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, 2014 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)*
601 Jefferson, Suite 3600 **Houston, Texas**	**77002**
(Address of principal executive offices)	*(Zip Code)*

(713) 751-7507

(Registrant's telephone number, including area code)
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 (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they were affiliates of the registrant) was approximately $1.3 billion on June 30, 2014 based on a price of $16.57 per unit, which was the closing price of the Common Units as reported on the daily composite list for transactions on the New York Stock Exchange on that date.

As of February 27, 2015, there were 122,299,825 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE.

None.

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Forward-Looking Statements

Statements included in this Annual Report on Form 10-K may constitute forward-looking statements. In addition, we and our representatives may from time to time make other oral or written statements which are also forward-looking statements.

Such forward-looking statements include, among other things, statements regarding:

- our business strategy;
- our financial strategy;
- prices of and demand for coal, oil, natural gas, aggregates and industrial minerals;
- 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;
- our liquidity and access to capital and financing sources;
- projected production levels by our lessees, VantaCore Partners LLC, and the operators of our oil and gas working interests;
- OCI Wyoming LLC's 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 management's 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" and "us" 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 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.

Item 1. *Business*

We are a limited partnership formed in April 2002, and we completed our initial public offering in October 2002. We engage 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. Executing on our plans to diversify our business, we have completed over $900 million in acquisitions since January 2013. For the year ended December 31, 2014, we recorded revenues and other income of $399.8 million and Adjusted EBITDA of $300.3 million. Approximately $226.7 million (57%) of our 2014 revenues and other income were attributable to coal-related sources, and $173.0 million (43%) of our revenues and other income were attributed to non-coal-related sources. Adjusted EBITDA is a non-GAAP financial measure. For a reconciliation of Adjusted EBITDA to net income, see "Item 6. Selected Financial Data—Non-GAAP Financial Measures—Adjusted EBITDA."

Our 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. 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. We also own and manage infrastructure assets that generate additional revenues, primarily in the Illinois Basin.

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. However, the majority of our aggregates and industrial mineral revenues come from VantaCore Partners LLC, which we acquired in October 2014. VantaCore specializes in the construction materials industry and operates three hard rock quarries, five sand and gravel plants, two asphalt plants and a marine terminal. VantaCore's current operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

We own a 49% non-controlling equity interest in a trona ore mining operation and soda ash refinery in the Green River Basin, Wyoming. OCI 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.

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.

Partnership Structure and Management

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We conduct our business through two wholly owned operating companies: NRP (Operating) LLC and NRP Oil and Gas LLC. 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, Mr. Robertson is entitled to nominate ten directors, five of whom must be independent 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 several 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 601 Jefferson Street, Suite 3600, Houston, Texas 77002 and our phone number is (713) 751-7507.

Coal and Coal-Related Properties

Coal Royalty Business

Royalty businesses principally own and manage mineral reserves. As an owner of coal reserves, we typically are not responsible for operations on our coal properties, but instead enter into leases with operators granting them the right to mine and sell reserves from our property in exchange for a royalty payment. 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.

Under our standard lease, lessees calculate royalty payments due to us and are required to report tons of coal removed as well as the sales prices of the extracted coal. 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. Our current coal royalty leases provide for the payment of approximately $103 million in minimums to us during 2015.

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 lessee pursuant to the terms of the lease.

Coal Royalty Revenues, Reserves and Production

The following summary table sets forth coal royalty revenues and average coal royalty per ton from the properties that we owned or controlled for the years ending December 31, 2014, 2013 and 2012. Coal royalty revenues were generated from the properties in each of the areas as follows:

	Coal Royalty Revenues			Average Coal Royalty Per Ton		
	Year Ended December 31,			Year Ended December 31,		
	2014	2013	2012	2014	2013	2012
	(In thousands)			($ per ton)		
Area						
Appalachia:						
Northern	$ 8,621	$ 14,643	$ 15,768	$0.92	$1.27	$1.50
Central	89,627	105,004	156,390	$4.46	$5.05	$5.99
Southern	20,292	26,156	29,325	$5.18	$6.30	$7.89
Total Appalachia	118,540	145,803	201,483	$3.55	$4.00	$5.00
Illinois Basin	54,049	56,001	49,538	$4.10	$4.28	$4.38
Northern Powder River Basin	7,804	7,569	8,501	$2.74	$2.72	$3.58
Gulf Coast	3,793	3,290	1,212	$3.47	$3.39	$2.60
Total	$184,186	$212,663	$260,734	$3.65	$3.99	$4.79

The following summary table sets forth coal production data and reserve information for the properties that we owned or controlled for the years ending December 31, 2014, 2013 and 2012. All of the reserves reported below are recoverable reserves as determined by the SEC's Industry Guide 7. In excess of 90% of the reserves listed below are currently leased to third parties. Coal production data and reserve information for the properties in each of the areas are as follows:

	Coal Production and Reserves					
	Production for Year Ended December 31,			Proven and Probable Reserves at December 31, 2014		
	2014	2013	2012	Underground	Surface	Total
	(Tons in thousands)					
Area						
Appalachia:						
Northern	9,339	11,505	10,486	469,206	27,864	497,070
Central	20,092	20,801	26,098	1,017,993	260,598	1,278,591
Southern	3,914	4,151	3,718	83,846	24,730	108,576
Total Appalachia	33,345	36,457	40,302	1,571,045	313,192	1,884,237
Illinois Basin	13,177	13,087	11,299	330,137	15,025	345,162
Northern Powder River Basin	2,844	2,778	2,377	—	94,157	94,157
Gulf Coast	1,093	970	466	—	2,696	2,696
Total	50,459	53,292	54,444	1,901,182	425,070	2,326,252

We classify low sulfur coal as coal with a sulfur content of less than 1.0%, medium sulfur coal as coal with a sulfur content between 1.0% and 1.5% and high sulfur coal as coal with a sulfur content of greater than 1.5%. Compliance coal is coal which meets the standards of Phase II of the Clean Air Act and is that portion of low sulfur coal that, when burned, emits less than 1.2 pounds of sulfur dioxide per million Btu. As of December 31, 2014, approximately 49% of our reserves were low sulfur coal and 32% of our reserves were compliance coal. 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. We own both steam and metallurgical coal reserves in Northern, Central and Southern Appalachia, as well as the Gulf Coast, and we own steam coal reserves in the Illinois Basin and the Northern Powder River Basin. In 2014, approximately 32% of the production and 40% of the coal royalty revenues from our properties were from metallurgical coal.

The following table sets forth our estimate of the sulfur content, the typical quality of our coal reserves and the type of coal in each area as of December 31, 2014.

Sulfur Content, Typical Quality and Type of Coal

		Sulfur Content				Typical Quality		Type of Coal	
	Compliance Coal(1)	Low (<1.0%)	Medium (1.0% to 1.5%)	High (>1.5%)	Total	Heat Content (Btu per pound)	Sulfur (%)	Steam	Met(2)
		(Tons in thousands)						(Tons in thousands)	
Area									
Appalachia									
Northern	50,097	72,816	24,466	399,788	497,070	12,831	2.58	487,508	9,562
Central	623,881	885,689	332,186	60,716	1,278,591	13,311	0.90	858,899	419,692
Southern	72,273	78,337	27,499	2,740	108,576	13,509	0.84	78,590	29,986
Total Appalachia	746,251	1,036,842	384,151	463,244	1,884,237	13,196	1.34	1,424,997	459,240
Illinois Basin	—	—	2,183	342,979	345,162	11,497	3.28	345,162	—
Northern Powder River Basin	—	94,157	—	—	94,157	8,800	0.65	94,157	—
Gulf Coast	96	2,696	—	—	2,696	6,922	0.69	2,600	96
Total	746,347	1,133,695	386,334	806,223	2,326,252			1,866,916	459,336

(1) Compliance coal 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.

(2) 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.

We have engaged outside consultants to conduct reserve studies of our existing properties. These studies are an ongoing process and we will update the reserve studies based on our review of the following factors: the size of the properties, the amount of production that has occurred, or the development of new data which may be used in these studies. In connection with most acquisitions, we have either commissioned new studies or relied on recent reserve studies completed prior to the acquisition. In addition to these studies, we base our estimates of reserve information on engineering, economic and geological data assembled and analyzed by our internal geologists and engineers. 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 Properties

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

Appalachia

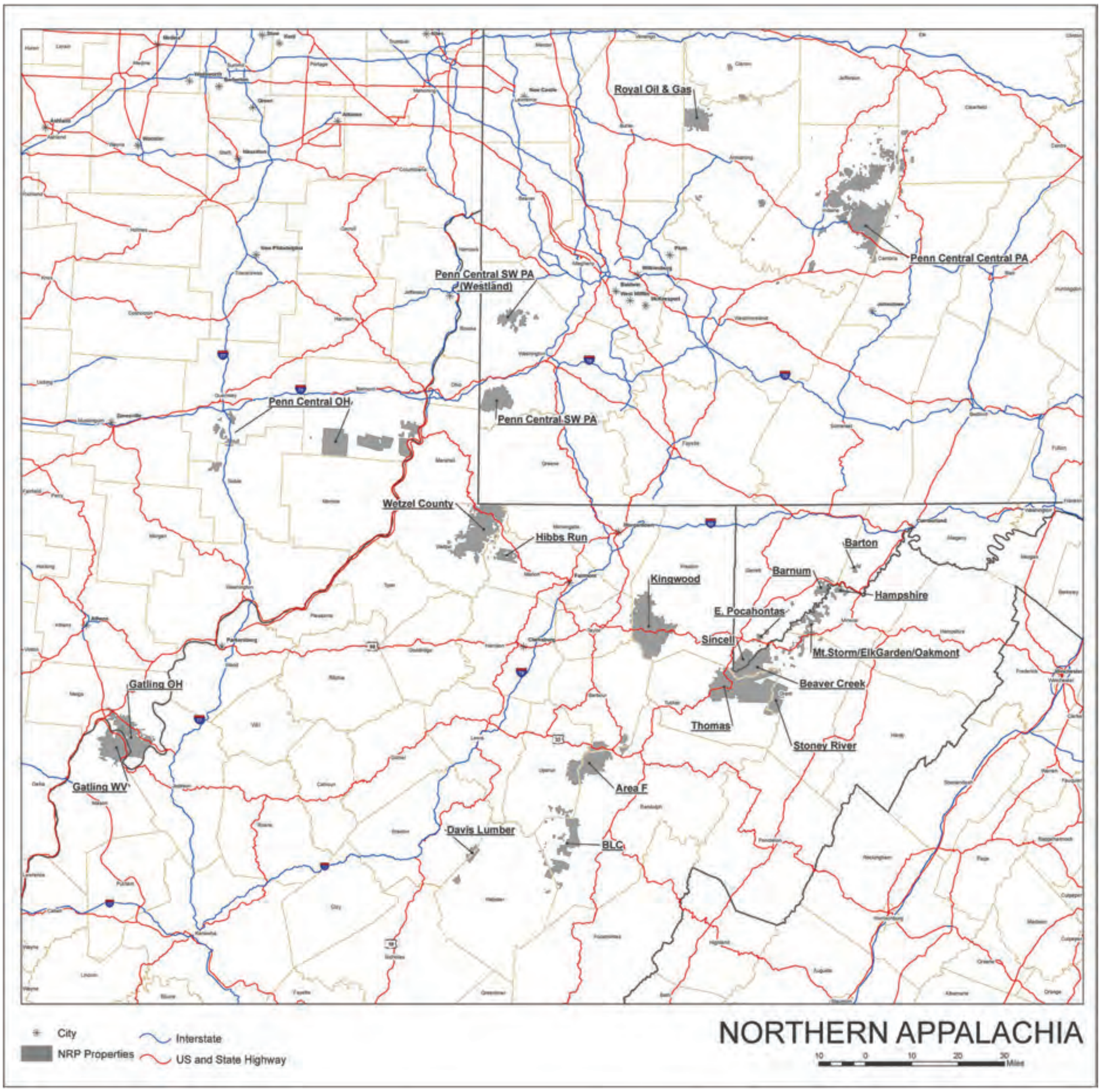
Northern Appalachia

Hibbs Run. The Hibbs Run property is located in Marion County, West Virginia. In 2014, 6.0 million tons were produced from the property by Consolidation Coal Company. 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 such as First Energy and PPL.

Beaver Creek. The Beaver Creek property is located in Grant and Tucker Counties, West Virginia. In 2014, 1.4 million tons were produced from this property. We lease this property to Mettiki Coal, LLC, a subsidiary of Alliance Resource Partners L.P. Coal is produced from an underground longwall mine and is transported by truck to a preparation plant operated by the lessee. Coal is shipped primarily by truck to the Mount Storm power plant of Dominion Power.

AFG-Ohio. The AFG-Ohio property is located in Belmont County, Ohio. In 2014, 1.4 million tons were produced from the property. We lease this property to subsidiaries of Murray Energy Corporation. Coal is produced from an underground longwall mine and shipped by rail and barge to customers including AEP, Duke Energy and First Energy.

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



Central Appalachia

VICC/Alpha. The VICC/Alpha property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. In 2014, 3.8 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. Major customers include American Electric Power, Southern Company, Tennessee Valley Authority, VEPCO and U.S. Steel and to various export 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 Patriot Coal Corporation. In 2014, 2.9 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 steam customers such as American Electric Power, Dayton Power and Light, Detroit Edison and to various export metallurgical customers.

Pinnacle. The Pinnacle property is located in Wyoming and McDowell Counties, West Virginia. In 2014, 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 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 2014, 2.1 million tons were produced from this property. We primarily lease the property to a subsidiary of Alpha Natural Resources, Inc. Production comes from both underground and surface mines. This property has the ability to ship coal on both the CSX and Norfolk Southern railroads.

VICC/Kentucky Land. The VICC/Kentucky Land property is located primarily in Perry, Leslie and Pike Counties, Kentucky. In 2014, 1.7 million tons were produced from this property. Coal is produced from a number of lessees, including subsidiaries of TECO 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 customers such as Southern Company, Tennessee Valley Authority, and American Electric Power.

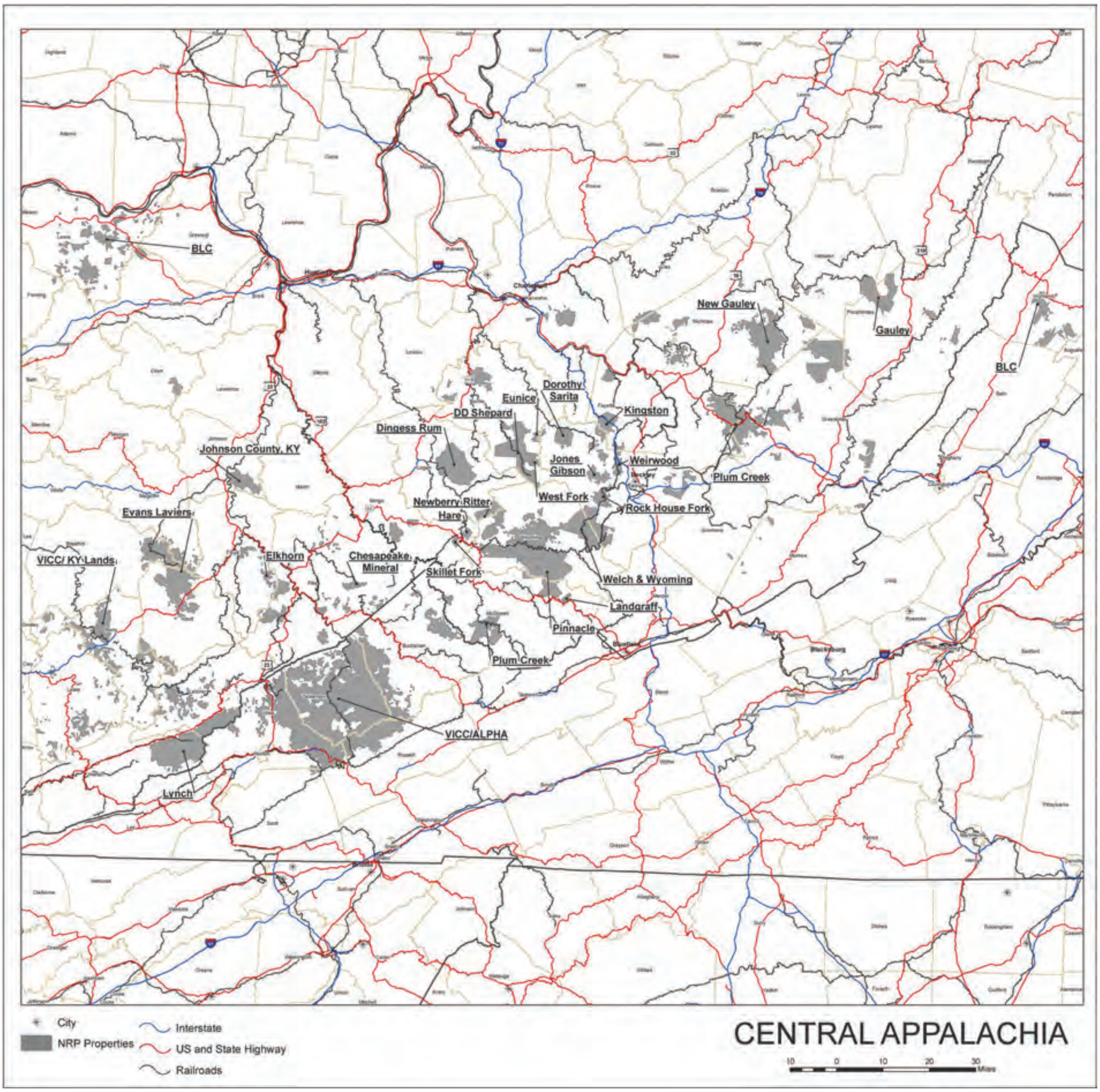
Lone Mountain. The Lone Mountain property is located in Harlan County, Kentucky. In 2014, 1.4 million tons were produced from this property. We lease the property to a subsidiary of Arch Coal, Inc. Production comes from underground mines and is transported primarily by beltline to a preparation plant on adjacent property and shipped on the Norfolk Southern or CSX railroads to utility and metallurgical customers such as SCANA and US Steel.

Kingston. The Kingston property is located in Fayette and Raleigh Counties, West Virginia. This property is leased to a subsidiary of Alpha Natural Resources, Inc. In 2014, 1.1 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 a preparation plant on the property or shipped raw. During 2014, the lessee idled the surface mines on the property in response to market conditions. Coal is shipped via both the CSX railroad and by truck to barges to steam customers and various export metallurgical customers.

D.D. Shepard. The D.D. Shepard property is located in Boone County, West Virginia. This property is primarily leased to a subsidiary of Patriot Coal Corporation. In 2014, 641,000 tons were produced from the property. Both steam and metallurgical coal are produced by the lessees from underground and surface mines. Coal is transported from the mines via belt or truck to preparation plants on the property. Coal is shipped via the CSX railroad to various domestic and export metallurgical customers.

Pardee. The Pardee property is located in Letcher County, Kentucky and Wise County, Virginia. In 2014, 512,000 tons were produced from this property. We lease the property to a subsidiary of Arch Coal, Inc. and Revelation Energy. In late 2014, Arch surrendered the surface mineable coal on the lease and we entered into a new lease for those reserves with Revelation Energy. Production comes from underground mines and is transported by truck or beltline to a preparation plant on the property and shipped on the Norfolk Southern railroad primarily to domestic and export metallurgical customers such as Algoma Steel and Arcelor.

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

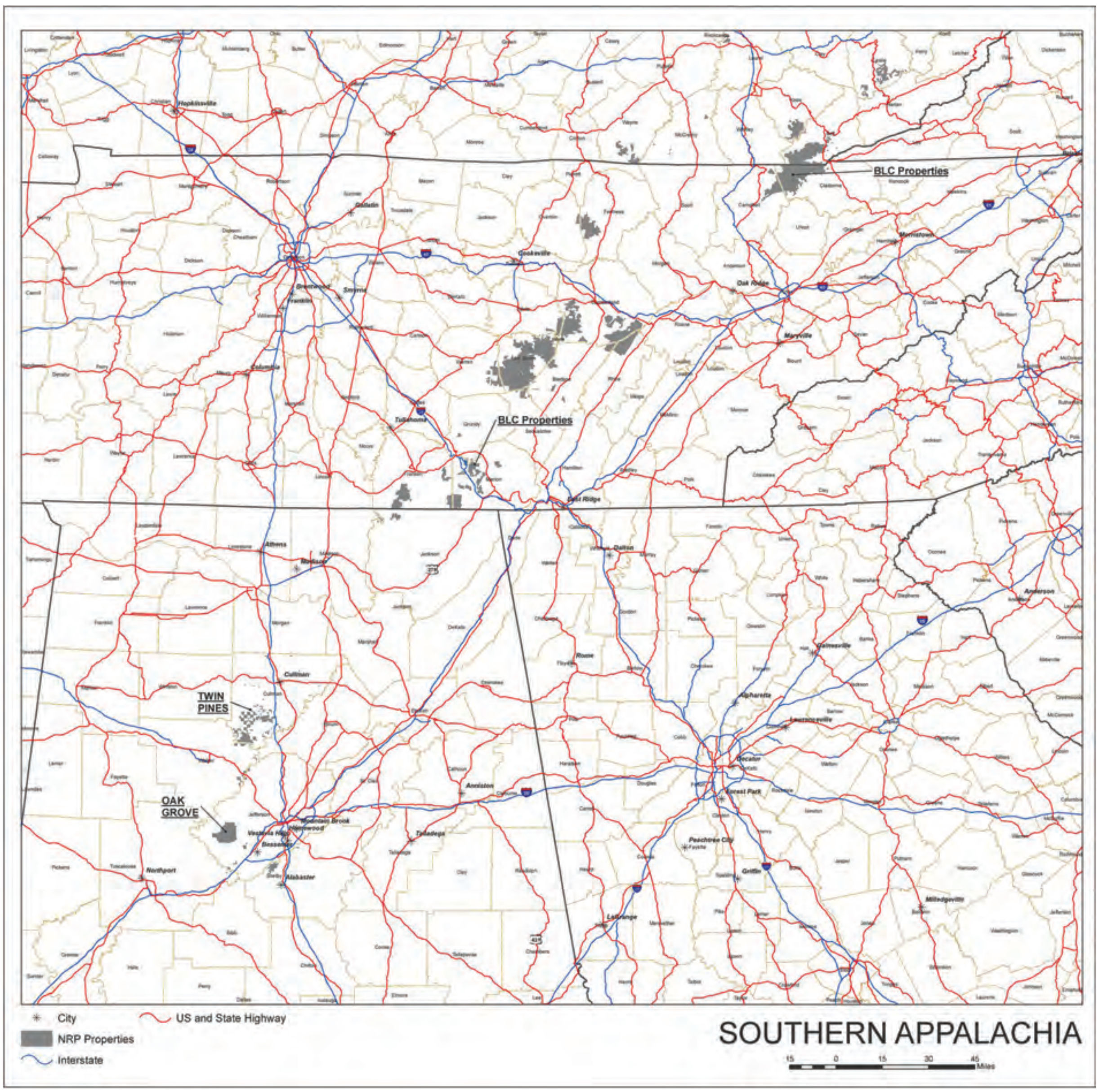


Southern Appalachia

Oak Grove. The Oak Grove property is located in Jefferson County, Alabama. In 2014, 2.4 million tons were produced from this property. We lease the property to a subsidiary of Cliffs Natural Resources, Inc. Production comes from an underground 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 2014, 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. Major customers include South Carolina Electric & Gas, and numerous medium and small industrial customers.

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



Illinois Basin

Williamson. The Williamson property is located in Franklin and Williamson Counties, Illinois. The property is under lease to a subsidiary of Foresight Energy LP, and in 2014, 6.0 million tons were mined on the property. This production is from a longwall mine and is shipped primarily via the Canadian National railroad to customers such as Duke Energy and to various export customers.

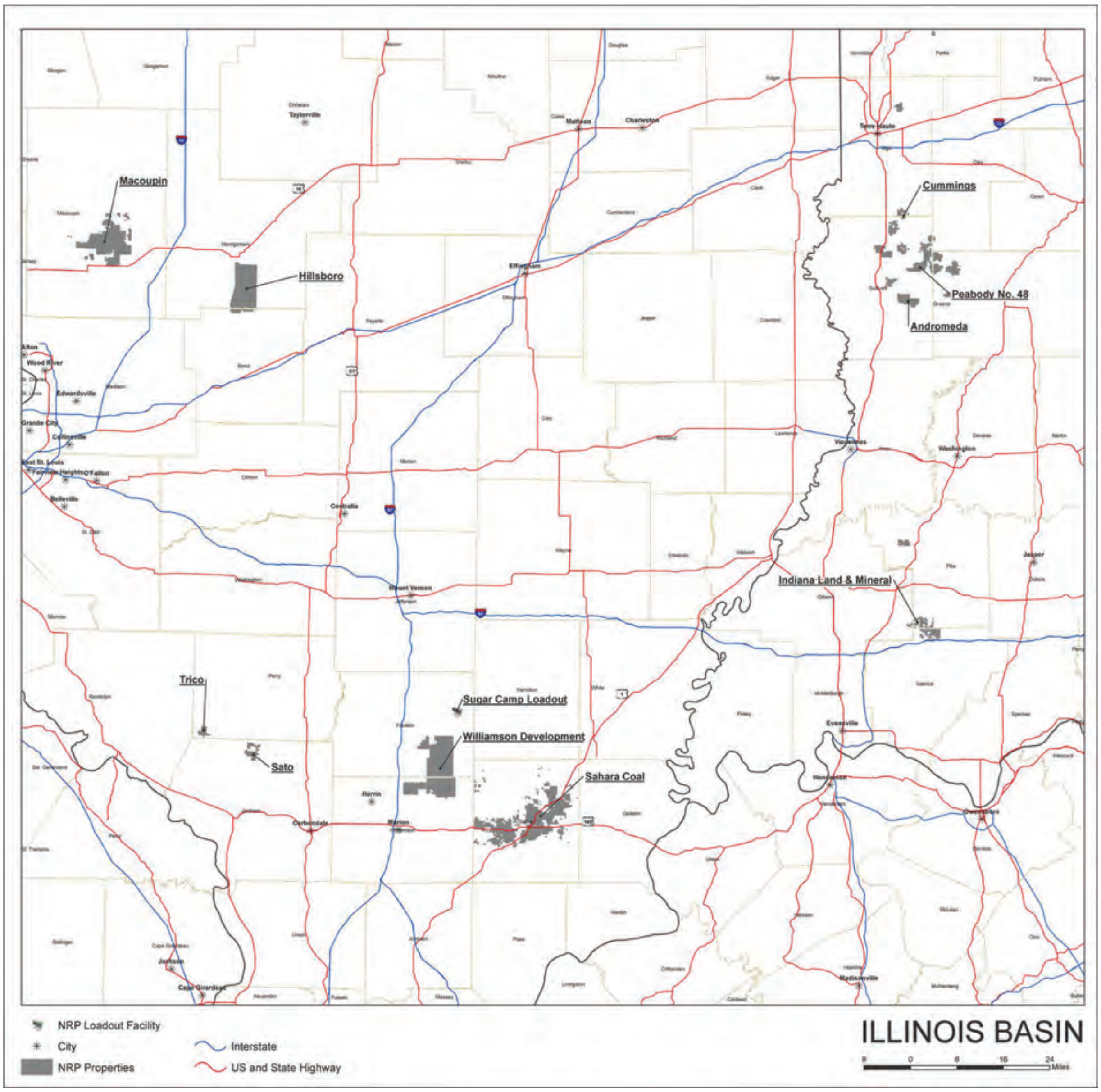
Hillsboro. The Hillsboro property is located in Montgomery and Bond Counties, Illinois. The property is under lease to a subsidiary of Foresight Energy LP, and in 2014, 5.4 million tons were shipped from the property. Production is currently from an underground longwall mine and is shipped via either the Union Pacific, Norfolk Southern or Canadian National railroads or by barges to domestic utilities or export customers.

Macoupin. The Macoupin property is located in Macoupin County, Illinois. The property is under lease to a subsidiary of Foresight Energy LP, and in 2014, 1.1 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 customers such as Western KY Energy and other midwest utilities or loaded into barges for shipment to export customers.

Sahara. The Sahara property is located in Saline, Hamilton and Williamson Counties in Illinois. This property was acquired in June of 2014. The property is under lease to a subsidiary of Peabody Energy Corporation, and following the acquisition in 2014, 486,000 tons were mined on the property. Production is currently from an underground mine and is shipped via barge primarily to Tennessee Valley Authority.

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 LP. See "—Coal Transportation and Processing Assets."

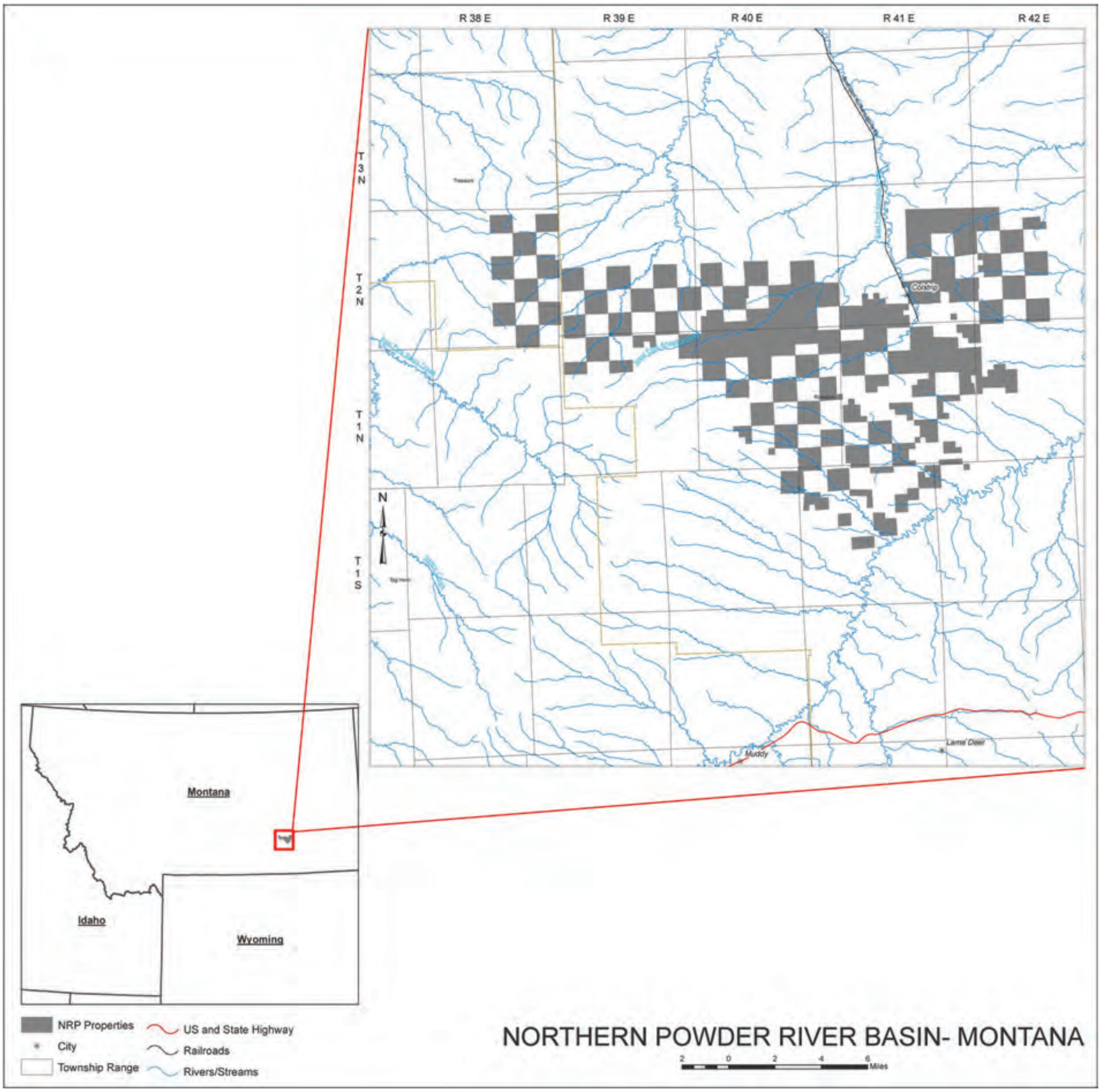
The map below shows the location of our properties in the Illinois Basin.



Northern Powder River Basin

Western Energy. The Western Energy property is located in Rosebud and Treasure Counties, Montana. In 2014, 2.8 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 properties in the Northern Powder River Basin.



Coal Transportation and Processing Assets

We own preparation plants and related material handling facilities that we lease to third parties. Similar to our royalty structure, the throughput fees for the use of these facilities are based on a percentage of the ultimate sales price for the material that is processed.

In addition to our preparation plants, we own handling and transportation infrastructure related to certain of our coal and aggregates properties. We own loadout and other transportation assets at the 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 operated by an affiliate 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.

Total revenues from our coal transportation and processing assets were $22.0 million for the year ended December 31, 2014.

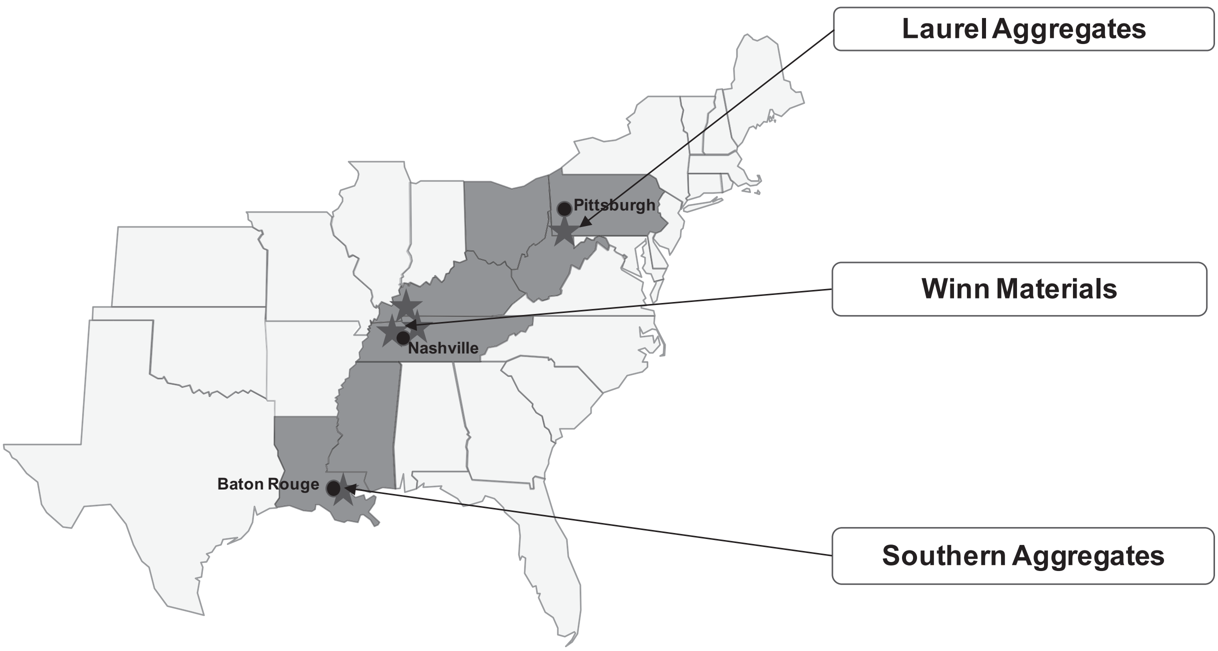
Aggregates and Industrial Minerals Business

Aggregates are crushed stone, sand and gravel, utilized in the construction of the majority of our country's infrastructure. Aggregates are used in nearly every residential, commercial and building construction project and in most public works projects, such as roads, highways, bridges, railroad beds, dams, airports, water and sewage treatment plants and systems and tunnels. Through our subsidiary, VantaCore Partners LLC, we mine and produce construction materials. In addition, we own aggregates reserves throughout the United States, a portion of which are leased to third parties in exchange for royalty payments.

Industrial minerals include non-fuel mineral resources such as soda ash, sand, lime, potash and rare earths, among others, that are mined and processed for a wide range of industrial and consumer applications such as glass, abrasives, soaps and detergents. We own a 49% noncontrolling equity interest in OCI Wyoming's trona mining and soda ash production operation.

VantaCore Partners LLC Construction Materials Business

VantaCore is a construction materials company that we acquired on October 1, 2014. VantaCore operates three limestone quarries, five sand and gravel plants, two asphalt plants and a marine terminal. VantaCore is headquartered in Philadelphia, Pennsylvania, and its operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana. As of December 31, 2014, VantaCore controlled approximately 292 million tons of estimated aggregates reserves. The reserve estimates for each of VantaCore's properties were prepared internally and audited by an independent third party advisor. For the three months ended December 31, 2014, VantaCore sold approximately 1.9 million tons of crushed stone and gravel, including brokered stone, 0.4 million tons of sand and 40,000 tons of asphalt. VantaCore's three operating businesses are Laurel Aggregates, located in Lake Lynn, Pennsylvania, Winn Materials/McIntosh Construction, located near Clarksville, Tennessee, 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 mine and an underground mine 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 primarily of oilfield service companies and natural gas exploration and production companies and also include 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 and around 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 and 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.

Southern Aggregates

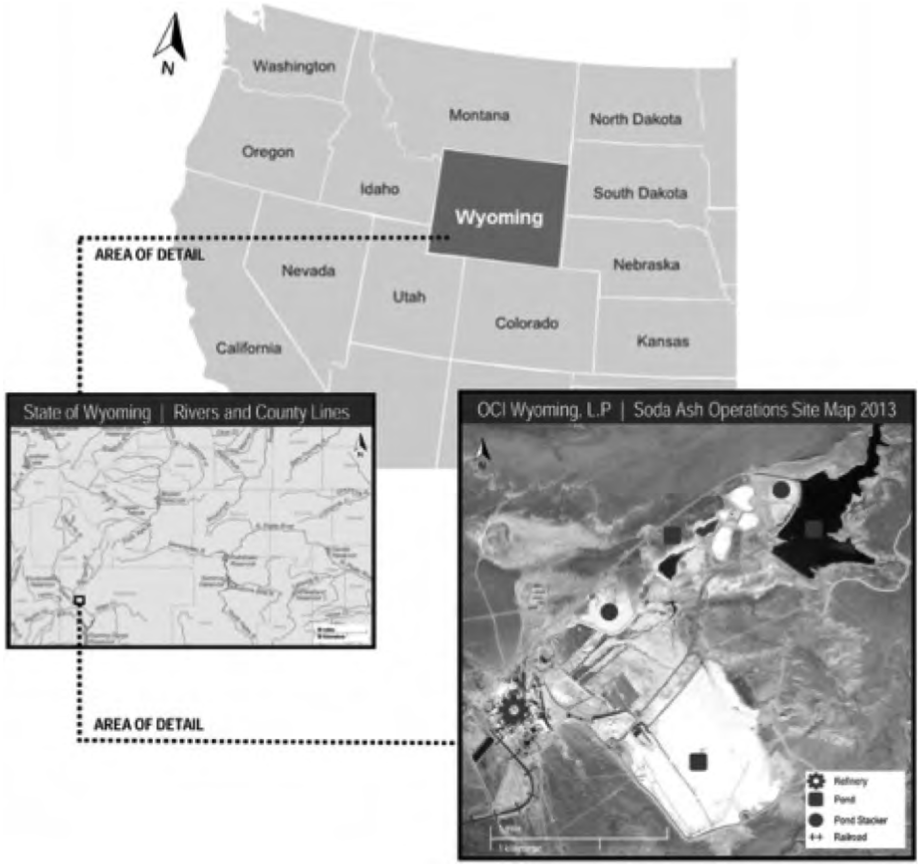
Southern Aggregates is a sand and gravel mining company based in Denham Springs, Louisiana approximately 25 miles northeast of Baton Rouge, Louisiana. Southern operates five sand and gravel operations. Suction dredges extract sand and gravel, and the mined material is processed at plants generally located at each site. The plants separate gravel and saleable sand from waste sand and clays, and the waste is 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 based on its sales volumes. 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.

Trona Mining and Soda Ash Production Business

We own a 49% non-controlling equity interest in OCI Wyoming LLC ("OCI 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. OCI 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 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.

OCI 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. OCI 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 view of OCI 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. OCI 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. OCI 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. OCI Wyoming's deca rehydration process enables OCI 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, OCI 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, 2014, OCI Wyoming shipped approximately 96.0% 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. OCI Wyoming leases a fleet of more than 1,700 hopper cars that serve as dedicated modes of shipment to its domestic customers. For export, OCI 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 OCI Wyoming's export sales. For domestic sales, OCI Chemical Co. provides similar services.

OCI Wyoming's largest customer is ANSAC, which buys soda ash (through OCI 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, OCI Chemical, on OCI Wyoming's behalf, negotiates directly with, and OCI Wyoming exports to, customers in markets not served by ANSAC.

OCI Wyoming is party to nine mining leases and one license for its subsurface mining rights. Some of the leases are renewable at OCI Wyoming's option upon expiration. OCI Wyoming pays royalties to the State of Wyoming, the U.S. Bureau of Land Management and Anadarko Petroleum or its affiliates, 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 OCI Wyoming is obligated to pay minimum royalties or annual rentals to its lessors and licensor regardless of actual sales. The royalty rates paid to OCI Wyoming's lessors and licensor may change upon renewal of such leases and license.

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

Aggregates/Industrial Minerals Royalty Business

We own 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. The structure of these leases is similar to our coal leases, and these leases typically also require minimum rental payments in addition to royalties. See "—Coal and Coal-Related Properties—Coal Royalty Business" for a description of our royalty structure. In 2006, we bought our first aggregates reserves property on the Puget Sound in Washington State. Since that time, we have made several other aggregates reserve purchases in multiple U.S. geographies. During 2014, our aggregates lessees produced 3.5 million tons of aggregates from these properties and we received $8.7 million in aggregates royalty revenues, including overriding royalty revenues.

Oil and Natural Gas Properties

We generate oil and gas revenues from non-operated working interests, royalty interests and overriding royalty interests in producing oil and gas wells. During 2014, we generated $59.6 million in revenues from our interests in oil and gas properties. 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 and the Mississippian Lime formation. NRP owns a 51% interest in BRP LLC, which owns oil and gas mineral rights, in northern Louisiana. See "—BRP LLC Joint Venture."

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, 2014, 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 14.5% in approximately 196 wells that were producing as of December 31, 2014.

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.

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. Our estimated proved reserves as of December 31, 2014 were prepared by Netherland, Sewell & Associates, Inc., 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.

The following tables set forth our estimated proved and related standardized measure of discounted cash flows by reserve category as of December 31, 2014. Netherland Sewell prepared its report covering properties representing 100% of our estimated proved reserves as of December 31, 2014. Prices were calculated using the unweighted average of the first-day-of-the-month pricing for the twelve months ended December 31, 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.

	Estimated Proved Reserves as of December 31, 2014(1)				
	Crude Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total Proved Reserves (MBoe)(2)	Standardized Measure of Discounted Cash Flows(3)
					(in thousands)
Proved Developed Producing	8,918	1,093	13,069	12,189	$286,179
Proved Developed Non-Producing	12	5	92	32	655
Proved Undeveloped	1,053	131	1,209	1,386	18,363
Total	9,983	1,229	14,370	13,607(4)	$305,197

(1) Includes reserves attributable to our 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) 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.

(4) Includes 12,144 MBoe of estimated proved reserves attributable to our non-operated working interests in oil and natural gas properties in the Williston Basin, approximately 10% of which were proved undeveloped reserves.

Proved Undeveloped Reserves

As of December 31, 2014, our estimated proved undeveloped reserves were 1,386 MBoe. During 2014, we participated in 33 wells related to the conversion of estimated proved undeveloped reserves with associated capital expenditures of $5.2 million. During 2014, we converted 704 MBoe of estimated proved undeveloped reserves to estimated proved developed reserves. As of December 31, 2014, 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.

For additional information on our estimated proved reserves, see Note 19 to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

Qualifications of Technical Persons and 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, 2014. 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.

Production and Price History

The following table sets forth summary information concerning our production results, average sales prices and production costs for the year ended December 31, 2014 in total and for each field containing 15 percent or more of our total proved reserves as of December 31, 2014. Production and price information for the years ended December 31, 2013 and 2012 is not included, as our oil and natural gas producing activities were not material to our results of operations for those years.

	Year Ended December 31, 2014		
	Williston Basin(1)	Royalty and Overriding Royalty Interests(2)	Total
Net Production Volumes:			
Crude oil (MBbl)	578	33	611
NGLs (MBbl)	53	18	71
Natural gas (MMcf)	408	1,313	1,721
Average sales prices:			
Crude oil ($/Bbl)	$77.85	$82.91	$78.12
NGLs ($/Bbl)	$33.64	$34.56	$33.87
Natural gas ($/Mcf)	$ 5.04	$ 4.17	$ 4.37
Average costs ($/Boe):			
Production expenses	$13.08	—	$13.08
Ad valorem and severance taxes	$ 7.91	—	$ 7.91
General and administrative expense	$ 4.86	—	$ 4.86
DD&A expense	$25.73	$22.06	$24.70

(1) Represents volume, price and cost information relating to our non-operated Williston Basin working interest properties.

(2) Represents information relating to our royalty and overriding royalty interests in oil and gas properties. These interests are recorded net of costs.

For additional information on our production, sales prices and costs, see Note 19 to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

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 year ended December 31, 2014. Well information for the years ended December 31, 2013 and 2012 is not included, as our oil and natural gas producing activities were not material to our results of operations for those years. 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.

	Year Ended December 31, 2014					
	Productive		Dry		Total	
	Gross	Net	Gross	Net	Gross	Net
Development	123	4.4	0	0	123	4.4
Exploratory	0	0	0	0	0	0
Total	123	4.4	0	0	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, 2014. 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.

	As of December 31, 2014							
	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	442	47	0	0	25	0.1	0	0
Other	0	0	0	0	100	5.2	987	76
Total	442	47	0	0	125	5.3	987	76

(1) As of December 31, 2014, we also owned non-operated working interests in 40 gross oil wells in various stages of development in the Williston Basin.

(2) 57 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.

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, 2014:

	Undeveloped Acres as of December 31, 2014			
	Acres Leased to NRP(1)		Net ORRI and Fee Mineral Acres	
	Gross	Net	ORRI(2)	Fee Mineral(3)
Williston Basin	610	384	0	0
Other	0	0	25,162	30,696
Total	610	384	25,162	30,696

(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.

(3) Represents net fee mineral acres owned by NRP and BRP LLC and leased to third parties.

Delivery Commitments

As of December 31, 2014, we had no material delivery commitments.

BRP LLC Joint Venture

BRP LLC is a joint venture between NRP and International Paper Company, in which we own a 51% interest. As of December 31, 2014, BRP owned approximately 10 million mineral acres in 31 states. While the vast majority of the 10 million acres remain largely undeveloped, BRP currently holds 71 mineral leases and 17 cell tower leases and has an active program to identify additional opportunities to lease its minerals to operating parties. For the year ended December 31, 2014, BRP generated $8.0 million in revenue.

BRP's assets include approximately 300,000 gross acres of oil and gas mineral rights in Louisiana, of which over 54,000 acres were leased as of December 31, 2014. In addition to the leased mineral acreage, BRP holds a 1% overriding royalty interest on approximately 28,000 mineral acres in Louisiana. As of December 31, 2014, BRP owned nearly 95,000 net mineral acres of coal rights (primarily lignite and some bituminous coal) in the Gulf Coast region, of which approximately 5,800 acres are leased in Louisiana, Alabama and Texas. In addition, BRP also 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.

Significant Customers

In 2014, we had total revenues of $81.5 million from Foresight Energy LP and its affiliated companies and $48.8 million from Alpha Natural Resources. Each of these lessees represented more than 10% of our total revenues. The loss of one or both of these lessees could have a material adverse effect on us. In addition, the closure or loss of revenue from Foresight's Williamson mine, which accounted for 10% of our revenue in 2014, could have a material adverse effect on us, but we do not believe that the loss of any other single mine on our properties would have a material adverse effect on our revenues or distributable cash flow.

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.

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 OCI Wyoming does. Some of OCI 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 OCI 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 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.

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 approximately 99% of our coal and aggregates reserves in fee as of December 31, 2014. We lease the remainder from unaffiliated third parties, including leasing aggregates reserves for VantaCore's construction materials business. OCI Wyoming also leases or licenses its trona reserves. As of December 31, 2014, 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. However, to our knowledge none of the violations to date, nor the monetary penalties assessed, have been material to our lessees or operations.

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 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. We do not accrue for such 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 OCI 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 and building 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 January 2014, EPA published proposed new source performance standards for greenhouse gas emissions from new fossil fuel-fired electric generating units. The effect of the proposed rules would be to require partial carbon capture and sequestration on any new coal-fired power plants, which may amount to their effective prohibition. In June 2014, EPA proposed the Clean Power Plan, which outlined a multi-factor plan to cut carbon emissions from existing electric generating units, including coal-fired power plants. Under this proposed rule, existing power plants would be required to cut their carbon dioxide emissions 30% from 2005 levels by the year 2030. The effect of the proposed rules would be to require 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. EPA intends to finalize these rules in the summer of 2015, both of which have been challenged by industry participants and other parties. The implementation of these rules as proposed would have a material adverse effect on the demand for coal by electric power generators.

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. While there is no way to estimate the impact of this pledge, it 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.

On January 14, 2015, EPA announced plans to propose 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). EPA expects to propose the new regulations in the summer of 2015 and 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 OCI 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. 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 OCI 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 89 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 now employ 269 people who support VantaCore's construction aggregates mining and production operations. None of these employees are subject to a collective bargaining agreement.

Segment Information

We conduct all of our operations in a single segment – the ownership and leasing of natural resources and related transportation and processing infrastructure. Substantially all of our owned properties are subject to leases, and revenues are earned based on the volume and price of minerals extracted, processed or transported. Included in revenues and other income from these natural resource properties are royalties from coal, aggregates, oil and gas, timber, related transportation and processing infrastructure revenues, as well as other income from our equity investment in OCI Wyoming's trona mine and soda ash refinery operations, and revenues from the VantaCore aggregates mining and production operation purchased during 2014.

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 charters for our Audit Committee, Conflicts Committee and Compensation, Nominating and Governance Committee. Also, 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

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on the common units are dependent on the amount of cash we generate, distributions may 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. To the extent our board of directors deems appropriate, it may determine to decrease the amount of the quarterly distribution.

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

As of December 31, 2014, we and our subsidiaries had approximately $1.5 billion of total indebtedness. The terms and conditions governing our indebtedness, including NRP's 9.125% senior notes, Opco's revolving credit facility, term loan 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, sell assets or raise equity, and our ability to pursue acquisitions may be limited. 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 and term loan both mature in 2016. We will be required to repay or refinance the amounts outstanding under these credit facilities prior to their maturity. 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.

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. In such event, we may not be able to access funding under the facility necessary to operate our business or 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 access the capital markets may be challenging in the current commodity price environment. 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.

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, 2014, we took an impairment charge of $17.6 million relating to certain of our coal related properties. With the continued weakness in the coal markets, we intend to closely monitor our coal assets impairment risk. Future impairment analyses could result in downward adjustments to the carrying value of our assets.

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 could 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 January 2014, EPA published proposed new source performance standards for GHG emissions from new fossil fuel-fired electric generating units. The effect of the proposed rules would be to require partial carbon capture and sequestration on any new coal-fired power plants, which may amount to their effective prohibition. In June 2014, EPA proposed the Clean Power Plan, which outlined a multi-factor plan to cut carbon emissions from existing electric generating units, including coal-fired power plants. Under this proposed rule, existing power plants would be required to cut their carbon dioxide emissions 30% from 2005 levels by the year 2030. The effect of the proposed rules would be to require 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. EPA intends to finalize these rules in the summer of 2015, both of which have been challenged by industry participants and other parties. The implementation of these rules as proposed would have a material adverse effect on the demand for coal by electric power generators and as a result on our coal related-revenues.

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 January 2015, EPA announced plans to propose 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). EPA expects to propose the new regulations in the summer of 2015 and a final rule is expected in 2016. Any such rules could have a material adverse effect on our oil and natural gas revenues.

Mining operations are subject to operating risks that could result in lower revenues to us. In addition, we are subject to operating risks as a result of the VantaCore acquisition that we have not previously experienced.

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.

Prior to the VantaCore acquisition, we did not operate aggregates mining and production assets. VantaCore currently operates three hard rock quarries, five sand and gravel plants, two asphalt plants and a marine terminal. As an operator of these assets, we will be 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 and prevent us from realizing all of the anticipated benefits of the acquisition.

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 fallen significantly since the first half of 2014 to their lowest levels since 2008. 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.

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 OCI 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.

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.

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 2014, we derived 20% and 12% of our total revenues and other income from Foresight Energy LP and Alpha Natural Resources, respectively. Foresight's Williamson mine alone was responsible for approximately 10% of our total revenues and other income in 2014. As a result, we have significant concentration of revenues with these lessees. If our lessees merge or otherwise consolidate, or if we acquire additional reserves from existing lessees, then our revenues could become more dependent on fewer mining companies. If issues occur at those companies that impact their ability to pay us royalties, our revenues and ability to make future distributions would be adversely affected.

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 OCI Wyoming's soda ash production operations. If the market price for soda ash declines, OCI 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 OCI Wyoming receives for its soda ash depend on numerous factors beyond OCI 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. Substantial or extended declines in prices for soda ash could have a material adverse effect on our results of operations. In addition, OCI Wyoming relies on natural gas as the main energy source in its soda ash production process. Accordingly, high natural gas prices increase OCI 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, which is recovering at a slow pace.

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.

We may incur unanticipated costs or delays in connection with the integration of VantaCore and future aggregates operations into our company.

There are risks with respect to the integration of VantaCore into our company that may result in unanticipated costs or delays to us. Such risks include:

- integrating additional personnel into our company, including the 269 people employed by VantaCore;
- establishing the internal controls and procedures for the acquired businesses that we are required to maintain under the Sarbanes-Oxley Act of 2002;
- consolidating other corporate and administrative functions;
- diversion of management's attention away from our other business concerns;
- loss of key employees; and
- the assumption of any undisclosed or other potential liabilities of the acquired company.

Similar risks may apply to the integration of future aggregates operations that we may acquire through the VantaCore platform. Any significant costs and delays resulting from the risks described above could cause us not to realize the anticipated benefits of these acquisitions.

We may be subject to risks in connection with oil and gas asset acquisitions.

The acquisition of oil and gas properties requires an assessment of several factors, including:

- recoverable reserves;
- the pace of development and drilling and completion activities by operators;
- future crude oil and natural gas prices and their differentials;
- the availability of and access to takeaway and transportation;
- future development costs, operating costs and property taxes;
- governmental regulations; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities prior to acquisition. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller of the subject properties may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental and other liabilities and acquire properties on an "as is" basis.

Our business will be adversely affected if we are unable to make acquisitions or access the bank and capital markets to finance our growth.

Because our reserves decline due to production, our future success and growth depend, in part, upon our ability to make acquisitions to replace reserves that are depleted. If we are unable to make acquisitions on acceptable terms, our revenues will decline as our reserves are depleted. Our ability to acquire additional interests in mineral reserves or make other acquisitions is dependent in part on our ability to access the bank and capital markets. We cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues, results of operations and quarterly distributions. In addition, if we are unable to successfully integrate the companies, businesses or properties we are able to acquire, our revenues may decline and we could experience a material adverse effect on our business, financial condition or results of operations.

There is a possibility that any acquisition could be dilutive to our earnings and reduce our ability to make distributions to unitholders. Any debt we incur to finance an acquisition may also reduce our ability to make distributions to unitholders. Our ability to make acquisitions in the future also could be limited by restrictions under our existing or future debt agreements, competition from other mineral companies for attractive properties or the lack of suitable acquisition candidates.

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 OCI Wyoming or our non-operated oil and gas working interest properties. We have limited approval rights with respect to OCI Wyoming, and our partner controls most business decisions, including decisions with respect to distributions and capital expenditures. Adverse developments in OCI 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.

Oil and gas development activities require substantial capital. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could 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. We have capital expenditures and operating expenses associated with the wells in which we own working interests and are required to fund our proportionate share on any wells in which we decide to participate. 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. We may not be able to obtain debt or equity financing on terms favorable to us, or at all. 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, OCI 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 OCI 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. OCI 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 OCI Wyoming's facility, and alternative methods of transportation are impracticable or cost-prohibitive. Any substantial interruption in or increased costs related to the transportation of OCI Wyoming's soda ash 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.

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:

- 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.

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.

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.

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.

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

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.

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 use of this proration method may not be permitted under existing Treasury Regulations. The U.S. Treasury Department's proposed Treasury Regulations allowing a similar monthly simplifying convention are not final and do not specifically authorize the use of the proration method we have adopted. If the IRS were to successfully challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose 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 recently 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 2. ***Properties*.**

The information required by this Item is included under “Item 1. Business” in this Annual Report on Form 10-K and is incorporated by reference herein.

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.

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 Issuer 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 23, 2015, there were approximately 43,400 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, 2013 to December 31, 2014, and the quarterly cash distribution declared and paid with respect to each quarter per common unit.

	Price Range		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2013					
First Quarter	$23.95	$18.93	$0.5500	05/06/2013	05/14/2013
Second Quarter	$24.37	$20.08	$0.5500	08/05/2013	08/14/2013
Third Quarter	$22.39	$18.98	$0.5500	11/05/2013	11/14/2013
Fourth Quarter	$21.57	$18.99	$0.3500	01/21/2014	01/31/2014
2014					
First Quarter	$20.72	$14.80	$0.3500	05/05/2014	05/14/2014
Second Quarter	$16.57	$12.78	$0.3500	08/05/2014	08/14/2014
Third Quarter	$16.91	$12.56	$0.3500	11/05/2014	11/14/2014
Fourth Quarter	$13.83	$ 7.97	$0.3500	02/05/2015	02/13/2015

Cash Distributions to Partners

	General Partner(1)	Limited Partners(2)	Total Distributions
		(in thousands)	
2013 Distributions	$4,930	$241,588	$246,518
2014 Distributions	$3,241	$158,801	$162,042

(1) Represents distributions on our general partner's 2% general partner interest in us.

(2) Includes distributions on 1,560,000 common units held by our general partner.

Unregistered Sales of Equity Securities

As previously reported, in connection with the closing of the VantaCore acquisition, on October 1, 2014, we issued 2,426,690 common units to certain of the owners of VantaCore in exchange for their interests in VantaCore and VantaCore GP upon closing of the acquisition. The aggregate offering price of the common units as of the date of issuance was approximately $31.6 million. On December 4, 2014, we issued an additional 813 units to certain of the former owners of VantaCore in connection with a post-closing adjustment to the purchase price for the acquisition. The aggregate offering price of such additional common units as of the date of issuance was approximately $8,500. Such common units were issued and sold in reliance upon an exemption from the registration requirements of the Securities Act of 1933, pursuant to Section 4(2) thereof.

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."

	Natural Resource Partners L.P. Selected Financial Data For the Years Ended December 31,				
	2014	2013	2012	2011	2010
	(in thousands, except per unit data)				
Total revenues and other income	$ 399,752	$ 358,117	$ 379,147	$ 377,683	$ 301,401
Asset impairments	$ 26,209	$ 734	$ 2,568	$ 161,336	$ —
Income from operations	$ 188,919	$ 236,236	$ 267,165	$ 104,135	$ 196,061
Net income	$ 108,830	$ 172,078	$ 213,355	$ 54,026	$ 154,461
Basic and diluted net income per limited partner unit	$ 0.94	$ 1.54	$ 1.97	$ 0.50	$ 1.54
Distributions paid ($ per unit)	$ 1.40	$ 2.20	$ 2.20	$ 2.17	$ 2.16
Weighted average number of common units outstanding	113,262	109,584	106,028	106,028	81,917
Cash from operations	$ 210,755	$ 247,074	$ 271,408	$ 305,574	$ 258,694
Distributable cash flow(1)	$ 217,710	$ 309,394	$ 298,899	$ 311,174	$ 260,274
Adjusted EBITDA(1)	$ 300,322	$ 340,345	$ 328,116	$ 329,660	$ 253,074
Balance sheet data:					
Cash and cash equivalents	$ 50,076	$ 92,513	$ 149,424	$ 214,922	$ 95,506
Total assets	$2,444,724	$1,991,856	$1,764,672	$1,665,649	$1,664,036
Long-term debt	$1,394,240	$1,084,226	$ 897,039	$ 836,268	$ 661,070
Partners' capital	$ 720,155	$ 616,789	$ 617,447	$ 644,915	$ 825,180

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

Non-GAAP Financial Measures

Distributable Cash Flow

Under our partnership agreement, we are required to distribute all of our available cash each quarter. Because distributable cash flow is a significant liquidity metric that is an indicator of our ability to generate cash flows in order to make quarterly cash distributions to our partners, we view it as the most important measure of our success as a company. Distributable cash flow is also the quantitative standard used in the investment community with respect to publicly traded partnerships.

Our distributable cash flow represents cash flow from operations, plus returns on unconsolidated equity investments, proceeds from sales of assets, and returns on direct financing lease and contractual overrides. 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.

Reconciliation of "Net cash provided by operating activities" to "Distributable cash flow"

	Year Ended December 31,				
	2014	2013	2012	2011	2010
			(in thousands)		
Net cash provided by operating activities	$210,755	$247,074	$271,408	$305,574	$258,694
Returns on unconsolidated equity investments	3,633	48,833	—	—	—
Returns on direct financing lease and contractual overrides	1,904	2,558	2,669	—	—
Proceeds from sales of assets	1,418	10,929	24,822	5,600	1,580
Distributable cash flow	$217,710	$309,394	$298,899	$311,174	$260,274

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income less equity and other unconsolidated investment income; plus distributions from unconsolidated affiliates, interest expense, gross, 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 insolation or as a substitute for operating income, net income or 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 company'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 useful in evaluating our financial performance because this measure is widely used by financial analysts, investors and rating agencies for comparative purposes. NRP entered the high-yield bond market in 2013, and Adjusted EBITDA is a financial measure widely used by investors in that 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 or loss, the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDA reported by different companies.

Reconciliation of "Net income" to "Adjusted EBITDA"

	Year Ended December 31,				
	2014	2013	2012	2011	2010
			(in thousands)		
Net income	$108,830	$172,078	$213,355	$ 54,026	$154,461
Less equity and other unconsolidated investment income	(41,416)	(34,186)	—	—	—
Add distributions from unconsolidated affiliates	46,638	72,946	—	—	—
Add depreciation, depletion and amortization	79,876	64,377	58,221	65,118	56,978
Add asset impairments	26,209	734	2,568	161,336	—
Add interest expense, gross	80,185	64,396	53,972	49,180	41,635
Adjusted EBITDA	$300,322	$340,345	$328,116	$329,660	$253,074

Adjusted EBITDA presented in the table above differs from the EBITDDA definitions contained in Opco's debt agreement covenants. In calculating EBITDDA for purposes of Opco's debt covenant compliance, pro forma effect may be given to acquisitions and dispositions made during the relevant period. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Contractual Obligations and Commercial Commitments—Opco Debt" for a description of Opco's debt agreements.

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

The following discussion of the financial condition and results of operations should be read in conjunction with the historical financial statements and notes thereto included elsewhere in this filing and the financial statements and footnotes included elsewhere in this Annual Report on Form 10-K for the year ended December 31, 2014.

As used in this Item 7, unless the context otherwise requires: "we," "our" and "us" 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 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 engage 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. Executing on our plans to diversify our business, we have completed over $900 million in acquisitions since January 2013. For the year ended December 31, 2014, we recorded revenues and other income of $399.8 million and Adjusted EBITDA of $300.3 million. Approximately $226.7 million (57%) of our 2014 revenues and other income were attributable to coal-related sources, and $173.0 million (43%) of our revenues and other income were attributed to non-coal-related sources. Adjusted EBITDA is a non-GAAP financial measure. For a reconciliation of Adjusted EBITDA to net income, see "Item 6. Selected Financial Data—Non-GAAP Financial Measures—Adjusted EBITDA."

Our 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. We do not operate any coal mines, but lease our coal 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. We also own and manage infrastructure assets that generate additional revenues, primarily in the Illinois Basin.

We own or lease aggregates and industrial minerals located in a number of states across the country. We derive a small percentage of our aggregates and industrial minerals revenues by leasing our owned reserves to third party operators who mine and sell the reserves in exchange for royalty payments. However, the majority of our aggregates and industrial minerals revenues come through our ownership of VantaCore Partners LLC, which we acquired in October 2014. VantaCore specializes in the construction materials industry and operates three hard rock quarries, five sand and gravel plants, two asphalt plants and a marine terminal. VantaCore's current operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

We own a 49% non-controlling equity interest in a trona ore mining operation and soda ash refinery in the Green River Basin, Wyoming. OCI 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.

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.

Current Liquidity Position

As of December 31, 2014, we had $100 million in available borrowing capacity under Opco's revolving credit facility, $27 million available under the NRP Oil and Gas revolving credit facility and $50.1 million in cash.

We have $80.9 million in principal payments due on NRP Operating's senior notes each year through 2018, and NRP Operating's revolving credit facility and term loan facility both mature in 2016. While we believe we have sufficient liquidity to meet our current financial needs, we will be required to repay or refinance the amounts outstanding under Opco's credit facilities prior to their maturity. While we believe we will be able to refinance these amounts, we may not be able to do so on terms acceptable to us, if at all, or the borrowing capacity under Opco's revolving credit facility may be substantially reduced. Our ability to refinance these amounts may depend in part on our ability to access the debt or equity capital markets, which will be challenging in the current commodity price environment. See "—Liquidity and Capital Resources" for a further description of our indebtedness, cash flows and capital expenditures.

Current Results/Market Outlook

Our revenues and other income from sources other than coal represented 43% of our total revenues and other income in 2014, as compared to 23% of total revenues and other income in 2013. Although our total revenues and other income for 2014 increased over 2013, our coal-related revenues were down 17% compared to the same period. The majority of the decrease in coal-related revenues was due to lower Appalachian coal royalty revenues, which were down approximately 19% from 2013. During 2014, our investment in OCI Wyoming's trona mining and soda ash production operations contributed $41.4 million in other income, up $7.2 million from 2013, and our oil and gas revenues increased to $59.6 million, triple our oil and gas revenues in 2013.

The coal markets remained challenged during the year and do not currently show signs of recovery. Although thermal coal prices continue to be depressed, we believe that thermal coal production from our properties in the low-cost Illinois Basin will continue to remain strong in spite of the weak thermal markets. We expect the markets for thermal coal from our other regions to remain weak during 2015. We continue to have substantial exposure to metallurgical coal, from which we derived approximately 40% of our coal royalty revenues and 32% of the related production during 2014. The first quarter 2015 benchmark price for metallurgical coal remains at a multi-year low, and the global metallurgical coal market continues to suffer from oversupply in addition to reduced demand from China and a relatively strong U.S. dollar. We do not anticipate that metallurgical coal prices will recover in 2015. While we have not been significantly impacted so far by the various metallurgical coal mine idlings announced during the second half of 2014, additional mine idlings resulting in reductions of production of metallurgical coal from our properties may occur in 2015 if prices remain at current levels. In addition, if coal prices continue to remain depressed for an extended period of time, the lessees on some of our coal properties may close some of their mines causing some of our coal properties to be impaired.

Our trona mining and soda ash refinery investment performed in line with our expectations during 2014. The international market for soda ash continues to grow, as global production capacity for high-cost synthetic soda ash continues to be reduced, and OCI Wyoming's sales through ANSAC were better than expected. Domestic sales volumes, which are typically sold at higher prices than soda ash sold internationally, have remained relatively stable. The cash we receive from OCI Wyoming is in part determined by the quarterly distribution declared by OCI Resources LP. In February 2015, OCI Resources LP paid a quarterly distribution of $0.5315 per common unit with respect to the fourth quarter of 2014, representing a slight increase over the distribution paid with respect to the third quarter of 2014. OCI Resources LP also announced its intention to increase its distributions with respect to 2015 by 3% to 6%.

VantaCore's construction aggregates mining and production business is largely dependent on the strength of the local markets that it serves. Its operations based in Clarksville, Tennessee and Baton Rouge, Louisiana will depend on the pace of commercial and residential construction in those areas, each of which has been slowly recovering from the 2008-2009 recession. VantaCore's Laurel Aggregates operation in southwestern Pennsylvania serves many of the producers and oilfield service companies operating in the Marcellus and Utica Shales. To the extent that the pace of exploration and development of natural gas in those areas slows due to low natural gas prices, we expect that VantaCore's business will be affected. In addition, VantaCore's business is seasonal, with lower production and sales expected during the first quarter of each year due to winter weather.

Global oil prices have declined significantly since the second quarter of 2014 due to increased oil supply driven by robust onshore U.S. development activity, coupled with reduced global demand and a strong U.S. dollar. Natural gas prices are also low due to record levels of production and high storage inventories. As of the date of this filing, we have not hedged any of our future oil or natural gas production and, as a result, our oil and gas revenues will continue to be impacted by the current price environment. However, we are able to manage the capital expenditures associated with our Williston Basin non-operated working interest properties by evaluating well proposals on a well-by-well basis. We will 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.

Political, Legal and Regulatory Environment Affecting Our Coal Business

The political, legal and regulatory environment continues to be difficult for the coal industry. The Environmental Protection Agency ("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. In addition, the electric utility industry, which is the most significant end-user of domestic coal, is subject to extensive regulation regarding the environmental impact of its power generation activities. In January 2014, EPA published proposed new source performance standards for GHG emissions from new fossil fuel-fired electric generating units. The effect of the proposed rules would be to require partial carbon capture and sequestration on any new coal-fired power plants, which may amount to their effective prohibition. In June 2014, EPA proposed the Clean Power Plan, which outlined a multi-factor plan to cut carbon emissions from existing electric generating units, including coal-fired power plants. Under this proposed rule, existing power plants would be required to cut their carbon dioxide emissions 30% from 2005 levels by the year 2030. The effect of the proposed rules would be to require 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. EPA intends to finalize these rules in the summer of 2015, both of which have been challenged by industry participants and other parties. The implementation of these rules as proposed would have a material adverse effect on the demand for coal by electric power generators and as a result on our coal related-revenues.

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), which regulates emissions of nitrogen oxide and sulfur dioxide, and the Mercury and Air Toxics Rule (MATS), which regulates 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.

Significant Acquisitions

Sanish Field. On November 12, 2014, we completed the purchase of a 40% member interest in Kaiser-Whiting, LLC ("Kaiser LLC") for $339 million, subject to customary post-closing purchase price adjustments. Effective November 13, 2014, NRP Oil and Gas withdrew as a member of Kaiser LLC and an undivided 40% interest in Kaiser LLC's assets was distributed out of Kaiser LLC and assigned directly to NRP Oil and Gas. The assets distributed to us included non-operated working interests in approximately 6,086 net acres with an average working interest of approximately 14.5%. The assets, located in the Sanish Field in Mountrail County, North Dakota, are all held by production and include 196 producing oil and gas wells as of December 31, 2014. See "Note 3. Significant Acquisitions" to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

VantaCore Partners. On October 1, 2014, we completed the acquisition of VantaCore, a privately held company specializing in the construction materials industry, for $201 million in cash and common units, subject to customary post-closing purchase price adjustments. Headquartered in Philadelphia, Pennsylvania, VantaCore operates three hard rock quarries, five sand and gravel plants, two asphalt plants and a marine terminal.

VantaCore's current operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana. See "Note 3. Significant Acquisitions" to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

Sundance. In December 2013, we acquired non-operated working interests in oil and gas properties in the Williston Basin of North Dakota, including properties producing from the Bakken/Three Forks play, from Sundance Energy, Inc. for $29.4 million, following post-closing purchase price adjustments. The properties, which are all held by production are located in McKenzie, Mountrail and Dunn counties and are actively being developed.

Abraxas. In August 2013, we acquired non-operated working interests in producing oil and gas properties in the Williston Basin of North Dakota and Montana, including properties producing from the Bakken/Three Forks play, from Abraxas Petroleum Corporation for $38.0 million, following post-closing purchase price adjustments.

OCI Wyoming. In January 2013, we acquired a non-controlling equity interest in OCI Wyoming, an operator of a trona ore mining operation and a soda ash refinery in the Green River Basin, Wyoming, from Anadarko Holding Company and its subsidiary, Big Island Trona Company for $292.5 million. The acquisition agreement provides for up to the net present value of $50 million in additional contingent consideration payable by us should certain performance criteria be met as defined in the purchase and sales agreement in any of 2013, 2014 or 2015. As of December 31, 2014 we had accrued $14.5 million for contingent consideration payments, of which we expect to pay $3.8 million to Anadarko with respect to 2014.

Critical Accounting Policies

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 included elsewhere in this Annual Report on Form 10-K. The following critical accounting policies are affected by estimates and assumptions used in the preparation of Consolidated Financial Statements.

Equity Investments

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 OCI 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 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.

Revenues

Coal Related Revenues. Coal related revenues consist primarily of royalties as well as transportation and processing fees. 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. 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.

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.

Aggregates and Industrial Minerals Related Revenues. Aggregates and industrial minerals related revenues consist primarily of revenues generated in VantaCore's construction aggregates business, royalties and overriding royalties. 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. Aggregates and industrial minerals royalty and overriding 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. 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.

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. 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 2014, we recorded impairment expense of $26.9 million on certain of our coal reserves, a preparation plant, intangible assets and aggregates properties. For further discussion relating to our 2014 impairments see "Note 7. Plant and Equipment," "Note 8. Minerals Rights" and "Note 9. Intangible Assets" 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.

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.

Recent Accounting Pronouncements

In May 2014, the FASB amended revenue recognition topics and created a new topic relating to revenue recognition that will supersede existing guidance under U.S. GAAP. The core principle of the new guidance is to recognize revenue when promised goods or services are transferred to the customer and in an amount that reflects the consideration expected in exchange for those goods or services. To achieve this core principle, an entity should (1) identify the contract(s) with the customer, (2) identify the performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract and (5) recognize revenue when each performance obligation is satisfied**.** The guidance also specifies the accounting for some costs to obtain or fulfill a contract with a customer. Disclosure requirements include sufficient qualitative and quantitative information to enable financial statement users to understand the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. The new topic is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. The guidance allows for either full adoption or a modified retrospective adoption. We are currently evaluating the requirements to determine the impact, if any, of this new topic on its financial position, results of operations and cash flows.

Other accounting standards that have been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Partnership's financial position, results of operations or cash flows.

Results of Operations

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

Adjusted EBITDA

Adjusted EBITDA declined 12% in 2014 to $300.3 million from $340.3 million generated in 2013. The decrease is mainly related to the special distribution of $44.8 million received in 2013 from OCI Wyoming as well as lower coal related revenues offset by higher earnings from our investments in aggregates and oil and gas. 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 a reconciliation of this measure to net income.

Distributable Cash Flow

Distributable cash flow for 2014 decreased by $91.7 million, or 30%, from 2013 to $217.7 million. This change was due primarily to a $44.8 million special distribution received from OCI 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 a reconciliation of this measure to net cash provided by operating activities.

Coal Related Revenues and Production

	For the Years Ended December 31, 2014	2013	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data) (Unaudited)			
Regional Statistics				
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	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 gross royalty 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	$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 payment	—	10,370	(10,370)	100%
Coal bonus payment	98	—	98	100%
Reserve swap	5,690	8,149	(2,459)	(30)%
Wheelage	3,442	3,593	(151)	(4)%
Total	$ 42,538	$ 61,531	$(18,993)	(31)%
Total coal related revenues	$226,724	$274,194	$(47,470)	(17)%

Total coal related revenues. Total coal related revenues comprised approximately 57% and 77% of our total revenues and other income for the years ended December 31, 2014 and 2013, respectively. The following is a discussion of the major categories of coal related revenue:

Coal royalty revenues and production. Coal royalty revenues comprised approximately 46% and 59% of our total revenues and other income for the years ended December 2014 and 2013, respectively. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. Coal royalty revenues decreased $27.3 million or 19% for the year ended December 31, 2014 compared to the same period of 2013, while production decreased 3.1 million tons or 9%.

Production from our properties in the Central Appalachian region decreased by 3%. This decrease was primarily due to a greater proportion of mining on adjacent property and some lessees temporarily idling production on our property. In addition, pricing realized by our lessees for both thermal and metallurgical coal in Central Appalachia is generally below the levels received in the same period in 2013, causing a larger percentage decrease in coal royalty revenues compared to the decrease in production.

The Southern Appalachian region also had decreased production and coal royalty revenues. This was due to a new lessee being slower in building its production after succeeding a former lessee and one lessee temporarily idling a mining unit on our property. In general our lessees received lower sales prices for both thermal and metallurgical coal causing a larger percentage decrease in coal royalty revenue compared to the decrease in production.

With respect to Northern Appalachia, for the year ended December 31, 2014 there was a decrease in coal royalty revenues and production. These decreases were primarily due to the net effect of two longwall mines having a greater proportion of their production on adjacent property in 2014 in the normal course of its mining plan.

Illinois Basin. Coal royalty revenues for the year ended December 31, 2014 decreased 3% when compared to the same period in 2013, while production was nearly constant. The Williamson mine in Illinois had lower production as did one of our properties in Indiana. These decreases were offset by higher production at the Hillsboro mine and the Macoupin mine where an additional mining unit was added. We also received increased revenue from a coal reserve acquisition completed in June 2014.

Northern Powder River Basin. Coal royalty revenues and production on our Western Energy property were about the same for the year ended December 31, 2014 when compared to 2013.

Gulf Coast. Coal royalty revenues and production slightly increased for the year ended December 31, 2014 compared to the same period in 2013, due to one lessee having a greater proportion of mining on our property.

Other coal related revenues. Other coal related revenues for the year ended December 31, 2014 decreased 31% compared to the same period in 2013. The following is a discussion of the revenues derived from each of the major sources of other coal-related revenue:

Override revenues for the year ended December 31, 2014 decreased by 56% compared to the same period in 2013 primarily due to one lessee moving its mining operations from an area on which we receive an overriding royalty onto property on which we receive coal royalty revenues, another lessee exhausting the reserves subject to the override and other lessees mining less on the area subject to our overriding royalty.

Transportation and processing fees decreased by $0.5 million or 2%, for the year ended December 31, 2014, when compared to the same period in 2013. The decrease is primarily due to the temporary idling of two processing facilities in response to market conditions which was partially offset by increased tonnage put through our Macoupin facilities.

Minimums recognized as revenue were about the same for both years.

During the year ended December 31, 2014 we also recognized revenue of $5.7 million related to a reserve swap completed in the third quarter. During 2013 we recognized $8.1 million on a similar swap. In addition, 2013 included a condemnation payment of $10.4 million.

Wheelage revenue decreased by 4% for the year ended December 31, 2014 compared to the same period in 2013. This increase was due to the normal fluctuations of tonnage that are subject to wheelage charges.

Aggregates and Industrial Minerals Revenues, and Other Related Income

	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)			
VantaCore:				
Tonnage sold	2,295	N/A	N/A	N/A
Revenues	$42,051	N/A	N/A	N/A
Operating expenses	$32,309	N/A	N/A	N/A
Royalty revenues	$12,073	$13,479	$ (1,406)	(10)%
Total aggregates and industrial minerals related revenues	$54,124	$13,479	$ 40,645	302%
Soda ash revenues and distributions:				
Equity and other unconsolidated investment earnings	$41,416	$34,186	$ 7,230	21%
Cash distributions received from OCI Wyoming	$46,638	$72,946	$(26,308)	(36)%

Total aggregates and industrial minerals revenues, and other related income. Total aggregates related revenues, and other related income represented approximately 24% and 13% of our total revenues and other income for both periods ended December 31, 2014 and 2013, respectively. The following is a discussion of the major categories of these revenues:

VantaCore operating revenues contributed $42.1 million. We acquired VantaCore on October 1, 2014.

Aggregates and industrial minerals related revenues decreased 10% for 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.

Equity and other unconsolidated investment earnings. Income from our investment in the OCI Wyoming trona mining and soda ash production business was $41.4 million for the year ended December 31, 2014, and we received $46.6 million in cash distributions during the year. For the same period in 2013, we recorded equity income of $34.2 million and received $72.9 million in cash, which included a one-time special distribution of $44.8 million. The increase in equity income of 21% over 2013 is due to improved earnings from OCI Wyoming in 2014 over 2013.

Oil and Gas Revenues

	For the Years Ended December 31, 2014	2013	Increase (Decrease)	Percentage Change
	(Dollars in thousands, except per unit data) (Unaudited)			
Williston Basin non-operated working interests:				
Production volumes:				
Oil (MBbl)	578	N/A	N/A	N/A
Natural gas (Mcf)	408	N/A	N/A	N/A
NGL (MBoe)	53	N/A	N/A	N/A
Average sales price per unit:				
Oil (Bbl)	$ 77.85	N/A	N/A	N/A
Natural gas (Mcf)	$ 5.04	N/A	N/A	N/A
NGL (Boe)	$ 33.64	N/A	N/A	N/A
Revenues:				
Oil	$44,995	N/A	N/A	N/A
Natural gas	2,056	N/A	N/A	N/A
NGL	1,783	N/A	N/A	N/A
Total	$48,834	N/A	N/A	N/A
Other oil and gas revenues:				
Royalty and overriding royalty revenues	10,732	N/A	N/A	N/A
Total oil and gas revenues	$59,566	$17,080	$42,486	249%

Oil and gas revenues increased $42 million for the year ended December 31, 2014 when compared to the year ended December 31, 2013. The increase in revenues 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 on November 12, 2014.

Our average oil price received from our Williston Basin properties for the year ended December 31, 2014 was $77.85.

Due to the decline in oil prices in the fourth quarter of 2014, our average price for the fourth quarter decreased to $63.17 which represents an 18.9% reduction as compared to full year.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Adjusted EBITDA

Adjusted EBITDA increased 4% to $340.3 million mainly due to our investment in OCI Wyoming that generated $72.9 million that more than offset the significant declines of $69.2 million that we saw from our coal related revenues. 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 a reconciliation of this measure to net income.

Distributable Cash Flow

Distributable cash flow increased by $10.5 million, or 4%, to $309.4 million mainly due to distributions of $72.9 million from OCI Wyoming in 2013, offset by lower cash flows from coal related assets and proceeds from the sale of a preparation plant in 2012 of $4.7 million. 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 a reconciliation of this measure to net cash provided by operating activities.

Coal Related Revenues and Production

	For the Years Ended December 31, 2013	2012	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data) (Unaudited)			
Regional Statistics				
Coal royalty production (tons)				
Appalachia				
Northern	11,505	10,486	1,019	10%
Central	20,801	26,098	(5,297)	(20)%
Southern	4,151	3,718	433	12%
Total Appalachia	36,457	40,302	(3,845)	(10)%
Illinois Basin	13,087	11,299	1,788	16%
Northern Powder River Basin	2,778	2,377	401	17%
Gulf Coast	970	466	504	108%
Total	53,292	54,444	(1,152)	(2)%
Average coal royalty revenue per ton				
Appalachia				
Northern	$ 1.27	$ 1.50	$ (.23)	(15%)
Central	5.05	5.99	(.94)	(16%)
Southern	6.30	7.89	(1.59)	(20%)
Total Appalachia	4.00	5.00	(1.00)	(20)%
Illinois Basin	4.28	4.38	(.10)	(2)%
Northern Powder River Basin	2.72	3.58	(.86)	(24)%
Gulf Coast	3.39	2.60	.79	30%
Combined average gross royalty per ton	$ 3.99	$ 4.79	(.80)	(17)%
Coal royalty revenues				
Appalachia				
Northern	$ 14,643	$ 15,768	$ (1,125)	(7)%
Central	105,004	156,390	(51,386)	(33)%
Southern	26,156	29,325	(3,169)	(11)%
Total Appalachia	145,803	201,483	(55,680)	(28)%
Illinois Basin	56,001	49,538	6,463	13%
Northern Powder River Basin	7,569	8,501	(932)	(11)%
Gulf Coast	3,290	1,212	2,078	171%
Total	$212,663	$260,734	$(48,071)	(18)%
Other coal related revenues				
Override revenue	$ 10,372	$ 13,979	$ (3,607)	(26)%
Transportation and processing fees	22,519	27,354	(4,835)	(18)%
Minimums recognized as revenue	6,528	23,029	(16,501)	(72)%
Condemnation payments	10,370	8,463	1,907	23%
Gain on Sale of Assets	—	4,715	(4,715)	(100)%
Reserve swap	8,149	—	8,149	100%
Wheelage	3,593	5,078	(1,485)	(29)%
Total	$ 61,531	$ 82,618	$(21,087)	(26)%
Total coal related revenues	$274,194	$343,352	$(69,158)	(20)%

Total coal related revenues. Total coal related revenues comprised approximately 77% and 91% of our total revenues and other income for the years ended December 31, 2013 and 2012, respectively. The following is a discussion of the major categories of coal related revenue:

Coal royalty revenues and production. Coal royalty revenues comprised approximately 59% and 69% of our total revenues and other income for the year ended December 31, 2013 and 2012, respectively. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. Coal royalty revenues decreased $55.7 million or 28% for the year ended December 31, 2013 compared to the same period of 2012, while production decreased 3.8 million tons or 10%.

Production from our properties in the Central Appalachian region declined by 20% due to a combination of the idling of mining units or mines, lower sales volumes from mines on our property and some mining units moving off of our property to adjacent properties in the normal course of their mine plans. In addition, pricing realized by our lessees for both thermal and metallurgical coal in Central Appalachia is generally below the levels of the same period in 2012, causing a higher percentage decrease in coal royalty revenues compared to the decrease in production.

The Southern Appalachian region also had increased production but decreased coal royalty revenues. The increased production was due to one of our lessees having more normal production for 2013 after a slower start in 2012 after making repairs to its preparation plant that was damaged by a tornado in 2011. In addition prices from the metallurgical sales from our properties were lower than the same period in 2012, which contributed to the decrease in coal royalty revenue.

With respect to Northern Appalachia, during the year ended December 31, 2013 there was also a decrease in coal royalty revenue while we had an increase in production of 1.0 million tons or 10%. The increase in tonnage was due to some lessees having a higher proportion of production on our properties. Those increases were generally from leases with lower revenue per ton which caused the decrease in coal royalty revenue.

Illinois Basin. Coal royalty revenues for the year ended December 31, 2013 increased $6.5 million or 13% when compared to the same period in 2012, and production increased by 1.8 million tons, or 16%. The increased production was primarily due to production from the Hillsboro mine which operated its longwall for the entire year of 2013 after starting operation in 2012. This increase in production was partially offset by lower production from the Williamson mine and lower production from the Macoupin mine which idled one of its producing units in early 2013.

Northern Powder River Basin. Coal royalty revenues decreased on our Western Energy property despite having higher production in 2013. The higher production was due to the normal variations in production that occur on our checkerboard ownership. The lower coal royalty revenue was due to the timing of revenue recognition by the lessee in the third quarter of 2012 that did not occur in 2013.

Gulf Coast. Coal royalty revenue and production for the year ended December 31, 2013 increased compared to the same period in 2012 due to a mine having a greater proportion of production on our property in 2013.

Other coal related revenues. Other coal related revenues for the year ended December 31, 2013 decreased 26% compared to the same period in 2012. The following is a discussion of the revenues derived from each of the major sources of other coal-related revenue:

Override revenue for the year ended December 31, 2013 decreased by 26% compared to the same period in 2012 due to one lessee moving its mining operations from an area on which we receive an overriding royalty onto property on which we receive coal royalty revenue, one lessee exhausting the reserves subject to the override and other lessees mining fewer tons on properties on which we receive an overriding royalty.

Transportation and processing fees decreased 18% for the year ended December 31, 2013, when compared to the same period in 2012. The decrease in revenue was due to lower tonnage put through our all our facilities except Sugar Camp and the sale of one of our processing facilities.

Minimums recognized as revenue decreased $16.5 million or 72% for the year ended December 31, 2013 when compared to the same period in 2012, primarily due to two lessees having significant previously paid minimums losing the ability to recoup them during 2012 that did not occur in 2013.

We recorded a reserve swap for the year ended December 31, 2013 of $8.1 million on our Illinois property. No swap occurred during 2012.

Wheelage revenue decreased by 29% for the year ended December 31, 2013 compared to the same period in 2012. This decrease was due to the normal fluctuations of tonnage that are subject to wheelage charges.

Aggregates and Industrial Minerals Revenues, and Other Related Income

	For the Years Ended December 31, 2013	2012	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data) (Unaudited)			
Aggregates and industrial minerals related revenues	$13,479	$9,524	$3,955	42%
Soda ash revenues and distributions:				
Equity and other unconsolidated investment earnings	$34,186	N/A	N/A	N/A
Cash distributions received from OCI Wyoming	$72,946	N/A	N/A	N/A

Total aggregates and industrial minerals revenues, and other related income. Total aggregates and industrial minerals revenues, and other related income represented approximately 4% and 3% of our total revenues and other income for the year ended December 31, 2013 and 2012, respectively. The following is a discussion of the major categories of these revenues:

Aggregates and industrial minerals related revenues were up $4.0 million or 42% compared to 2012 due to an increase of $1.2 million in minimums recognized as revenue during 2013. Override revenues also increased on our frac sand properties by $1.6 million during the year ended December 31, 2013. This override was acquired during the fourth quarter of 2012 and did not contribute until 2013.

Equity and other unconsolidated investment earnings. Income from our investment in the OCI Wyoming trona mining and soda ash production business was $34.2 million for the year ended December 31, 2013 and we received $72.9 million in cash distributions which included a special distribution of $44.8 million during the year ended December 31, 2013. We did not own this interest until January 2013.

Oil and Gas Revenues

Oil and gas revenues increased $7.5 million for the year ended December 31, 2013 when compared to the same period in 2012. The increase is primarily due to revenues from our Williston Basin non-operated working interest properties which were acquired during the second half of 2013.

Other Operating Results

Other Revenues. In addition to coal related revenues, aggregates and industrial minerals revenues and oil and gas revenues, we generated approximately 1% of our total revenues and other income from other sources for the years ended December 31, 2014 and 2013 and less than 1% for 2012. Other sources of revenues primarily include: rentals, metal revenue and timber royalties.

Operating expenses. Included in total expenses are:

- Depreciation, depletion and amortization of $79.9 million, $64.4 million and $58.2 million for the years ended December 31, 2014, 2013 and 2012, respectively. The increase in 2014 over 2013 is due to a full year depletion on oil and gas acquisitions acquired in the fourth quarter of 2013 as well as depletion on the Kaiser Francis oil and gas acquisition acquired during the second half of 2014. Also contributing to the increase in depreciation, depletion and amortization is the added expense associated with the acquisition of VantaCore in the fourth quarter of 2014. The increase in 2013 over 2012 is primarily due to increased oil and gas depletion and higher coal depletion due to the reserve swap that occurred in 2013 being at a higher per ton rate.

- General and administrative expenses of $36.4 million, $36.8 million and $29.7 million for the years ended December 31, 2014, 2013 and 2012, respectively. General and administrative expenses are primarily impacted by accruals under our long-term incentive plan attributable to fluctuations in our unit price and additional personnel required to manage our properties. In 2014, we recorded additional expenses incurred for the VantaCore and Kaiser Francis acquisitions, these costs were partially offset by lower accruals for our long term incentive plan due to a drop in the unit price. In 2013, we recorded increases in both long term incentive plan accruals and additional personnel over the two previous years.
- Property, franchise and other taxes of $21.3 million, $16.5 million and $17.7 million for the years ended December 31, 2014, 2013 and 2012, respectively. The increase in property, franchise and other taxes reflects the inclusion of severance tax from our oil and gas properties acquired in late 2013 and 2014. A substantial portion of our property taxes in our coal and aggregates royalty business is reimbursed to us by our lessees and is reflected as property tax revenue on our consolidated statements of comprehensive income.

Interest Expense. Interest expense was $80.2 million, $64.4 million and $54.0 million for the years ended December 31, 2014, 2013 and 2012, respectively. Interest 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

Liquidity and Financing Activities

As of December 31, 2014, we had $100 million in available borrowing capacity under Opco's revolving credit facility and $27 million of available borrowing capacity under the NRP Oil and Gas revolving credit facility. In addition to the amounts available under our revolving credit facilities, we had $50.1 million in cash at December 31, 2014. Generally, we satisfy our working capital requirements with cash generated from operations. We finance our acquisitions with available cash, borrowings under our revolving credit facilities, and the issuance of debt securities and common units. We typically access the capital markets to refinance amounts outstanding under our revolving credit facilities as we approach the limits under those facilities. Our current liabilities exceeded our current assets by approximately $11.8 million as of December 31, 2014, because we used cash to repay the principal on Opco's notes rather than refinancing the amounts due.

As of December 31, 2014, we were in compliance with all of our debt covenant ratios. Opco's revolving credit facility and term loan facility both mature during 2016. In addition, we are required to make approximately $81 million of principal payments in connection with Opco's senior notes each year through 2018. We also have $425 million principal amount of 9.125% senior notes issued by NRP and NRP Finance, as co-issurers, that mature in 2018. In addition, we will be required to repay or refinance the amounts outstanding under Opco's credit facilities prior to their maturity. While we believe we will be able to refinance these amounts, we may not be able to do so on terms acceptable to us, if at all, or the borrowing capacity under Opco's revolving credit facility may be substantially reduced. 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. In addition, our ability to refinance our debt may depend in part or our ability to access the debt or equity capital markets, which will be challenging in the current market environment. For a more complete discussion of factors that will affect our liquidity, see "Item 1A. Risk Factors—Risks Related to Our Business."

During 2014, we engaged in several financing transactions in connection with our two major acquisitions. We funded the purchase price of VantaCore through the borrowing of $169.0 million under Opco's revolving credit facility and the issuance of 2,427,503 common units to certain of the sellers. We funded the $339 million purchase price of the Sanish Field acquisition using a combination of the net proceeds of $100.4 million (including our general partner's proportionate capital contribution to maintain its 2% general partner interest in us) from a public offering of 8,500,000 common units at a public offering price of $12.02 per common unit, the net proceeds of $122.6 million from a private offering of an additional $125 million principal amount of our 9.125% Senior Notes due 2018 at an offering price of 99.5%, and borrowings of $117.0 million under the amended NRP Oil and Gas revolving credit facility. Also during 2014, we sold 1,559,914 common units in connection with our "at-the-market" offering program at an average price of $16.05 per common unit for approximately $25.2 million in net proceeds, including our general partner's proportionate capital contribution in order to maintain its 2% general partner interest in us. We used the net proceeds from these sales for general partnership purposes, including the repayment of principal due on Opco's senior notes.

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, we anticipate higher operating capital expenditures in 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. These maintenance capital expenditures reduce our cash available for distribution to our unitholders. We finance the capital expenditures associated with our Williston Basin non-operated working interest oil and gas assets through a combination of cash flow from operations and borrowings under the NRP Oil and Gas revolving credit facility and are able to control the level of these capital expenditures by evaluating well proposals on a well-by-well basis. We will 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. The capital expenditures in connection with VantaCore's construction aggregates mining and production operations are generally funded through cash flow from operations.

Cash Flows

Net cash provided by operating activities for the years ended December 31, 2014, 2013 and 2012 was $210.8 million, $247.1 million and $271.4 million, respectively. The majority of our cash provided by operations is generated from coal royalty revenues, our equity interest in OCI Wyoming and beginning in 2014, oil and gas revenues.

Net cash used in investing activities for the years ended December 31, 2014, 2013 and 2012 was $520.5 million, $302.8 million and $212.7 million, respectively. Our 2014 investing activities consisted of our Sanish Field oil and gas 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 OCI Wyoming and two acquisitions of non-operated working interests in oil and gas properties located in the Williston Basin of North Dakota and Montana. During 2012, the majority of our investing activities consisted of acquiring reserves, plant and equipment and related intangibles as well as assets relating to Sugar Camp. These uses in 2012 were slightly offset by $24.8 million in proceeds from asset sales.

Net cash flows provided by financing activities for the year ended December 31, 2014 were $267.3 million. Net cash flows used in financing activities for the years ended December 31, 2013 and 2012 were $1.2 million and $124.2 million, respectively. During 2014, 2013 and 2012 we had proceeds from loans of $637.4 million, $567.0 million and $148.0 million, respectively. During 2014, 2013 and 2012, these proceeds were offset by repayment of debt of $328.0 million, $386.2 million and $30.8 million, respectively. Also during 2014, 2013 and 2012 we paid cash distributions to our unitholders of $162.0 million, $246.5 million and $238.0 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.

Contractual Obligations and Commercial Commitments

NRP Debt

Senior Notes. In September 2013, NRP and NRP Finance, as co-issuers, completed a private offering of $300 million principal amount of 9.125% Senior Notes due 2018 at an offering price of 99.007% of par. The notes were offered and sold to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, as amended, and to persons outside the United States pursuant to Regulation S under the Securities Act. The notes were issued pursuant to an indenture, dated September 18, 2013, among NRP, NRP Finance Corporation and Wells Fargo Bank, National Association, as trustee. The notes bear interest at a rate of 9.125% per year, payable semiannually in arrears on April 1 and October 1 of each year, beginning on April 1, 2014. The notes will mature on October 1, 2018.

In October 2014, NRP and NRP Finance issued an additional $125 million in aggregate principal amount of the 9.125% Senior Notes due 2018 at an offering price of 99.5% of par. The notes were issued pursuant to the existing indenture and constitute the same series of securities as the existing 9.125% Senior Notes due 2018 issued in September 2013. In the offering, $105 million in aggregate principal amount of the notes were sold in a private offering to the initial purchasers thereof to be offered and sold to qualified institutional buyers pursuant to Rule 144A under the Securities Act, and to persons outside the United States pursuant to Regulation S under the Securities Act. The remaining $20 million in aggregate principal amount of the notes were sold in a separate private offering to Cline Trust Company, LLC.

The notes are the senior unsecured obligations of NRP and NRP Finance. The notes rank equal in right of payment to all existing and future senior unsecured debt of NRP and NRP Finance and senior in right of payment to any subordinated debt of NRP and NRP Finance. The notes are effectively subordinated in right of payment to all future secured debt of NRP and NRP Finance to the extent of the value of the collateral securing such indebtedness and will be structurally subordinated in right of payment to all existing and future debt and other liabilities of NRP's subsidiaries, including Opco's revolving credit facility and term loan facility, each series of Opco's existing senior notes, and NRP Oil and Gas's revolving credit facility. None of NRP's subsidiaries guarantee the notes.

NRP and NRP Finance have the option to redeem the notes, in whole or in part, at any time on or after April 1, 2016, at the redemption prices (expressed as percentages of principal amount) of 106.844% for the six-month period beginning on April 1, 2016, 104.563% for the twelve-month period beginning on October 1, 2016 and 100.000% beginning on October 1, 2017 and at any time thereafter, together with any accrued and unpaid interest to the date of redemption. In addition, before April 1, 2016, NRP and NRP Finance may redeem all or any part of the notes at a redemption price equal to the sum of the principal amount thereof, 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 for the senior notes contains covenants that limit the ability of NRP and certain of its subsidiaries to incur or guarantee additional indebtedness. Under the indenture, NRP 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 and certain of its subsidiaries to incur additional indebtedness is further limited in the event the amount of indebtedness of NRP and its subsidiaries that is senior to NRP's unsecured indebtedness exceeds certain thresholds. The indenture contains additional covenants that, among other things, limit NRP's ability and the ability of certain of its subsidiaries to declare or pay any dividend or distribution on, purchase or redeem units or purchase or redeem subordinated debt; make investments; create certain liens; enter into agreements that restrict distributions or other payments from NRP's restricted subsidiaries as defined in the indenture to NRP; sell assets; consolidate, merge or transfer all or substantially all of the assets of NRP and its restricted subsidiaries; engage in transactions with affiliates; create unrestricted subsidiaries; and enter into certain sale and leaseback transactions.

Opco Debt

As of the date of this filing, Opco's debt consisted of:

- $200.0 million under the floating rate revolving credit facility, due August 2016;
- $75.0 million under the floating rate term loan, due January 2016;
- $18.5 million of 4.91% senior notes due 2018;
- $107.1 million of 8.38% senior notes due 2019;
- $46.2 million of 5.05% senior notes due 2020;
- $1.3 million of 5.31% utility local improvement obligation due 2021;
- $24.3 million of 5.55% senior notes due 2023;
- $67.5 million of 4.73% senior notes due 2023;
- $150.0 million of 5.82% senior notes due 2024;
- $45.5 million of 8.92% senior notes due 2024;
- $161.5 million of 5.03% senior notes due 2026; and
- $46.2 million of 5.18% senior notes due 2026.

Senior Notes. Opco issued the senior notes listed above under a note purchase agreement as supplemented from time to time. The senior notes are unsecured but are guaranteed by Opco's subsidiaries. Opco may prepay the senior notes at any time together with a make-whole amount (as defined in the note purchase agreement). If any event of default exists under the note purchase agreement, the noteholders will be able to accelerate the maturity of the senior notes and exercise other rights and remedies.

The senior note purchase agreement contains 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 to consolidated fixed charges (consisting of consolidated interest expense and consolidated operating lease expense) at not less than 3.5 to 1.0.

All of Opco's senior notes require annual principal payments in addition to semi-annual interest payments. Opco also makes annual principal and interest payments on the utility local improvement obligation.

Revolving Credit Facility. As of the date of this report, Opco had $100 million in available borrowing capacity under its $300 million revolving credit facility, which matures on August 9, 2016.

During 2014, Opco's borrowings and repayments under its revolving credit facility were as follows:

	Quarter Ending			
	March 31	June 30	September 30	December 31
	(In thousands)			
Outstanding balance, beginning of period	$20,000	$20,000	$15,000	$ 7,000
Borrowings under credit facility	—	—	—	394,000
Less: Repayments under credit facility	—	(5,000)	(8,000)	(201,000)
Outstanding balance, ending period	$20,000	$15,000	$ 7,000	$ 200,000

Opco's obligations under its revolving credit facility are unsecured but are guaranteed by its subsidiaries. Opco may prepay all amounts outstanding under the credit facility at any time without penalty. Indebtedness under Opco's revolving credit facility bears interest, at our option, at either:

- the Alternate Base Rate (as defined in the credit agreement) plus an applicable margin ranging from 0% to 1%; or
- the Adjusted LIBO Rate (as defined in the credit agreement) plus an applicable margin ranging from 1.00% to 2.25%.

Opco incurs a commitment fee on the unused portion of the revolving credit facility at a rate ranging from 0.18% to 0.40% per annum.

The Opco revolving credit facility contains covenants requiring Opco to maintain:

- a ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the credit agreement) not to exceed 4.0 to 1.0; and
- a ratio of consolidated EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated lease operating expense) not less than 3.5 to 1.0.

Under an accordion feature in the credit facility, Opco may request its lenders to increase their aggregate commitment to a maximum of $500 million on the same terms. However, Opco cannot be certain that its lenders will elect to participate in the accordion feature. To the extent the lenders decline to participate, Opco may elect to bring new lenders into the facility, but cannot make any assurance that the additional credit capacity will be available on existing or comparable terms.

Term Loan. In connection with the OCI Wyoming soda ash business acquisition in January 2013, Opco entered into a 3-year, $200 million term loan facility. The term loan facility is guaranteed by Opco's operating subsidiaries and bore interest at a weighted average rate of 2.22% in 2014. We repaid $101 million of the term loan during 2013 and an additional $24 million in the fourth quarter of 2014. The remaining balance of $75.0 million is due on January 23, 2016. The term loan facility contains financial covenants and other terms that are identical to those of Opco's revolving credit facility.

NRP Oil and Gas Debt

Revolving Credit Facility. In August 2013, NRP Oil and Gas entered into a 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 be a $500 million facility with an initial borrowing base of $137 million and will mature on November 12, 2019. 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 NRP nor any of its other subsidiaries is a guarantor of such facility. As of December 31, 2014, NRP Oil and Gas had $110.0 million outstanding under the facility.

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 (i) 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 (ii) a current ratio of at least 1.0 to 1.0. The credit facility also contains other customary covenants, subject to certain agreed exceptions, including covenants restricting the ability of NRP Oil and Gas to, among other items, incur indebtedness; create, assume or permit to exist liens; be a party to or be liable on any hedging contract; engage in mergers or consolidations; transfer, lease, exchange, alienate or dispose of material assets or properties; pay distributions; make any acquisitions of, capital contributions to or other investments in any entity or property; extend credit or make advances or loans; or engage in transactions with affiliates. Events of default under the credit facility include payment defaults, misrepresentations and breaches of covenants by NRP Oil and Gas. The credit facility also contains a cross-default provision with respect to any indebtedness of NRP's.

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.

Long-Term Contractual Obligations

The following table reflects our long-term non-cancelable contractual obligations as of December 31, 2014:

	Payments Due by Period						
Contractual Obligations	**Total**	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**
				(In millions)			
NRP:							
Long-term debt principal payments (including current maturities)(1)	$ 425.0	$ —	$ —	$ —	$425.0	$ —	$ —
Long-term debt interest payments(2)	155.2	38.8	38.8	38.8	38.8	—	—
NRP Oil and Gas:							
Long-term debt principal payments	110.0	—	—	—	—	110.0	—
Opco:							
Long-term debt principal payments (including current maturities)(3)	943.1	81.0	356.0	81.0	81.0	76.4	267.7
Long-term debt interest payments(4)	187.0	38.4	33.3	28.2	23.2	18.2	45.7
Rental leases(5)	2.7	0.7	0.7	0.7	0.6	—	—
Total	$1,823.0	$158.9	$428.8	$148.7	$568.6	$204.6	$313.4

(1) On September 18, 2013, NRP and NRP Finance issued $300 million of 9.125% senior notes at an offering price of 99.007% of par value due October 1, 2018. On October 17, 2014 NRP and NRP Finance issued an additional $125 million of 9.125% senior notes at an offering price of 99.5% of par value.

(2) The amounts indicated in the table include interest due on NRP's 9.125% senior notes.

(3) The amounts indicated in the table include principal due on Opco’s senior notes, credit facility, term loan 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 leases office space for approximately $100,000 per year through 2017. These rental obligations are included in the table above.

Shelf Registration Statements and “At-the-Market” Program

In April 2012 we filed an automatically effective shelf registration statement on Form S-3 with the SEC that is available for registered offerings of common units and debt securities. In October 2014, we issued 8,500,000 common units in an underwritten public offering pursuant to this registration statement at a public offering price of $12.02 per common unit. We used the net proceeds of approximately $100.4 million from this offering, including our general partner’s proportionate capital contribution to maintain its 2% general partner interest in us, to fund a portion of the purchase price of the Sanish Field acquisition.

In August 2012, we filed a shelf registration statement on Form S-3 that registered all of the common units held by Adena Minerals. This shelf registration statement was declared effective by the SEC in September 2012. Following the effectiveness of this registration statement, Adena distributed 15,181,716 common units to its shareholders, and we subsequently filed prospectus supplements to register the resale of these common units by those shareholders. The shelf registration statement filed in August 2012 also registered up to $500 million in equity securities to be sold by NRP. In November 2013, we filed a prospectus supplement and entered into an Equity Distribution Agreement relating to the offer and sale from time to time of common units having an aggregate offering price of $75 million through one or more managers acting as sales agents at prices to be agreed upon at the time of sale. Under the terms of the Equity Distribution Agreement, we may also sell common units from time to time to any manager as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to any manager as principal would be pursuant to the terms of a separate terms agreement between NRP and such manager. Sales of common units in this “at-the-market” (“ATM”) program are made pursuant to the shelf registration statement declared effective in September 2012. For the year ended December 31, 2014, we sold 1,559,914 common units for an average price of $16.05 for gross proceeds of $25.0 million.

In April 2013, we filed a resale shelf registration statement on Form S-3 to register the 3,784,572 common units issued in the January 2013 private placement in connection with the OCI Wyoming acquisition. This shelf registration statement was declared effective by the SEC in May 2013. A portion of the common units issued in the private placement were issued, directly and indirectly, to certain of our affiliates, including Corbin J. Robertson, Jr. and Christopher Cline.

We cannot control the resale of the common units by any of the selling unitholders under the shelf registration statements described above, and the amounts, prices and timing of the issuance and sale of any equity or debt securities by NRP will depend on market conditions, our capital requirements and compliance with our credit facilities, term loan and senior notes.

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, 2014, 2013 and 2012.

Environmental

The operations our lessees conduct on our properties, as well as the aggregates/industrial minerals and oil and gas operations in which we have 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, we may be liable for certain environmental conditions occurring on the surface properties. The terms of substantially all of our 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 us against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. We make regular visits to the mines to ensure compliance with lease terms, but the duty to comply with all regulations rests with the lessees. We believe that our lessees will be able to comply with existing regulations and do not expect any lessee’s failure to comply with environmental laws and regulations to have a material impact on our financial condition or results of operations. We have neither incurred, nor are aware of, any material environmental charges imposed on us related to our properties for the period ended December 31, 2014. We are not associated with any environmental contamination that may require remediation costs. However, our lessees do conduct reclamation work on the properties under lease to them. Because we are not the permittee of the mines being reclaimed, we are not responsible for the costs associated with these reclamation operations. In addition, West Virginia has established a fund to satisfy any shortfall in reclamation obligations. As an owner of working interests in oil and natural gas operations, we are responsible for our proportionate share of any losses and liabilities, including environmental liabilities, arising from uninsured and underinsured events. We are also responsible for losses and liabilities, including environmental liabilities that may arise from uninsured and underinsured events.

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

Partnership Agreement

Our 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, we reimburse our general partner and its affiliates for expenses incurred on our behalf. All direct general and administrative expenses are charged to us as incurred. We also reimburse indirect general and administrative costs, including certain legal, accounting, treasury, information technology, insurance, administration of employee benefits and other corporate services incurred by our general partner and its affiliates.

The reimbursements to our general partner for services performed by Western Pocahontas Properties and Quintana Minerals Corporation are as follows:

	For the Years Ended December 31,		
	2014	2013	2012
	(In thousands)		
Reimbursement for services	$11,798	$11,480	$9,791

For additional information, see “Item 13. Certain Relationships and Related Transactions, and Director Independence—Omnibus Agreement.”

Transactions with Cline Affiliates

Various companies controlled by Chris Cline, including Foresight Energy LP, lease coal reserves from NRP, and we provide coal transportation services to them for a fee. Mr. Cline, both individually and through affiliated companies, owns a 31% interest in our general partner, as well as 4,917,548 common units, at the time of this filing. At December 31, 2014, we had accounts receivable totaling $9.2 million from Cline affiliates. In addition, the overriding royalty and the lease of the loadout facility at the Sugar Camp mine are classified as contracts receivable of $50.0 million on our Consolidated Balance Sheets. Revenues from the Cline affiliates are as follows:

	For The Years Ended December 31,		
	2014	2013	2012
		(In thousands)	
Coal royalty revenues	$52,415	$54,322	$48,567
Processing and transportation fees	20,594	19,258	21,923
Minimums recognized as revenue	—	3,477	17,785
Override revenue	2,847	3,226	4,066
Other revenue	5,690	8,149	—
	$81,546	$88,432	$92,341

As of December 31, 2014, we had received $86.8 million in minimum royalty payments that have not been recouped by Cline affiliates, of which $16.0 million was received in 2014.

During the fourth quarter of 2012, we recognized an impairment of $2.6 million related to the assets at the Gatling West Virginia location, a location leased to and affiliate of Chris Cline.

During 2014 and 2013, we recognized non-cash gains of $5.7 million and $8.1 million on reserve exchanges in Illinois with Williamson Energy, a subsidiary of Foresight Energy LP. The tons received during 2014 and 2013 were fully mined during each of those years, while the tons exchanged are not included in current mine plans. The gains are included in Coal related revenues on the Consolidated Statement of Comprehensive Income.

We entered into a lease agreement related to the rail loadout and associated facilities at Sugar Camp that has been accounted for as a direct financing lease. Total projected remaining payments under the lease at December 31, 2014 are $86.3 million with unearned income of $39.0 million. The net amount receivable under the lease as of December 31, 2014 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—affiliate on the accompanying Consolidated Balance Sheets.

In a separate transaction, we acquired a contractual overriding royalty interest from a Cline affiliate that provides for payments based upon production from specific tons at the 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, 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.

Note to Cline Trust Company, LLC

Donald R. Holcomb, one of our directors, is a manager of Cline Trust Company, LLC, which owns approximately 5.35 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. Cline Trust Company, LLC purchased the $20 million of our 9.125% Senior Notes due 2018 in our offering of $125 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 our 9.125% Senior Notes due 2018 was $19.9 million as of December 31, 2014 and is included with our long term debt.

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. In connection with the formation of Quintana Capital, the Partnership 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 governance documents of Quintana Capital's affiliated investment funds reflect the guidelines set forth in NRP's conflicts policy. See "Item 13. Certain Relationships and Related Transactions, and Director Independence—Quintana Capital Group GP, Ltd."

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. We own and lease 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.

For the years ended December 31, 2014, 2013 and 2012, the revenues from Taggart prior to the sale to Forge were as follows:

	For the Years Ended December 31,		
	2014	2013	2012
	(In thousands)		
Processing revenue	$—	$1,761	$5,580

During the third quarter of 2012, we sold a preparation plant back to Taggart Global for $12.3 million. We received $10.5 million in cash and a note receivable from Taggart, payable over three years for the balance. We recorded a gain of $4.7 million included in Other income or the Consolidated Statements of Income for 2012. The net book value of the asset sold was $7.6 million. During 2013, the note receivable that we held was paid in full.

At December 31, 2013, a fund controlled by Quintana Capital owned a majority 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. Revenues from Corsa are as follows:

	For the Years Ended December 31,		
	2014	2013	2012
	(In thousands)		
Coal royalty revenues	$3,013	$4,594	$3,486

NRP also had accounts receivable totaling $0.3 million from Corsa at each of December 31, 2013 and December 31, 2014.

Office Building in Huntington, West Virginia

We lease an office building in Huntington, West Virginia from Western Pocahontas at market rates. The terms of the lease were approved by our Conflicts Committee. We pay $0.6 million each year in lease payments.

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.

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.

The market price of soda ash directly affects the profitability of OCI Wyoming's operations. If the market price for soda ash declines, OCI 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. In addition, crude oil and natural gas prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. These markets will likely continue to be volatile in the future.

Interest Rate Risk

Our exposure to changes in interest rates results from borrowings under the Opco revolving credit facility, the Opco term loan and the NRP Oil and Gas revolving credit facility, which are subject to variable interest rates based upon LIBOR or the federal funds rate plus an applicable margin. Management monitors interest rates and may enter into interest rate instruments to protect against increased borrowing costs. At December 31, 2014, we had $385 million outstanding in variable interest debt. If interest rates were to increase by 1%, annual interest expense would increase approximately $3.9 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, 2014 and 2013, and the related consolidated statements of comprehensive income, partners' capital and cash flows for each of the three years in the period ended December 31, 2014. 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 OCI Wyoming LLC (OCI Wyoming) (a Limited Liability Company in which Natural Resource Partners L.P. owns a 49% interest). Natural Resource Partners L.P.'s investment in OCI Wyoming constituted approximately $264 million and $269 million of Natural Resource Partners L.P.'s assets as of December 31, 2014 and 2013, and total revenues of $41 million and $34 million for the two years in the period ended December 31, 2014. 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 solely 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 provides 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. and subsidiaries at December 31, 2014 and 2013, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

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, 2014, 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 February 27, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 27, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying balance sheets of OCI Wyoming LLC (the "Company") as of December 31, 2014 and 2013, and the related statements of operations and comprehensive income, members' equity, and cash flows for the years then ended, 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, 2014 and 2013, and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Atlanta, Georgia
February 26, 2015

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS
(In thousands, except for unit information)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 50,076	$ 92,513
Accounts receivable, net of allowance for doubtful accounts	66,455	33,737
Accounts receivable — affiliates	9,494	7,666
Inventory	5,814	—
Other	4,279	1,691
Total current assets	136,118	135,607
Land	25,243	24,340
Plant and equipment, net	60,093	26,435
Mineral rights, net	1,781,852	1,405,455
Intangible assets, net	60,733	66,950
Equity and other unconsolidated investments	264,020	269,338
Loan financing costs, net	13,905	11,502
Long-term contracts receivable — affiliates	50,008	51,732
Goodwill	52,012	—
Other assets	740	497
Total assets	$2,444,724	$1,991,856
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 32,416	$ 8,659
Accounts payable — affiliates	950	391
Current portion of long-term debt	80,983	80,983
Accrued incentive plan expenses — current portion	7,048	8,341
Property, franchise and other taxes payable	8,318	7,830
Accrued interest	18,216	17,184
Total current liabilities	147,931	123,388
Deferred revenue	160,260	142,586
Accrued incentive plan expenses	6,554	10,526
Asset retirement obligation	4,905	—
Other non-current liabilities	10,679	14,341
Long-term debt	1,394,240	1,084,226
Partners' capital:		
Common units outstanding: (122,299,825 and 109,812,408)	709,019	606,774
General partner's interest	12,245	10,069
Non-controlling interest	(650)	324
Accumulated other comprehensive loss	(459)	(378)
Total partners' capital	720,155	616,789
Total liabilities and partners' capital	$2,444,724	$1,991,856

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

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands, except per unit data)

	For the Years Ended December 31,		
	2014	2013	2012
Revenues and other income:			
Coal related revenues	$226,724	$274,194	$343,352
Aggregates related revenues	54,124	13,479	9,524
Oil and gas related revenues	59,566	17,080	9,561
Equity and other unconsolidated investment income	41,416	34,186	—
Property taxes	13,609	15,416	15,273
Other	4,313	3,762	1,437
Total revenues and other income	399,752	358,117	379,147
Operating expenses:			
Depreciation, depletion and amortization	79,876	64,377	58,221
Asset impairments	26,209	734	2,568
General and administrative	36,437	36,821	29,714
Property, franchise and other taxes	21,279	16,463	17,678
Oil and gas lease operating expenses	9,144	739	—
Aggregates operating expenses	32,309	—	—
Transportation costs	1,604	1,644	1,944
Coal royalty and override payments	3,975	1,103	1,857
Total operating expenses	210,833	121,881	111,982
Income from operations	188,919	236,236	267,165
Other income (expense)			
Interest expense	(80,185)	(64,396)	(53,972)
Interest income	96	238	162
Income before non-controlling interest	108,830	172,078	213,355
Non-controlling interest	—	—	—
Net income	$108,830	$172,078	$213,355
Net income attributable to:			
General partner	$ 2,177	$ 3,442	$ 4,267
Limited partners	$106,653	$168,636	$209,088
Basic and diluted net income per limited partner unit	$ 0.94	$ 1.54	$ 1.97
Weighted average number of common units outstanding	113,262	109,584	106,028
Comprehensive income	$108,749	$172,143	$213,405

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

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(In thousands, except unit data)

	Common Units		General Partner	Non-Controlling Interest	Accumulated Other Comprehensive	
	Units	Amounts	Amounts	Amounts	Income (Loss)	Total
Balance at December 31, 2011	106,027,836	$ 629,253	$10,517	$ 5,638	$(493)	$ 644,915
Distributions to unitholders	—	(233,263)	(4,758)	—	—	(238,021)
Distributions to non-controlling interests	—	—	—	(2,793)	—	(2,793)
Costs associated with equity transactions	—	(59)	—	—	—	(59)
Net income for the year ended December 31, 2012	—	209,088	4,267	—	—	213,355
Loss on interest hedge	—	—	—	—	50	50
Comprehensive income	—	—	—	—	50	213,405
Balance at December 31, 2012	106,027,836	$ 605,019	$10,026	$ 2,845	$(443)	$ 617,447
Issuance of common units	3,784,572	75,000	—	—	—	75,000
Capital contribution	—	—	1,531	—	—	1,531
Cost associated with equity transactions	—	(293)	—	—	—	(293)
Distributions to unitholders	—	(241,588)	(4,930)	—	—	(246,518)
Distributions to non-controlling interests	—	—	—	(2,521)	—	(2,521)
Net income for the year ended December 31, 2013	—	168,636	3,442	—	—	172,078
Interest rate swap from unconsolidated investments	—	—	—	—	13	13
Loss on interest hedge	—	—	—	—	52	52
Comprehensive income	—	—	—	—	65	172,143
Balance at December 31, 2013	109,812,408	$ 606,774	$10,069	$ 324	$(378)	$ 616,789
Issuance of common units	10,059,914	127,202	—	—	—	127,202
Issuance of common units for acquisitions	2,427,503	31,604	—	—	—	31,604
Capital contribution	—	—	3,240	—	—	3,240
Cost associated with equity transactions	—	(4,413)	—	—	—	(4,413)
Distributions to unitholders	—	(158,801)	(3,241)	—	—	(162,042)
Distributions to non-controlling interests	—	—	—	(974)	—	(974)
Net income for the year ended December 31, 2014	—	106,653	2,177	—	—	108,830
Interest rate swap from unconsolidated investments	—	—	—	—	(96)	(96)
Unrealized loss on investments	—	—	—	—	(25)	(25)
Loss on interest hedge	—	—	—	—	40	40
Comprehensive income	—	—	—	—	(81)	108,749
Balance at December 31, 2014	122,299,825	$ 709,019	$12,245	$ (650)	$(459)	$ 720,155

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

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Years Ended December 31,		
	2014	2013	2012
Cash flows from operating activities:			
Net income	$ 108,830	$ 172,078	$ 213,355
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	79,876	64,377	58,221
Non-cash interest charge	3,328	2,200	605
Non-cash gain on reserve swap	(5,690)	(8,149)	—
Equity and other unconsolidated investment income	(41,416)	(34,186)	—
Distributions of earnings from unconsolidated investments	43,005	24,113	—
Gain on sale of assets	(1,386)	(10,921)	(13,575)
Asset impairment	26,209	734	2,568
Change in operating assets and liabilities (net of effects of acquisitions):			
Inventory	748	—	—
Accounts receivable	(10,693)	6,826	(802)
Other assets	(795)	(516)	(236)
Accounts payable and accrued liabilities	(4,411)	2,197	1,909
Accrued interest	1,032	6,919	(496)
Deferred revenue	17,674	19,240	11,684
Accrued incentive plan expenses	(5,265)	2,284	(3,461)
Property, franchise and other taxes payable	(291)	(122)	1,636
Net cash provided by operating activities	210,755	247,074	271,408
Cash flows from investing activities:			
Acquisition of land, coal, other mineral rights and related intangibles	(339,768)	(72,000)	(180,534)
Acquisition of equity interests	—	(293,085)	—
Acquisition of aggregates business	(168,978)	—	—
Oil and gas capital expenditures	(16,258)	—	—
Distributions from unconsolidated investments	3,633	48,833	—
Acquisition of plant and equipment	(2,454)	—	(681)
Proceeds from sale of assets	1,418	10,929	24,822
Return on direct financing lease and contractual override	1,904	2,558	2,669
Investment in direct financing lease	—	—	(59,009)
Net cash used in investing activities	(520,503)	(302,765)	(212,733)
Cash flows from financing activities:			
Proceeds from loans	637,375	567,020	148,000
Proceeds from issuance of common units	127,202	75,000	—
Deferred financing costs	(5,094)	(9,209)	—
Repayments of loans	(327,983)	(386,230)	(30,800)
Payment of obligation related to acquisitions	—	—	(500)
Costs associated with equity transactions	(4,413)	(293)	(59)
Distributions to unitholders	(162,042)	(246,518)	(238,021)
Distributions to non-controlling interests	(974)	(2,521)	(2,793)
Capital contribution by general partner	3,240	1,531	—
Net cash provided by (used in) financing activities	267,311	(1,220)	(124,173)
Net (decrease) in cash and cash equivalents	(42,437)	(56,911)	(65,498)
Cash and cash equivalents at beginning of period	92,513	149,424	214,922
Cash and cash equivalents at end of period	$ 50,076	$ 92,513	$ 149,424
Supplemental cash flow information:			
Cash paid during the period for interest	$ 76,155	$ 55,191	$ 53,842
Non-cash investing activities:			
Units issued for acquisition of aggregate operations	$ 31,604	—	—
Note receivable related to sale of assets	—	—	$ 1,808
Non-cash contingent consideration on equity investments	—	$ 15,000	—

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

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Organization

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, 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.

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, which was acquired in October 2014. VantaCore specializes in the construction materials industry and operates three hard rock quarries, five sand and gravel plants, two asphalt plants and a marine terminal. VantaCore's current operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

The Partnership also owns a 49% non-controlling equity interest in a trona ore mining operation and soda ash refinery in the Green River Basin, Wyoming. OCI 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 the 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 and NRP Oil and Gas LLC. NRP GP has sole responsibility for conducting its 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, five of whom must be independent 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

Reclassification

Certain reclassifications have been made to the Consolidated Statements of Comprehensive Income. Amounts relating to prior year's coal royalties, processing fees, transportation fees, minimums recognized as revenue, override royalties and other have been reclassified into a single line item "Coal related revenues" on this year's Consolidated Statements of Comprehensive Income. Amounts relating to prior year's aggregates royalties, processing fees, minimums recognized as revenue, override royalties and other have been reclassified into a single line item "Aggregates related revenues" on this year's Consolidated Statements of Comprehensive Income. Amounts relating to prior year's oil and gas revenues and minimums recognized as revenue have been reclassified into a single line item "Oil and gas related revenues" on this year's Consolidated Statements of Comprehensive Income. The following is reclassification reconciliation:

	For The Year Ended December 31, 2013			For The Year Ended December 31, 2012			
	As Reported	As Reclassified		As Reported	As Reclassified		
	Total	Coal Related Revenues	Aggregates Related Revenues	Total	Coal Related Revenues	Aggregates Related Revenues	Oil & Gas Related Revenues
Revenues:							
Coal royalties	$212,663	$212,663	$ —	$260,734	$260,734	$ —	$ —
Equity and other unconsolidated investment income	34,186	—	—	—	—	—	—
Aggregate royalties	7,643	—	7,643	6,598	—	6,598	—
Processing fees	5,049	4,542	507	8,299	7,841	458	—
Transportation fees	17,977	17,977	—	19,513	19,513	—	—
Oil and gas royalties	17,080	—	—	9,160	—	—	9,160
Property taxes	15,416	—	—	15,273	—	—	—
Minimums recognized as revenue	8,285	6,528	1,757	23,956	23,029	526	401
Override royalties	13,499	10,372	3,127	15,527	13,979	1,548	—
Other	26,319	22,112	445	20,087	18,256	394	—
Total revenues	$358,117	$274,194	$13,479	$379,147	$343,352	$9,524	$9,561

Principles of Consolidation

The financial statements include the accounts of Natural Resource Partners L.P. and its wholly owned subsidiaries, as well as BRP LLC, a joint venture with International Paper Company controlled by the Partnership. Intercompany transactions and balances have been eliminated.

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.

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.

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. Accounts are charged off when collection efforts are complete and future recovery is doubtful.

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 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 initially recorded using the FASB's business combination and asset purchase authoritative guidance depending on circumstances. 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 minerals, 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.

Equity Investments

The Partnership accounts for non-marketable investments using the equity method of accounting if the investment gives it the ability to exercise significant influence over, but not control of, an investee. Significant influence generally exists if the Partnership has an ownership interest representing between 20% and 50% of the voting stock of the investee.

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.

The Partnership's carrying value in an equity method investee company is reflected in the caption "Equity and other unconsolidated investments" in the Partnership's Consolidated Balance Sheets. The Partnership's 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 the Partnership's 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.

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.

Asset Impairment

The Partnership has developed procedures to periodically evaluate its 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. 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, the Partnership intends to closely monitor its coal and oil and gas assets and the impairment evaluation process may be completed more frequently if deemed necessary by the Partnership. Future impairment analyses could result in downward adjustments to the carrying value of the Partnership's assets.

The Partnership evaluates its 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. No impairment losses have been recognized for equity investments as of December 31, 2014.

In accordance with accounting and disclosure guidance for goodwill, the Partnership tests its 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 the reporting units, business, industry, or economic trends.

Share-Based Payment

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 service or vesting 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. Incentive Plans."

Deferred Revenue

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.

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 and environmental 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."

Revenues

Coal related revenues. Coal related revenue consist primarily of royalties as well as transportation and processing fees. Royalty revenues are recognized on the basis of tons of mineral sold by the Partnership's lessees and the corresponding revenue from those sales. Generally, the lessees make payments to the Partnership 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 the Partnership's lessees and the corresponding revenue from those sales. Generally, the lessees of the processing facilities make payments to the Partnership 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. Transportation fees are recognized on the basis of tons of material transported over the beltlines. Under the terms of the transportation contracts, the Partnership receives a fixed price per ton for all material transported on the beltlines.

Oil and Gas Revenues. Oil and gas related revenues consist of non-operated working interests, royalties and overriding royalties. Revenues related to the Partnership's non-operated working interests in oil and gas assets are recognized based on the amount actually sold. The Partnership also has capital expenditure and operating expenditure obligations associated with the non-operated working interests. The Partnership's 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 the 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. Some leases are subject to minimum annual payments or delay rentals.

Aggregates and Industrial Minerals Related Revenues. Aggregates and industrial minerals related revenues consist primarily of revenues generated by VantaCore's construction aggregates business, royalties and overriding royalties. 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 at either market or contractual prices. Aggregates royalty and overriding royalty revenues are recognized on the basis of tons of mineral sold by the Partnership's lessees and the corresponding revenue from those sales. Generally, the lessees make payments to the Partnership based on the greater of a percentage of the gross sales price or a fixed price per ton of mineral they sell. 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 the Partnership considers 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.

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 Property taxes revenue and in Property, franchise and other taxes expense, respectively, in the Consolidated Statements of Comprehensive Income.

Transportation Revenue and Expense

Shipping and handling costs invoiced to aggregate customers and paid to third-party carriers are recorded as Aggregate related revenues and Aggregates operating expenses in the Consolidated Statements of Comprehensive Income.

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.

New Accounting Standards

In May 2014, the FASB amended revenue recognition topics and created a new topic relating to revenue recognition that will supersede existing guidance under U.S. GAAP. The core principle of the new guidance is to recognize revenue when promised goods or services are transferred to the customer and in an amount that reflects the consideration expected in exchange for those goods or services. To achieve this core principle, an entity should (1) identify the contract(s) with the customer, (2) identify the performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract and (5) recognize revenue when each performance obligation is satisfied. The guidance also specifies the accounting for some costs to obtain or fulfill a contract with a customer. Disclosure requirements include sufficient qualitative and quantitative information to enable financial statement users to understand the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. The new topic is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. The guidance allows for either full adoption or a modified retrospective adoption. The Partnership is currently evaluating the requirements to determine the impact, if any, of this new topic on its financial position, results of operations and cash flows.

Other accounting standards that have been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Partnership's financial position, results of operations or cash flows.

3. Significant Acquisitions

VantaCore. Consistent with the Partnership's diversification plan, on October 1, 2014, the Partnership completed its acquisition of VantaCore Partners LLC ("VantaCore"), a privately held company specializing in the construction materials industry, for $201 million in cash and common units. Headquartered in Philadelphia, Pennsylvania, VantaCore operates three hard rock quarries, five sand and gravel plants, two asphalt plants and a marine terminal. VantaCore's current operations are located in Pennsylvania, West Virginia, Tennessee, Kentucky and Louisiana.

Transaction costs through December 31, 2014 associated with this acquisition were $2.9 million and were expensed as incurred. These expenses are reflected in General and administrative expense on the Consolidated Statements of Comprehensive Income. Included in the consolidated statements of comprehensive income for the year ended December 31, 2014 were revenue of $42.1 million and operating expenses of $32.3 million, including depreciation and depletion of $3.2 million.

The Partnership accounted for the transaction in accordance with the authoritative guidance for business combinations, which requires the acquired assets and liabilities to be recorded at fair values as of the acquisition date of October 1, 2014. The following table summarizes the purchase price and the preliminary estimated values of assets acquired and liabilities assumed and are subject to revision as the Partnership continues to complete appraisals of the fair value of the assets acquired and liabilities assumed. The preliminary allocation was based on the book values of the assets and liabilities assumed with the excess of purchase price over net book value allocated to goodwill. Adjustments to the estimated fair values may be recorded during the allocation period, not to exceed one year from the date of acquisition.

Preliminary Purchase Price Allocation—VantaCore Partners LLC Acquisition

	October 1, 2014 (In thousands)
Consideration	
Cash	$168,978
NRP common units(1)	31,604
Total consideration given	$200,582
Preliminary Allocation of Purchase Price	
Current assets	$ 37,222
Land, property and equipment	40,411
Mineral rights	87,907
Other assets	3,268
Current liabilities	(16,953)
Asset retirement obligation	(3,285)
Goodwill	52,012
Fair value of net assets acquired	$200,582

(1) Includes 2,426,690 units issued on October 1, 2014 at $13.02, closing price on that day and 813 units issued for a post-closing adjustment on December 4, 2014 at $10.48.

Sanish Field. Consistent with the Partnership's diversification plans, in November 2014, the Partnership completed the purchase of a 40% member interest in Kaiser-Whiting, LLC ("Kaiser LLC") for $339 million, subject to customary post-closing purchase price adjustments. Effective November 13, 2014, NRP Oil and Gas withdrew as a member of Kaiser LLC and an undivided 40% interest in Kaiser LLC's assets was distributed out of Kaiser LLC, and assigned directly to the Partnership. The assets distributed to the Partnership included non-operated working interests in approximately 6,086 net acres with an average working interest of approximately 14.5%. The assets, located in the Sanish Field in Mountrail County, North Dakota, are all held by production and include 192 producing wells.

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 General and administrative expense on the Consolidated Statements of Comprehensive Income. Included in the consolidated statements of comprehensive income for the year ended December 31, 2014, was revenue of $12.8 million and operating costs of $9.1 million including depletion expense of $6.7 million related to the Sanish Field acquisition.

The Partnership accounted for the transaction in accordance with the authoritative guidance for business combinations, which requires the acquired assets and liabilities to be recorded at fair values as of the acquisition date of November 12, 2014. The following table summarizes the preliminary purchase price and the preliminary estimated values of assets acquired and liabilities assumed and are subject to revision as the Partnership continues to complete appraisals of the fair value of the assets and liabilities assumed. Adjustments to the estimated fair values may be recorded during the allocation period, not to exceed one year from the date of acquisition.

Preliminary Purchase Price Allocation—Sanish Field Acquisition

	November 12, 2014 (In thousands)
Mineral rights	
Proven oil and gas properties	$298,627
Probable and possible resources	40,800
Total fair value of oil and gas properties acquired	339,427
Asset retirement obligation	(427)
Fair value of net assets acquired	$339,000

Pending the final purchase price adjustments and allocation, the net assets acquired of approximately $339.4 million are included in Mineral Rights in the accompanying Consolidated Balance Sheet. The acquisition qualifies as a business combination, and as such, the Partnership estimated the fair value of each asset acquired and liability assumed as of the acquisition date. Fair value measurements utilize assumptions of market participants. To determine the fair value of the oil and gas assets, the Partnership used an income approach based on a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk-adjusted discount rates. The Partnership determined the appropriate discount rates used for the discounted cash flow analyses by using a weighted average cost of capital from a market participant perspective plus reserve-specific risk premiums for the assets acquired. The Partnership estimated reserve-specific risk premiums taking into consideration that the related reserves are primarily oil, among other hydrocarbons. Given the unobservable nature of some of the significant inputs, they are deemed to be Level 3 in the fair value hierarchy. The initial estimate of asset retirement obligation liability was based upon historical information from Kaiser LLC.

Pro Forma Financial Information

As stated above, the Partnership completed the Sanish Field acquisition on November 13, 2014 and the VantaCore acquisition on October 1, 2014. Below are the combined results of operations for the twelve months ended December 31, 2014 and 2013 as if the acquisitions had occurred on January 1, 2013.

The unaudited pro forma results reflect significant pro forma adjustments related to funding the acquisition through the issuance of Partnership units and debt and additional depletion expense as a result of the Kaiser and VantaCore acquisitions. The pro forma results do not include any cost savings or other synergies that may result from the acquisition or any estimated costs that have been or will be incurred by the Partnership to integrate the properties acquired. The pro forma results are not necessarily indicative of what actually would have occurred if the acquisition had been completed as of the beginning of the period, nor are they necessarily indicative of future results.

	For the Years ended December 31,	
	2014	2013
	(In thousands)	
Revenue and other income except aggregate and oil and gas related revenues	$286,062	$327,558
Aggregates related revenues	137,220	152,032
Oil and gas related revenues	110,235	100,343
Total revenue	$533,517	$579,933
Net income	$122,319	$197,164
Basic and diluted net income per limited partner unit	$ 0.99	$ 1.60

Sundance. On December 19, 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. On August 9, 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 $36.1 million, capital expenditures of $22.9 and operating expenses of $12.3 million were included in the Consolidated Statements of Comprehensive Income and Consolidated Balance Sheet for the year ended December 31, 2014. For the year ended December 31, 2013, revenues and total operating expenses from the Abraxas and Sundance acquisitions were $5.4 million and $2.9 million, respectively.

4. Equity and Other Investments

The Partnership owns a 49% non-controlling equity interest in OCI Wyoming LLC (OCI Wyoming). The investment was acquired from Anadarko Holding Company (Anadarko) and its subsidiary, Big Island Trona Company for $292.5 million during 2013. OCI Wyoming's operations consist of the mining of trona ore, which, when refined, become soda ash. All soda ash is sold through an affiliated sales agent to various domestic and European customers and to American Natural Soda Ash Corporation for export primarily to Asia and Latin America. Included in fair value adjustments, is an increase in the Partnership's proportionate fair value of property, plant and equipment of $65.4 million, which will be depreciated using the straight-line method over a weighted average life of 28 years. Also, $132.7 million has been assigned to a right to mine asset which will be amortized using the units of production method. Under the equity method of accounting, these amounts are not reflected individually in the accompanying consolidated financial statements but are used to determine periodic charges to amounts reflected as income earned from the equity investment.

The acquisition agreement provides for a net present value of up to $50 million in cumulative additional contingent consideration payable by the Partnership should certain performance criteria as defined in the purchase and sale agreement be met by OCI Wyoming in any of the years 2013, 2014 or 2015. At December 31, 2014, the Partnership had accrued $14.5 million of contingent consideration that is included in Equity and other unconsolidated investments. The current portion of $3.8 million is included in Accounts payable and accrued liabilities and the long term portion of $10.7 million is included in Other non-current liabilities. During 2014 the Partnership paid a $0.5 million payment for contingent consideration.

The table below summarizes the differences between the carrying amount of the Partnership's investment and the amount of the Partnership's underlying equity in the net assets of OCI Wyoming. For both the twelve month periods ended December 31, 2014 and 2013, the Partnership derived approximately 10% of its revenues and other income from its equity investment in OCI Wyoming.

	For the Year Ended December 31,	
	2014	2013
	(In thousands)	
Net book value of NRP's equity interests	$101,311	$ 96,692
Equity and other unconsolidated investments	$264,020	$269,338
Excess of NRP's investment over net book value of NRP's equity interest	$162,709	$172,646
Income allocation to NRP's equity interests	$ 47,354	$ 37,036
Amortization of basis difference	$ (5,938)	$ (2850)
Equity and other unconsolidated investment income	$ 41,416	$ 34,186

The following summarized financial information was taken from the OCI Wyoming-prepared financial statements.

	For the Year Ended December 31,	
	2014	2013
	(In thousands)	
Sales	$465,032	$442,132
Gross profit	$118,439	$ 94,299
Net Income	$ 96,640	$ 79,655
Current assets	$200,622	$201,265
Noncurrent assets	$202,282	$194,508
Current liabilities	$ 47,704	$ 39,663
Noncurrent liabilities	$149,192	$158,779

5. Allowance for Doubtful Accounts

Activity in the allowance for doubtful accounts for the years ended December 31, 2014, 2013 and 2012 was as follows:

	2014	2013	2012
		(In thousands)	
Balance, January 1	$ 275	$ 711	$393
Provision charged to operations:			
Additions to the reserve	774	278	318
Collections of previously reserved accounts	(373)	—	—
Total charged (credited) to operations	401	278	318
Non-recoverable balances written off	—	(714)	—
Balance, December 31	$ 676	$ 275	$711

The Partnership acquired $0.5 million of allowances for doubtful accounts with its acquisition of VantaCore.

6. Inventory

The components of inventories at December 31, 2014 are as follows:

	2014
	(In thousands)
Aggregates	$4,596
Supplies and parts	1,218
	$5,814

All of the Partnership's inventory for 2014 was acquired with its acquisition of VantaCore. For the year ended December 31, 2013, the Partnership did not have inventory.

7. Plant and Equipment

The Partnership's plant and equipment consist of the following:

	December 31, 2014	December 31, 2013
	(In thousands)	
Construction in process	$ 457	$ —
Plant and equipment at cost	89,759	55,271
Less accumulated depreciation	(30,123)	(28,836)
Net book value	$ 60,093	$ 26,435

	For the Years ended December 31,		
	2014	2013	2012
	(In thousands)		
Total depreciation expense on plant and equipment	$7,631	$5,966	$6,825

During the fourth quarter of 2014, the Partnership impaired a preparation plant. The impairment charge was $0.8 million and is included in Asset impairments in the Consolidated Statements of Comprehensive Income for the year ending December 31, 2014.

8. Mineral Rights

The Partnership's mineral rights consist of the following:

	December 31, 2014	December 31, 2013
	(In thousands)	
Coal	$1,541,572	$1,574,914
Oil and gas	560,395	204,906
Aggregates	211,490	100,080
Other	15,014	15,020
Less accumulated depletion and amortization	(546,619)	(489,465)
Net book value	$1,781,852	$1,405,455

	For the years ended December 31,		
	2014	2013	2012
	(In thousands)		
Total depletion and amortization expense on mineral interests	$68,603	$54,595	$47,042

During its annual impairment analysis, the Partnership 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. While these conditions affect the Partnership's ability to lease properties, other events such as a lessee's bankruptcy, a lease cancellation, lease modifications, a permanent idling of a property could result in triggering events warranting further analysis. 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. The resulting impairment expense of $19.8 million relating to coal and aggregates mineral properties is included in Asset impairments on the Consolidated Statements of Comprehensive Income.

9. Intangible Assets

Amounts recorded as intangible assets along with the balances and accumulated amortization at December 31, 2014 and 2013 are reflected in the table below:

	December 31, 2014	December 31, 2013
	(In thousands)	
Contract intangibles	$ 82,972	$ 89,421
Other intangibles	3,004	—
Less accumulated amortization	(25,243)	(22,471)
Net book value	$ 60,733	$ 66,950

	For the Years Ended December 31,		
	2014	2013	2012
	(In thousands)		
Total amortization expense on intangible assets	$3,642	$3,816	$4,354

Included in intangible assets are certain contract intangibles with a net book value of $1.3 million at December 31, 2014 that were deemed held for sale. During the fourth quarter $52.0 million of goodwill was added relating to the VantaCore acquisition. This amount represents the preliminary residual value and will be adjusted as the Partnership continues complete appraisals of fair value relating to the acquisition.

During the second quarter of 2014, the Partnership and a lessee amended an aggregates lease, 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.

Estimated amortization expense (In thousands)	
For year ended December 31, 2015	$3,486
For year ended December 31, 2016	3,743
For year ended December 31, 2017	3,326
For year ended December 31, 2018	3,126
For year ended December 31, 2019	3,053

10. Long-Term Debt

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 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.

Long-term debt consists of the following:

	December 31, 2014	December 31, 2013
	(In thousands)	
NRP LP Debt:		
$425 million 9.125% senior notes, with semi-annual interest payments in April and October, maturing October 2018, $300 million issued at 99.007% and $125 million issued at 99.5%	$ 422,167	$ 297,170
Opco Debt:		
$300 million floating rate revolving credit facility, due August 2016	200,000	20,000
$200 million floating rate term loan, due January 2016	75,000	99,000
4.91% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2018	18,467	23,084
8.38% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, maturing in March 2019	107,143	128,571
5.05% senior notes, with semi-annual interest payments in January and July, with annual principal payments in July, maturing in July 2020	46,154	53,846
5.31% utility local improvement obligation, with annual principal and interest payments, maturing in March 2021	1,345	1,538
5.55% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2023	24,300	27,000
4.73% senior notes, with semi-annual interest payments in June and December, with scheduled principal payments beginning December 2014, maturing in December 2023	67,500	75,000
5.82% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, maturing in March 2024	150,000	165,000
8.92% senior notes, with semi-annual interest payments in March and September, with scheduled principal payments beginning March 2014, maturing in March 2024	45,455	50,000
5.03% senior notes, with semi-annual interest payments in June and December, with scheduled principal payments beginning December 2014, maturing in December 2026	161,538	175,000
5.18% senior notes, with semi-annual interest payments in June and December, with scheduled principal payments beginning December 2014, maturing in December 2026	46,154	50,000
NRP Oil and Gas Debt:		
Reserve-based revolving credit facility due 2019	110,000	—
Total debt	1,475,223	1,165,209
Less—current portion of long term debt	(80,983)	(80,983)
Long-term debt	$1,394,240	$1,084,226

NRP LP Debt

Senior Notes. In September 2013, NRP LP, together with NRP Finance as co-issuer, issued $300 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 of approximately $289.0 million were used to repay all of the outstanding borrowings under Opco's revolving credit facility and $91.0 million of Opco's term loan. The senior notes call for semi-annual interest payments on April 1 and October 1 of each year, beginning on April 1, 2014. The notes will mature on October 1, 2018.

In October 2014, NRP LP, together with NRP Finance as co-issuer, issued an additional $125 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 after expenses from the issuance of the Senior Notes of approximately $122.6 million 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 as April 1 and October 1 of each year, beginning on April 1, 2015. The notes will mature on October 1, 2018.

The indenture for the senior notes contains covenants that, among other things, limit the ability of the 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.

Opco Debt

Senior Notes. Opco made principal payments of $80.8 million on its senior notes during the year ended December 31, 2014. The Opco senior note purchase agreement contains 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 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 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.

Revolving Credit Facility. The weighted average interest rates for the debt outstanding under Opco's revolving credit facility for the twelve months ended December 31, 2014 and year ended December 31, 2013 were 1.98% and 2.23%, respectively. Opco incurs a commitment fee on the undrawn portion of the revolving credit facility at rates ranging from 0.18% to 0.40% per annum. The facility includes an accordion feature whereby Opco may request its lenders to increase their aggregate commitment to a maximum of $500 million on the same terms.

Opco's revolving credit facility contains covenants requiring Opco to maintain:

- a ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the credit agreement) not to exceed 4.0 to 1.0 and,
- a ratio of consolidated EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated lease operating expense) of not less than 3.5 to 1.0 for the four most recent quarters.

Term Loan Facility. During 2013, Opco issued $200 million in term debt. The weighted average interest rates for the debt outstanding under the term loan for the twelve months ended December 31, 2014 and 2013 were 2.22% and 2.43% respectively. Opco repaid $101 million in principal under the term loan during the third quarter of 2013 and an additional $24 million during the fourth quarter of 2014. Repayment terms call for the remaining outstanding balance of $75 million to be paid on January 23, 2016. The debt is unsecured but guaranteed by the subsidiaries of Opco.

Opco's term loan contains covenants requiring Opco to maintain:

- a ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the credit agreement) not to exceed 4.0 to 1.0 and,
- a ratio of consolidated EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated lease operating expense) of not less than 3.5 to 1.0 for the four most recent quarters.

NRP Oil and Gas Debt

Revolving Credit Facility. In August 2013, NRP Oil and Gas entered into a 5-year, $100 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 be a $500 million facility with an initial borrowing base of $137 million and will mature on November 12, 2019. 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. At December 31, 2014, there was $110.0 million outstanding under the credit facility. The weighted average interest rate for the debt outstanding under the credit facility for the twelve months ended December 31, 2014 was 2.37%.

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.

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.

Consolidated Principal Payments

The consolidated principal payments due are set forth below:

	NRP LP	Opco			NRP Oil and Gas	
	Senior Notes	Senior Notes	Credit Facility	Term Loan	Credit Facility	Total
	(In thousands)					
2015	$ —	$ 80,983	$ —	$ —	$ —	$ 80,983
2016	—	80,983	200,000	75,000	—	355,983
2017	—	80,983	—	—	—	80,983
2018	425,000(1)	80,983	—	—	—	505,983
2019	—	76,366	—	—	110,000	186,366
Thereafter	—	267,758	—	—	—	267,758
	$425,000	$668,056	$200,000	$75,000	$110,000	$1,478,056

(1) The 9.125% senior notes due 2018 were issued at a discount and as of December 31, 2014 were carried at $422.2 million.

NRP LP, Opco and NRP Oil and Gas were in compliance with all terms under their long-term debt as of December 31, 2014. Opco's revolving credit facility and term loan facility both mature in 2016. While the Partnership believes it has sufficient liquidity to meet its current financial needs, the Partnership will be required to repay or refinance the amounts outstanding under Opco's credit facilities prior to their maturity. While the Partnership believes it will be able to refinance these amounts, it may not be able to do so on terms acceptable to them, if at all, or the borrowing capacity under Opco's revolving credit facility may be substantially reduced. The Partnership's ability to refinance these amounts may depend in part on its ability to access the debt or equity capital markets, which will be challenging in the current commodity price environment.

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 amount of the Partnership's financial instruments included in accounts receivable and accounts payable approximates their fair value due to their short-term nature except for the accounts receivable—affiliate relating to the Sugar Camp override that includes both current and long-term portions. The Partnership's cash and cash equivalents include money market accounts and are considered a Level 1 measurement. The fair market value and carrying value of the contractual override and long-term senior notes are as follows:

	Fair Value As Of		Carrying Value As Of	
	December 31, 2014	December 31, 2013	December 31, 2014	December 31, 2013
	(In thousands)			
Assets				
Sugar Camp override, current and long-term	$ 5,162	$ 6,852	$ 4,870	$ 6,063
Liabilities				
Long-term debt, current and long-term	$1,096,520	$1,071,880	$1,090,223	$1,046,209

The fair value of the Sugar Camp override and long-term debt is estimated by discounting expected future cash flows at a comparable term risk-free treasury interest rate plus a market rate component comparable to the yield premium observed on debt securities of similar risk and maturity, which is a Level 3 measurement. Since the Partnership's credit facilities and term loan are variable rate debt, their fair values approximate their carrying amounts.

12. Related Party Transactions

Reimbursements to Affiliates of the Partnership's 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. All 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. The Partnership had accounts payable of $0.4 million with Western Pocahontas Properties and $0.6 million with Quintana Minerals Corporation.

The reimbursements to affiliates of the Partnership's general partner for services performed by Western Pocahontas Properties and Quintana Minerals Corporation are as follows:

	For the Years Ended December 31,		
	2014	2013	2012
		(In thousands)	
Reimbursement for services	$11,798	$11,480	$9,791

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

Transactions with Cline Affiliates

Various companies controlled by Chris Cline, including Foresight Energy LP, lease coal reserves from the Partnership, and the Partnership provides coal transportation services to them for a fee. Mr. Cline, both individually and through another affiliate, Adena Minerals, LLC, owns a 31% interest (unaudited) in the Partnership's general partner, as well as 4,917,548 common units (unaudited) at December 31, 2014. At December 31, 2014, the Partnership had accounts receivable totaling $9.2 million from Cline affiliates. In addition, the overriding royalty and the lease of the loadout facility at the Sugar Camp mine are classified as contracts receivable of $50.0 million on the Partnership's Consolidated Balance Sheets. Revenues from the Cline affiliates are as follows:

	For The Years Ended December 31,		
	2014	2013	2012
		(In thousands)	
Coal royalty revenues	$52,415	$54,322	$48,567
Processing and transportation fees	20,594	19,258	21,923
Minimums recognized as revenue	—	3,477	17,785
Override revenue	2,847	3,226	4,066
Other revenue	5,690	8,149	—
	$81,546	$88,432	$92,341

As of December 31, 2014, the Partnership had received $86.8 million in minimum royalty payments that have not been recouped by Cline affiliates, of which $16.0 million was received during 2014.

During the fourth quarter of 2012, the Partnership recognized an asset impairment of $2.6 million related to the assets at the Gatling, WV location, a location leased to an affiliate of Chris Cline, due to receiving a termination notice in December 2012 that the lease was cancelled as of June 2013.

During 2014 and 2013, the Partnership recognized gains of $5.7 million and $8.1 million on reserve swaps in Illinois with Williamson Energy, a subsidiary of Foresight Energy LP. The gains are reflected in the table above in the "Other revenue" line. The fair value of the reserves was estimated using Level 3 cash flow approach. The expected cash flows were developed using estimated annual sales tons, forecasted sales prices and anticipated market royalty rates. The tons received during 2014 and 2013 were fully mined during each of those years, while the tons exchanged are not included in the current mine plans. The gains are located in Coal related revenues on the Consolidated Statements of Comprehensive Income.

The Partnership entered into a lease agreement related to the rail loadout and associated facilities at Sugar Camp that has been accounted for as a direct financing lease. Total projected remaining payments under the lease at December 31, 2014 are $86.3 million with unearned income of $39.0 million. The net amount receivable under the lease as of December 31, 2014 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—affiliate on the accompanying Consolidated Balance Sheets.

In a separate transaction, the Partnership acquired a contractual overriding royalty interest from a Cline affiliate that provides for payments based upon production from specific tons at the 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, 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.

Note to Cline Trust Company, LLC

Donald R. Holcomb, one of the Partnership's directors, is a manager of Cline Trust Company, LLC, which owns approximately 5.35 million of the Partnership's common units and $20 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 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. Cline Trust Company, LLC purchased the $20 million of the Partnership's 9.125% Senior Notes due 2018 in the Partnership's offering of $125 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, 2014 and is included with the Partnership's long term debt.

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. 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 NRP's conflicts policy.

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.

For the years ended December 31, 2014, 2013 and 2012, the revenues from Taggart prior to the sale to Forge were as follows:

	For the Years Ended December 31,		
	2014	2013	2012
	(In thousands)		
Processing revenue	$—	$1,761	$5,580

During the third quarter of 2012, the Partnership sold a preparation plant back to Taggart Global for $12.3 million. The Partnership received $10.5 million in cash and a note receivable from Taggart, payable over three years for the balance. The Partnership recorded a gain of $4.7 million included in Coal related revenues on the Consolidated Statements of Income during 2012. The net book value of the asset sold was $7.6 million. During 2013, the note receivable that the Partnership held was paid in full.

At December 31, 2014, a fund controlled by Quintana Capital owned a majority interest in Corsa Coal Corp., 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. Revenues from Corsa are as follows:

	For the Years Ended December 31,		
	2014	2013	2012
	(In thousands)		
Coal royalty revenues	$3,013	$4,594	$3,486

At each of December 31, 2013 and 2014, the Partnership also had accounts receivable totaling $ 0.3 million from Corsa.

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 of the beginning and ending carrying amounts of the Partnership's asset retirement obligations. The table does not include the short-term balance of $68,000, which is included in Accounts payable and accrued 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,	
	2014	2013
	(In thousands)	
Balance, January 1	$ 39	$39
Liabilities incurred in current period	4,697	—
Accretion expense	237	—
Balance, December 31	$4,973	$39

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.

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, 2014. 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. In addition, West Virginia has established a fund to satisfy any shortfall in reclamation obligations. 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.

15. Major Lessees

The Partnership has the following lessees that generated in excess of ten percent of total revenues in any one of the years ended December 31, 2014, 2013, and 2012. Revenues from these lessees are as follows:

	For the Years Ended December 31,					
	2014		2013		2012	
	Revenues	Percent	Revenues	Percent	Revenues	Percent
			(Dollars in thousands)			
Foresight Energy and affiliates	$81,546	20.4%	$88,432	24.7%	$92,341	24.4%
Alpha Natural Resources	$48,783	12.2%	$55,147	15.4%	$81,077	21.4%

In 2014, the Partnership derived 32.6% of its revenue from the two companies listed above. As a result, the Partnership has a significant concentration of revenues with those lessees, although in most cases, with the exception of the Williamson mine operated by Foresight Energy, the exposure is spread over a number of different mining operations and leases. Foresight's Williamson mine alone was responsible for approximately 10.2%, 13.0% and 12.4% of the Partnership's total revenues for 2014, 2013 and 2012, respectively.

Approximately 50% of the Partnership's accounts receivable result from amounts due from third-party companies in the coal industry, with approximately 30% of the Partnership's total revenues being attributable to coal royalty revenues from Appalachia. This concentration of customers may impact the Partnership's overall credit risk, either positively or negatively, in that these entities may be collectively affected by the same changes in economic or other conditions. Receivables are generally not collateralized.

16. 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.

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.

A summary of activity in the outstanding grants for the year ended December 31, 2014 are as follows:

Outstanding grants at the beginning of the period	1,012,984
Grants during the period	454,884
Grants vested and paid during the period	(285,500)
Forfeitures during the period	(28,975)
Outstanding grants at the end of the period	1,153,393

Grants typically vest at the end of a four-year period and are paid in cash upon vesting. The liability fluctuates with the market value of the Partnership common units and because of changes in estimated fair value determined each quarter using the Black-Scholes option valuation model. Risk free interest rates and historical volatility are reset at each calculation based on current rates corresponding to the remaining vesting term for each outstanding grant and ranged from 0.26% to 1.06% and 33.40% to 43.43%, respectively at December 31, 2014. The Partnership's cumulative average dividend rate of 7.46% was used in the calculation at December 31, 2014. The Partnership accrued expenses related to its plans to be reimbursed to its general partner of $1.0 million, $9.6 million and $2.9 million for the years ended December 31, 2014, 2013 and 2012, respectively. In connection with the Long-Term Incentive Plans, cash payments of $6.5 million, $7.0 million and $6.6 million were paid during each of the years ended December 31, 2014, 2013, and 2012, respectively. The grant date fair value was $17.73, $25.27 and $33.38 per unit for awards in 2014, 2013 and 2012, respectively.

In connection with the phantom unit awards, the CNG committee also granted tandem Distribution Equivalent Rights, or DERs, which entitle the holders to receive distributions equal to the distributions paid on the Partnership's common units. The DERs are payable in cash upon vesting but may be subject to forfeiture if the grantee ceases employment prior to vesting.

The unaccrued cost, associated with unvested outstanding grants and related DERs at December 31, 2014, was $5.2 million.

17. Subsequent Events (Unaudited)

The following represents material events that have occurred subsequent to December 31, 2014 through the time of the Partnership's filing of its Annual Report on Form 10-K with the SEC:

Distributions

On January 20, 2015, the Partnership declared a distribution of $0.35 per unit that was paid on February 13, 2015 to unitholders of record on February 5, 2015.

Dividends and Distributions Received From Unconsolidated Equity and Other Investments

Subsequent to December 31, 2014, the Partnership received $10.9 million in cash distributions from OCI Wyoming.

18. Supplemental Financial Data (Unaudited)

Shown below are selected unaudited quarterly data.

Selected Quarterly Financial Information
(In thousands, except per unit data)

2014	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues and other income	$ 80,309	$ 90,561	$ 91,609	$137,273
Depreciation, depletion and amortization	$ 14,647	$ 16,350	$ 18,621	$ 30,258
Asset impairment	$ —	$ 5,624	$ —	$ 20,585
Income from operations	$ 52,439	$ 50,403	$ 55,027	$ 31,050
Net income	$ 32,605	$ 31,407	$ 36,173	$ 8,645
Net income per limited partner unit	$ 0.29	$ 0.28	$ 0.32	$ 0.07
Weighted average number of common units outstanding	109,848	110,403	111,244	121,449

2013	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues and other income	$ 94,332	$ 86,804	$ 82,237	$ 94,744
Depreciation, depletion and amortization	$ 14,762	$ 17,411	$ 17,852	$ 14,352
Income from operations	$ 62,528	$ 55,332	$ 51,624	$ 66,752
Asset impairment	$ 291	$ 443	$ —	$ —
Gain on Department of Highway condemnation	$ —	$ —	$ —	$ 10,370
Net income	$ 47,906	$ 41,065	$ 36,126	$ 46,981
Net income per limited partner unit	$ 0.43	$ 0.37	$ 0.32	$ 0.42
Weighted average number of common units outstanding	108,887	109,812	109,812	109,812

19. Supplemental Oil and Gas Data (Unaudited)

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

Capitalized Costs:

	For The Year Ended December 31, 2014
	(In Thousands)
Proven properties	$361,554
Unproven properties	46,400
Intangible drilling costs	25,217
Wells and related equipment	5,382
Gathering assets	—
Well plugging	—
Total property, plant, and equipment	438,553
Accumulated depreciation, depletion, and amortization	(18,993)
Net capitalized costs	$419,560

Costs incurred for property acquisition, exploration, and development:

	For the Year Ended December 31, 2014
	(In thousands)
Property acquisitions	
Proven properties	$298,627
Unproven properties	40,800
Development	5,340
Exploration	—
Total	$344,767

Results of Operations for Producing Activities:

	For the Year Ended December 31, 2014
	(In thousands)
Production revenue	$48,834
Royalty and overriding royalty revenue(1)	10,732
Total oil and gas related revenue	59,566
Operating costs and expense:	
Depreciation, depletion and amortization	23,936
General and administrative	3,400
Property, franchise and other taxes	5,529
Lease operating expenses	9,144
Total operating costs and expense	42,009
Total income from operations	$17,557

(1) Includes $1.9 million of nonproduction revenues including lease bonus payments.

Production and Price History

The following table sets forth summary information concerning the Partnership's production results, average sales prices and production costs for the year ended December 31, 2014 for the Partnership's Williston Basin properties. Production and price information for the years ended December 31, 2013 and 2012 is not included, as the Partnership's oil and natural gas producing activities were not material to the Partnership's results of operations for those years.

	For The Year Ended December 31, 2014		
	Williston Basin(1)	Royalty and Overriding Royalty Interests(2)	Total
Net Production Volumes:			
Crude oil (MBbl)	578	33	611
NGLs (MBbl)	53	18	71
Natural gas (MMcf)	408	1,313	1,721
Average sales prices:			
Crude oil ($/Bbl)	$77.85	$82.91	$78.12
NGLs ($/Bbl)	$33.64	$34.56	$33.87
Natural gas ($/Mcf)	$ 5.04	$ 4.17	$ 4.37
Average costs ($/Boe):			
Production expenses	$13.08	—	$13.08
Ad valorem and severance taxes	$ 7.91	—	$ 7.91
General and administrative expense	$ 4.86	—	$ 4.86
DD&A expense	$25.73	$22.06	$24.70

(1) Represents volume, price and cost information relating to the Partnership's non-operated Williston Basin working interest properties.

(2) Represents information relating to the Partnership's royalty and overriding royalty interests in oil and gas properties. These interests are recorded net of costs.

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, 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.

The following tables set forth the Partnership's estimated proved and related standardized measure of discounted cash flows by reserve category as of December 31, 2014. Netherland Sewell prepared its report covering properties representing 100% of the Partnership's estimated proved reserves as of December 31, 2014. Prices were calculated using the unweighted average of the first-day-of-the-month pricing for the twelve months ended December 31, 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.

	Estimated Proved Reserves as of December 31, 2014(1)				
	Crude Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total Proved Reserves (MBoe)(2)	Standardized Measure of Discounted Cash Flows(3)
					(in thousands)
Proved Developed Producing	8,918	1,093	13,069	12,189	$286,179
Proved Developed Non-Producing	12	5	92	32	655
Proved Undeveloped	1,053	131	1,209	1,386	18,363
Total	9,983	1,229	14,370	13,607(4)	$305,197

(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) 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.

(4) Includes 12,144 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 10% of which were proved undeveloped reserves.

The following table represents the capitalized development well cost activity as indicated:

	For the Year Ended December 31, 2014
	(In Thousands)
Costs pending the determination of proved reserves at December 31, 2014	
For a period one year or less	$5,340
For a period greater than one year but less than five years	—
For a period greater than five years	—
Total	$5,340

	For the Year Ended December 31, 2014
	(In Thousands)
Costs reclassified to wells, equipment and facilities based on the determination of proved reserves	$5,177
Costs expensed due to determination of dry hole or abandonment of project	—

Standardized Measure of Discounted Future Net Cash Flows:

	For the Year Ended December 31, 2014
	(In Thousands)
Future Cash Flows:	
Revenues	$920,454
Production costs	312,666
Development costs	20,072
Future Net Cash Flows	587,716
Discount to present value at a 10% annual rate	282,519
Total standardized measure of discounted net cash flows	$305,197

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, 2014. 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 are effective 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, 2014 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, 2014. 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.

Our management's evaluation of the effectiveness of our internal control over financial reporting does not include the internal controls of VantaCore Partners LLC, which is included in the 2014 consolidated financial statements of Natural Resource Partners L.P. and constituted $219.7 million and $204.5 of total and net assets, respectively, as of December 31, 2014 and $42.1 million and $3.5 million of revenues and net income, respectively, for the year then ended.

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, 2014, 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.

As indicated in the accompanying Management's Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of VantaCore Partners LLC, which is included in the 2014 consolidated financial statements of Natural Resource Partners L.P. and constituted $219.7 million and $204.5 of total and net assets, respectively, as of December 31, 2014 and $42.1 million and $3.5 million of revenues and net income, respectively, for the year then ended. Our audit of internal control over financial reporting of Natural Resource Partners L.P. also did not include an evaluation of the internal control over financial reporting of VantaCore.

In our opinion, Natural Resource Partners L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, 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, 2014 and 2013, and the related consolidated statements of comprehensive operations, partners' equity and cash flows for each of the three years in the period ended December 31, 2014 and our report dated February 27, 2015 expressed an unqualified opinion there thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 27, 2015

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 February 27, 2015. 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, five of whom must be independent 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.	67	Chairman of the Board and Chief Executive Officer
Wyatt L. Hogan(1)	43	President
Craig W. Nunez	53	Chief Financial Officer and Treasurer
Kevin F. Wall(2)	58	Chief Operating Officer
Kevin J. Craig	46	Executive Vice President, Coal
Dennis F. Coker	47	Vice President, Aggregates
David M. Hartz	41	Vice President, Oil and Gas
Kathy H. Roberts	63	Vice President, Investor Relations
Kathryn S. Wilson	40	Vice President, General Counsel and Secretary
Gregory F. Wooten	58	Vice President, Chief Engineer
Kenneth Hudson	60	Controller
Robert T. Blakely	73	Director
Russell D. Gordy	64	Director
Donald R. Holcomb	58	Director
Robert B. Karn III	73	Director
S. Reed Morian	69	Director
Richard A. Navarre	54	Director
Corbin J. Robertson, III	44	Director
Stephen P. Smith	53	Director
Leo A. Vecellio, Jr.	68	Director

(1) Mr. Hogan will become President and Chief Operating Officer effective March 1, 2015.

(2) Mr. Wall will retire as Chief Operating Officer effective March 1, 2015.

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 World Health and Golf Association. In 2006, Mr. Robertson was inducted into the Texas Business Hall of Fame.

Wyatt L. Hogan has served as President of GP Natural Resource Partners LLC since September 2014, and effective March 1, 2015, Mr. Hogan will become President and Chief Operating Officer 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 OCI Wyoming LLC. Mr. Hogan also serves as a member of the Boards of the National Mining Association and the American Coalition for Clean Coal Electricity.

Craig W. Nunez has served as Chief Financial Officer and Treasurer of GP Natural Resource Partners LLC since January 1, 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, he has been a FINRA-registered Investment Advisor Representative with Searle & Co since July 2012 and has 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 1999 to February 2006.

Kevin F. Wall has served as Chief Operating Officer of GP Natural Resource Partners LLC since September 2014 and will retire from such position effective March 1, 2015. Mr. Wall served as Executive Vice President, Operations of GP Natural Resource Partners LLC from December 2008 through August 2014 and as Vice President—Engineering for GP Natural Resource Partners LLC from 2002 to 2008. Mr. Wall has also served as Vice President—Engineering of the general partner of Western Pocahontas Properties Limited Partnership since 1998, of the general partner of Great Northern Properties Limited Partnership since 1992, and of New Gauley Coal Corporation since 1998. Mr. Wall also represents NRP as one of its appointees to the Board of Managers of OCI Wyoming LLC. He has performed duties in the land management, planning, project evaluation, acquisition and engineering areas since 1981. He is a Registered Professional Engineer in West Virginia and is a member of the American Institute of Mining, Metallurgical, and Petroleum Engineers and of the National Society of Professional Engineers. Mr. Wall also serves on the Executive Committee for the National Council of Coal Lessors, the Board of Directors of Leadership Tri-State and the Board of the Virginia Center for Coal and Energy Research and is a past president of the West Virginia Society of Professional Engineers.

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 joined NRP in 2005 from CSX Transportation, where he served as Terminal Manager for the West Virginia Coalfields. Mr. Craig has extensive experience in business development, operations, finance and marketing within the coal industry. 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 is currently serving 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.

Dennis F. Coker is Vice President, Aggregates of GP Natural Resource Partners LLC. Mr. Coker joined NRP in March 2008 from Hanson Building Materials America, where he had been employed since 2002, and most recently served as Director, Corporate Development. Mr. Coker has 19 years of experience in the mining and materials industry, with the last 15 years focused on corporate development activity. Mr. Coker also represents NRP as one of its appointees to the Board of Managers of OCI Wyoming LLC. Mr. Coker also serves as Treasurer on the Executive Board of the National Stone Sand and Gravel Association.

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 National Association of Publicly Traded Partnerships and has served on the local board of directors of the National Investor Relations Institute and maintained professional affiliations with various energy industry organizations. 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.

Kenneth Hudson has served as the Controller of GP Natural Resource Partners LLC since 2002. He has served as Controller of the general partner of Western Pocahontas Properties Limited Partnership and of New Gauley Coal Corporation since 1988 and of the general partner of Great Northern Properties Limited Partnership since 1992. He was also Controller of Blackhawk Mining Co., Quintana Coal Co. and other related operations from 1985 to 1988. Prior to that time, Mr. Hudson worked in public accounting.

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. 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 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 Boards of Trustees of numerous publicly listed closed-end funds, exchange traded funds and mutual 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 his retirement in 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, and is an Advisory Board member for Secure Energy, LLC. He is a member of the Hall of Fame of the College of Business, 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.

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 been the Executive Vice President and Chief Financial Officer for NiSource, Inc. since June 2008. Mr. Smith is also the Chief Financial Officer and Chief Accounting Officer and a Director of the general partner of Columbia Pipeline Partners LP, which completed its initial public offering in February 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.

Corporate Governance

Board Attendance and Executive Sessions

The Board met nine times in 2014. During that period, every director attended all of the Board meetings, with the exception of Mr. Blakely, who missed two meetings, Mr. Morian, who missed one meeting, and Corbin J. Robertson, III, who missed one meeting. During 2014, 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 2014. 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, 601 Jefferson Street, Suite 3600, 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 2014, 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 2014, 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 at which candid discussions of financial management, accounting and internal control issues took place.

The Committee approved the engagement of Ernst & Young LLP as our independent auditors for the year ended December 31, 2014 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 AU Section 380, *Communication 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 2014 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 2014, 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, 2014, 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 December 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 2014. On December 22, 2014, S. Reed Morian filed a Form 4 reporting the purchase of 20,000 common units in the open market on December 11, 2014 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 2014, 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, 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.

Executive Officer Compensation Strategy and Philosophy

Under our partnership agreement, we are required to distribute all of our available cash each quarter. Our primary business objective is to generate cash flows at levels that can sustain long-term quarterly cash distributions to our investors. Our executive officer compensation strategy has been designed to motivate and retain our executive officers and to align their interests with those of our unitholders. Our objectives in determining the compensation of our executive officers are to retain qualified people and encourage them to build the partnership in a way that ensures the stability of the cash distributions to our unitholders and growth in our asset base. We do not tie our compensation to achievement of specific financial targets or fixed performance criteria, but rather evaluate the appropriate compensation on an annual basis in light of our overall business objectives.

In accordance with our objective of sustaining and increasing the quarterly distribution over the long-term, we believe that optimal alignment between our unitholders and our executive officers is best achieved by compensating our executive officers through sharing a percentage of distributions received by our general partner and through distribution equivalent rights ("DERs") tied to long-term equity-based compensation. The DERs are contingent rights, granted in tandem with specific 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 its units during the period such phantom unit are outstanding. Our compensation for executive officers consists of four primary components:

- base salaries;
- annual cash incentive awards, including bonuses and cash payments made by our general partner based on a percentage of the cash it receives from common units that the general partner owns;
- long-term equity incentive compensation; and
- perquisites and other benefits.

Mr. Robertson does not receive a salary or an annual bonus in his capacity as Chief Executive Officer. Rather, for the reasons discussed in greater detail below, Mr. Robertson is compensated exclusively through long-term phantom unit grants awarded by the CNG Committee and through sharing a percentage of the distributions received by the general partner. 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 December of each year, our CNG Committee reviews the performance of the executive officers and the amount of time expected to be spent by each NRP officer on NRP business, and determines the salaries for each officer for the upcoming year. All of our executive officers other than Mr. Robertson spend 93% or more of their time on NRP matters, and NRP bears the allocated cost of their time. Mr. Robertson has historically spent approximately 50% of his time on NRP matters.

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. 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 issued phantom units 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 typically vest four years from the date of grant. In connection with the phantom unit awards, the CNG Committee has also granted tandem DERs, which entitle the holders to receive upon vesting of the related phantom units an amount in cash equal to the distributions paid on our common units during the period in which the phantom units were outstanding. The DERs have a four-year vesting period. Through these awards, each executive officer’s interest is aligned with those of our unitholders in sustaining and increasing our quarterly cash distributions over the long-term, increasing the value of our common units, and maintaining a steady growth profile for NRP.

Role of Compensation Experts

The CNG Committee did not retain any consultants to evaluate compensation of officers or directors in 2014. 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.

Role of Our Executive Officers in the Compensation Process

Mr. Robertson provided recommendations to the CNG Committee in its evaluation of the 2014 compensation programs for our executive officers. Mr. Wall, our Chief Operating Officer, provided Mr. Hogan, our President, with recommendations relating to the executive officers that are based in Huntington. Mr. Hogan then reviewed these recommendations and provided these recommendations, along with recommendations relating to the executive officers based in Houston, to Mr. Robertson. 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 2014 executive officer compensation programs.

Evaluation of 2014 Performance; Components of Compensation

2014 Performance

Although we reduced our quarterly distribution in January 2014 primarily due to continued pressure on the coal industry, we used the additional liquidity to fund a portion of the purchase prices of the acquisition of

VantaCore Partners LLC, an operating construction aggregates producer, and the acquisition of additional non-operated working interests in oil and gas assets in the Williston Basin of North Dakota from an affiliate of Kaiser-Francis Oil Company. These efforts are reflective of NRP management's desire to continue to grow and diversify the partnership and create value for our unitholders.

During 2014, NRP's financial performance met or exceeded the guidance issued to the public markets in January 2014 as confirmed in August 2014. We recorded revenues and other income in 2014 of $388.9 million, which were 8.5% higher than our revenues in 2013. In addition, although distributable cash flow was down 31% compared to 2013, our distribution coverage ratio for 2014 was approximately 1.3x.

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 determined generally to increase 2015 salaries for the management team, with the exceptions of Mr. Dunlap, who retired as our Chief Financial Officer and Treasurer effective January 1, 2015, and Mr. Wall, who will retire as our Chief Operating Officer effective March 1, 2015. The amount of the increases varied among the management team members based on their expected contributions to the company during 2015.

Annual Cash Incentive Awards

Each named executive officer, participated in two cash incentive programs in 2014, 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 2015 by the CNG Committee based on similar criteria used to evaluate the annual base salaries. The bonuses awarded with respect to 2014 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 as a result of NRP's strong performance during 2014 in a difficult commodity price environment and as a result of their contributions to the company during 2014, including with respect to the two significant acquisitions completed during the year. The increase in Mr. Hogan's bonus also reflects his additional responsibilities as President. The bonuses for Mr. Dunlap, who retired as our Chief Financial Officer and Treasurer effective January 1, 2015, and Mr. Wall, who will retire as our Chief Operating Officer effective March 1, 2015 were kept constant at 2013 levels.

Under the second cash incentive program, our general partner has set aside 7.5% of the cash distributions it receives on an annual basis with respect to distributions on 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 amount of the 7.5% that is 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. Because they are ultimately reimbursed by the general partner and not NRP, the incentive payments made with respect to this program do not have any impact on our financial statements or cash available for distribution to our unitholders. Since the cost of these awards is not borne by NRP, we have not disclosed the amounts of these awards in the Summary Compensation Table, but have included the amounts separately in a footnote to the table. With the exception of Mr. Hogan, whose amount decreased by less than 2% over 2013, and Ms. Wilson, who was not a named executive officer with respect to 2013, the amounts received by the named executive officers, including Mr. Robertson, were significantly lower for 2014 as compared to 2013. The per unit distribution paid by NRP during the calendar year ended December 31, 2014 was 37% lower than that paid in 2013, resulting in a decreased overall amount allocated to the executive officers. The amount received by Mr. Hogan reflected his significantly increased responsibility and contributions as President of NRP but was approximately 28% less than the amount received by Mr. Carter, NRP's former President and Chief Operating Officer, with respect to 2013. The remaining portion of the cash awards under this program was allocated equally among NRP's other executive officers, including Mr. Robertson. We believe that these awards align the interests of our executive officers directly with our unitholders.

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. We consider long-term equity-based incentive compensation to be the most important element of our compensation program for executive officers because we believe that these awards keep 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.

Consistent with this approach, we have 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.

Our CNG Committee has generally 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 have structured the phantom unit awards so that our executive officers and directors directly benefit along with our unitholders when our unit price increases, and experience reductions in the value of their incentive awards when our unit price declines. Similarly, because the awards are forfeited by the executives upon termination of employment in most instances, the long-term vesting component of these awards encourages our senior executives and employees to remain with NRP over an extended period of time, thereby ensuring continuity in our management team. This strategy has proved effective as NRP's senior management team has experienced no turnover since the initial public offering.

In determining 2015 LTIP awards for NRP's executive officers, at the February 2015 meeting, the CNG Committee considered the financial performance of NRP for the year ended December 31, 2014 as well as the projected financial performance of NRP for the year ending December 31, 2015. When determining the 2015 LTIP awards, the CNG Committee's goal was to incentivize the management team during this difficult commodity price cycle and foster the retention of such officers. Mr. Robertson's 2015 award was increased consistent with the level of increases in awards to him in prior years. Mr. Dunlap's 2015 award was lower than the previous year due to his retirement from NRP effective January 1, 2015 and the expectation that he will allocate approximately 50% of his time to NRP during 2015. Mr. Hogan's 2015 award was increased relative to 2014 in order to reflect his increased responsibilities as President of NRP. Mr. Wall did not receive a 2015 award due to his retirement from NRP effective March 1, 2015. However, the CNG Committee has determined that all of Mr. Wall's outstanding LTIP awards will be vested upon his retirement from NRP effective March 1, 2015. Ms. Wilson's 2015 award was increased to a level consistent with that of NRP's other executive officers.

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 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. The payments made to Messrs. Dunlap, Hogan, Wall and Carter under the defined contribution plan exceeded $10,000 in each of 2012, 2013 and 2014, but did not exceed $25,000 for any individual in any year. The payment made to Ms. Wilson, who was not a named executive officer in 2012 or 2013, under the defined contribution plan in 2014 exceeded $10,000 but did not exceed $25,000. None of NRP, Quintana or Western Pocahontas maintains a pension plan or a defined benefit retirement plan. As noted in the Summary Compensation Table, in 2012, 2013 and 2014 we also reimbursed Quintana and Western Pocahontas for car allowances provided to Messrs. Dunlap, Wall and Carter.

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, 2014, our named executive officers held 272,425 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 2012, 2013 or 2014. 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 of directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the year ended December 31, 2014.

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 expense in 2012, 2013 and 2014 based on time allocated by each individual to Natural Resource Partners. In 2014, Messrs. Robertson, Dunlap, Hogan and Wall and Ms. Wilson spent approximately 50%, 96%, 100%, 95% and 93%, respectively, of their time on NRP matters. Mr. Carter retired as President and Chief Operating Officer effective September 1, 2014. Prior to that, Mr. Carter spent approximately 97% of this time on NRP matters. Phantom unit awards in the table below represent all amounts paid to the named executive officers in 2014 with respect to the vesting of such awards, as NRP bears 100% of the costs of all awards under the LTIP.

Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($)	Phantom Unit Awards(4) ($)	All Other Compensation(5) ($)	Total ($)
Corbin J. Robertson, Jr.	2014	—	—	595,728	—	595,728
Chairman and CEO	2013	—	—	712,000	—	712,000
	2012	—	—	830,400	—	830,400
Dwight L. Dunlap(1)	2014	327,343	126,900	186,165	39,056	679,464
Chief Financial Officer and Treasurer	2013	328,193	126,900	222,500	38,537	716,130
	2012	325,189	141,000	259,500	37,577	763,266
Wyatt L. Hogan	2014	377,654	225,000	186,165	33,336	822,155
President	2013	344,970	126,900	222,500	31,358	725,728
	2012	328,337	141,000	259,500	30,988	759,825
Kevin F. Wall	2014	215,759	126,900	186,165	35,099	563,923
Chief Operating Officer	2013	205,485	126,900	222,500	33,781	588,666
	2012	205,485	141,000	259,500	33,781	639,766
Kathryn S. Wilson(2)	2014	291,375	100,000	121,007	30,869	543,251
Vice President, General Counsel and Secretary						
Nick Carter(3)	2014	252,200	133,000	297,864	99,458(6)	782,522
Former President and Chief Operating	2013	378,300	199,260	356,000	40,473	974,033
Officer	2012	378,300	221,400	415,200	39,851	1,054,751

(1) Mr. Dunlap retired as Chief Financial Officer and Treasurer effective January 1, 2015.

(2) Ms. Wilson was not a named executive officer for purposes of this Summary Compensation Table during 2013 or 2012.

(3) Mr. Carter retired as President and Chief Operating Officer effective September 1, 2014. Mr. Carter remained employed by Western Pocahontas Properties Limited Partnership from September 1, 2014 through December 31, 2014 and provided consulting services to Natural Resource Partners L.P. during that time. He continued to receive his 2014 salary and employee benefits through December 31, 2014. One-half of the expenses related to Mr. Carter's salary and employee benefits for the last four months of 2014 was borne by Natural Resource Partners L.P.

(4) Amounts represent the grant date fair value of phantom unit awards determined in accordance with Accounting Standards Codification Topic 718. For information regarding the assumptions used in calculating these amounts for 2014, see Note 16 to the audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

(5) Includes portions of automobile allowance, 401(k) matching and retirement contributions allocated to Natural Resource Partners by Quintana and Western Pocahontas. The table does not include any cash compensation paid by the general partner to each named executive officer. The general partner may distribute up to 7.5% of any cash it receives with respect to the common units that it received in connection with the elimination of the incentive distribution rights. We do not reimburse the general partner for any of these payments, and the payments are not an expense of NRP. The table below shows the amounts paid by the general partner that are not reimbursed by NRP:

Compensation Received from General Partner and Not Reimbursed by NRP

Individual	Year	$
Corbin J. Robertson, Jr.	2014	180,000
	2013	456,000
	2012	456,000
Dwight L. Dunlap	2014	180,000
	2013	391,000
	2012	391,000
Wyatt L. Hogan	2014	384,000
	2013	391,000
	2012	391,000
Kevin F. Wall	2014	180,000
	2013	391,000
	2012	391,000
Kathryn S. Wilson	2014	180,000
Nick Carter	2014	—
	2013	536,000
	2012	536,000

(6) Includes $65,000 salary and $7,061 for 401K match, retirement contribution and car allowance in other compensation received by Mr. Carter for the months of September through December 2014. These amounts represent 50% of the total salary and other compensation received by Mr. Carter during that period.

Grants of Plan-Based Awards in 2014

Named Executive Officer	Grant Date	Number of Phantom Units(1) (#)	Grant Date Fair Value of Unit Awards(2) ($)
Corbin J. Robertson, Jr.	2/12/2014	33,600	595,728
Dwight L. Dunlap	2/12/2014	10,500	186,165
Wyatt L. Hogan	2/12/2014	10,500	186,165
Kevin F. Wall	2/12/2014	10,500	186,165
Kathryn S. Wilson	2/12/2014	6,825	121,007
Nick Carter	2/12/2014	16,800	297,864

(1) The phantom units were granted in February 2014 and will vest in February 2018.

(2) Amounts represent the grant date fair value of phantom unit awards determined in accordance with Accounting Standards Codification Topic 718.

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 of directors 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 of directors 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. The CNG Committee regularly makes awards of phantom units on an annual basis in February.

Outstanding Awards at December 31, 2014

The table below shows the total number of outstanding phantom units held by each named executive officer at December 31, 2014. The phantom units shown below have been awarded over the last four years, with a portion of the phantom units vesting in February in each of 2015, 2016, 2017 and 2018.

Named Executive Officer	Number of Phantom Units That Have Not Vested (#)	Market Value of Phantom Units That Have Not Vested(1) ($)
Corbin J. Robertson, Jr.	130,600(2)	1,754,120
Dwight L. Dunlap	39,500(3)	526,270
Wyatt L. Hogan	39,500(3)	526,270
Kevin F. Wall	39,500(3)	526,270
Kathryn S. Wilson	23,325(4)	273,247
Nick Carter	—	—

(1) Based on a unit price of $9.25, the closing price for the common units on December 31, 2014. The value also includes the value of the accrued DERs as of December 31, 2014.

(2) Includes 33,000 phantom units vested on February 10, 2015, 32,000 phantom units vesting on February 14, 2016, 32,000 phantom units vesting on February 13, 2017 and 33,600 phantom units vesting on February 12, 2018.

(3) Includes 9,000 phantom units vested on February 10, 2015, 10,000 phantom units vesting on February 14, 2016, 10,000 phantom units vesting on February 13, 2017 and 10,500 phantom units vesting on February 12, 2018.

(4) Includes 4,500 phantom units vested on February 10, 2015, 5,500 phantom units vesting on February 14, 2016, 6,500 phantom units vesting on February 13, 2017 and 6,825 phantom units vesting on February 12, 2018. 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.

Phantom Units Vested in 2014

The table below shows the phantom units that vested with respect to each named executive officer in 2014, along with the value realized by each individual.

Named Executive Officer	Number of Phantom Units That Vested (#)	Value Realized on Vesting ($)
Corbin J. Robertson, Jr.	33,000	803,880
Dwight L. Dunlap	8,000	194,880
Wyatt L. Hogan	8,000	194,880
Kevin F. Wall	8,000	194,880
Kathryn S. Wilson	3,500	62,335(1)
Nick Carter(2)	77,800	1,592,214

(1) Includes accrued DERs from February 12, 2013, the date of the grant of these units to Ms. Wilson.

(2) Includes the phantom units and amount paid to Mr. Carter upon the vesting of all of his phantom units upon his retirement effective September 1, 2014 pursuant to the terms of Mr. Carter's Continued Employment and Separation Agreement. In accordance with the terms of the phantom units, Mr. Carter received for each phantom unit an amount in cash equal to the average closing price of NRP's common units for the 20 trading days immediately preceding the vesting date, together with associated DERs. See "—Potential Payments upon Termination or Change in Control."

Potential Payments upon Termination or Change in Control

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, 2014, based on the 20-day average of the common units of $9.78 on December 31, 2014 and includes amounts for accrued DERs.

Named Executive Officer	Number of Phantom Units That Have Not Vested (#)	Potential Post-Employment Payments Required Upon Change in Control ($)	Potential Cash Payments Required Upon Change in Control ($)
Corbin J. Robertson, Jr.	130,600	—	1,823,142
Dwight L. Dunlap	39,500	—	547,146
Wyatt L. Hogan	39,500	—	547,146
Kevin F. Wall	39,500	—	547,146(1)
Kathryn S. Wilson	23,325	—	285,575(2)
Nick Carter	—	—	—

(1) The CNG Committee has determined that all of Mr. Wall's phantom units will vest upon his retirement effective March 1, 2015. In accordance with the terms of the phantom units, Mr. Wall will receive for each phantom unit an amount in cash equal to the average closing price of NRP's common units for the 20 trading days immediately preceding the vesting date, together with associated DERs.

(2) 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.

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. However, in connection with Mr. Carter's retirement on September 1, 2014, Mr. Carter, NRP and Western Pocahontas entered into a Continued Employment and Separation Agreement. Pursuant to that agreement, Mr. Carter continued to receive his salary and benefits through December 2014 (of which $72,061, or 50%, was borne by NRP), a bonus payment of $133,000 on December 31, 2014 (all of which was borne by NRP), and a payment of $1,251,174 upon the accelerated vesting of all of his 63,800 outstanding phantom units on September 1, 2014.

Directors' Compensation for the Year Ended December 31, 2014

The table below shows the directors' compensation for the year ended December 31, 2014. 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 ($)	Phantom Unit Awards(1)(2) ($)	Total ($)
Robert Blakely	85,000	84,651	169,651
Russell Gordy	65,000	16,710	81,710
Donald Holcomb	60,000	16,710	76,710
Robert Karn III	85,000	84,651	169,651
S. Reed Morian	60,000	84,651	144,651
Richard Navarre	65,000	16,710	81,710
Corbin J. Robertson, III	60,000	59,978	119,978
Stephen Smith	80,000	84,651	164,651
Leo A. Vecellio, Jr.	65,000	84,651	149,651

(1) Amounts represent the grant date fair value of unit awards determined in accordance with FASB stock compensation authoritative guidance.

(2) As of December 31, 2014, each director held 14,865 phantom units, of which 3,580 vested on February 10, 2015, 3,700 will vest on February 14, 2016, 3,700 will vest on February 13, 2017 and 3,885 will vest on February 12, 2018.

In 2014, 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.

2015 Long-Term Incentive Awards

In February 2015, the CNG Committee awarded 36,000 phantom units to Mr. Robertson, 4,000 phantom units to Mr. Dunlap, 18,000 phantom units to Mr. Hogan, and 9,500 phantom units to Ms. Wilson. The phantom units included tandem DERs, pursuant to which the phantom units will accrue the quarterly distributions paid by NRP on its common units. NRP will pay the amounts accrued under the DERs upon the vesting of the phantom units in February 2019. The CNG Committee also approved an award of 4,100 phantom units, including tandem DERs, to each of the members of the Board of Directors. These phantom units will vest in February 2019.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2014, Messrs. Blakely, Gordy, Karn and Vecellio served on the CNG Committee. None of Messrs. Blakely, Carmichael, 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 of Directors or CNG Committee.

Item 12. *Security Ownership of Certain Beneficial Owners and Management*

The following table sets forth, as of February 27, 2015, 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.

Name of Beneficial Owner	Common Units	Percentage of Common Units(1)
Corbin J. Robertson, Jr.(2)	24,346,308	19.9%
Western Pocahontas Properties(3)	17,279,860	14.1%
Wyatt L. Hogan(4)	12,500	*
Craig W. Nunez	—	—
Kevin F. Wall(5)	4,000	*
Kevin J. Craig	18,000	*
Dennis F. Coker	4,500	*
David M. Hartz	1,140	*
Kenneth Hudson	8,000	*
Kathy H. Roberts	20,000	*
Kathryn S. Wilson	—	—
Gregory F. Wooten	—	—
Robert T. Blakely	22,500	*
Russell D. Gordy	70,000	*
Donald R. Holcomb(6)	5,469,950	4.5%
Robert B. Karn III(7)	5,634	*
Richard A. Navarre	—	—
S. Reed Morian(8)	6,161,588	5.0%
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	37,895,563	31.0%

* Less than one percent.

(1) Percentages based upon 122,299,825 common units issued and outstanding. 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 601 Jefferson Street, Suite 3600, 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 601 Jefferson Street, Suite 3600, 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) Includes 500 common units held by Mr. Wall's daughter. Mr. Wall disclaims beneficial ownership of these securities.

(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.

(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 601 Jefferson, Suite 3600, Houston, TX 77002, the address for BHJ Investments is 601 Jefferson, Suite 3600, Houston, TX 77002 and the address for The Corbin James Robertson III 2009 Family Trust is 601 Jefferson, Suite 3600, Houston, TX 77002. The following common units are pledged as collateral for loans: 295,413 common units owned directly by Mr. Robertson and 31,000 of the units held by CIII Capital Management, LLC.

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 5.35 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.

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

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 available on our website at *www.nrplp.com* and is available in print 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, 2014, 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 2014 and 2013. 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:

	2014	2013
Audit Fees(1)	$1,056,542	$753,502
Audit-Related Fees	—	—
Tax Fees(2)	738,626	654,776
All Other Fees(3)	1,910	1,995

(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) OCI Wyoming LLC Financial Statements. The financial statements of OCI 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 C Note (incorporated by reference to Exhibit 4.4 to Current Report on Form 8-K filed June 23, 2003).
4.12	—	Form of Series D Note (incorporated by reference to Exhibit 4.12 to Annual Report on Form 10-K filed February 28, 2007).
4.13	—	Form of Series E Note (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K filed March 29, 2007).
4.14	—	Form of Series F Note (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q filed May 7, 2009).
4.15	—	Form of Series G Note (incorporated by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q filed May 7, 2009).
4.16	—	Form of Series H Note (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q filed May 5, 2011).
4.17	—	Form of Series I Note (incorporated by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q filed May 5, 2011).
4.18	—	Form of Series J Note (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on June 15, 2011).
4.19	—	Form of Series K Note (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed on October 3, 2011).
4.20	—	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).
4.21	—	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
4.22	—	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).
4.23	—	Form of 9.125% Senior Notes due 2018 (contained in Exhibit 1 to Exhibit 4.22).
4.24	—	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).
4.25	—	Registration Rights Agreement, dated October 17, 2014, by and among Natural Resource Partners L.P., NRP Finance Corporation and Wells Fargo Securities, LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.4 to Current Report on Form 8-K filed on October 20, 2014).
10.1	—	Second Amended and Restated Credit Agreement, dated as of August 10, 2011 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on August 11, 2011).
10.2	—	First Amendment to the Second Amended and Restated Credit Agreement, dated as of January 23, 2013 (incorporated by reference to Exhibit 10.3 to Current Report on Form 8-K filed on January 25, 2013).
10.3	—	Second Amendment to the Second Amended and Restated Credit Agreement, dated as of June 7, 2013 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on June 10, 2013).
10.4	—	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).
10.5+	—	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).
10.6+	—	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).
10.7+	—	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).
10.8	—	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).
10.9	—	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).
10.10	—	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
10.11	—	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).
10.12	—	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).
10.13	—	Term Loan Agreement, dated as of January 23, 2013, by and among Natural Resource Partners, L.P., Citibank, N.A., as administrative agent, Citigroup Global Markets, Inc., Wells Fargo Securities, LLC and Compass Bank, as joint lead arrangers and joint bookrunners and Wells Fargo Bank, National Association and Compass Bank, as co-syndication agents (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed on January 25, 2013).
10.14	—	First Amendment to Term Loan Agreement, dated as of June 7, 2013 (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed on June 10, 2013).
10.15	—	Limited Liability Company Agreement of OCI Wyoming LLC, dated June 30, 2014 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed by OCI Resources LP on July 2, 2014).
10.16	—	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).
10.17	—	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).
10.18		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).
10.19	—	Purchase Agreement dated October 9, 2014 by and among Natural Resource Partners L.P., NRP Finance Corporation and Wells Fargo Securities, LLC (as the representative of the several initial purchasers) (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on October 10, 2014).
10.20	—	Equity Distribution Agreement dated November 12, 2013 by and among the Partnership, NRP (GP) LP, GP Natural Resource Partners LLC, and Citigroup Global Markets Inc. BB&T Capital Markets, a division of BB&T Securities, LLC, UBS Securities LLC and Wells Fargo Securities, LLC, as Managers (incorporated by reference to Exhibit 1.1 to Current Report on Form 8-K filed on November 12, 2013).
10.21+	—	Continued Employment and Separation Agreement dated effective as of September 1, 2014, by and among Natural Resource Partners L.P., Western Pocahontas Properties Limited Partnership and Nick Carter (incorporated by reference to Exhibit 10.3 filed on November 7, 2014).
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 OCI Wyoming LLC as of and for the years ended December 31, 2013 and 2014.
101*	— The following financial information from the Annual Report on Form 10-K of Natural Resource Partners L.P. for the year ended December 31, 2014, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Comprehensive Income, (iii) Consolidated Statements of Cash Flows, and (iv) Notes to Consolidated Financial Statements, tagged as blocks of text.

* Submitted 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: February 27, 2015

By: /s/ CORBIN J. ROBERTSON, JR.
Corbin J. Robertson, Jr.
Chairman of the Board and
Chief Executive Officer
(Principal Executive Officer)

Date: February 27, 2015

By: /s/ CRAIG W. NUNEZ
Craig W. Nunez
Chief Financial Officer and
Treasurer
(Principal Financial Officer)

Date: February 27, 2015

By: /s/ KENNETH HUDSON
Kenneth Hudson
Controller
(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: February 27, 2015

/s/ ROBERT T. BLAKELY

Robert T. Blakely
Director

Date: February 27, 2015

/s/ RUSSELL D. GORDY

Russell D. Gordy
Director

Date: February 27, 2015

/s/ DONALD R. HOLCOMB

Donald R. Holcomb
Director

Date: February 27, 2015

/s/ ROBERT B. KARN III

Robert B. Karn III
Director

Date: February 27, 2015

/s/ S. REED MORIAN

S. Reed Morian
Director

Date: February 27, 2015

/s/ RICHARD A. NAVARRE

Richard A. Navarre
Director

Date: February 27, 2015

/s/ CORBIN J. ROBERTSON III

Corbin J. Robertson III
Director

Date: February 27, 2015

/s/ STEPHEN P. SMITH

Stephen P. Smith
Director

Date: February 27, 2015

/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
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. 333-180907, Form S-3 No. 333-183314 and Form S-3 No. 333-187883) of Natural Resource Partners L.P. and in the related Prospectuses of our reports dated February 27, 2015, 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, 2014.

/s/ Ernst & Young LLP

Houston, Texas
February 27, 2015

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements on Form S-3 (Nos. 333-180907, 333-183314, and 333-187883) of Natural Resource Partners L.P., of our report dated February 26, 2015, relating to the financial statements of OCI Wyoming LLC for the year ended December 31, 2014, appearing in the Annual Report on Form 10-K of Natural Resource Partners L.P. for the year ended December 31, 2014.

/s/ DELOITTE & TOUCHE LLP

Atlanta, Georgia
February 26, 2015

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 January 21, 2015 included in the Company's Annual Report on Form 10-K for the year ended December 31, 2014, filed with the U.S. Securities and Exchange Commission on or about February 27, 2015, as well as to the incorporation by reference thereof into the Company's Registration Statements on Form S-3 (Nos. 333-180907, 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
February 27, 2015

Exhibit 31.1

CERTIFICATION OF PRINCIPAL 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: February 27, 2015

Exhibit 31.2

CERTIFICATION OF PRINCIPAL 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 and Treasurer

Date: February 27, 2015

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, 2014 filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Corbin J. Robertson, Jr., Chief Executive Officer and Chairman of the Board 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.

/s/ Corbin J. Robertson, Jr.
Name: Corbin J. Robertson, Jr.
Date: February 27, 2015

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, 2014 filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Craig W. Nunez, Chief Financial Officer and Treasurer 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:

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

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

/s/ Craig W. Nunez
Name: Craig W. Nunez
Date: February 27, 2015

Exhibit 95.1

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 year ended December 31, 2014.

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, LLC/40-03094	2	0	0	0	0	$ 3,407(7)
Laurel Aggregates of Delaware, LLC/36-08891	5	0	0	0	0	$ 1,489(8)
Southern Aggregates, LLC-Plant 11/16-01537	1	0	0	0	0	$ 150
Southern Aggregates, LLC-Plant 1/16-01388	2	0	0	0	0	$ 617
Southern Aggregates, LLC-Plant 7/16-01519	4	0	0	0	0	$ 1,143
Southern Aggregates, LLC-Plant 6/16-00336	1	0	0	0	0	$ 524
Southern Aggregates, LLC-Plant 9/16-01536	1	0	0	0	0	$ 634
Southern Aggregates, LLC-Plant 12/16-01546	0	0	0	0	0	$ 0

(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 months ended December 31, 2014 on all citations and orders, including those citations and orders that are not required to be included within the above chart.

(7) Excludes penalties for three non-S&S citations issued in 2014 that were not assessed until 2015.

(8) Excludes penalties for eight citations (two of which were S&S) issued in 2014 that were not assessed until 2015.

Mine Name / MSHA Identification Number	*Total Number of Mining Related Fatalities*	*Received Notice of Pattern of Violations Under Section 104(e) (yes/no)* (9)	*Legal Actions Pending as of Last Day of Period*	*Legal Actions Initiated During Period*	*Legal Actions Resolved During Period*
Winn Materials, LLC/40-03094	0	0	6	6	3
Laurel Aggregates of Delaware, LLC/36-08891	0	0	1	1	0
Southern Aggregates, LLC-Plant 11/16-01537	0	0	1	1	0
Southern Aggregates, LLC-Plant 1/16-01388	0	0	2	2	0
Southern Aggregates, LLC-Plant 7/16-01519	0	0	1	1	0
Southern Aggregates, LLC-Plant 6/16-00336	0	0	0	0	0
Southern Aggregates, LLC-Plant 9/16-01536	0	0	0	0	0
Southern Aggregates, LLC-Plant 12/16-01546	0	0	0	0	0

(9) 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, 2014 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, LLC/40-03094	4	2	0	0	0	0
Laurel Aggregates of Delaware, LLC/36-08891	1	0	0	0	0	0
Southern Aggregates, LLC-Plant 11/16-01537	0	1	0	0	0	0
Southern Aggregates, LLC-Plant 1/16-01388	0	2	0	0	0	0
Southern Aggregates, LLC-Plant 7/16-01519	0	1	0	0	0	0
Southern Aggregates, LLC-Plant 6/16-00336	0	0	0	0	0	0
Southern Aggregates, LLC-Plant 9/16-01536	0	0	0	0	0	0
Southern Aggregates, LLC-Plant 12/16-01546	0	0	0	0	0	0

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DAN PAUL SMITH
JOSEPH J. SPELLMAN

January 21, 2015

Mr. Tim Chung
Natural Resource Partners L.P.
601 Jefferson Street, Suite 3600
Houston, Texas 77002

Dear Mr. Chung:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2014, 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 or about the date of this letter. 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, 2014, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	8,918.3	1,092.9	13,069.1	539,307.4	286,178.7
Proved Developed Non-Producing	12.1	5.2	92.2	1,032.4	654.8
Proved Undeveloped	1,053.3	130.6	1,208.7	47,376.7	18,363.2
Total Proved	9,983.7	1,228.7	14,370.0	587,716.6	305,196.7

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.

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.

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201-2737 • PH: 214-969-5401 • FAX: 214-969-5411 nsai@nsai-petro.com
1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010-3034 • PH: 713-654-4950 • FAX: 713-654-4951 netherlandsewell.com

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 2014. For oil and NGL volumes, the average West Texas Intermediate posted price of $91.48 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $4.350 per MMBTU is adjusted 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 $82.78 per barrel of oil, $25.00 per barrel of NGL, and $4.406 per MCF of gas.

Operating costs used in this report are based on operating expense records of NRP LP. These 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 persons responsible for preparing the estimates presented herein meet 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 III
By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ Steven W. Jansen
By:
Steven W. Jansen, P.E. 112973
Petroleum Engineer

Date Signed: January 21, 2015

SWJ:DEC

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.*

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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.

DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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

OCI Wyoming LLC
(A Majority-Owned Subsidiary of OCI Resources LP)

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

OCI WYOMING LLC
(A Majority Owned Subsidiary of OCI Resources LP)

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Managers and Members of

OCI Wyoming LLC

Atlanta, Georgia

We have audited the accompanying balance sheets of OCI Wyoming LLC (the "Company") as of December 31, 2014 and 2013, and the related statements of operations and comprehensive income, members' equity, and cash flows for the years then ended, 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, 2014 and 2013, and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Atlanta, Georgia

February 26, 2015

OCI WYOMING LLC
(A Majority Owned Subsidiary of OCI Resources LP)

BALANCE SHEETS
AS OF DECEMBER 31, 2014 AND 2013
(In thousands of dollars)

	2014	2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 30,520	$ 45,969
Accounts receivable, net	35,457	34,401
Accounts receivable - ANSAC	70,410	58,051
Due from affiliates, net	19,489	20,394
Inventory	43,237	41,710
Other current assets	1,509	740
Total current assets	200,622	201,265
PROPERTY, PLANT, AND EQUIPMENT, NET	201,402	193,277
OTHER NON-CURRENT ASSETS	880	1,231
TOTAL ASSETS	$402,904	$395,773
LIABILITIES AND MEMBERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 13,069	$ 13,189
Due to affiliates	5,347	375
Accrued expenses	29,288	26,099
Total current liabilities	47,704	39,663
LONG-TERM DEBT	145,000	155,000
OTHER NON-CURRENT LIABILITIES	4,192	3,779
Total liabilities	196,896	198,442
COMMITMENTS AND CONTINGENCIES		
MEMBERS' EQUITY:		
Members' equity — OCI Resources LP	105,445	100,919
Members' equity — Natural Resource Partners LP	101,311	96,962
Accumulated other comprehensive loss	(748)	(550)
Total members' equity	206,008	197,331
TOTAL LIABILITIES AND MEMBERS' EQUITY	$402,904	$395,773

See notes to financial statements.

OCI WYOMING LLC
(A Majority Owned Subsidiary of OCI Resources LP)

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

	2014	2013
SALES - AFFILIATES	$236,685	$211,645
SALES - OTHERS	228,347	230,487
Total net sales	465,032	442,132
COST OF PRODUCTS SOLD	222,848	225,160
FREIGHT COSTS	123,745	122,673
Total cost of products sold	346,593	347,833
GROSS PROFIT	118,439	94,299
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES - AFFILIATES	16,192	12,506
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES - OTHERS	577	36
LOSS ON DISPOSAL OF ASSETS, NET	1,032	—
OPERATING INCOME	100,638	81,757
OTHER INCOME (EXPENSE):		
Interest income	78	56
Interest expense	(5,140)	(2,838)
Other income, net	1,064	680
Total other income (expense)	(3,998)	(2,102)
NET INCOME	96,640	79,655
OTHER COMPREHENSIVE INCOME (LOSS)		
Income (loss) on derivative financial instruments	(198)	30
COMPREHENSIVE INCOME	$ 96,442	$ 79,685

See notes to financial statements.

OCI WYOMING LLC
(A Majority Owned Subsidiary of OCI Resources LP)

STATEMENTS OF MEMBERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2014 AND 2013
(In thousands of dollars)

	OCI 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 through 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**

See notes to financial statements.

OCI WYOMING LLC
(A Majority Owned Subsidiary of OCI Resources LP)

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

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

See notes to financial statements

1. Corporate Structure

A 51% membership interest in OCI Wyoming LLC (the "Company," "we," "us," or "our") is owned by OCI Resources LP ("OCIR" or the "Partnership"). Natural Resource Partners LP (NRP) owns a 49% membership interest in the Company. OCIR is a master limited partnership traded on the New York Stock exchange and is currently owned 74.84% by OCI Wyoming Holding Co. (OCIWHCO) and 25.16% by the general public. OCI Chemical Corporation (OCICC), which is ultimately 100% owned by OCI Enterprises, Inc. (OCIE), owns 100% of OCIWHCO. On June 30, 2014, the Company converted from a Delaware limited partnership to a Delaware limited liability company.

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 soda ash processed is sold through the Company's sales agent, OCICC, to various domestic and European customers and to American Natural Soda Ash Corporation (ANSAC) for export. 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 sales and services.

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 2014 and 2013 there were no significant accounts receivable bad debt expenses, write-offs or recoveries.

Inventory - Inventory and stores inventory is valued at the lower of cost or market on a first-in, first-out basis. Costs include raw materials, direct labor, and manufacturing overhead. Market is based on current replacement cost for raw materials and stores inventory and on net realizable value for finished goods. Stores inventory represents parts materials and supplies 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 and 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

When property, plant, and equipment are sold or otherwise disposed of, the cost and related accumulated depreciation are removed from the accounts and any resulting gain or loss is reflected in operations for the year.

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 Company has interest rate swaps recorded within accrued expenses with an aggregate notional value of $76,000 and a fair value of a liability of $748 at December 31, 2014 and an aggregate notional value of $101,500 and a fair value of a liability of $550 at December 31, 2013. These contracts are for periods consistent with the exposure being hedged and generally will mature on July 18, 2018, the maturity date of the long-term debt under our Wyoming Credit Facility.

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 does not apply hedge accounting for these contracts. These contracts are for periods consistent with the exposure being hedged and generally have maturities of one year or less. The fair value of forward contracts, which are predominantly used to purchase U.S. dollars and sell Euros, totaled an asset of $617 and a liability of $541 at December 31, 2014 and 2013, respectively. These currency hedges have a notional value of $6,900 and $26,360 at December 31, 2014 and 2013, respectively.

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. As a result of a revised mine reserve study, effective January 1, 2015, the mining reserve will be amortized over a remaining life of 68 years. During 2014 and 2013 the remaining life was 66 years and 67 years, respectively. The liability was discounted using the credit-adjusted risk free rate of 7% 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 interest expense.

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 interest expense.

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 interest rate swaps and foreign exchange contracts are fair valued 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 February 26, 2015, 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. This update is effective for annual reporting periods beginning on or after December 15, 2016 and interim periods therein and requires expanded disclosures. We are currently assessing the impact the adoption of ASU 2014-09 will have on our consolidated financial statements.

3. ACCOUNTS RECEIVABLE, NET

Accounts receivable, net as of December 31, 2014 and 2013 consists of the following:

	2014	2013
Trade receivables	$24,691	$23,888
Other receivables	10,854	10,522
	35,545	34,410
Allowance for doubtful accounts	(88)	(9)
Total	$35,457	$34,401

4. INVENTORY

Inventory as of December 31, 2014 and 2013 consists of the following:

	2014	2013
Raw materials	$ 6,413	$ 5,754
Finished goods	10,363	10,496
Stores inventory	26,461	25,460
Total	$43,237	$41,710

5. PROPERTY, PLANT, AND EQUIPMENT, NET

Property, plant, and equipment as of December 31, 2014 and 2013 consists of the following:

	2014	2013
Land and land improvements	$ 192	$ 192
Depletable land	2,957	1,982
Buildings and building improvements	129,514	128,927
Internal-use computer software	4,468	4,141
Machinery and equipment	567,289	566,361
Total	704,420	701,603
Less accumulated depreciation, depletion and amortization	(536,163)	(531,191)
Total net book value	168,257	170,412
Construction in progress	33,145	22,865
Property, plant, and equipment, net	$ 201,402	$ 193,277

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

6. ACCRUED EXPENSES

Accrued expenses as of December 31, 2014 and 2013 consists of the following:

	2014	2013
Accrued freight costs	$ 1,373	$ 464
Accrued energy costs	5,718	6,128
Accrued royalty costs	4,445	3,995
Accrued employee compensation	6,739	5,116
Accrued other taxes	4,608	4,154
Accrued derivatives	748	1,091
Other accruals	5,657	5,151
Total	$29,288	$26,099

7. DEBT

Long-term debt as of December 31, 2014 and 2013 consists of the following:

	2014	2013
Variable Rate Demand Revenue Bonds, principal due October 1, 2018, interest payable monthly, bearing monthly interest rate of 0.14% (2014) and 0.16% (2013)	$ 11,400	$ 11,400
Variable Rate Demand Revenue Bonds, principal due August 1, 2017, interest payable monthly, bearing monthly interest rate of 0.14% (2014) and 0.16% (2013)	8,600	8,600
OCI Wyoming Credit Facility, unsecured principal due July 18, 2018, interest payable quarterly, bearing quarterly variable interest at 1.9781% (2014) and 1.996% (2013).	125,000	135,000
Total debt	145,000	155,000
Less current portion of long-term debt	—	—
Total long-term debt	$145,000	$155,000

Aggregate maturities required on long-term debt at December 31, 2014 are as follows:

2017	$ 8,600
2018	136,400
Total	$145,000

Revenue Bonds

The above revenue bonds require the Company to maintain standby letters of credit totaling $20,333 at December 31, 2014. 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, 2014, the Company was in compliance with these debt covenants.

OCI 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 "OCI Wyoming Credit Facility"), with a syndicate of lenders, which will mature on the fifth anniversary of the closing date of such credit facility. The OCI 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 OCI Wyoming Credit Facility has an accordion feature that allows OCI 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 OCI 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 OCI Wyoming Credit Facility are unsecured.

The OCI 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 OCI Wyoming Credit Facility also requires quarterly maintenance of a leverage ratio (as defined in the OCI Wyoming Credit Facility) of not more than 3.00 to 1.00 and a fixed charge coverage ratio (as defined in the OCI 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 OCI Wyoming Credit Facility also requires that consolidated capital expenditures, as defined in the OCI Wyoming Credit Facility, not exceed $50 million in any fiscal year.

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

Under the OCI Wyoming Credit Facility, a change of control is triggered if OCI Chemical 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 OCIR (or any entity that performs the functions the general partner of OCIR). In addition, a change of control would be triggered if OCIR 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, 2014.

Loans under the OCI 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 OCI 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.

8. OTHER NON-CURRENT LIABILITIES

Other non-current liabilities as of December 31, 2014 and 2013 consists of the following:

	2014	2013
Reclamation reserve at beginning of year	$3,779	$3,560
Accretion expense	413	219
Reclamation reserve at end of year	$4,192	$3,779

9. EMPLOYEE BENEFIT PLANS

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

Retirement Plans - Benefits provided under the OCI Pension Plan for Salaried Employees and OCI 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. OCIE'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 $3,140 and $8,421 for the years ended December 31, 2014 and 2013, respectively. The decrease in pension costs was driven by favorable effects of higher actuarial discount rates and market returns.

Savings Plan - The OCI 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, 2014 and 2013 were $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.

OCIE accounts for postretirement benefits on an accrual basis over an employee's period of service. The postretirement plan, excluding pensions, are not funded, and OCIE 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 OCIE's postretirement benefits decreased by $8.7 million and resulted in a prior service credit of $7.7 million which will be recognized as a reduction of net periodic postretirement benefit costs in future years. The Company's allocated portion of postretirement benefit costs was income of $260 and $55 for the years ended December 31, 2014 and 2013, respectively.

10. 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 a 10 year track lease agreement with Union Pacific Company for certain rail track used in connection with the rail yard.

OCICC, 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 10 years. OCICC's obligations related to these rail car leases are $9,664 in 2015, $7,153 in 2016, $5,665 in 2017, $4,402 in 2018, $3,585 in 2019 and $4,421 in 2020 and thereafter.

As of December 31, 2014, the total minimum rental commitments under the Company's various operating leases, including renewal periods are as follows:

	Leased Land	Track Lease	Total
2015	$ 75	$ 33	$ 108
2016	75	33	108
2017	75	33	108
2018	75	33	108
2019	75	33	108
2020 and thereafter	1,575	66	1,641
Total	$ 1,950	$ 231	$2,181

From time to time, the Company has various litigation, claims, and assessments that arise in the normal course of business. Management does not believe, based upon its evaluation and discussion with counsel, that the ultimate outcome of any current matters, individually or in the aggregate, would have a material effect on the Company's financial position, results of operations, or cash flows.

Off-Balance Sheet Arrangements - The Company has a self-bond agreement with the Wyoming Department of Environmental Quality under which we commit to pay directly for reclamation costs. As of December 31, 2014, 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 increased in August 2013 and is subject to change upon periodic re-evaluation by the Land Quality Division.

11. AFFILIATES TRANSACTIONS

OCICC is the exclusive sales agent for the Company and through its membership in ANSAC, OCICC 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 OCICC are charged directly to the Company. Selling, general and administrative expenses also include amounts charged to the Company by OCIE, OCICC, and OCIR 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.

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

	2014	2013
OCIE	$ 8,955	$ 5,537
OCICC	3,415	4,387
ANSAC	2,930	2,582
OCIR	892	—
Total selling, general and administrative expenses - affiliates	$16,192	$12,506

ANSAC allocates its expenses to ANSAC's 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, 2014 and 2013 these costs were $9,194 and $6,692, respectively.

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

	2014	2013
ANSAC	$230,762	$200,413
OCI Alabama LLC	5,923	7,282
OCI Company Limited	—	3,950
Total	$236,685	$211,645

As of December 31, 2014 and 2013, the Company had receivables and payables representing arm's length transactions with affiliated entities as follows:

	2014		2013	
	Receivables from Affiliates	Payables to Affiliates	Receivables from Affiliates	Payables to Affiliates
OCIE	$ 1,594	$ 2,848	$ 110	$ 252
OCICC	8,268	1,171	10,460	—
OCI Chemical Europe NV	9,183	—	7,822	—
OCI Company Limited	—	—	1,919	—
Other	444	1,328	83	123
Total	$ 19,489	$ 5,347	$ 20,394	$ 375

12. 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, 2014 and 2013 are as follows:

	2014	2013
Domestic	$194,801	$195,062
International:		
ANSAC	230,762	200,413
Other	39,469	46,657
Total international	270,231	247,070
Total net sales	$465,032	$442,132

The Company's largest customer by sales is ANSAC. There were no other customers who individually accounted for ten percent or more of total net sales for the years ended December 31, 2014 and 2013.

13. SUBSEQUENT EVENTS

On January 15, 2015, the members of the board of managers of OCI Wyoming LLC approved the payment on January 16, 2015 of a cash distribution to the general partners and the limited partners in the aggregate amount of $22,250.

In February 2015, the Company entered into a natural gas forward contract with a notional value of approximately $17,568 and maturity dates ranging from 2015 to 2020, to mitigate volatility in the gas prices. The maturity of the notional value is $911 in 2015, $2,889 in 2016, $3,179 in 2017, $3,385 in 2018, $3,552 in 2019 and $3,652 in 2020.

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