NATURAL RESOURCE PARTNERS LP
Form 10-K
February 27, 2015
Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **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 *(State or other jurisdiction of incorporation or organization)*	**35-2164875** *(I.R.S. Employer Identification Number)*
601 Jefferson, Suite 3600 **Houston, Texas** *(Address of principal executive offices)*	**77002** *(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 x 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 x

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 x 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 x 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.

x 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 x

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.

Table of Contents

Table of Contents

Item		Page
	PART I	
1.	Business	2
1A.	Risk Factors	29
1B.	Unresolved Staff Comments	45
2.	Properties	46
3.	Legal Proceedings	46
4.	Mine Safety Disclosures	46
	PART II	
5.	Market for Registrant s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities	47
6.	Selected Financial Data	48
7.	Management s Discussion and Analysis of Financial Condition and Results of Operations	50
7A.	Quantitative and Qualitative Disclosures About Market Risk	73
8.	Financial Statements and Supplementary Data	75
9.	Changes In and Disagreements with Accountants on Accounting and Financial Disclosure	109
9A.	Controls and Procedures	109
9B.	Other Information	110
	PART III	
10.	Directors and Executive Officers of the Managing General Partner and Corporate Governance	111
11.	Executive Compensation	118
12.	Security Ownership of Certain Beneficial Owners and Management	128
13.	Certain Relationships and Related Transactions, and Director Independence	129
14.	Principal Accountant Fees and Services	136
	PART IV	
15.	Exhibits, Financial Statement Schedules	139

Table of Contents

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.

Table of Contents

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.

Table of Contents

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 Year Ended December 31, (In thousands)			Average Coal Royalty Per Ton Year Ended December 31, ($ per ton)		
	2014	**2013**	**2012**	**2014**	**2013**	**2012**
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 (Tons in thousands)					
	Production for Year Ended December 31,			Proven and Probable Reserves at December 31, 2014		
	2014	**2013**	**2012**	**Underground**	**Surface**	**Total**
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

Table of Contents

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.

Table of Contents

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

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

12

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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,

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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;

Table of Contents

- 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.

Table of Contents

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