NATURAL RESOURCE PARTNERS LP
Form 10-K
February 28, 2013

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2012 or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 1-31465

NATURAL RESOURCE PARTNERS L.P.

(Exact name of registrant as specified in its charter)

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

(713) 751-7507

(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**

Common Units representing limited partnership interests New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ 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 þ

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 þ 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 þ 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. þ

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.

þ 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 þ

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, 2012 based on a price of $22.17 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 28, 2013, there were 109,812,408 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE.

None.

Table of Contents

Forward-Looking Statements

Statements included in this 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 capital expenditures and acquisitions, expected commencement dates of mining, projected quantities of future production by our lessees producing from our reserves, and projected demand or supply for coal, aggregates and oil and gas that will affect sales levels, prices and royalties realized by us.

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. Please read Item 1A. Risk Factors for important factors that could cause our actual results of operations or our actual financial condition to differ.

PART I

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 mineral properties in the United States. We own coal reserves 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. As of December 31, 2012, we owned or controlled approximately 2.4 billion tons of proven and probable coal reserves, and we also owned approximately 500 million tons of aggregate reserves in a number of states across the country. We do not operate any 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. Our lessees are generally required to make payments to us based on the higher of a percentage of the gross sales price or a fixed price per ton, in addition to minimum payments.

In 2012, our lessees produced 54.4 million tons of coal from our properties and our coal royalty revenues were $260.7 million. Processing fees and transportation fees added $27.8 million to our total revenues. In addition, we received $9.2 million in oil and gas royalties, and our lessees produced 5.3 million tons of aggregates resulting in aggregate royalties of $6.6 million.

Partnership Structure and Management

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We own our subsidiaries through a wholly owned operating company, NRP (Operating) 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 makes 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 nine 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.

Our operations headquarters 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.

Royalty Business

Royalty businesses principally own and manage mineral reserves. As an owner of mineral reserves, we typically are not responsible for operating on our 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 5- to 10-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 us and are required to report tons of coal or aggregates removed as well as the sales prices of the extracted minerals. Therefore, to a great extent, amounts reported as royalty revenue are based upon the reports of our lessees. We periodically audit this information by examining certain records and internal reports of our lessees, and we perform periodic mine inspections to verify that the information that our lessees have submitted to us is accurate. Our audit and inspection processes are designed to identify material variances from lease terms as well as differences between the information reported to us and the actual results from each property. Our audits and inspections, however, are in periods subsequent to when the revenue is reported and any adjustment identified by these processes might be in a reporting period different from when the royalty revenue was initially recorded.

Our royalty revenues are affected by changes in long-term and spot commodity prices, production volumes, unseasonal weather, lessees supply contracts and the royalty rates in our leases. The prevailing prices for coal and oil and gas depend on a number of factors, including the supply-demand relationship, the price and availability of alternative fuels, global economic conditions and governmental regulations. The prevailing price for aggregates generally depends on local economic conditions. In addition to their royalty obligation, 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. We do not typically receive minimum royalties with respect to our oil and gas properties, but do typically receive bonus payments at the time of execution of the lease.

Because we do not operate any mines, we do not bear ordinary operating costs and have 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 aggregate properties. We typically pay property taxes on our properties, which are then reimbursed by the lessee pursuant to the terms of the lease.

Our business is not seasonal, although at times severe or abnormal weather can cause a short-term decrease in production by our lessees due to the weather s negative impact on production and transportation.

Acquisitions

We are a growth-oriented company and have completed a number of acquisitions. For a discussion of our recent acquisitions, please see Recent Acquisitions in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Coal Royalty Revenues, Reserves and Production

The following summary table sets forth coal royalty revenues and average coal royalty revenue per ton from the properties that we owned or controlled for the years ending December 31, 2012, 2011 and 2010. Coal royalty revenues were generated from the properties in each of the areas as follows:

	Coal Royalty Revenues For the Years Ended December 31, (In thousands)			Average Coal Royalty Revenue Per Ton For the Years Ended December 31, ($ per ton)		
	2012	**2011**	**2010**	**2012**	**2011**	**2010**
Area						
Appalachia						
Northern	$ 15,768	$ 20,578	$ 18,676	$ 1.50	$ 3.92	$ 3.81
Central	156,390	196,789	144,934	$ 5.99	$ 6.66	$ 5.36
Southern	29,325	11,717	19,405	$ 7.89	$ 6.91	$ 6.87
Total Appalachia	201,483	229,084	183,015	$ 5.00	$ 6.28	$ 5.26
Illinois Basin	49,538	41,324	30,210	$ 4.38	$ 4.38	$ 3.90
Northern Powder River Basin	8,501	7,658	8,444	$ 3.58	$ 2.86	$ 1.89
Gulf Coast	1,212	1,155	92	$ 2.60	$ 2.21	$ 1.77
Total	$ 260,734	$ 279,221	$ 221,761	$ 4.79	$ 5.68	$ 4.71

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, 2012, 2011 and 2010. All of the reserves reported below are recoverable reserves as determined by Industry Guide 7. In excess of 90% of the reserves listed below are currently leased to third parties. Coal production data and reserve information for the properties in each of the areas are as follows:

Coal Production and Reserves

	Production for the Year Ended December 31,			Proven and Probable Reserves at December 31, 2012		
	2012	**2011**	**2010**	**Underground**	**Surface**	**Total**
			(Tons in thousands)			
Area						
Appalachia						
Northern	10,486	5,251	4,900	489,635	29,381	519,016
Central	26,098	29,555	27,056	1,040,883	221,123	1,262,006
Southern	3,718	1,695	2,824	95,824	25,063	120,887
Total Appalachia	40,302	36,501	34,780	1,626,342	275,567	1,901,909
Illinois Basin	11,299	9,445	7,753	353,182	14,039	367,221
Northern Powder River Basin	2,377	2,682	4,467		99,780	99,780
Gulf Coast	466	523	52		4,672	4,672
Total	54,444	49,151	47,052	1,979,524	394,058	2,373,582

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, 2012, approximately 49% of our reserves were low sulfur coal and 33% of our reserves were compliance coal. Unless otherwise indicated, we present the quality of the coal throughout this Form 10-K on an as-received basis, which assumes 6% moisture for Appalachian reserves, 12% moisture for Illinois Basin reserves and 25% moisture for Northern Powder River Basin reserves. We own both steam and metallurgical coal reserves in Northern, Central and Southern Appalachia, and we own steam coal reserves in the Illinois Basin and the Northern Powder River Basin. In 2012, approximately 32% of the production and 44% 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, 2012.

Sulfur Content, Typical Quality and Type of Coal

		Sulfur Content				Typical Quality		Type of Coal	
Area	**Compliance Coal(1)**	**Low (less than 1.0%)**	**Medium (1.0% to 1.5%)**	**High (greater than 1.5%)**	**Total**	**Heat Content (Btu per pound)**	**Sulfur (%)**	**Steam**	**Metallurgical(2)**
		(Tons in thousands)						(Tons in thousands)	
Appalachia									
Northern	50,658	73,387	24,466	421,163	519,016	12,836	2.61	509,454	9,562
Central	637,363	895,988	315,002	51,016	1,262,006	13,273	0.89	869,852	392,154
Southern	83,548	89,612	27,977	3,298	120,887	13,507	0.82	79,827	41,060
Total Appalachia	771,569	1,058,987	367,445	475,477	1,901,909	13,168	1.35	1,459,133	442,776
Illinois Basin			2,230	364,991	367,221	11,507	3.26	367,221	
Northern Powder River Basin		99,780			99,780	8,800	0.65	99,780	
Gulf Coast	185	4,672			4,672	6,949	0.69	4,487	185
Total	771,754	1,163,439	369,675	840,468	2,373,582			1,930,621	442,961

(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. Some of these factors and assumptions include:

- future coal prices, mining economics, capital expenditures, severance and excise taxes, and development and reclamation costs;
- future mining technology improvements;
- the effects of regulation by governmental agencies; and
- geologic and mining conditions, which may not be fully identified by available exploration data and may differ from our experiences in other areas of our reserves.

As a result, actual coal tonnage recovered from identified reserve areas or properties may vary from estimates or may cause our estimates to change from time to time. Any inaccuracy in the estimates related to our reserves could result in royalties that vary from our expectations.

Transportation and Processing Revenues

We own preparation plants and related material handling facilities. 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. These facilities generated $8.3 million in processing revenues for 2012.

In addition to our preparation plants, we own handling and transportation infrastructure related to our coal and aggregate properties. For the year ended December 31, 2012, we recognized $19.5 million in revenue from these assets. 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.

Aggregates Royalty Revenues, Reserves and Production

We own and manage aggregate reserves, but do not engage in the mining, processing or sale of aggregate related products. We own approximately 500 million tons of aggregate reserves located in a number of states across the country. During 2012, our lessees produced 5.3 million tons of aggregates, and our aggregate royalties were $6.6 million.

Oil and Gas Properties

We generated $9.2 million, or 2% of our total revenues, from approximately 494,000 net leased oil and gas mineral acres in 2012. Our oil and gas royalty revenue is primarily derived from lease bonus payments, oil and gas royalty interests and overriding royalty interests paid to us from the lessees. We have leased our mineral interests to third parties for the exploration and production of oil and gas, principally in the Appalachian Basin, Louisiana and Oklahoma. In addition, we own an overriding royalty on approximately 88,000 net mineral acres in the Marcellus Shale. When we lease our mineral interests, we may negotiate a lease bonus payment and retain a royalty interest. We are not an operator with respect to any of the oil and gas activities on our properties. In addition to our leased acres, a large portion of our mineral acres contain yet undetermined commercial potential and are available to be leased and may contribute revenue in the future.

Significant Customers

In 2012, we had total revenues of $92.3 million from Foresight Energy and other Cline affiliates and $81.1 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 12.4% of our revenue in 2012, 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 other 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. The industry has recently undergone significant consolidation. This consolidation has led to a number of our lessees parent companies having significantly larger financial and operating resources than their competitors. Our 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.

Regulation and Environmental Matters

General. Our lessees are obligated to conduct mining operations 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 and comprehensive regulatory requirements, violations during mining operations are not unusual and, notwithstanding compliance efforts, we do not believe violations by our lessees 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. We do not currently expect that future compliance will have a material effect on us.

While it is not possible to quantify the costs of compliance by our lessees with all applicable federal, state and local laws and regulations, those costs have been and are expected to continue to be significant. The lessees 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 coal, is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for coal mined by our lessees. The possibility exists that new legislation or regulations could be adopted that have a significant 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 substantial costs that could impact us.

Air Emissions. The Federal 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. Installation of additional emissions control technologies and other measures required under U.S. Environmental Protection Agency (EPA) regulations will make it more costly to operate coal-fired power plants and, depending on the requirements of individual state and regional implementation plans, could make coal a less attractive fuel source in the planning and building of power plants in the future. Any reduction in coal s share of power generating capacity could negatively impact our lessees ability to sell coal, which would have a material effect on our coal royalty revenues.

In March 2005, the EPA issued a final Clean Air Interstate Rule (CAIR), which caps nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. Since a majority of controls required by the CAIR have been installed, we believe that the financial impact of the CAIR on coal markets has been factored into the price of coal nationally and that its impact on demand has largely been taken into account by the marketplace. However, in response to a remand of CAIR by the Court of Appeals for the D.C. Circuit on July 11, 2008, the EPA on August 8, 2011 adopted a replacement program, called the Cross-State Air Pollution Rule (CSAPR), which is both broader in its geographic coverage and deeper in emission reductions than required by CAIR. The CSAPR, in turn, was vacated by opinion of the D.C. Circuit on August 21, 2012. Although the mandate has not yet issued pending disposition of petitions for rehearing, CSAPR remains unenforceable, and is not likely to be reinstated; rather, all state regulations that were based on the CAIR are still in effect. We are unable to predict whether further judicial review proceedings may reinstate CSAPR or what rules EPA may be proposed in the event that the vacatur takes full legal effect, and, therefore, unable to predict any effect on NRP.

In June 2005, the EPA announced final amendments to its regional haze program originally developed in 1999 to improve visibility in national parks and wilderness areas. Under the Regional Haze Rule, affected states were to have developed implementation plans by December 17, 2007, that, among other things, identify facilities that will have to reduce emissions and comply with stricter emission limitations. The vast majority of states failed to submit their plans by December 17, 2007, and the EPA issued a Finding of Failure to Submit plans on January 15, 2009. On May 30, 2012, the EPA Administrator signed a final rule under which the emission caps imposed under the CSAPR for a given state would supplant the obligations of that state with regard to visibility protection. EPA s plans to revisit this rule in light of the vacatur of the CSAPR have yet to be announced.

On December 16, 2011, the EPA Administrator signed the Mercury and Air Toxics Rule, which will impose limits on the hazardous air pollutant emissions allowed for the nation s existing and future coal-fueled generation fleet. The limits imposed by those rules may limit demand for or otherwise restrict sales of our lessees coal, which would reduce royalty revenues.

Other continued tightening of the already stringent regulation of emissions is likely, such as the EPA s revision to the national ambient air quality standard for sulfur dioxide finalized June 22, 2010. As a result of these and other tightening of ambient air quality standards, some states will be required to amend their existing state implementation plans to attain and maintain compliance with the new air quality standards. These plan revisions may call for significant additional emission control at coal-fired power plants.

The U.S. Department of Justice, on behalf of the EPA, has filed lawsuits against a number of utilities with coal-fired electric generating facilities alleging violations of the new source review provisions of the Clean Air Act. The EPA has alleged that certain modifications have been made to these facilities without first obtaining permits issued under the new source review program. Several of these lawsuits have settled, but others remain pending. Depending on the ultimate resolution of these cases, demand for our coal could be affected, which could have an adverse effect on our coal royalty revenues.

Carbon Dioxide and Greenhouse Gas Emissions. In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other greenhouse gases, or GHGs, present an endangerment to public health and welfare because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. Legal challenges to these findings have been rejected by the D.C. Circuit Court of Appeals, and we cannot predict the outcome of impending petitions to the Supreme Court. Based on its findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under various provisions of the Clean Air Act. Shortly after issuing its finding, EPA adopted rules regulating GHG emissions from motor vehicles, and other rules requiring permits for emissions of GHGs from many stationary sources, including coal-fired electric power plants, effective January 2, 2011. The 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, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011. As a result of revisions to its preconstruction permitting rules that became fully effective on January 2, 2011, the EPA is now requiring new sources, including coal-fired power plants, to undergo control technology reviews for GHGs (predominately carbon dioxide) as a condition of permit issuance. These reviews may impose limits on GHG emissions, or otherwise be used to compel consideration of alternative fuels and generation systems, as well as increase litigation risk for and so discourage development of coal-fired power plants.

In addition, in March 2012, the EPA proposed new source performance standards to govern GHG emissions from electric generating units, including those fired by coal. The proposal, if adopted, would in effect prohibit the construction of new coal-fired power plants, because it would require them to meet the same GHG emission rate as a comparably sized gas-fired power plant. The consent decree also represents the EPA s agreement to consider adopting a GHG limitation program governing existing sources, as well, which the EPA may attempt to use to establish a cap-and-trade-like system on emissions of power plants GHG emissions. The EPA continues to delay any such proposal.

Several states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired electric generating facilities. Other regional programs are being considered in several regions of the country. It is possible that future federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, which could negatively impact our lessees coal sales, and thereby have an adverse effect on our coal royalty revenues.

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. In conjunction with mining the property, 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.

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. These persons include the owner or operator of the site where the release occurred, and companies that improperly stored or disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources.

Products such as explosives used by coal companies in operations generate waste containing hazardous substances. We could become liable under federal and state Superfund and waste management statutes if our lessees are unable to pay environmental cleanup costs. CERCLA authorizes the EPA and, in some cases, third parties, to take actions in response to threats to the public health or the environment, and to seek recovery from the responsible classes of persons of the costs they incurred in connection with such response. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other wastes released into the environment.

Water Discharges. Our lessees operations can result in discharges of pollutants into waters. The Clean Water Act and analogous state laws and regulations create two permitting programs for our lessees. The National Pollutant Discharge Elimination System (NPDES) program under Section 402 of the statute is administered by the states or the 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 the 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.

Our lessees generally obtain individual permits from the Corps of Engineers authorizing the construction of valley fills for the disposal of overburden from mining operations. The application process for acquiring individual permits has become more cumbersome and can require the preparation of an environmental impact statement as part of the application. Small underground coal mines that must construct fills, limited by acreage and length, as part of their mining operations may qualify for another version of the Section 404 permit known as nationwide permit 50. Both individual and nationwide permits are subject to challenge in citizens lawsuits. Such challenges result in delays in our lessees obtaining the required mining permits to conduct their operations, which could, in turn, have an adverse effect on our coal royalty revenues.

Beginning in 2009, the EPA put in place a series of policies for mines in Central Appalachia that have had the effect of slowing the issuance of both Section 404 fill permits by the Corps and Section 402 NPDES permits by state agencies. These policies, among other things, seek to impose limits on a specific conductance (conductivity) and sulfate at levels that can be unachievable absent treatment at many mines. The technologies available to treat conductivity and/or sulfate are expensive and may be impracticable at all but the largest underground mines. These policies are subject to challenge in federal district court in Washington, D.C. in *National Mining Association v. Jackson*. In two separate opinions, the district court rejected the EPA s process for reviewing state-issued Section 402 permits and determined that the EPA s policies constituted unlawful rulemaking for conductivity and fell outside of the EPA s statutory authority. The EPA has appealed the final July 2012 decision.

Notwithstanding the outcome of this suit, environmental groups have issued Notices of Intent to Sue (NOIs) to companies that own coal and other minerals and lease them for mining. The NOI is a notification required by the Clean Water Act before an individual is allowed to file a suit in federal court. A number of land companies, including NRP, have received NOIs. At least one case not involving NRP is now proceeding to trial in the federal court for the Western District of Virginia.

The Clean Water Act also requires states to develop anti-degradation policies to ensure non-impaired water bodies in the state do not fall below applicable water quality standards. These and other regulatory developments may 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 royalty revenues.

Federal and state surface mining laws require mine operators to post reclamation bonds to guarantee the costs of mine reclamation. West Virginia s bonding system requires coal companies to post site-specific bonds in an amount up to $5,000 per acre and imposes a per-ton tax on mined coal currently set at $0.279/ton, which is paid to the West Virginia Special Reclamation Fund (SRF). The site-specific bonds are used to reclaim the mining operations of companies that default on their obligations under the West Virginia Surface Coal Mining and Reclamation Act. The SRF is used where the site-specific bonds are insufficient to accomplish reclamation.

Historically, the West Virginia Department of Environmental Protection (WVDEP) did not issue an NPDES permit to itself when it undertook water treatment at abandoned mine sites. This changed following a November 2010 decision of the Court of Appeals for the Fourth Circuit in *West Virginia Highlands Conservancy v Huffman*. On all such sites, the WVDEP must secure an NPDES permit and treat polluting discharges to meet water quality standards. On August 2, 2011, the West Virginia Highlands Conservancy and other environmental groups filed actions against WVDEP claiming that WVDEP was required to obtain NPDES permits with water quality based effluent limits for 171 bond forfeiture sites not included in the original Fourth Circuit Huffman decision. One action was filed in the Southern District of West Virginia and one in the Northern District. Simultaneously with each action, a Consent Decree executed by the Plaintiffs and WVDEP was filed. The Consent Decrees obligate WVDEP to obtain NPDES permits with water quality based effluent limitations for all sites at issue over the next four years. The decrees also require WVDEP to prepare and submit to the plaintiffs and the Special Reclamation Fund Advisory Committee (SRFAC) a report showing the capital, and operation and maintenance costs anticipated to be incurred in complying with the Consent Decrees. The Consent Decrees were entered by each district court and WVDEP has proceeded to obtain the first group of NPDES permits. In addition, an estimate has been prepared of the additional capital and maintenance costs required for water treatment obligations imposed by the requirement for NPDES permits. As a result of these increased costs, the SRFAC recommended and the West Virginia Legislature enacted an increase in the special reclamation tax from $0.144/ton to $0.279/ton in 2012.

The Federal Safe Drinking Water Act (SDWA) and its state equivalents affect coal mining operations by imposing requirements on the underground injection of fine coal slurries, fly ash and flue gas scrubber sludge, and by requiring permits to conduct such underground injection activities. In addition to establishing the underground injection control program, the SDWA also imposes regulatory requirements on owners and operators of public water systems. This regulatory program could impact our lessees reclamation operations where subsidence or other mining-related problems require the provision of drinking water to affected adjacent homeowners.

Mine Health and Safety Laws. The operations of our lessees 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 (POV) program, if a mine s rate of injuries or significant and substantial citations exceed a certain threshold. A mine that is placed in a POV program will receive additional scrutiny from MSHA.

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 the EPA, there are no assurances that they will not experience difficulty and delays in obtaining mining permits in the future.

Employees and Labor Relations

We do not have any employees. To carry out our operations, affiliates of our general partner employ approximately 78 people who directly support our 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 revenue from these natural resource properties are royalties from coal, aggregates, oil and gas and timber as well as related transportation and processing infrastructure revenues.

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 and 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 Corporate Governance Guidelines and our committee charters will be made available upon written request.

Item 1A. *Risk Factors*
Risks Related to Our Business

A substantial or extended decline in coal prices could reduce our coal royalty revenues and the value of our reserves.

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;
- the price and availability of alternative fuels, especially natural gas;
- 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. In early 2012, natural gas prices dropped below $2.50/Mcf and, although the prices have rebounded above $3.00/Mcf, a number of utilities have switched generation 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. In addition, prices for metallurgical coal hit multi-year lows in the second half of 2012 as demand for steel declined significantly. A substantial or extended decline in coal prices could materially and adversely affect us in two ways. First, lower prices may reduce the quantity of coal that may be economically produced from our properties. This, in turn, could reduce our coal royalty revenues and the value of our coal reserves. Second, even if production is not reduced, the royalties we receive on each ton of coal sold may be reduced.

Our lessees mining operations are subject to operating risks that could result in lower royalty revenues to us.

The most significant risk faced by our lessees that impacts NRP is permitting. As a result of recent judicial decisions and the increased involvement of the Administration and the EPA in the permitting process, there is substantial uncertainty relating to the ability of our lessees to be issued valley fill permits necessary to conduct mining operations in Central Appalachia. The non-issuance of permits has limited the ability of our lessees to open new operations, expand existing operations, and may preclude new acquisitions in which NRP might otherwise be involved.

Our royalty revenues are largely dependent on our lessees level of production from our mineral reserves, and any interruptions to the production of coal from our reserves would reduce our coal royalty revenues. The level of our lessees production is subject to operating conditions or events beyond their or our 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;

the price of natural gas, which is a competing fuel in the generation of electricity;

changes in governmental regulation and enforcement policy related to the coal industry or the electric utility industry;

mining and processing equipment failures and unexpected maintenance problems;

interruptions due to transportation delays;

adverse weather and natural disasters, such as heavy rains and flooding;

labor-related interruptions; and

fires and explosions.

Our lessees may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from their operations. If our lessees are pursued for these sanctions, costs and liabilities, their mining operations and, as a result, our royalty revenues could be adversely affected.

Any decrease in the demand for metallurgical coal could result in lower coal production by our lessees, which would reduce our coal royalty revenues.

Our lessees produce a significant amount of the metallurgical coal that is used in both the U.S. and foreign steel industries. In 2012, approximately 32% of the coal production and 44% of the coal royalty revenues from our properties were from metallurgical coal. Since the amount of steel that is produced is tied to global economic conditions, a decline in those conditions could result in the decline of steel, coke and metallurgical coal production. 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.

Any change in fuel consumption patterns by electric power generators resulting in a decrease in the use of coal could result in lower coal production by our lessees, which would reduce our coal royalty 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 new power plants will be built to produce electricity. Most of these new power plants will be fired by natural gas because of lower construction costs compared to coal-fired plants and because natural gas is a cleaner burning fuel. The increasingly stringent requirements of the federal Clean Air Act has 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. The environmental lobby is applying substantial pressure on utilities to limit the construction of new coal-fired generation plants in favor of alternative sources of energy. To the extent that these efforts are successful, it could reduce the demand for our coal.

The adoption of climate change legislation or regulations restricting emissions of greenhouse gases could result in reduced demand for our coal.

In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other greenhouse gases, or GHGs, present an endangerment to public health and welfare because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. Legal challenges to these findings have been rejected by the D.C. Circuit Court of Appeals, and we cannot predict the outcome of impending petitions to the Supreme Court. Based on its findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under various provisions of the Clean Air Act. Shortly after issuing its findings, EPA adopted rules, effective January 2, 2011, regulating GHG emissions from motor vehicles, and other rules requiring permits for emissions of GHGs from many stationary sources, including coal-fired electric power plants. The 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, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011. As a result of revisions to its preconstruction permitting rules that became fully effective on January 2, 2011, the EPA is now requiring new sources, including coal-fired power plants, to undergo control technology reviews for GHGs (predominately carbon dioxide) as a condition of permit issuance. These reviews may impose limits on GHG emissions, or otherwise be used to compel consideration of alternative fuels and generation systems, as well as increase litigation risk for and so discourage development of coal-fired power plants.

In addition, in March 2012, the EPA proposed new source performance standards to govern GHG emissions from electric generating units, including those fired by coal. The proposal, if adopted, would in effect prohibit the construction of new coal-fired power plants, because it would require them to meet the same GHG emission rate as a comparably sized gas-fired power plant. The consent decree also represents the EPA s agreement to consider adopting a GHG limitation program governing existing sources, as well, which the EPA may attempt to use to establish a cap-and-trade-like system on emissions of power plants GHG emissions. The EPA continues to delay any such proposal.

Several states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired electric generating facilities. Other regional programs are being considered in several regions of the country. It is possible that future federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, which could negatively impact our lessees coal sales, and thereby have an adverse effect on our coal royalty revenues.

In addition to the climate change legislation, our lessees are subject to numerous other federal, state and local laws and regulations that may limit their ability to produce and sell minerals from our properties.

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

New environmental legislation, new regulations and new interpretations of existing environmental laws, including regulations governing permitting requirements, could further regulate or tax the mineral industry and may also require our lessees to change their operations significantly, to incur increased costs or to obtain new or different permits, any of which could decrease our royalty revenues. Such increased scrutiny and enforcement of our lessees operations may result in increased compliance costs, revisions to permits, or changes in operations, which could decrease our royalty revenues.

As a result of ongoing consolidation in the coal industry and our partnership with Foresight Energy, we derive a greater percentage of our revenues from a smaller number of lessees.

In 2012, we derived 24.4% of our revenues from Foresight Energy and other Cline affiliates and 21.4% from Alpha Natural Resources. Foresight s Williamson mine alone was responsible for approximately 12.4% of our revenues in 2012. As a result, we have significant concentration of revenues with those lessees, although in most cases, with the exception of Williamson, the exposure is spread out over a number of different mining operations and leases. 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 royalty revenues and ability to make future distributions would be adversely affected.

Our business will be adversely affected if we are unable to acquire additional mineral reserves or access the capital markets to finance our growth.

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

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

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

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

- the payment of minimum royalties;
- marketing of the minerals mined;
- mine plans, including the amount to be mined and the method of mining;
- processing and blending minerals;
- expansion plans and capital expenditures;
- credit risk of their customers;
- permitting;
- insurance and surety bonding;
- acquisition of surface rights and other mineral estates;
- employee wages;

- transportation arrangements;

- compliance with applicable laws, including environmental laws; and

- mine closure and reclamation.

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

Our investments in operating businesses expose us to risks that we do not experience in the royalty business.

Our recent acquisition of a general partner interest in the trona operations of OCI Wyoming L.P. subjects us to operational and other contingent liabilities to which we are not exposed through our ownership of mineral rights and royalties. Further, we will not own 100 percent of, and only have limited approval rights with respect to, OCI Wyoming, and our partner will be able to control most business decisions, including decisions with respect to distributions and capital expenditures. In addition, we are ultimately responsible for operating the transportation infrastructure at the Williamson mine, and have assumed the capital and operating risks associated with that business. As a result of these investments, we could experience increased costs as well as increased liability exposure associated with operating these facilities.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce the production of minerals mined from our properties.

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

Our lessees depend upon railroads, barges, trucks and beltlines to deliver minerals to their customers. Disruption of those transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks and other events could temporarily impair the ability of our lessees to supply minerals to their customers. Our lessees transportation providers may face difficulties in the future that may impair the ability of our lessees to supply minerals to their customers, resulting in decreased royalty revenues to us.

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

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

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

Our reserve estimates may vary substantially from the actual amounts of minerals our lessees may be able to economically recover 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;
- future mining technology improvements;
- the effects of regulation by governmental agencies; and
- geologic and mining conditions, which may not be fully identified by available exploration data and may differ from our experiences in areas where our lessees currently mine.

16

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.

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

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

Risks Inherent in an Investment in Natural Resource Partners L.P.

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 will depend on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

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

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

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

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

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have little practical ability to remove our general partner or otherwise change its management. Our general partner may not be removed except upon the vote of the holders of at least 66 2/3% of our outstanding units (including units held by our general partner and its affiliates). Because the owners of our general partner, along with directors and executive officers and their affiliates, own a significant percentage of our outstanding common units, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates.

In addition, the following provisions of our partnership agreement may discourage a person or group from attempting to remove our general partner or otherwise change our management:

- generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and

- our partnership agreement contains limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders ability to influence the manner or direction of management.

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

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

Our general partner may cause us to issue an unlimited number of common units, without unitholder approval (subject to applicable New York Stock Exchange (NYSE) rules). We may also issue at any time an unlimited number of equity securities ranking junior or senior to the common units without unitholder approval (subject to applicable NYSE rules). The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

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

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

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

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

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner. Under Delaware law, however, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the control of our business. In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

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

These conflicts may include the following:

- we do not have any employees and we rely solely on employees of affiliates of the general partner;
- under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership;
- the amount of cash expenditures, borrowings and reserves in any quarter may affect cash available to pay quarterly distributions to unitholders;

the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner s liability;

under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not necessarily the result of arm s-length negotiations; and

the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us.

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

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

In addition, a change of control would constitute an event of default under our revolving credit agreement. During the continuance of an event of default under our revolving credit agreement, the administrative agent may terminate any outstanding commitments of the lenders to extend credit to us and/or declare all amounts payable by us immediately due and payable. A change of control also may trigger payment obligations under various compensation arrangements with our officers.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to you would be substantially reduced.

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

If we were treated as a corporation for U.S. federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely be liable for state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because taxes would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, our treatment as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of such a tax on us by any state will reduce the cash available for distribution to you.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such legislative proposal would eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Any modification to U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the qualifying income requirement to be treated as a partnership for U.S. federal income tax purposes.

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

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

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

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

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

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

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

Investments in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raise issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their shares of our taxable income. If you are a tax exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

We will treat each purchaser of common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

To maintain the uniformity of the economic and tax characteristics of our common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. The U.S. Treasury Department has issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

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

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

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

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

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

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

In addition to federal income taxes, you are likely subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in any of those jurisdictions. You are likely required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We own property and conduct business in a number of states in the United States. Most of these states impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is your responsibility to file all United States federal, state and local tax returns.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Major Coal Properties

The following is a summary of our major coal producing properties in each region.For information regarding our Coal Reserves and Production as well as other information related to our coal properties, please see Item 1. Business.

Northern Appalachia

Hibbs Run. The Hibbs Run Property is located in Marion County, West Virginia. In 2012, 3.8 tons were produced from the property. We lease this property to subsidiaries of Consol Energy. 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.

AFG-Ohio. The AFG-Ohio property is located in Belmont County, Ohio. In 2012, 3.1 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.

Beaver Creek. The Beaver Creek property is located in Grant and Tucker Counties, West Virginia. In 2012, 2.3 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. It 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.

Area F. The Area F property is located in Randolph and Upshur Counties, West Virginia. In 2012, 199,000 tons were produced from the property. We lease this property to Carter Roag, a subsidiary of Metinvest. Coal from this property is produced from an underground mine. The raw coal is trucked to a preparation plant operated by the lessee. Coal is shipped via rail and exported for use by Metinvest.

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

Central Appalachia

VICC/Alpha. The VICC/Alpha property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. In 2012, 5.0 million tons were produced from this property. We primarily lease this property to a subsidiary of Alpha Natural Resources. 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.

Lynch. The Lynch property is located in Harlan and Letcher Counties, Kentucky. In 2012, 3.1 million tons were produced from this property. We primarily lease the property to a subsidiary of Alpha Natural Resources. Production comes from both underground and surface mines. Coal is transported by truck to a preparation plant on the property and is shipped primarily on the CSX railroad to utility customers such as Georgia Power and Orlando Utilities. The lessee also has the ability to ship coal on the Norfolk Southern railroad and this coal goes to utility customers and domestic and export metallurgical customers. During the second half of 2012, the lessee idled some mines on this property that served the steam market.

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 and Patriot Coal. In 2012, 3.1 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 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.

VICC/Kentucky Land. The VICC/Kentucky Land property is located primarily in Perry, Leslie and Pike Counties, Kentucky. In 2012, 2.3 million tons were produced from this property. Coal is produced from a number of lessees 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 2012, 1.7 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 customers such as Georgia Power and the Tennessee Valley Authority.

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 Corp. In 2012, 1.6 million 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 2012, 1.3 million tons were produced from this property. We lease the property to a subsidiary of Arch Coal, Inc. Production comes from underground and surface mines and is transported by truck or beltline to a preparation plant on the property and shipped primarily on the Norfolk Southern railroad to utility customers such as Georgia Power and the Tennessee Valley Authority and domestic and export metallurgical customers such as Algoma Steel and Arcelor.

Kingston. The Kingston property is located in Fayette and Raleigh Counties, West Virginia. This property is leased to a subsidiary of Alpha Natural Resources. In 2012, 1.3 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. Coal is shipped via both the CSX railroad and by truck to barges to steam customers and various export metallurgical customers.

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

Southern Appalachia

Oak Grove. The Oak Grove property is located in Jefferson County, Alabama. In 2012, 2.0 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 2012, 1.7 million tons were produced from these properties. We lease these properties to a number of operators including Appolo Fuels Inc., Bell County Coal Corporation and Kopper-Glo Fuels. 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 Southern Company, South Carolina Electric & Gas, and numerous medium and small industrial customers.

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

IllinoisBasin

Williamson. The Williamson property is located in Franklin and Williamson Counties, Illinois. The property is under lease to an affiliate of Foresight Energy, and in 2012, 7.3 million tons were mined on the property. This production is from a longwall mine. Production is shipped primarily via the Canadian National railroad to customers such as Duke and to various export customers.

Hillsboro. The Hillsboro property is located in Montgomery and Bond Counties, Illinois. The property is under lease to an affiliate of Foresight Energy, and in 2012, 1.8 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 an affiliate of Foresight Energy, and in 2012, 1.8 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.

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

Northern Powder River Basin

Western Energy. The Western Energy property is located in Rosebud and Treasure Counties, Montana. In 2012, 2.4 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 and by the Burlington Northern Santa Fe railroad to Minnesota Power. A small amount of coal is transported by truck to other customers.

The map below shows the location of our properties in the Northern Powder River Basin.

BRP Properties

BRP is a venture between NRP and International Paper Company, of which NRP owns a 51% interest. As of December 31, 2012, BRP had acquired, in several stages from International Paper, approximately 9.1 million mineral acres in 31 states. While the vast majority of the 9.1 million acres remain largely undeveloped and underexplored, BRP currently holds 59 revenue generating mineral leases and 17 cell tower leases. In addition, a significant number of mineral prospects and deposits with yet undetermined commercial potential have been identified through a variety of efforts including exploration drilling, coring, drill logs, electric logs, inferences derived from published information, geological reports, geological maps, in-house efforts and consulting investigations. These prospects and deposits are not necessarily near-term commercial opportunities due to a variety of factors such as location, market, economic and production uncertainties, but have long-term development potential.

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 under 41 leases as of December 31, 2012. In addition to the leased mineral acreage, BRP holds a 1% gross production royalty interest on approximately 22,000 mineral acres in Louisiana. The remaining oil and gas mineral acreage in Louisiana is not leased but a number of acres are in areas with development potential. BRP has over 500 acres leased in Pennsylvania and approximately 300 acres leased in Texas.

As of December 31, 2012, BRP owned nearly 95,000 net mineral acres of coal rights (primarily lignite) in the Gulf Coast region, of which approximately 5,000 acres are leased under four separate leases in Louisiana and Alabama. In addition to the coal rights, BRP has aggregate reserves (including limestone, granite, clay, and sand and gravel) under lease in six states.

BRP also owns copper rights in Michigan s Upper Peninsula that are subject to a development agreement with Highland Copper Company Inc. By the end of 2012, Highland had drilled approximately 175 core holes representing approximately 80,000 total feet that have been cored, sampled and analyzed for copper. Highland expects to complete a feasibility study on the reserves in 2013.

Other mineral rights held by BRP as of December 31, 2012 included coalbed methane rights in four Gulf Coast states, metal prospect rights in four states, approximately 450,000 acres of water and water royalty rights in East Texas, geothermal rights and geothermal royalty interests in the Gulf Coast and Pacific Northwest, and carbon sequestration rights primarily in the Gulf Coast region.

The map on the following page illustrates the location of BRP s current mineral rights.

Title to Property

We owned approximately 99% of our coal, aggregates and oil and gas reserves in fee as of December 31, 2012. We lease the remainder from unaffiliated 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 owned by different 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.

Item 3. ***Legal Proceedings***

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, we believe these claims will not have a material effect on our financial position, liquidity or operations.

Item 4. ***Mine Safety Disclosures***

Not applicable.

PART II

Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities

Our common units are listed and traded on the NYSE under the symbol NRP . As of February 14, 2013, there were approximately 43,000 beneficial and registered holders of our common units. The computation of the approximate number of unitholders is based upon a broker survey.

The following table sets forth the high and low sales prices per common unit, as reported on the NYSE Composite Transaction Tape from January 3, 2011 to December 31, 2012, and the quarterly cash distribution declared and paid with respect to each quarter per common unit.

	Price Range		Cash Distribution History		
	High	**Low**	**Per Unit**	**Record Date**	**Payment Date**
2011					
First Quarter	$ 37.80	$ 32.24	$ 0.5400	05/05/2011	05/13/2011
Second Quarter	$ 35.44	$ 29.26	$ 0.5400	08/05/2011	08/12/2011
Third Quarter	$ 35.03	$ 23.98	$ 0.5500	11/04/2011	11/14/2011
Fourth Quarter	$ 30.48	$ 23.36	$ 0.5500	02/03/2012	02/14/2012
2012					
First Quarter	$ 28.70	$ 23.36	$ 0.5500	05/04/2012	05/14/2012
Second Quarter	$ 25.08	$ 21.45	$ 0.5500	08/03/2012	08/14/2012
Third Quarter	$ 23.04	$ 18.67	$ 0.5500	11/05/2012	11/14/2012
Fourth Quarter	$ 22.50	$ 16.90	$ 0.5500	02/05/2013	02/14/2013

Cash Distributions to Partners

(In thousands)

	General Partner	Limited Partners	Total Distributions
2011			
Distributions	$ 4,696	$ 230,080	$ 234,776
2012			
Distributions	$ 4,758	$ 233,263	$ 238,021

We must distribute all of our cash on hand at the end of each quarter, less cash reserves established by our general partner. We refer to this cash as available cash as that term is defined in our partnership agreement. The amount of available cash may be greater than or less than the quarterly distribution. Provisions of our credit facility and note purchase agreement may restrict our ability to make distributions under certain limited circumstances. Please see Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations- Contractual Obligations and Commercial Commitments.

Item 6. ***Selected Financial Data***

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

NATURAL RESOURCE PARTNERS L.P.

(In thousands, except per unit and per ton data)

	For the Years Ended December 31,				
	2012	**2011**	**2010**	**2009**	**2008**
Total revenues	$ 379,147	$ 377,683	$ 301,401	$ 256,084	$ 291,665
Asset impairments	$ 2,568	$ 161,336	$	$	$
Income from operations	$ 267,165	$ 104,135	$ 196,061	$ 153,975	$ 197,007
Net income	$ 213,355	$ 54,026	$ 154,461	$ 114,080	$ 170,006
Basic and diluted net income per limited partner unit	$ 1.97	$ 0.50	$ 1.54	$ 1.17	$ 1.95
Distributions paid ($ per unit)	$ 2.20	$ 2.17	$ 2.16	$ 2.16	$ 2.02
Weighted average number of common units outstanding	106,028	106,028	81,917	67,702	64,891
Cash from operations	$ 271,408	$ 305,574	$ 258,694	$ 210,669	$ 229,956
Balance sheet data:					
Cash and cash equivalents	$ 149,424	$ 214,922	$ 95,506	$ 82,634	$ 89,928
Total assets	$ 1,764,672	$ 1,665,649	$ 1,664,036	$ 1,523,590	$ 1,301,340
Long-term debt	$ 897,039	$ 836,268	$ 661,070	$ 626,587	$ 478,822
Partners capital	$ 617,447	$ 644,915	$ 825,180	$ 765,226	$ 743,341

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

The following discussion of the financial condition and results of operations should be read in conjunction with the historical financial statements and notes thereto included elsewhere in this filing. For more detailed information regarding the basis of presentation for the following financial information, see the Notes to the Consolidated Financial Statements.

Executive Overview

Our Business

We engage principally in the business of owning, managing and leasing mineral properties in the United States. We own coal reserves 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. As of December 31, 2012, we owned or controlled approximately 2.4 billion tons of proven and probable coal reserves, and we also owned approximately 500 million tons of aggregate reserves in a number of states across the country. We do not operate any 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.

Our revenue and profitability are dependent on our lessees ability to mine and market our reserves. Most of our coal is produced by large companies, many of which are publicly traded, with experienced and professional sales departments. A significant portion of our coal is sold by our lessees under coal supply contracts that have terms of one year or more. In contrast, our aggregate properties are typically mined by regional operators with significant experience and knowledge of the local markets. The aggregates are sold at current market prices, which historically have increased along with the producer price index for sand and gravel. Over the long term, both our coal and aggregate royalty revenues are affected by changes in the market for and the market price of the commodities.

In our coal and aggregate royalty business, our lessees generally make payments to us based on the greater of a percentage of the gross sales price or a fixed royalty per ton of coal or aggregates they sell, subject to minimum monthly, quarterly or annual payments. These minimum royalties are generally recoupable over a specified period of time, which varies by lease, if sufficient royalties are generated from production in those future periods. We do not recognize these minimum royalties as revenue until the applicable recoupment period has expired or they are recouped through production. Until recognized as revenue, these minimum royalties are recorded as deferred revenue, a liability on our balance sheet.

During 2012, we generated $111.8 million of our revenues from sources other than coal and aggregate royalty revenues, compared to $91.7 million for 2011. The majority of the increase was due to a $14.8 million increase in minimums recognized as revenue resulting from the expiration of the recoupment period on certain leases. We also recognized $13.6 million from the sale of assets, including $8.5 million from the sale of a right of way for highway construction and $4.7 million from the sale of a preparation plant.

In addition to the minimums recognized as revenue and gains on sales of assets, other sources of revenue include: processing and transportation fees; oil and gas royalty revenue; overriding royalties; wheelage payments; rentals; property tax revenue; and timber sales. The processing and transportation fees and overriding royalties were primarily derived from the coal-related assets.

Our Current Liquidity Position

Our credit facility does not mature until August 2016 and, as of December 31, 2012, we had $152 million in available capacity under the facility. In addition to the amounts available under our credit facility, we had approximately $149.4 million in cash at December 31, 2012. In January 2013, we acquired the interests in OCI Wyoming described in Note 16. Subsequent Events. to our financial statements. In connection with that acquisition, we entered into a three-year, $200 million term loan. We also used $16 million of cash on hand to acquire the interests. After the closing of the acquisition, we had still had $152 million in available capacity under our credit facility. We believe that the combination of the capacity under our credit facility and our cash on hand gives us enough liquidity to meet our current financial needs.

We hold a $35 million senior note that matures in June 2013 that we intend to refinance at or prior to its maturity. In addition, because the annual principal payments on our other senior notes will increase significantly beginning in 2013, we may choose to refinance some or all of the principal payments as they come due. We typically access the capital markets to refinance amounts outstanding under our credit facility as we approach the limits under that facility, the timing of which depends on the pace and size of our acquisition program.

Current Results/Market Outlook

For the year ended December 31, 2012, our lessees produced 59.7 million tons of coal and aggregates, generating $267.3 million in royalty revenues from our properties, and our total revenues were $379.1 million. We continue to have substantial exposure to metallurgical coal, from which we derived approximately 44% of our coal royalty revenues and 32% of the related production. While the demand for domestic steel was strong over the first half of the year, it began to decline in the third quarter, and prices for metallurgical coal dropped significantly in the fourth quarter and remain low heading into 2013. Primarily as a result of lower metallurgical prices and demand, but also due to the continued weakness in the steam coal market, our coal royalty revenues from Central Appalachia declined materially in 2012 as compared to 2011. However, over the full year, we saw the benefits of the diversity of our assets, with significant improvements in coal royalty revenues from our Illinois and Southern Appalachia properties as well as other sources of revenues offsetting much of the decline in Central Appalachia.

The market for steam coal remained soft as expected in 2012, with extremely low natural gas prices resulting in significant displacement of coal by gas for domestic power production. Further, the federal government regulations dealing with air quality at power plants have led to the announcement of planned closures of a number of coal-fired power plants, which will have an impact on future demand. In response to these events, a number of coal companies reduced their production over the course of the year, which has resulted in lower production from our properties.

Looking ahead to 2013, the production cutbacks by a number of our lessees, coupled with the continued soft demand for both steam and metallurgical coal, will likely result in lower coal royalty revenues for NRP. However, the reduced coal royalty revenues will be offset in part by revenues from our newly acquired interest in OCI Wyoming s soda ash operations.

Growth Through Acquisitions

In 2012, we spent approximately $240 million to acquire additional assets that will help secure the future growth of the partnership. Included in these acquisitions were additional steam coal reserves and transportation infrastructure in Illinois, metallurgical coal reserves in Virginia, oil and gas mineral rights in Oklahoma, an overriding royalty on oil and gas reserves in the liquids-rich portion of the Marcellus Shale play, and an overriding royalty on frac sand reserves in Wisconsin. These efforts are reflective of NRP management s desire to continue to grow and diversify the assets of the partnership and attempt to ensure the stability of future revenues and distributions to our unitholders.

Political, Legal and Regulatory Environment

The political, legal and regulatory environment continues to be difficult for the coal industry. The Environmental Protection Agency, or EPA, has used its authority to create significant delays in the issuance of new permits and the modification of existing permits, which has led to substantial delays and increased costs for coal operators. In addition to its involvement in the permitting process, in December 2009, the EPA determined that six greenhouse gases, including carbon dioxide and methane, endanger the public health and welfare of current and future generations. In *Coalition for Responsible Regulation v. EPA*, several petitioners challenged the EPA s findings, but in June 2012 the D.C. Circuit Court upheld all of the regulations promulgated by the EPA. The petitioners have appealed the ruling and have requested to have several issues in the case heard *en banc*, but the ruling was a significant victory for the EPA.

Over the past year, the industry has successfully challenged EPA policy, regulations and guidance in several other court decisions, including *Mingo Logan Coal Co. v. EPA, National Mining Association v. Jackson, and EME Homer City Generation, L.P. v. EPA*. While each of these cases has unique facts and circumstances, the general theme in these cases is that the EPA has overreached its authority in a number of instances. However, the EPA has continued to promulgate regulations that will negatively affect the viability of coal-fired generation, which will ultimately reduce coal consumption and the production of coal from our properties. Additionally, citizens groups have continued to be active in bringing lawsuits against operators, as well as challenging permits issued by the Army Corps of Engineers.

In addition to the increased oversight of the EPA, the Mine Safety and Health Administration, or MSHA, has increased its involvement in the approval of plans and enforcement of safety issues in connection with mining. MSHA s involvement has increased the cost of mining due to more frequent citations and much higher fines imposed on our lessees as well as the overall cost of regulatory compliance. Combined with the difficult economic environment and the higher costs of mining in general, MSHA s recent increased participation in the mine development process has reduced production from mines, caused some mines to be idled and has delayed the opening of new mines.

Distributable Cash Flow

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

Our historical distributable cash flow represents cash flow from operations, proceeds from sale of assets and return on direct financing lease and contractual override less actual principal payments and cash reserves set aside for scheduled principal payments on our senior notes. Although distributable cash flow is a non-GAAP financial measure, we believe it is a useful adjunct to net cash provided by operating activities under GAAP. Distributable cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities. Distributable cash flow may not be calculated the same for NRP as for other companies. A reconciliation of distributable cash flow to net cash provided by operating activities is set forth below.

We have historically reduced our distributable cash flow by the amount of cash we have reserved for principal payments due on our senior notes in the next calendar year. However, to present our distributable cash flow more in line with MLP practice and because we intend to refinance some or all of the principal payments that are due in 2013 and 2014, we are no longer going to reduce distributable cash flow by reserves for future principal payments. This change in our reporting of distributable cash flow does not change our long-term intention to pay down our debt.

Reconciliation of GAAP Net cash provided by operating activities

to Non-GAAP Distributable cash flow

	For the Years Ended December 31,		
	2012	**2011**	**2010**
Net cash provided by operating activities	$ 271,408	$ 305,574	$ 258,694
Less scheduled principal payments	(30,800)	(31,518)	(32,234)
Less reserves for future principal payments	(52,234)	(31,159)	(31,699)
Add reserves used for scheduled principal payments	30,800	31,518	32,234
Return on direct financing lease	2,669		
Proceeds from sale of assets	24,822	5,600	1,180
Distributable cash flow	$ 246,665	$ 280,015	$ 228,175

Recent Acquisitions

We are a growth-oriented company and have closed a number of acquisitions over the last several years. Our most recent acquisitions are briefly described below.

OCI. On January 24, 2013, we acquired non-controlling equity interests in OCI Wyoming Co. and OCI Wyoming, L.P. The interests are comprised of a 48.51% general partner interest in OCI LP and 20% of the common stock and 100% of the preferred stock in OCI Co. OCI Co owns a 1% limited partnership interest in OCI LP and has the right to receive a $14.5 million annual priority distribution before distributions are paid to other interests. The 80% common interest in OCI Co is owned by OCI Chemical Corporation and the 50.49% interest in OCI LP is owned by OCI Wyoming Holding Co., a subsidiary of OCI Chemical Corporation.

The three investments were acquired from Anadarko Holding Company and its subsidiary, Big Island Trona Company for $292.5 million. The purchase price was funded from the proceeds of a $200 million term loan, $76.5 million in equity and GP interests issued in a private placement and the balance from operating cash. The acquisition agreement provides for up to $50 million in additional contingent consideration should certain performance criteria be met as defined in the purchase and sales agreement in any of 2013, 2014 or 2015.

Marcellus Override. In December 2012, we acquired an overriding royalty interest on approximately 88,000 net acres of overriding royalty interests in oil and gas reserves located in the Marcellus Shale for $30.3 million.

Hi-Crush Override. On October 30, 2012, we acquired an overriding royalty interest in frac sand reserves located on approximately 561 acres near Wyeville, Wisconsin for approximately $15.0 million.

Colt. Between September 2009 and September 2012, we acquired approximately 200 million tons of coal reserves related to the Deer Run Mine in Illinois from Colt, LLC, an affiliate of the Cline Group, for a total purchase price of $255 million.

Oklahoma Oil and Gas. From December 2011 through June 2012, we acquired approximately 19,200 net mineral acres located in the Mississippian Lime oil play in Northern Oklahoma for $63.9 million.

Sugar Camp. In March 2012, we acquired the rail loadout associated infrastructure assets for $50.0 million and a contractual overriding royalty for $8.9 million interest on certain tonnage at the Sugar Camp mine in Illinois. The rail loadout and infrastructure assets were purchased from Sugar Camp Energy, LLC and the contractual overriding royalty interest was purchased from Ruger, LLC, both affiliates of the Cline Group.

Litz-Moore. In March 2012, we acquired metallurgical coal reserves adjacent to current NRP holdings in Virginia for $2.8 million.

Royal. In July 2011, we acquired approximately 44,000 acres of coal reserves and coal bed methane located in Pennsylvania and Illinois from Royal Oil and Gas Corporation for $8.0 million.

NBR Sand. In June 2011, we acquired an overriding royalty interest in approximately 711 acres of frac sand reserves near Tyler, Texas for $16.5 million.

East Tennessee Materials. In March 2011, we acquired approximately 500 acres of mineral and surface rights related to limestone reserves in Cleveland, Tennessee near Chattanooga for $4.7 million.

CALX Resources. In February 2011, we acquired approximately 500 acres of mineral and surface rights related to limestone reserves on the Tennessee River near Paducah, Kentucky for $16.0 million.

Critical Accounting Policies

Coal and Aggregate Royalties. Coal and aggregate royalty revenues are recognized on the basis of tons of mineral sold by our lessees and the corresponding revenue from those sales. Generally, the lessees make payments to us based on the greater of a percentage of the gross sales price or a fixed price per ton of mineral they sell, subject to minimum annual or quarterly payments.

Processing and Transportation Fees. Processing fees are recognized on the basis of tons of material processed through the facilities by our lessees and the corresponding revenue from those sales. Generally, the lessees of the processing facilities make payments to us based on the greater of a percentage of the gross sales price or a fixed price per ton of coal that is processed and sold from the facilities. The processing leases are structured so that the lessees are responsible for operating and maintenance expenses associated with the facilities. Transportation fees are recognized on the basis of tons of coal transported over the beltlines. Under the terms of the transportation contracts, we receive a fixed price per ton for all coal transported on the beltlines.

Oil and Gas Royalties. Oil and gas royalties are recognized on the basis of volume of hydrocarbons sold by lessees and the corresponding revenue 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.

Minimum Royalties. Most of our lessees must make minimum annual or quarterly payments which are generally recoupable over certain time periods. These minimum payments are recorded as deferred revenue when received. The deferred revenue attributable to the minimum payment is recognized as revenues either when the lessee recoups the minimum payment through production or immediately following the period during which the lessee is allowed to recoup the minimum payment.

Lessee Audits and Inspections. We periodically audit lessee information by examining certain records and internal reports of our lessees. Our regional managers also perform periodic mine inspections to verify that the information that has been 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. Our audits and inspections, however, are in periods subsequent to when the revenue is reported and any adjustment identified by these processes might be in a reporting period different from when the revenue was initially recorded.

Depreciation, Depletion and Amortization. We depreciate our plant and equipment on a straight line basis over the estimated useful life of the asset. We deplete mineral properties on a units-of-production basis by lease, based upon minerals mined in relation to the net cost of the mineral properties and estimated proven and probable tonnage in those properties. We amortize intangible assets on a units-of-production basis, unless classified as a temporarily idled asset then a minimum amortization is applied. Oil and gas mineral rights are depleted over the units of production. We estimate proven and probable reserves with the assistance of third-party consultants, as well as estimation techniques and recoverability assumptions. We update our estimates of reserves periodically and this may result in material adjustments to reserves and depletion rates that we recognize prospectively. Historical revisions have not been material.

Asset Impairment. If facts and circumstances suggest that a long-lived asset or an intangible asset may be impaired, the carrying value is reviewed. If this review indicates that the value of the asset will not be recoverable, as determined based on projected undiscounted cash flows related to the asset over its remaining life, then the carrying value of the asset is reduced to its estimated fair value.

Share-Based Payments. We account for our Long-Term Incentive Plan awards under Financial Accounting Standards Board s (FASB) stock compensation authoritative guidance. This authoritative guidance provides that grants must be accounted for using the fair value method, which requires us to estimate the fair value of the grant and charge or credit the estimated fair value to expense over the service or vesting period of the grant based on fluctuations in value. In addition, this authoritative guidance requires that estimated forfeitures be included in the periodic computation of the fair value of the liability and that the fair value be recalculated at each reporting date over the service or vesting period of the grant.

Recent Accounting Pronouncements

In June 2011, the FASB amended the presentation of comprehensive income. The amendments in this update give us the option to present the total comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. We adopted this amendment on January 1, 2012 and elected to present other comprehensive income in a single continuous statement, Consolidated Statements of Comprehensive Income. We also elected to present changes in accumulated other comprehensive income in the Consolidated Statements of Partners Capital.

In May 2011, the FASB amended fair value measurement and disclosure requirements. The amendments result in common fair value measurement and disclosure requirements in U.S. GAAP and International Financial Reporting Standards (IFRSs). Some of the amendments clarify the FASB s intent about the application of existing fair value measurement requirements. Other amendments change a particular principal or requirement for measuring fair value or for disclosing information about fair value measurements. We adopted this amendment on January 1, 2012. The amendment did not have a material impact on our financial position, results of operations, cash flows or notes to the financial statements.

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

Results of Operations

Summary of 2012 and 2011 Royalties and Production

(In thousands, except percent and per ton data)

	For the Years Ended December 31, 2012	For the Years Ended December 31, 2011	Increase (Decrease)	Percentage Change
Coal royalties				
Appalachia				
Northern	$ 15,768	$ 20,578	$ (4,810)	(23)%
Central	156,390	196,789	(40,399)	(21)%
Southern	29,325	11,717	17,608	150%
Total Appalachia	201,483	229,084	(27,601)	(12)%
Illinois Basin	49,538	41,324	8,214	20%
Northern Powder River Basin	8,501	7,658	843	11%
Gulf Coast	1,212	1,155	57	5%
Total	$ 260,734	$ 279,221	$ (18,487)	(7)%
Production (tons)				
Appalachia				
Northern	10,486	5,251	5,235	100%
Central	26,098	29,555	(3,457)	(12)%
Southern	3,718	1,695	2,023	119%
Total Appalachia	40,302	36,501	3,801	10%
Illinois Basin	11,299	9,445	1,854	20%
Northern Powder River Basin	2,377	2,682	(305)	(11)%
Gulf Coast	466	523	(57)	(11)%
Total	54,444	49,151	5,293	11%
Average gross royalty revenue per ton				
Appalachia				
Northern	$ 1.50	$ 3.92	$ (2.42)	(62)%
Central	$ 5.99	$ 6.66	$ (0.67)	(10)%
Southern	$ 7.89	$ 6.91	$ 0.98	14%
Total Appalachia	$ 5.00	$ 6.28	$ (1.28)	(20)%
Illinois Basin	$ 4.38	$ 4.38	$	
Northern Powder River Basin	$ 3.58	$ 2.86	$ 0.72	25%
Gulf Coast	$ 2.60	$ 2.21	$ 0.39	18%
Combined average gross royalty revenue per ton	$ 4.79	$ 5.68	$ (0.89)	16%
Aggregates				
Royalty revenues	$ 6,598	$ 6,640	$ (42)	(1)%
Aggregate Bonus Royalty	$	$ 94	$ (94)	(100)%
Production	5,287	5,930	(643)	(11)%
Average gross royalty revenue per ton	$ 1.25	$ 1.12	$ 0.13	12%
Oil and Gas				
Royalty	$ 9,160	$ 14,017	$ (4,857)	(35)%

Coal Royalty Revenues and Production

Coal royalty revenues comprised approximately 69% of our total revenue for the year ended December 31, 2012 and 74% of our total revenue in 2011. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. The combination of lower production and lower prices in Central Appalachia, together with a lower royalty rate in Northern Appalachia, were the primary reasons coal royalty revenues decreased by $27.6 million in 2012. The 3.5 million ton decrease in production in Central Appalachia was the result of our lessees reducing production in response to the weaker coal market and the effect of some lessees having a lower proportion of production on our properties. Production in Northern Appalachia increased by 5.2 million tons, but these increases were mainly on leases with a lower revenue per ton, and therefore still resulted in reduced revenue of $4.8 million. The decreases are partially offset by an increase in production and revenue in Southern Appalachia, due primarily to one of our lessees resuming production for the entire year after it completed repairs to its preparation plant that was damaged by a tornado in 2011.

Illinois Basin. Coal royalty revenues and production on our properties were both higher in 2012. Coal royalty revenues increased by $8.2 million and production increased by 1.9 million tons. The increased production was mainly due to production from our Hillsboro property that began longwall operations in the third quarter of 2012. In addition, we had increased production at the Williamson mine.

Northern Powder River Basin. Our coal royalty revenues increased by $843,000 over last year despite a production decrease of 305,000 tons on our Western Energy property. The lower production was due to the normal variations that occur due to the checkerboard nature of our ownership. The higher revenue per ton was due to the timing of revenue recognition by the lessee in the third quarter.

Aggregates Royalty Revenues and Production

For the year ended December 31, 2012, we recognized $6.6 million in royalty revenue from aggregates. For the same period for 2011, we recognized royalty revenue from aggregates of $6.7 million, which included bonus revenue of $0.1 million under one of our leases. We had production of 5.3 million tons and 5.9 million tons for 2012 and 2011, respectively. Although production declined, our revenue per ton increased and helped keep the royalty revenue nearly constant. Also, we do not include revenues from our frac sand properties in Texas and Wisconsin in aggregate royalties, but include those revenues in overriding royalties. We received $1.5 million in revenues from the Texas property in 2012.

Oil and Gas Royalty Revenues

Oil and gas royalty revenues for the years ended December 31, 2012 and 2011 were $9.2 million and $14.0 million, respectively. In 2012, we saw a significant decline in royalty revenues from our Louisiana BRP properties due to low gas prices and reduced drilling activity, which was offset in part by $1.1 million in royalty revenues received from our recently acquired Oklahoma properties. Included in revenue for the years ended 2012 and 2011 were bonus payments of $2.6 million and $2.1 million, respectively.

Summary of 2011 and 2010 Royalties and Production

(In thousands, except percent and per ton data)

	For the Years Ended December 31, 2011	For the Years Ended December 31, 2010	Increase (Decrease)	Percentage Change
Coal royalties				
Appalachia				
Northern	$ 20,578	$ 18,676	$ 1,902	10%
Central	196,789	144,934	51,855	36%
Southern	11,717	19,405	(7,688)	(40)%
Total Appalachia	229,084	183,015	46,069	25%
Illinois Basin	41,324	30,210	11,114	37%
Northern Powder River Basin	7,658	8,444	(786)	(9)%
Gulf Coast	1,155	92	1,063	NMF*
Total	$ 279,221	$ 221,761	$ 57,460	26%
Production (tons)				
Appalachia				
Northern	5,251	4,900	351	7%
Central	29,555	27,056	2,499	9%
Southern	1,695	2,824	(1,129)	(40)%
Total Appalachia	36,501	34,780	1,721	5%
Illinois Basin	9,445	7,753	1,692	22%
Northern Powder River Basin	2,682	4,467	(1,785)	(40)%
Gulf Coast	523	52	471	NMF*
Total	49,151	47,052	2,099	4%
Average gross royalty revenue per ton				
Appalachia				
Northern	$ 3.92	$ 3.81	$ 0.11	3%
Central	$ 6.66	$ 5.36	$ 1.30	24%
Southern	$ 6.91	$ 6.87	$ 0.04	1%
Total Appalachia	$ 6.28	$ 5.26	$ 1.02	19%
Illinois Basin	$ 4.38	$ 3.90	$ 0.48	12%
Northern Powder River Basin	$ 2.86	$ 1.89	$ 0.97	51%
Gulf Coast	$ 2.21	$ 1.77	$ 0.44	25%
Combined average gross royalty revenue per ton	$ 5.68	$ 4.71	$ 0.97	21%
Aggregates				
Royalty revenues	$ 6,640	$ 4,869	$ 1,771	36%
Aggregate Bonus Royalty	$ 94	$ (639)	$ 733	NMF*
Production	5,930	4,365	1,565	36%
Average gross royalty revenue per ton	$ 1.12	$ 1.12	$	0%
Oil and Gas				
Royalty	$ 14,017	$ 7,720	$ 6,297	82%

* (NMF) Not meaningful.

Coal Royalty Revenues and Production

Coal royalty revenues comprised approximately 74% of our total revenue for both years ended December 31, 2011 and 2010, respectively. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. Primarily as a result of higher prices being received by our lessees in Northern and Central Appalachia, coal royalty revenues increased by $46.1 million in 2011. The 1.7 million ton increase in production was the result of several of our lessees in Northern and Central Appalachia having a greater proportion of production on our properties or mines moving onto our property. We also benefitted from much higher prices for the significant metallurgical coal production from our Central Appalachia properties. Additionally, repairs were completed at a preparation plant that was damaged by fire in 2010, allowing those mines to produce for the entire year. These increases more than offset the reduction in production in Southern Appalachia caused by a lessee having its preparation plant damaged by a tornado in late April.

Illinois Basin. Coal royalty revenues and production on our properties were both higher in 2011. Coal royalty revenues increased by $11.1 million and production increased by 1.7 million tons. The increased production was due to production from our Williamson and Macoupin properties. The combination of having a greater proportion of our production from properties with higher royalty rates and our lessees receiving higher prices increased our royalty per ton.

Northern Powder River Basin. The decrease in both coal royalty revenues of $0.8 million and production of 1.8 million tons on our Western Energy property was due to the normal variations that occur due to the checkerboard nature of our ownership. The higher prices received by our lessee and the resultant higher revenue per ton did help to partially offset some of the lower production.

Aggregates Royalty Revenues and Production

For the year ended December 31, 2011, we recognized $6.7 million in royalty revenue from aggregates, which included a bonus payment of $0.1 million under the terms of one of our leases. For the same period for 2010, we recognized royalty revenue from aggregates of $4.2 million, which included bonus revenue reversal of $0.6 million under the same lease. We had production of 5.9 million tons and 4.4 million tons for each of these years. Although production declined at our largest property in Dupont, Washington, the total production from our properties increased due to our recent acquisitions of additional reserves.

Oil and Gas Royalty Revenues

Oil and gas royalty revenues increased 82% to $14.0 million due to a full year of ownership of the BRP properties. Oil and gas royalty revenues include production revenues as well as bonus payments.

Other Operating Results

Processing and Transportation Revenues. We generated $8.3 million, $13.5 million and $9.6 million in processing revenues for the years ended December 31, 2012, 2011 and 2010, respectively. Our processing revenues are derived primarily from our ownership of coal preparation plants. We do not operate the preparation plants, but receive a fee for material processed through them. Similar to our coal royalty structure, the throughput fees are based on a percentage of the ultimate sales price for the material that is processed through the facilities. During 2012, lower volumes and prices at our plants in Appalachia coupled with the sale of a preparation plant contributed to lower processing revenues when compared to 2011. The increase in processing revenues for the year ended December 31, 2011 over 2010 is primarily due to higher volumes at higher prices. The increase in 2011 also reflects the addition of the loadout facility at Macoupin being online for a full year.

In addition to our preparation plants, we own coal handling and transportation infrastructure in Illinois. In contrast to our typical royalty structure, we receive a fixed rate per ton for coal transported over these facilities. At the Williamson mine in Illinois, we operate the coal handling and transportation infrastructure and have subcontracted out that responsibility to a third party. We generated transportation fees from these assets of approximately $19.5 million, $16.7 million and $14.6 million for the years ended December 31, 2012, 2011 and 2010, respectively. The steady increase in transportation fees from 2010 to 2012 is due to increased volumes from our lessee operations in the Illinois Basin.

Additional Revenues. In addition to coal royalties, aggregate royalties, oil and gas royalties and processing and transportation revenues, we generated approximately 20%, 13% and 14% of our revenues from other sources for the years ended December 31, 2012, 2011 and 2010, respectively. These other sources include: property taxes, minimums recognized as revenues, overriding royalties, timber, rentals, wheelage and other income. In 2012, we recognized $24.0 million from minimums recognized as revenue. Due to higher minimums recognized as revenue in 2012, the percentage of other revenue is higher than usual in that year. Of the $24.0 million, we recognized $9.6 million on our Gatling Ohio lease and $8.2 million on our Macoupin lease. Also included in other revenue in 2012 is a gain from sale of assets of $13.6 million, including $8.5 million from the sale of a right of way for highway construction and $4.7 million from the sale of a preparation plant.

Operating expenses. Included in total expenses are:

Depreciation, depletion and amortization of $58.2 million, $65.1 million and $57.0 million for the years ended December 31, 2012, 2011 and 2010, respectively. Amortization increased during 2011 due to a refinement of our accounting policy for contract amortization. The decrease in 2012 was primarily related to assets acquired from Gatling, LLC and Gatling Ohio, LLC that were impaired during the third and fourth quarters of 2011.

General and administrative expenses of $29.7 million, $29.6 million and $29.9 million for the years ended December 31, 2012, 2011 and 2010, respectively. General and administrative expenses are primarily impacted by accruals under our long-term incentive plan attributable to fluctuations in our unit price and additional personnel required to manage our properties.

Property, franchise and other taxes of $17.7 million, $14.5 million and $15.1 million for the years ended December 31, 2012, 2011 and 2010, respectively. A substantial portion of our property taxes is reimbursed to us by our lessees and is reflected as property tax revenue on our statements of comprehensive income. For the year ended December 31, 2012, we recognized higher Kentucky and West Virginia property taxes.

Interest Expense. Interest expense was $54.0 million, $49.2 million and $41.6 million for the years ended December 31, 2012, 2011 and 2010, respectively. Interest increased due to additional debt incurred in 2012 and 2011 to fund acquisitions.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

We satisfy our working capital requirements with cash generated from operations. We finance our property acquisitions with available cash, borrowings under our revolving credit facility, and the issuance of our senior notes and additional common units. While our ability to satisfy our debt service obligations and pay distributions to our unitholders depends in large part on our future operating performance, our ability to make acquisitions will depend on prevailing economic conditions in the financial markets as well as the coal, oil and gas and aggregate/industrial minerals industries and other factors, some of which are beyond our control. For a more complete discussion of factors that will affect cash flow we generate from operations, please read Item 1A. Risk Factors. Our capital expenditures, other than for acquisitions, have historically been minimal.

During 2012, we continued to review our banking relationships and our internal policies regarding deposit concentrations with specific attention to effectively managing risk in the current banking environment.

Our credit facility does not mature until August 2016 and, as of December 31, 2012, we had $152 million in available capacity under the facility. In addition to the amounts available under our credit facility, we had approximately $149.4 million in cash at December 31, 2012. In January 2013, we acquired the interests in OCI

Wyoming described in Note 15. Subsequent Events. to our financial statements. In connection with that acquisition, we entered into a three-year, $200 million term loan. The loan requires repayments of $10 million and $20 million in 2014 and 2015, respectively. We also used $16 million of cash on hand to acquire the interests. After the closing of the acquisition, we had still had $152 million in available capacity under our credit facility. We believe that the combination of the capacity under our credit facility and our cash on hand gives us enough liquidity to meet our current financial needs.

We hold a $35 million senior note that matures in June 2013 that we intend to refinance at or prior to its maturity. In addition, because the annual principal payments on our other senior notes will increase significantly beginning in 2013, we may choose to refinance some or all of the principal payments as they come due. To the extent that we use cash on hand to pay the principal payments as they come due, our outstanding principal balance will be reduced on our long-term debt as our minerals are depleted. We do typically access the capital markets to refinance amounts outstanding under our credit facility as we approach the limits under that facility, the timing of which depends on the pace and size of our acquisition program. In August 2011, we amended and extended our credit facility until August 2016. Our debt covenant ratios are in compliance for both our credit facility and our outstanding senior notes. For a more complete discussion of factors that will affect our liquidity, please read Item 1A. Risk Factors.

Net cash provided by operations for the years ended December 31, 2012, 2011 and 2010 was $271.4 million, $305.6 million and $258.7 million, respectively. The most significant portion of our cash provided by operations is generated from coal royalty revenues.

Net cash used in investing activities for the years ended December 31, 2012, 2011 and 2010 was $212.7 million, $115.1 million and $170.8 million, respectively. During 2012 the majority of our investing activities consisted of acquiring reserves, plant and equipment and related intangibles as well as assets relating to Sugar Camp. These uses were offset slightly by $24.8 million in proceeds from sale of assets. During 2011 and 2010 substantially all of our investing activities consisted of acquiring reserves, plant and equipment and other rights.

Net cash flows used in financing activities for the years ended December 31, 2012, 2011 and 2010 was $124.2 million, $71.1 million and $75.0 million, respectively. During 2012, 2011 and 2010 we had proceeds from loans of $148.0 million, $385.0 million and $140.0 million, respectively. During 2012, 2011 and 2010 these proceeds were offset by repayment of debt of $30.8 million, $210.5 million and $106.2 million, respectively. Also during 2012, 2011 and 2010 we paid distributions of $240.8 million, $234.8 million and $209.8 million, respectively. During 2010, we had proceeds of $110.4 million relating to issuance of common units as well as a $2.4 million contribution by our general partner.

Contractual Obligations and Commercial Commitments

Credit Facility. We amended and restated our $300 million revolving credit facility in August 2011, and as of the date of this report we had $152 million available to us under the facility. Under an accordion feature in the credit facility, we may request our lenders to increase their aggregate commitment to a maximum of $500 million on the same terms. However, we cannot be certain that our lenders will elect to participate in the accordion feature. To the extent the lenders decline to participate, we may elect to bring new lenders into the facility, but cannot make any assurance that the additional credit capacity will be available to us on existing or comparable terms.

During 2012, our borrowings and repayments under our credit facility were as follows:

	Quarters Ending			
	March 31, 2012	**June 30, 2012**	**September 30, 2012**	**December 31, 2012**
			(In thousands)	
Outstanding balance, beginning of period	$	$ 47,000	$ 73,000	$ 103,000
Borrowings under credit facility	47,000	26,000	30,000	45,000
Less: Repayments under credit facility				
Outstanding balance, ending period	$ 47,000	$ 73,000	$ 103,000	$ 148,000

Our obligations under the credit facility are unsecured but are guaranteed by our operating subsidiaries. We may prepay all loans at any time without penalty. Indebtedness under the revolving credit facility bears interest, at our option, at either:

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

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

The credit agreement contains covenants requiring us to maintain:

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

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

The senior note purchase agreement contains covenants requiring our operating subsidiary to:

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

Term Loan

On January 24, 2013, we issued $200 million in new term debt, which is priced at LIBOR + 2% and adjusts periodically with changes in LIBOR. Interest is payable initially in April 2013, with principal payments of $10.0 million on January 23, 2014, $20.0 million on January 23, 2015 and the balance of $170.0 million on January 23, 2016. The covenants under our term loan are identical to those in our credit facility.

Long-Term Debt

As of the date of this filing, our debt consisted of:

- $148.0 million of our $300 million floating rate revolving credit facility, due August 2016;

$35.0 million of 5.55% senior notes due 2013;

$200.0 million floating rate term loan due 2016;

$27.7 million of 4.91% senior notes due 2018;

$150.0 million of 8.38% senior notes due 2019;

$61.5 million of 5.05% senior notes due 2020;

$1.7 million of 5.31% utility local improvement obligation due 2021;

$30.3 million of 5.55% senior notes due 2023;

$75.0 million of 4.73% senior notes due 2023;

$180.0 million of 5.82% senior notes due 2024;

$50.0 million of 8.92% senior notes due 2024;

$175.0 million of 5.03% senior notes due 2026; and

$50.0 million of 5.18% senior notes due 2026.

Other than the 5.55% senior notes due 2013, which have only semi-annual interest payments, all of our senior notes require annual principal payments in addition to semi-annual interest payments. The scheduled principal payments on the 8.38% senior notes due 2019 do not begin until March 2013, the scheduled principal payments on the 8.92% senior notes due 2024 do not begin until March 2014, and the scheduled principal payments on the 4.73%, 5.03% and 5.18% senior notes do not begin until December 2014. We also make annual principal and interest payments on the utility local improvement obligation.

The following table reflects our long-term non-cancelable contractual obligations as of December 31, 2012 (in millions):

		Payments Due by Period					
Contractual Obligations	**Total**	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**
Long-term debt principal payments (including current maturities)(1) (2)	$ 984.3	$ 87.2	$ 81.0	$ 81.0	$ 229.0	$ 81.0	$ 425.1
Long-term debt interest payments(3)	278.5	48.1	43.5	38.4	33.3	28.2	87.0
Rental leases(4)	4.1	0.7	0.7	0.7	0.7	0.7	0.6
Total	$ 1,266.9	$ 136.0	$ 125.2	$ 120.1	$ 263.0	$ 109.9	$ 512.7

(1) The amounts indicated in the table include principal or interest due on our senior notes, as well as the utility local improvement obligation related to our property in DuPont, Washington. The table also includes the $148.0 million outstanding principal balance under our credit facility, which matures in August 2016.

(2) On January 24, 2013, we entered into a $200 million three year term loan that is not included in the table. We have principal payments due of $10 million in January 2014, $20 million in January 2015 and the remainder due upon maturity in January 2016.

(3) The amounts indicated in the table include interest due on our senior notes as well as the utility local improvement obligation related to our property in DuPont, Washington.

(4) On January 1, 2009, we entered into a ten-year lease agreement for the rental of office space from Western Pocahontas Properties Limited Partnership. The rental obligations from this lease are included in the table above.

Shelf Registration Statement

In addition to our credit facility, on April 24, 2012 we filed an automatically effective shelf registration statement on Form S-3 with the SEC that is available for registered offerings of common units and debt securities. This shelf replaced our previous shelf registration statement, which expired at the end of February 2012. On August 15, 2012, we filed another shelf registration statement that registered all of the common units held by Adena Minerals, as well as up to $500 million in equity or debt securities by NRP. Following the effectiveness of this registration statement, Adena distributed 15,181,716 common units to its shareholders, and we subsequently filed prospectus supplements to register the resale of these common units by those shareholders. We cannot control the resale of the common units by Adena or its shareholders, and the amounts, prices and timing of the issuance and sale of any equity or debt securities by NRP will depend on market conditions, our capital requirements and compliance with our credit facility and senior notes.

In January 2013, we acquired the interests in OCI Wyoming described in Recent Acquisitions . Because this acquisition requires us to file one year of audited financial statements of the acquired business pursuant to Items 2.01 and 9.01 of Form 8-K and Rule 3-05 of Regulation S-X, we will not be able to issue securities under our shelf registration statements until those financial statements are filed with the SEC. We anticipate making this filing by mid-April.

Off-Balance Sheet Transactions

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

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on operations for the years ended December 31, 2012, 2011 and 2010.

Environmental

The operations our lessees conduct on our properties are subject to federal and state environmental laws and regulations. Please see Item 1, Business Regulation and Environmental Matters. As an owner of surface interests in some properties, we may be liable for certain environmental conditions occurring on the surface properties. The terms of substantially all of our coal leases require the lessee to comply with all applicable laws and regulations, including environmental laws and regulations. Lessees post reclamation bonds assuring that reclamation will be completed as required by the relevant permit, and substantially all of the leases require the lessee to indemnify us against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. Because we have no employees, employees of Western Pocahontas Properties Limited Partnership make regular visits to the mines to ensure compliance with lease terms, but the duty to comply with all regulations rests with the lessees. We believe that our lessees will be able to comply with existing regulations and do not expect any lessee s failure to comply with environmental laws and regulations to have a material impact on our financial condition or results of operations. We have neither incurred, nor are aware of, any material environmental charges imposed on us related to our properties for the period ended December 31, 2012. We are not associated with any environmental contamination that may require remediation costs. However, our lessees do conduct reclamation work on the properties under lease to them. Because we are not the permittee of the mines being reclaimed, we are not responsible for the costs associated with these reclamation operations. In addition, West Virginia has established a fund to satisfy any shortfall in reclamation obligations.

Related Party Transactions

Partnership Agreement

Our general partner does not receive any management fee or other compensation for its management of Natural Resource Partners L.P. However, in accordance with the partnership agreement, we reimburse our general partner and its affiliates for expenses incurred on our behalf. All direct general and administrative expenses are charged to us as incurred. We also reimburse indirect general and administrative costs, including certain legal, accounting, treasury, information technology, insurance, administration of employee benefits and other corporate services incurred by our general partner and its affiliates.

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

	For the Years Ended December 31,		
	2012	2011	2010
	(In thousands)		
Reimbursement for services	$ 9,791	$ 9,136	$ 7,358

For additional information, please read Certain Relationships and Related Transactions, and Director Independence Omnibus Agreement.

Transactions with Cline Affiliates

Various companies controlled by Chris Cline lease coal reserves from NRP, and we provide coal transportation services to them for a fee. Mr. Cline, both individually and through affiliated companies, owns a 31% interest in our general partner, as well as 5,659,324 common units, at the time of this filing. At December 31, 2012, we had accounts receivable totaling $6.6 million from Cline affiliates. In addition, the overriding royalty and the lease of the loadout facility at the Sugar Camp mine are classified as contracts receivable of $57.1 million on our Consolidated Balance Sheets. Revenues from the Cline affiliates are as follows:

	For The Years Ended December 31,		
	2012	2011	2010
	(In thousands)		
Coal royalty revenues	$ 48,567	$ 42,474	$ 32,407
Processing fees	2,409	2,975	1,337
Transportation fees	19,514	16,689	14,324
Minimums recognized as revenue	17,785		12,400
Override revenue	4,066	2,691	1,904
Other revenue		2,990	
	$ 92,341	$ 67,819	$ 62,372

As of December 31, 2012, we had received $56.6 million in minimum royalty payments that have not been recouped by Cline affiliates, of which $27.7 million was received in the current year.

We recognized an asset impairment of $90.9 million during the third quarter of 2011 related to certain of our assets at the Gatling West Virginia location and $70.4 million during the fourth quarter of 2011 related to the Gatling Ohio location. During the fourth quarter of 2012, we recognized an additional impairment of $2.6 million related to the assets at the Gatling West Virginia location. These assets were acquired from and are leased by Cline affiliates.

In 2011, we recognized a $3.0 million non-cash gain on a reserve exchange of over one million tons in Illinois with Williamson Energy. The tons received were fully mined during 2012, while the tons exchanged are not included in the current mine plans.

Quintana Capital Group GP, Ltd.

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

A fund controlled by Quintana Capital owns a significant membership interest in Taggart Global USA, LLC, including the right to nominate two members of Taggart s 5-person board of directors. NRP currently has a memorandum of understanding with Taggart Global pursuant to which the two companies have agreed to jointly pursue the development of coal handling and preparation plants. NRP owns and leases the plants to Taggart Global, which designs, builds and operates the plants. The lease payments are based on the sales price for the coal that is processed through the facilities. To date, we have acquired four facilities under this agreement with Taggart with a total cost of $46.6 million. During the third quarter of 2012, we sold one of these facilities back to Taggart for $12.3 million, including $10.5 million in cash and a $1.8 million note receivable. The balance on the note receivable at December 31, 2012 was $1.7 million. Revenues from Taggart are as follows:

	For the Years Ended December 31,		
	2012	2011	2010
		(In thousands)	
Processing revenue	$ 5,580	$ 9,755	$ 5,874

At December 31, 2012, we had accounts receivable totaling $0.5 million from Taggart.

A fund controlled by Quintana Capital owns Kopper-Glo, a small coal mining company that is one of the Partnership s lessees with operations in Tennessee. Revenues from Kopper-Glo are as follows:

	For the Years Ended December 31,		
	2012	2011	2010
		(In thousands)	
Coal royalty revenues	$ 3,486	$ 1,629	$ 1,545

NRP also had accounts receivable totaling $0.3 million from Kopper-Glo at December 31, 2012.

Office Building in Huntington, West Virginia

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

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

We are exposed to market risk, which includes adverse changes in commodity prices and interest rates.

Commodity Price Risk

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

Interest Rate Risk

Our exposure to changes in interest rates results from borrowings under our credit facility, which are subject to variable interest rates based upon LIBOR or the federal funds rate plus an applicable margin. Management monitors interest rates and may enter into interest rate instruments to protect against increased borrowing costs. At December 31, 2012, we had $148 million outstanding in variable interest debt. If interest rates were to increase by 1%, annual interest expense would increase approximately $1.5 million, assuming the same principal amount remained outstanding during the year.

Item 8. ***Financial Statements and Supplementary Data***

INDEX TO FINANCIAL STATEMENTS

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners of Natural Resource Partners L.P.

We have audited the accompanying consolidated balance sheets of Natural Resource Partners L.P. as of December 31, 2012 and 2011, and the related consolidated statements of comprehensive income, partners capital, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Natural Resource Partners L.P. at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Natural Resource Partners L.P. s internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2013 expressed an unqualified opinion thereon**.**

/s/ Ernst & Young LLP

Houston, Texas

February 28, 2013

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS

(In thousands, except for unit information)

	December 31, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 149,424	$ 214,922
Accounts receivable, net of allowance for doubtful accounts	35,116	30,923
Accounts receivable affiliates	10,613	10,138
Other	1,042	832
Total current assets	196,195	256,815
Land	24,340	24,534
Plant and equipment, net	32,401	46,185
Mineral rights, net	1,380,428	1,257,501
Intangible assets, net	70,811	75,164
Loan financing costs, net	4,291	4,846
Long-term contracts receivable affiliates	55,576	
Other assets	630	604
Total assets	$ 1,764,672	$ 1,665,649
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 3,693	$ 2,366
Accounts payable affiliates	957	375
Obligation related to acquisition		500
Current portion of long-term debt	87,230	30,801
Accrued incentive plan expenses current portion	7,718	8,374
Property, franchise and other taxes payable	7,952	6,316
Accrued interest	10,265	10,761
Total current liabilities	117,815	59,493
Deferred revenue	123,506	113,303
Accrued incentive plan expenses	8,865	11,670
Long-term debt	897,039	836,268
Partners capital:		
Common units outstanding: (106,027,836)	605,019	629,253
General partner s interest	10,026	10,517
Non-controlling interest	2,845	5,638
Accumulated other comprehensive loss	(443)	(493)
Total partners capital	617,447	644,915
Total liabilities and partners capital	$ 1,764,672	$ 1,665,649

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

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In thousands, except per unit data)

	For the Years Ended December 31, 2012	2011	2010
Revenues:			
Coal royalties	$ 260,734	$ 279,221	$ 221,761
Aggregate royalties	6,598	6,734	4,230
Processing fees	8,299	13,475	9,604
Transportation fees	19,513	16,688	14,564
Oil and gas royalties	9,160	14,017	7,720
Property taxes	15,273	12,640	11,270
Minimums recognized as revenue	23,956	9,148	14,199
Override royalties	15,527	14,523	11,258
Other	20,087	11,237	6,795
Total revenues	379,147	377,683	301,401
Operating expenses:			
Depreciation, depletion and amortization	58,221	65,118	56,978
Asset impairments	2,568	161,336	
General and administrative	29,714	29,553	29,893
Property, franchise and other taxes	17,678	14,486	15,107
Transportation costs	1,944	2,033	1,864
Coal royalty and override payments	1,857	1,022	1,498
Total operating expenses	111,982	273,548	105,340
Income from operations	267,165	104,135	196,061
Other income (expense)			
Interest expense	(53,972)	(49,180)	(41,635)
Interest income	162	69	35
Income before non-controlling interest	213,355	55,024	154,461
Non-controlling interest		(998)	
Net income	$ 213,355	$ 54,026	$ 154,461
Net income attributable to:			
General partner	$ 4,267	$ 1,081	$ 2,570
Holders of incentive distribution rights	$	$	$ 25,966
Limited partners	$ 209,088	$ 52,945	$ 125,925
Basic and diluted net income per limited partner unit	$ 1.97	$ 0.50	$ 1.54
Weighted average number of common units outstanding	106,028	106,028	81,917
Comprehensive income	$ 213,405	$ 54,079	$ 154,512

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

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(In thousands, except unit data)

	Common Units			Holders of Incentive Distribution Rights			
	Units	Amounts	General Partner Amounts	Amounts	Non-Controlling Interest Amounts	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2009	69,451,136	$ 747,437	$ 13,409	$ 4,977	$	$ (597)	$ 765,226
Distributions		(174,709)	(4,197)	(30,943)			(209,849)
Issuance of common units, net	36,576,700	110,217					110,217
Capital contribution			2,350				2,350
Fees associated with elimination of IDRs		(2,341)					(2,341)
Non-controlling interest					5,065		5,065
Net income for the year ended December 31, 2010		125,925	2,570	25,966			154,461
Loss on interest hedge						51	51
Comprehensive income						51	154,512
Balance at December 31, 2010	106,027,836	$ 806,529	$ 14,132	$	$ 5,065	$ (546)	$ 825,180
Distributions		(230,080)	(4,696)		(52)		(234,828)
Non-controlling interest adjustment					(373)		(373)
Costs associated with equity transactions		(141)					(141)
Non-controlling interest					998		998
Net income for the year ended December 31, 2011		52,945	1,081				54,026
Loss on interest hedge						53	53
Comprehensive income						53	54,079
Balance at December 31, 2011	106,027,836	$ 629,253	$ 10,517	$	$ 5,638	$ (493)	$ 644,915
Distributions		(233,263)	(4,758				