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well* . A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible* . The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)* . Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs* . Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well* . An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well* . An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field* . An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i) : The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and 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 that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26) : Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

- *a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
- *b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

- *a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
- *b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
- *c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
- *d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
- *e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
- *f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects - such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations - by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);

The company's historical record at completing development of comparable long-term projects;

The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;

The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and

The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.3

Ciner Wyoming LLC

(A Majority-Owned Subsidiary of Ciner Resources LP)

Financial Statements as of December 31, 2015 and 2014 and for the Years Ended December 31, 2015, 2014, and 2013, and Report of Independent Registered Public Accounting Firm

CINER WYOMING LLC

(A Majority Owned Subsidiary of Ciner Resources LP)

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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 referred to above 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

CINER WYOMING LLC
(A Majority Owned Subsidiary of Ciner Resources LP)

BALANCE SHEETS
AS OF DECEMBER 31, 2015 AND 2014
(In thousands of dollars)

	2015	2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 18,158	$ 30,520
Accounts receivable, net	33,788	35,457
Accounts receivable - ANSAC	52,211	70,410
Due from affiliates, net	12,325	19,489
Inventory	26,376	22,466
Other current assets	1,837	1,509
Total current assets	144,695	179,851
PROPERTY, PLANT, AND EQUIPMENT, NET	212,819	201,402
OTHER NON-CURRENT ASSETS	21,026	21,651
TOTAL ASSETS	$ 378,540	$ 402,904
LIABILITIES AND MEMBERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 13,351	$ 13,069
Due to affiliates	4,634	5,347
Accrued expenses	25,033	29,288
Total current liabilities	43,018	47,704
LONG-TERM DEBT	110,000	145,000
OTHER NON-CURRENT LIABILITIES	6,808	4,192
Total liabilities	159,826	196,896
COMMITMENTS AND CONTINGENCIES		
MEMBERS' EQUITY:		
Members’ equity - Ciner Resources LP	113,681	105,445
Members’ equity - Natural Resource Partners LP	109,224	101,311
Accumulated other comprehensive loss	(4,191)	(748)
Total members' equity	218,714	206,008
TOTAL LIABILITIES AND MEMBERS' EQUITY	$ 378,540	$ 402,904

See notes to financial statements.

CINER WYOMING LLC
(A Majority Owned Subsidiary of Ciner Resources LP)

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013
(In thousands of dollars)

	2015	2014	2013
SALES - AFFILIATES	$ 265,289	$ 236,685	$ 211,645
SALES - OTHERS	221,104	228,347	230,487
Total net sales	486,393	465,032	442,132
COST OF PRODUCTS SOLD	232,853	222,848	225,160
FREIGHT COSTS	122,047	123,745	122,673
Total cost of products sold	354,900	346,593	347,833
GROSS PROFIT	131,493	118,439	94,299
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES - AFFILIATES	13,904	16,192	12,506
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES - OTHERS	1,315	577	36
LOSS ON DISPOSAL OF ASSETS, NET	202	1,032	—
OPERATING INCOME	116,072	100,638	81,757
OTHER INCOME (EXPENSE):			
Interest income	31	78	56
Interest expense	(3,975)	(5,140)	(2,838)
Other income (expense), net	(478)	1,064	680
Total other income (expense)	(4,422)	(3,998)	(2,102)
NET INCOME	111,650	96,640	79,655
OTHER COMPREHENSIVE INCOME (LOSS)			
Income (loss) on derivative financial instruments	(3,443)	(198)	30
COMPREHENSIVE INCOME	$ 108,207	$ 96,442	$ 79,685

See notes to financial statements.

CINER WYOMING LLC

(A Majority Owned Subsidiary of Ciner Resources LP)

STATEMENTS OF MEMBERS' EQUITY

FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013

(In thousands of dollars)

	Ciner Resources LP	Natural Resource Partners LP	OCI Wyoming Holding Co.	Big Island	OCI Wyoming Co.	Accumulated Other Comprehensive Income (Loss)	Total Members' Equity
Balance at January 1, 2013	**$ —**	**$ —**	**$ 138,369**	**$ 132,941**	**$ 9,837**	**$ (580)**	**280,567**
Allocation of net income through January 22, 2013	—	—	1,142	1,097	882	—	3,121
Transfer of interest	—	134,038	—	(134,038)	—	—	—
Allocation of net income from January 23, 2013 through July 17, 2013	—	15,011	15,623	—	7,372	—	38,006
Restructuring on July 18, 2013	—	(908)	(945)	—	1,853	—	—
Capital distribution to members through July 18, 2013	—	(70,060)	(72,920)	—	(19,941)	—	(162,921)
Allocation of net income from July 18, 2013 through September 17, 2013	—	5,356	4,477	—	1,092	—	10,925
Restructuring on September 18, 2013	86,841	—	(85,746)	—	(1,095)	—	—
Allocation of net income from September 18, 2013 trhough December 31, 2013	14,078	13,525	—	—	—	—	27,603
Other comprehensive income (loss)	—	—	—	—		30	30
Balance at December 31, 2013	**$ 100,919**	**$ 96,962**	**$ —**	**$ —**	**$ —**	**$ (550)**	**197,331**
Allocation of net income	49,286	47,354	—	—	—	—	96,640
Capital distribution to members	(44,760)	(43,005)	—	—	—	—	(87,765)
Other comprehensive income (loss)	—	—	—	—	—	(198)	(198)
Balance at December 31, 2014	**$ 105,445**	**$ 101,311**	**$ —**	**$ —**	**$ —**	**$ (748)**	**$ 206,008**
Allocation of net income	56,941	54,709	—	—	—	—	111,650
Capital distribution to members	(48,705)	(46,796)	—	—	—	—	(95,501)
Other comprehensive income (loss)	—	—	—	—	—	(3,443)	(3,443)
Balance at December 31, 2015	**$ 113,681**	**$ 109,224**	**$ —**	**$ —**	**$ —**	**$ (4,191)**	**$ 218,714**

See notes to financial statements.

CINER WYOMING LLC
(A Majority Owned Subsidiary of Ciner Resources LP)

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013
(In thousands of dollars)

	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 111,650	$ 96,640	$ 79,655
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	22,870	21,587	22,723
Loss on disposal of assets, net	202	1,032	—
Other non-cash items	755	(203)	—
(Increase) decrease in:			
Accounts receivable, net	1,668	(1,055)	809
Accounts receivable - ANSAC	18,199	(12,359)	(4,215)
Inventory	(3,660)	(1,499)	(45)
Other current and non-current assets	(816)	(153)	(1,470)
Due from affiliates, net	7,163	905	5,557
Increase (decrease) in:			
Accounts payable	1,792	(3,535)	66
Accrued expenses and other liabilities	(5,312)	3,230	(542)
Due to affiliates	(713)	4,971	(3,062)
Net cash provided by operating activities	153,798	109,561	99,476
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(35,659)	(27,255)	(16,241)
Proceeds from sale of fixed assets	—	10	—
Net cash used in investing activities	(35,659)	(27,245)	(16,241)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repayments on revolving credit facility	(40,000)	(10,000)	(32,000)
Borrowings on revolving credit facility	5,000	—	135,000
Cash distribution to members	(95,501)	(87,765)	(162,921)
Net cash used in financing activities	(130,501)	(97,765)	(59,921)
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(12,362)	(15,449)	23,314
CASH AND CASH EQUIVALENTS:			
Beginning of year	30,520	45,969	22,655
End of year	$ 18,158	$ 30,520	$ 45,969
SUPPLEMENTAL DISLCOSURE OF CASH FLOW INFORMATION:			
Interest paid during the year	$ 4,059	$ 4,274	$ 2,285
SUPPLEMENTAL DISCLOSURES OF NONCASH INVESTING ACTIVITIES :			
Capital expenditures on account	$ 3,033	$ 4,579	$ 745

See notes to financial statements

1. **Corporate Structure**

A 51% membership interest in Ciner Wyoming LLC (the "Company," "we," "us," or "our"), formerly OCI Wyoming LLC, is owned by Ciner Resources LP (CINR or the "Partnership"), formerly OCI Resources LP. NRP Trona LLC, a wholly owned subsidiary of Natural Resource Partners LP (NRP) owns a 49% membership interest in the Company. CINR is a master limited partnership traded on the New York Stock exchange and is currently owned approximately 75% by Ciner Wyoming Holding Co. (CINWHCO), formerly OCI Wyoming Holding Co., and approximately 25% by the general public. CINWHCO is 100% owned by Ciner Resources Corporation (CRC), formerly OCI Chemical Corporation, which is ultimately 100% owned by Ciner Enterprises, Inc. (CINE). CINE is 100% owned by Akkan Enerji ve Madencilik Anonim Sirketi ("Akkan"), which is 100% owned by Turgay Ciner, the Chairman of the Ciner Group, a Turkish conglomerate of companies engaged in energy and mining (including soda ash mining), media and shipping markets.

Completed sale transaction - On October 23, 2015, CINE acquired 100% of OCI Chemical Corporation in a stock purchase transaction from OCI Enterprises Inc. ("OCIE") (the "Transaction"). OCI Chemical Corporation was subsequently renamed Ciner Resources Corporation. CRC owns indirectly the Partnership through CINWHCOs approximately 75% ownership interest. As a result of the closing of the Transaction, OCIE no longer has any direct or indirect ownership interest in the Partnership.

In connection with the closing of the Transaction, CINE (as borrower), and CINWHCO and CRC (as guarantors), entered into a credit facility (as amended and restated or otherwise modified, the “Ciner Enterprises Credit Facility”), which is secured by certain assets, including the common units and the subordinated units of the Partnership owned by CINWHCO.

2. Nature of Operations and Summary of Significant Accounting Policies

Nature of Operations - The Company operations consist of the mining of trona ore, which, when processed, becomes soda ash. All our soda ash processed is sold to various domestic and European customers, and to American Natural Soda Ash Corporation (ANSAC) which is an affiliate for export sales. All mining and processing activities take place in one facility located in Green River, Wyoming.

A summary of the significant accounting policies is as follows:

Basis of Presentation - The accompanying financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America.

Use of Estimates - The preparation of financial statements, in accordance with accounting principles generally accepted in the United States of America, requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the dates of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition - We recognize revenue when the earnings process is complete, which is generally upon transfer of title. This transfer typically occurs upon shipment to the customer, which is normally free on board

("FOB") terms or upon receipt by the customer. In all cases, we apply the following criteria in recognizing revenue: (1) persuasive evidence of an arrangement exists; (2) delivery has occurred; (3) the selling price is fixed, determinable or reasonably estimated sales price has been agreed with the customer; and (4) collectability is reasonably assured. Customer rebates are accounted for as sales deductions. We record amounts billed for shipping and handling fees as revenue. Costs incurred for shipping and handling are recorded as costs of products sold.

Freight Costs - The Company includes freight costs billed to customers for shipments administered by the Company in gross sales. The related freight costs along with cost of products sold are deducted from gross sales to determine gross profit.

Cash and Cash Equivalents - The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. Cash equivalents consist primarily of money market deposit accounts.

Accounts Receivable - Accounts receivable are carried at the original invoice amount less an estimate for doubtful receivables. We generally do not require collateral against outstanding accounts receivable. The allowance for doubtful accounts is based on specifically identified amounts that the Company believes to be uncollectible. An additional allowance is recorded based on certain percentages of aged receivables, which are determined based on management's assessment of the general financial conditions affecting the Company's customer base. If actual collection experience changes, revisions to the allowance may be required. Accounts receivable are written off when deemed uncollectible. Recoveries of accounts receivable previously written off are recorded when received. During the years ended 2015, 2014 and 2013 there were no significant accounts receivable bad debt expenses, write-offs or recoveries.

Inventory - Inventory is carried at the lower of cost or market. Cost is determined using the first-in, first-out method for raw material and finished goods inventory and the weighted average cost method for stores inventory. Costs include raw materials, direct labor and manufacturing overhead. Market is based on current replacement cost for raw materials and stores inventory, and finished goods is based on net realizable value.

- *Raw material inventory* includes material, chemicals and natural resources being used in the mining and refining process.
- *Finished goods inventory* is the finished product soda ash.
- *Stores inventory* includes parts, materials and operating supplies which are typically consumed in the production of soda ash and currently available for future use.

Property, Plant, and Equipment - Property, plant, and equipment are stated at cost less accumulated depreciation. Depreciation is computed over the estimated useful lives of depreciable assets, using the straight-line method. The estimated useful lives applied to depreciable assets are as follows:

	Useful Lives
Land improvements	10 years
Depletable land	15-60 years
Buildings and building improvements	10-30 years
Internal-use computer software	3-5 years
Machinery and equipment	5-20 years
Furniture and fixtures	10 years

The Company's policy is to evaluate property, plant, and equipment for impairment whenever events or changes in circumstances indicate that its carrying amount may not be recoverable. An indicator of potential impairment would include situations when the estimated future undiscounted cash flows are less than the carrying value. The amount of any impairment then recognized would be calculated as the difference between estimated fair value and the carrying value of the asset.

Derivative Instruments and Hedging Activities - The Company may enter into derivative contracts from time to time to manage exposure to the risk of exchange rate changes on its foreign currency transactions, the risk of changes in natural gas prices, and the risk of the variability in interest rates on borrowings. Gains and losses on derivative contracts are reported as a component of the underlying transactions. The Company follows hedge accounting for its hedging activities. All derivative instruments are recorded on the balance sheet at their fair values. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. The Company designates its derivatives based upon criteria established for hedge accounting under generally accepted accounting principles. For a derivative designated as a fair value hedge, the gain or loss is recognized in earnings in the period of change together with the offsetting gain or loss on the hedged item attributed to the risk being hedged. For a derivative designated as a cash flow hedge, the effective portion of the derivative's gain or loss is initially reported as a component of accumulated other comprehensive income (loss) and subsequently reclassified into earnings when the hedged exposure affects earnings. Any significant ineffective portion of the gain or loss is reported in earnings immediately. For derivatives not designated as hedges, the gain or loss is reported in earnings in the period of change. The natural gas physical forward contracts are accounted for under the normal purchases and normal sales scope exception.

The company has entered into interest rate swap contracts, designed as cash flow hedges, to mitigate the exposure to possible increases in interest rates. These contracts are for periods consistent with the exposure being hedged and will mature on July 18, 2018, the maturity date of the long-term debt under the Ciner Wyoming Credit Facility. These contracts had an aggregate notional value of $74,000 and $76,000 at December 31, 2015 and December 31, 2014, respectively. At December 31, 2015, it was anticipated that $699 of losses currently recorded in accumulated other comprehensive income will be reclassified into earnings within the next 12 months.

In 2015, the Company enter into natural gas forward contracts, designed as cash flow hedges, to mitigate volatility in the price of certain of the natural gas the Company consumes. These contracts generally have various maturities through 2020. These contracts as of December 31, 2015, had an aggregate notional value of $15,831. The Company had no similar contracts outstanding as of December 31, 2014. At December 31, 2015, it was anticipated that $1,021 of losses currently recorded in accumulated other comprehensive income will be reclassified into earnings within the next 12 months.

The Company enters into foreign exchange forward contracts to hedge certain firm commitments denominated in currencies other than the U.S. dollar. However, the Company has not applied hedge accounting for these contracts at December 31, 2015. These contracts are for periods consistent with the exposure being hedged and generally have maturities of one year or less. These contracts, which are predominantly used to purchase U.S. dollars and sell Euros, had an aggregate notional value of $4,160 and $6,900 at December 31, 2015 and 2014, respectively.

The following table presents the fair value of derivative assets and liabilities and the respective balance sheet locations as of:

	Assets				Liabilities			
	December 31, 2015		December 31, 2014		December 31, 2015		December 31, 2014	
(In millions)	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Derivatives designated as hedges:								
Interest rate swap contracts - current		$ —		$ —	Accrued Expenses	$ 819	Accrued Expenses	$ 748
Natural gas forward contracts - current		—		—	Accrued Expenses	1,021		—
Natural gas forward contracts - non-current		—		—	Other non-current liabilities	2,351		—
Total derivatives designated as hedging instruments		$ —		$ —		$ 4,191		$ 748
Derivatives not designated as hedging instruments:								
Foreign exchange forward contracts	Other current assets	$ 129	Other current assets	$ 617		$ —		$
Total derivatives not designated as hedging instruments		$ 129		$ 617		$ —		$
Total derivatives		$ 129		$ 617		$ 4,191		$ 748

Income Tax - The Company is organized as a pass-through entity for federal income tax purposes. As a result, the members are responsible for federal income taxes based on their respective share of taxable income. Net income for financial statement purposes may differ significantly from taxable income reportable to members as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the membership agreement.

Reclamation Costs - The Company is obligated to return the land beneath its refinery and tailings ponds to its natural condition upon completion of operations and is required to return the land beneath its rail yard to its natural condition upon termination of the various lease agreements.

The Company accounts for its land reclamation liability as an asset retirement obligation, which requires that obligations associated with the retirement of a tangible long-lived asset be recorded as a liability when those obligations are incurred, with the amount of the liability initially measured at fair value. Upon initially recognizing a liability for an asset retirement obligation, an entity must capitalize the cost by recognizing an increase in the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the estimated useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement.

The estimated original liability calculated in 1996 for the refinery and tailing ponds was calculated based on the estimated useful life of the mine, which was 80 years, and on external and internal estimates as to the cost to restore the land in the future and state regulatory requirements. In 2016, the mining reserve will be amortized over a remaining life of 67 years. During 2015, 2014 and 2013 the remaining life was 68 years, 66 years, and 67 years, respectively. The liability was discounted using a weighted average credit-adjusted risk free rate of approximately 6% and is being accreted throughout the estimated life of the related assets to equal the total estimated costs with a corresponding entry being recorded to cost of products sold.

During 2011, the Company constructed a rail yard to facilitate loading and switching of rail cars. The Company is required to restore the land on which the rail yard is constructed to its natural conditions. The estimated liability for restoring the rail yard to its natural condition is calculated based on the land lease life of 30 years and on external and internal estimates as to the cost to restore the land in the future. The liability is discounted using a credit-adjusted risk-free rate of 4.25% and is being accreted throughout the estimated life of the related assets to equal the total estimated costs with a corresponding entry being recorded to cost of products sold.

Fair Value of Financial Instruments - The following methods and assumptions were used to estimate the fair values of each class of financial instruments:

Financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, accrued expenses and long-term debt. The carrying amounts of cash and cash equivalents, accounts receivable, accounts payable and accrued expenses approximate their fair value because of the nature of such instruments. Our long-term debt and derivative financial instruments are measured at their fair values with Level 2 inputs based on quoted market values for similar but not identical financial instruments.

Long-Term Debt - The fair value of our long-term debt is based on present rates for indebtedness with similar amounts, durations and credit risks.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Fair value accounting requires that these financial assets and liabilities be classified into one of the following three categories:

- Level 1-inputs to the valuation methodology are quoted prices (unadjusted) for an identical asset or liability in an active market.
- Level 2-inputs to the valuation methodology include quoted prices for a similar asset or liability in an active market or model-derived valuations in which all significant inputs are observable for substantially the full term of the asset or liability.
- Level 3-inputs to the valuation methodology are unobservable and significant to the fair value measurement of the asset or liability.

Subsequent Events - The Company has evaluated all subsequent events through March 11, 2016, the date the financial statements were available to be issued.

Recently Issued Accounting Standards - In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers (Topic 606) that requires companies to recognize revenue when a customer obtains control rather than when companies have transferred substantially all risks and rewards of a good or service. In August 2015, the amendments in ASU 2015-14 defer the effective date of ASU 2014-09 for all entities by one year. Public business entities, certain not-for-profit entities, and certain employee benefit plans should apply the guidance in ASU 2014-09 to annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. Earlier application permitted only as of annual reporting period beginning after December 15, 2016, including interim reporting periods therein. The Company is currently assessing the impact the adoption of ASU 2014-09 may have on its financial statements, as well as the available transition methods.

In July 2015, the FASB issued ASU No. 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory. ASU 2015-11 requires that inventory within the scope of this update be measured at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The amendments in this update do not apply to inventory that is measured using last-in, first-out (LIFO) or the retail inventory method. The amendments apply to all other inventory, which includes inventory that is measured using first-in, first-out (FIFO) or average cost. For public business entities, the amendments in this update are effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. For all other entities, the amendments in this Update are effective for fiscal years beginning after December 15,2016, and interim periods within fiscal years beginning after December 15, 2017. Earlier application is permitted by all entities as of the beginning of an interim or annual reporting period. The amendments should be applied prospectively. The adoption of this guidance is not expected to have a material impact upon our financial condition or results of operations.

In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities (ASU 2016-01). The standard amend certain aspects of recognition, measurement, presentation, and disclosure of financial assets and liabilities. ASU 2016-01 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The Company is currently evaluating the potential impact the adoption of ASU 2016-01 will have on its financial statements, as well as available transition methods.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842). The update amends existing standards for accounting for leases by lessees, with accounting for leases by lessors remaining largely unchanged from current guidance. The update requires that lessees recognize a lease liability and a right of use asset for all leases (with the exception of short-term leases) at the commencement date of the lease and disclose key information about leasing arrangements. The update is effective for interim and annual periods beginning after December 15, 2018 and must be adopted using a modified retrospective transition. The ASU No. 2016-02 provides for certain practical expedients and early adoption is permitted. The Company is evaluating the potential impact the adoption of ASU No. 2016-02 will have on its consolidated financial statements.

3. ACCOUNTS RECEIVABLE, NET

Accounts receivable, net as of December 31, 2015 and 2014 consists of the following:

	2015	2014
Trade receivables	$ 27,163	$ 24,691
Other receivables	6,767	10,854
	33,930	35,545
Allowance for doubtful accounts	(142)	(88)
Total	$ 33,788	$ 35,457

4. INVENTORY

Inventory as of December 31, 2015 and 2014 consists of the following:

	2015	2014
Raw materials	$ 9,110	$ 6,413
Finished goods	10,675	10,363
Stores inventory	27,089	26,461
Total	$ 46,874	$ 43,237
Less: Stores inventory reclassed to other non-current assets	(20,498)	(20,771)
Inventory - current	$ 26,376	$ 22,466

Subsequent to the issuance of the Company's financial statements for the year ended December 31, 2014, the Company identified a balance sheet misclassification relating to the portion of stores inventory that is not reasonably expected to be used during the year. That amount was presented as a component of inventory (a current asset) rather than as a non-current asset in the December 31, 2014 balance sheet. The correction of this error resulted in a decrease of current assets and inventory and a corresponding increase in other non-current assets of $20,771. The result of this correction did not impact the Companies statements of operations and comprehensive income, members' equity, and cash flows for any period presented. Management does not believe this misstatement is individually or collectively material to the financial statements.

5. PROPERTY, PLANT, AND EQUIPMENT, NET

Property, plant, and equipment as of December 31, 2015 and 2014 consists of the following:

	2015	2014
Land and land improvements	$ 192	$ 192
Depletable land	2,957	2,957
Buildings and building improvements	132,504	129,514
Internal-use computer software	4,863	4,468
Machinery and equipment	577,472	567,289
Total	717,988	704,420
Less accumulated depreciation, depletion and amortization	(547,277)	(536,163)
Total net book value	170,711	168,257
Construction in progress	42,108	33,145
Property, plant, and equipment, net	$ 212,819	$ 201,402

Depreciation, depletion and amortization expense on property, plant and equipment was $22,519, $21,235 and $22,723 for the years ended December 31, 2015, 2014 and 2013, respectively.

6. OTHER NON-CURRENT ASSETS

Other non-current assets as of December 31, 2015 and 2014 consist of the following:

	2015	2014
Stores inventory	$ 20,498	$ 20,771
Deferred financing costs	528	880
Total	$ 21,026	$ 21,651

7. ACCRUED EXPENSES

Accrued expenses as of December 31, 2015 and 2014 consists of the following:

	2015	2014
Accrued freight costs	$ 135	$ 1,373
Accrued energy costs	5,185	5,718
Accrued royalty costs	4,834	4,445
Accrued employee compensation	3,950	6,739
Accrued other taxes	4,532	4,608
Accrued derivatives	1,841	748
Other accruals	4,556	5,657
Total	$ 25,033	$ 29,288

8. DEBT

Long-term debt as of December 31, 2015 and 2014 consists of the following:

	2015	2014
Variable Rate Demand Revenue Bonds, principal due October 1, 2018, interest payable monthly, bearing monthly interest rate of 0.11% (2015) and 0.14% (2014)	$ 11,400	$ 11,400
Variable Rate Demand Revenue Bonds, principal due August 1, 2017, interest payable monthly, bearing monthly interest rate of 0.11% (2015) and 0.14% (2014)	8,600	8,600
Ciner Wyoming Credit Facility, unsecured principal expiring on July 18, 2018, variable interest rate was a weighted average rate of 2.0742% (2015) and 1.9781% (2014)	90,000	125,000
Total debt	110,000	145,000
Less current portion of long-term debt	—	—
Total long-term debt	$ 110,000	$ 145,000

Aggregate maturities required on long-term debt at December 31, 2015 are as follows:

2017	$ 8,600
2018	101,400
Total	$ 110,000

Revenue Bonds

The Variable Rate Demand Revenue Bonds are held by CINWYLLC. These revenue bonds require the Company to maintain standby letters of credit totaling $20,333 at December 31, 2015. These letters of credit require compliance with certain covenants, including minimum net worth, maximum debt to net worth, and interest coverage ratios. As of December 31, 2015, the Company was in compliance with these debt covenants.

Ciner Wyoming Credit Facility

On July 18, 2013, the Company entered into a $190,000 senior unsecured revolving credit facility, as amended on October 30, 2014 (as amended, the "Ciner Wyoming Credit Facility"), with a syndicate of lenders, which will mature on the fifth anniversary of the closing date of such credit facility. The Ciner Wyoming Credit Facility provides for revolving loans to fund working capital requirements, capital expenditures, to consummate permitted acquisitions and for all other lawful Company purposes. The Ciner Wyoming Credit Facility has an accordion feature that allows Ciner Wyoming to increase the available revolving borrowings under the facility by up to an additional $75,000, subject to the Company receiving increased commitments from existing lenders or new commitments from new lenders and the satisfaction of certain other conditions. In addition, the Ciner Wyoming Credit Facility includes a sublimit up to $20,000 for same-day swing line advances and a sublimit up to $40,000 for letters of credit. The Company's obligations under the Ciner Wyoming Credit Facility are unsecured.

The Ciner Wyoming Credit Facility contains various covenants and restrictive provisions that limit (subject to certain exceptions) the Company's ability to:

- make distributions on or redeem or repurchase units;
- incur or guarantee additional debt;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates of the Company;

- merge or consolidate with another Company; and
- transfer, sell or otherwise dispose of assets.

The Ciner Wyoming Credit Facility also requires quarterly maintenance of a leverage ratio (as defined in the Ciner Wyoming Credit Facility) of not more than 3.00 to 1.00 and a fixed charge coverage ratio (as defined in the Ciner Wyoming Credit Facility) of not less than 1.10 to 1.00 for the 2014 and 2015 fiscal years, respectively and not less than 1.15 to 1.00 thereafter. The Ciner Wyoming Credit Facility also requires that consolidated capital expenditures, as defined in the Ciner Wyoming Credit Facility, not exceed $50,000 in any fiscal year.

In addition, the Ciner Wyoming Credit Facility contains events of default customary for transactions of this nature, including (i) failure to make payments required under the Ciner Wyoming Credit Facility, (ii) events of default resulting from failure to comply with covenants and financial ratios in the Ciner Wyoming Credit Facility, (iii) the occurrence of a change of control, (iv) the institution of insolvency or similar proceedings against Ciner Wyoming and (v) the occurrence of a default under any other material indebtedness Ciner Wyoming may have. Upon the occurrence and during the continuation of an event of default, subject to the terms and conditions of the Ciner Wyoming Credit Facility, the lenders may terminate all outstanding commitments under the Ciner Wyoming Credit Facility and may declare any outstanding principal of the Ciner Wyoming Credit Facility debt, together with accrued and unpaid interest, to be immediately due and payable.

Under the Ciner Wyoming Credit Facility, a change of control is triggered if Ciner Resources and its wholly-owned subsidiaries, directly or indirectly, cease to own all of the equity interests, or cease to have the ability to elect a majority of the board of directors (or similar governing body) of the general partner of CINR (or any entity that performs the functions the general partner of CINR). In addition, a change of control would be triggered if CINR ceases to own at least 50.1% of the economic interests in the Company or cease to have the ability to elect a majority of the members of the Company's board of managers.

The Company was in compliance with all terms under its long-term debt agreements as of December 31, 2015.
Loans under the Ciner Wyoming Credit Facility bear interest at the Company's option at either:

- a Base Rate, which equals the highest of (i) the federal funds rate in effect on such day plus 0.50%, (ii) the administrative agent's prime rate in effect on such day and (iii) one-month LIBOR plus 1.0%, in each case, plus an applicable margin; or
- a LIBOR Rate plus an applicable margin.

The unused portion of the Ciner Wyoming Credit Facility is subject to an unused line fee ranging from 0.275% to 0.350% per annum based on the Company's then current consolidated leverage ratio.

In addition, there are restrictions in the Ciner Enterprises Credit Agreement that affect the Partnership. Specifically, Ciner Enterprises has agreed (subject to certain exceptions in addition to those described below) that it will not, and will not permit any of its subsidiaries, including Ciner Wyoming and us, to:

- make distributions on or redeem or repurchase equity interests, other than distributions to our and Ciner Wyoming's unitholders;
- incur or guarantee additional debt, other than debt incurred under the Revolving Credit Facility or the Ciner Wyoming Credit Facility, among certain other types of permitted debt;
- make certain investments and acquisitions, other than investments in each of Ciner Wyoming and us, in an amount not to exceed $10 million and $2 million per calendar year, respectively, and other exceptions set forth therein;
- incur certain liens or permit them to exist, other than, with respect to our and Ciner Wyoming's liens, an aggregate amount outstanding at any time equal to $200,000 and $1 million, respectively;

- enter into certain types of transactions with affiliates, other than transactions between Ciner Wyoming and us;
- merge or consolidate with another company; or
- transfer, sell, or otherwise dispose of assets, other than our and Ciner Wyoming's dispositions of assets with a net book value not to exceed $500,000 and $2.5 million, respectively, in any given year.

9. OTHER NON-CURRENT LIABILITIES

Other non-current liabilities as of December 31, 2015 and 2014 consists of the following:

	2015		2014	
Reclamation Reserve	$	4,457	$	4,192
Derivative instruments and hedges, fair value liabilities		2,351		—
Total	$	6,808	$	4,192

Details of the reclamation reserve shown above are as follows:

	2015		2014	
Reclamation reserve at beginning of year	$	4,192	$	3,779
Accretion expense		265		413
Reclamation reserve at end of year	$	4,457	$	4,192

10. EMPLOYEE BENEFIT PLANS

The Company participates in various benefit plans offered and administered by CRC (administered by OCIE prior to the Transaction) and is allocated its portions of the annual costs related thereto. The specific plans are as follows:

***Retirement Plans* -** Benefits provided under the Ciner Pension Plan for Salaried Employees and Ciner Pension Plan for Hourly Employees are based upon years of service and average compensation for the highest 60 consecutive months of the employee's last 120 months of service, as defined. Each plan covers substantially all full-time employees hired before May 1, 2001. CRC's funding policy is to contribute an amount within the range of the minimum required and the maximum tax-deductible contribution. The Company's allocated portion of net periodic pension cost was $7,731, $3,140 and $8,421 for the years ended December 31, 2015, 2014 and 2013, respectively. The increase in pension costs in 2015, was driven by unfavorable effects of lower actuarial discount rates and market returns assumptions in 2015 versus 2014.

Savings Plan - The Ciner 401(k) Retirement Plan covers all eligible hourly and salaried employees. Eligibility is limited to all domestic residents and any foreign expatriates who are in the United States indefinitely. The plan permits employees to contribute specified percentages of their compensation, while the Company makes contributions based upon specified percentages of employee contributions. The Plan was amended such that participants hired on or subsequent to May 1, 2001, will receive an additional contribution from the Company based on a percentage of the participant’s base pay. Contributions made by the Company for the years ended December 31, 2015, 2014 and 2013 were $2,582, $2,428 and $2,795, respectively.

Postretirement Benefits - Most of the Company's employees are eligible for postretirement benefits other than pensions if they reach retirement age while still employed.

CRC accounts for postretirement benefits on an accrual basis over an employee’s period of service. The postretirement plan, excluding pensions, are not funded, and CRC has the right to modify or terminate the plan. Effective January 1, 2013, the postretirement benefits for non-grandfathered retirees were amended to

replace the medical coverage for post-65-year-old members with a fixed dollar contribution amount. As a result of the amendment, the accumulated and projected benefit obligation for CRC's postretirement benefits
decreased by approximately $8,700 and resulted in a prior service credit of approximately $7,700 which was recognized as a reduction of net periodic postretirement benefit costs through year 2014. The post-retirement benefits had a benefits obligation of $21,263 and $22,765 for the years ended December 31, 2015 and 2014, respectively. The Company's allocated portion of postretirement benefit costs was an expense of $495 for the year ended December 31, 2015 and income of $260 and $55 for the years ended December 31, 2014 and 2013, respectively.

11. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Accumulated other comprehensive income (loss) as of December 31, 2015, 2014 and 2013 consists of the following:

	Interest Rate Swap Contract	Natural Gas Forwards Contracts	Total
BALANCE at January 1, 2013	$ (580)	$ —	$ (580)
Other comprehensive loss before reclassification	(849)	—	(849)
Amounts reclassified from accumulated other comprehensive loss	879	—	879
Net current-period other comprehensive income (loss)	30	—	30
BALANCE at December 31, 2013	$ (550)	$ —	$ (550)
Other comprehensive loss before reclassification	(1,294)	—	(1,294)
Amounts reclassified from accumulated other comprehensive loss	1,096	—	1,096
Net current-period other comprehensive income (loss)	(198)	—	(198)
BALANCE at December 31, 2014	$ (748)	$ —	$ (748)
Other comprehensive loss before reclassification	(1,098)	(3,722)	(4,820)
Amounts reclassified from accumulated other comprehensive loss	1,027	350	1,377
Net current-period other comprehensive income (loss)	(71)	(3,372)	(3,443)
BALANCE at December 31, 2015	$ (819)	$ (3,372)	$ (4,191)

The components of other comprehensive income/(loss), attributable to the Company, that have been reclassified out of Accumulated other comprehensive income consisted of the following:

	2015	2014	2013	Affected Line Items on the Consolidated Statements of Operations and Comprehensive Income
Details about other comprehensive income/(loss) components:				
Gains and losses on cash flow hedges:				
Interest rate swap contracts	$ 1,027	$ 1,096	$ 879	Interest expense
Commodity hedge contracts	350	—	—	Cost of Products Sold
Total reclassifications for the period	$ 1,377	$ 1,096	$ 879	

12. COMMITMENTS AND CONTINGENCIES

The Company leases mineral rights from the U.S. Bureau of Land Management, the state of Wyoming, Rock Springs Royalty Corp., a wholly owned subsidiary of Anadarko Holding Company (AHC), and other private parties. All of these leases provide for royalties based upon production volume. The remaining leases provide for minimum lease payments as detailed in the table below. The Company has a perpetual right of first refusal with respect to these leases and intends to continue renewing the leases as has been its practice.

The Company entered into a 10 year rail yard switching and maintenance agreement with a third party, Watco Companies, LLC, on December 1, 2011. Under the agreement, Watco provides rail-switching services at the Company's rail yard. The Company's rail yard is constructed on land leased by Watco from Rock Springs Grazing Association and Anadarko Land Corp; the Rock Springs Grazing Association land lease is renewable every 5 years for a total period of 30 years, while the Anadarko Land Corp. lease is perpetual. The Company has an option agreement with Watco to assign these leases to the Company at any time during the land lease term.

The Company entered into two track lease agreements, collectively, not to exceed 10 years with Union Pacific Company for certain rail tracks used in connection with the rail yard.

As of December 31, 2015, the total minimum rental commitments under the Company's various operating leases, including renewal periods are as follows:

	Leased Land	Track Leases	Total
2016	$ 75	70	145
2017	75	70	145
2018	75	70	145
2019	75	70	145
2020	75	70	145
2021 and thereafter	1,500	33	1,533
Total	$ 1,875	383	2,258

CRC, on behalf of the Company, typically enters into operating lease contracts with various lessors for railcars to transport product to customer locations and warehouses. Rail car leases under these contractual commitments range for periods from 1 to 7 years. CRC's obligations related to these rail car leases are $11,972 in 2016, $10,483 in 2017, $9,250 in 2018, $8,339 in 2019, $5,387 in 2020 and $5,707 in 2021 and thereafter. Total lease expense was approximately $12,415, $9,469 and $10,165 for the years ended December 31, 2015, 2014 and 2013, respectively.

Purchase Commitments - The Company has natural gas supply contracts to mitigate volatility in the price of natural gas. As of December 31, 2015, these contracts totaled $82,634 for the purchase of a portion of our gas requirement over approximately the next five years. The supply purchase agreements have specific commitments of $24,101 in 2016, $19,942 in 2017 $17,437 in 2018, $11,627 in 2019 and $9,527 in 2020. The Company has a separate contract that expires in 2021, for transportation of natural gas with an average annual cost of approximately $3,157 per year.

Legal and Environmental - From time to time the Company is party to various claims and legal proceedings related to its business. Although the outcome of these proceedings cannot be predicted with certainty, management does not currently expect any of the legal proceedings the Company is involved in to have a material effect on its business, financial condition and results of operations. The Company cannot predict the nature of any future claims or proceedings, nor the ultimate size or outcome of existing claims and legal proceedings and whether any damages resulting from them will be covered by insurance.

Off-Balance Sheet Arrangements - The Company has a self-bond agreement with the Wyoming Department of Environmental Quality under which it commits to pay directly for reclamation costs at our Wyoming Plant site.

As of December 31, 2015, the amount of the bond was $33,875, which is the amount we would need to pay the State of Wyoming for reclamation costs if we cease mining operations currently. The amount of this self-bond is subject to change upon periodic re-evaluation by the Land Quality Division.

13. AFFILIATES TRANSACTIONS

CRC is the exclusive sales agent for the Company and through its membership in ANSAC, CRC is responsible for promoting and increasing the use and sale of soda ash and other refined or processed sodium products produced. All actual sales and marketing costs incurred by CRC are charged directly to the Company. Selling, general and administrative expenses also include amounts charged to the Company by CRC and CINR principally consisting of salaries, benefits, office supplies, professional fees, travel, rent and other costs of certain assets used by the Company. These transactions do not necessarily represent arm's length transactions and may not represent all costs if the Company operated on a standalone basis.

As a result of the closing of the Transaction discussed in Note 1 - "Corporate Structure," CINE owns indirectly and controls the Company, therefore, OCIE and subsidiaries, including OCI Alabama LLC, are no longer related parties of the Company as of the Transaction date. The following table includes transactions with OCIE and subsidiaries prior to the Transaction date.

The total costs (recoveries) charged to the Company by affiliates for the years ended December 31, 2015, 2014 and 2013 are as follows:

	2015	2014	2013
OCI Enterprises Inc.	$ 4,535	$ 8,955	$ 5,537
CRC	5,587	3,415	4,387
ANSAC (1)	3,793	2,930	2,582
CINR	(11)	892	—
Total selling, general and administrative expenses - affiliates	$ 13,904	$ 16,192	$ 12,506

(1) ANSAC allocates its expenses to its members using a pro rata calculation based on sales.

Cost of products sold includes logistics services charged by ANSAC. For the years ended December 31, 2015, 2014 and 2013 these costs were $8,134, $9,194 and $6,692, respectively.

Net sales to affiliates for the years ended December 31, 2015, 2014 and 2013 are as follows:

	2015	2014	2013
ANSAC	$ 261,023	$ 230,762	$ 200,413
OCI Alabama LLC	4,266	5,923	7,282
OCI Company Limited	—	—	3,950
Total	$ 265,289	$ 236,685	$ 211,645

As of December 31, 2015 and 2014, the Company had due from/to with affiliates as follows:

	2015		2014	
	Due from Affiliates	Due to Affiliates	Due from Affiliates	Due to Affiliates
CINE	$ 25	$ —	$ —	$ —
OCI Enterprises Inc.	—	—	1,594	2,848
CRC	6,942	1,888	8,268	1,171
Ciner Resources Europe NV	4,814	—	9,183	—
Other	544	2,746	444	1,328
Total	$ 12,325	$ 4,634	$ 19,489	$ 5,347

As of December 31, 2015, included in Accounts receivable, net is $564 receivable from OCIE and subsidiaries and included within Accrued expenses is $464 payable to OCIE and subsidiaries.

14. MAJOR CUSTOMERS AND SEGMENT REPORTING

Our operations are similar in nature of products we provide and type of customers we serve. As the Company earns substantially all of its revenues through the sale of soda ash mined at a single location, we have concluded that we have one operating segment for reporting purposes. The net sales by geographic area for the years ended December 31, 2015, 2014 and 2013 are as follows:

	2015	2014	2013
Domestic	$ 194,036	$ 194,801	$ 195,062
International:			
ANSAC	261,024	230,762	200,413
Other	31,333	39,469	46,657
Total international	292,357	270,231	247,070
Total net sales	$ 486,393	$ 465,032	$ 442,132

15. SUBSEQUENT EVENTS

On January 13, 2016, the members of the Board of Managers of Ciner Wyoming, approved a cash distribution to the members in the aggregate amount of $25,000. The distribution was paid on February 5, 2016.

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