NATURAL RESOURCE PARTNERS LP
Form 10-K
February 28, 2011

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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, 2010 or

o **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 o

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 o 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 the filing requirements for the past 90 days. Yes þ No o

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 o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. o

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. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2) Yes o 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 $1.0 billion on June 30, 2010 based on a price of $23.64 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, 2011, there were 106,027,836 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE.
None.

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Forward-Looking Statements

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

Such forward-looking statements include, among other things, statements regarding 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 and aggregates that will affect sales levels, prices and royalties realized by us.

These forward-looking statements 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*

Natural Resource Partners L.P. is 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, 2010, we owned or controlled approximately 2.3 billion tons of proven and probable coal reserves and we also owned approximately 228 million tons of aggregate reserves in a number of states across the country. We do not operate any mines, but lease reserves to experienced mine operators under long-term leases that grant the operators the right to mine 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 2010, our lessees produced 47.1 million tons of coal from our properties and our coal royalty revenues were $221.8 million. Coal processing fees and coal transportation fees added $9.6 million and $14.6 million in revenue, respectively. In addition, our lessees produced 4.4 million tons of aggregates and our aggregate royalties were $4.2 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 mines, but instead enter into leases with mine 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 and wheelage payments due us and are required to report tons of coal or aggregates removed or hauled across our property as well as the sales prices of the extracted minerals. Therefore, to a great extent, amounts reported as royalty and wheelage revenue are based

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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 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 royalty or wheelage revenue was initially recorded.

Our royalty revenues are affected by changes in long-term and spot commodity prices, production volumes, lessees supply contracts and the royalty rates in our leases. The prevailing price for coal depends 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.

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. We typically pay property taxes and then are reimbursed by the lessee for the taxes on their leased property, pursuant to the terms of the lease.

Our business is not seasonal, although at times severe 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 over the last several years. 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 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, 2010, 2009 and 2008. Coal royalty revenues were generated from the properties in each of the areas as follows:

	Coal Royalty Revenues for the Years Ended December 31,			Average Coal Royalty Revenue per Ton for the Years Ended December 31,		
	2010	2009	2008	2010	2009	2008
		(In thousands)			($ per ton)	
Area						

Appalachia						
Northern	$ 18,676	$ 14,959	$ 17,074	$ 3.81	$ 3.03	$ 2.94
Central	144,934	132,543	156,109	5.36	4.73	4.34
Southern	19,405	19,382	19,839	6.87	6.00	4.64
Total Appalachia	183,015	166,884	193,022	5.26	4.61	4.19
Illinois Basin	30,210	22,019	21,695	3.90	3.31	2.61
Northern Powder River Basin	8,444	7,718	11,533	1.89	1.94	1.85
Gulf Coast	92			1.77		
Total	$ 221,761	$ 196,621	$ 226,250	$ 4.71	$ 4.20	$ 3.74

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The following table sets forth production data and reserve information for the properties that we owned or controlled for the years ending December 31, 2010, 2009, and 2008. 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 is as follows:

Production and Reserves

	Production for the Year Ended December 31,			**Proven and Probable Reserves at December 31, 2010**		
	2010	**2009**	**2008**	**Underground**	**Surface**	**Total**
			(Tons in thousands)			
Area						
Appalachia						
Northern	4,900	4,943	5,799	498,683	6,440	505,123
Central	27,056	28,032	35,967	1,064,679	233,045	1,297,724
Southern	2,824	3,233	4,273	98,695	25,382	124,077
Total Appalachia	34,780	36,208	46,039	1,662,057	264,867	1,926,924
Illinois Basin	7,753	6,656	8,313	229,056	13,868	242,924
Northern Powder River Basin	4,467	3,984	6,218		104,839	104,839
Gulf Coast(1)	52					
Total	47,052	46,848	60,570	1,891,113	383,574	2,274,687

(1) Includes lignite acquired in the BRP acquisition. Due to the number of mineral acres involved in the BRP transaction, we have not completed an analysis of the reserve quantity and quality for each mineral that was acquired. As a result, the reserves held by BRP are not included in the statistical information in this Form 10-K. We plan to complete a review of the BRP reserves by the end of 2011.

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, 2010, approximately 52% of our reserves were low sulfur coal and 35% 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 2010, approximately 32% of the production and 38% of the coal royalty revenues from our properties were from metallurgical coal.

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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, 2010.

Sulfur Content, Typical Quality and Type of Coal

		Sulfur Content				Typical Quality		Type of Coal	
	Compliance	Low (less than	Medium (1.0% to	High (greater than		Heat Content (Btu per	Sulfur		
rea	Coal(1)	1.0%)	1.5%)	1.5%)	Total	pound)	(%)	Steam	Metallurgica
	(Tons in thousands)							(Tons in thousands)	
ppalachia									
orthern	42,681	51,257	23,929	429,937	505,123	12,874	2.73	495,561	9,562
entral	659,117	926,864	318,798	52,062	1,297,724	13,269	0.89	894,702	403,022
outhern	86,195	92,301	28,089	3,687	124,077	13,504	0.82	80,536	43,541
otal Appalachia	787,993	1,070,422	370,816	485,686	1,926,924		1.36	1,470,799	456,125
inois Basin			2,686	240,238	242,924	11,531	3.02	242,924	
orthern Powder ver Basin		104,839			104,839	8,800	0.65	104,839	
ulf Coast(3)									
otal	787,993	1,175,261	373,502	725,924	2,274,687			1,818,562	456,125

(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.

(3) Includes lignite acquired in the BRP acquisition. Due to the number of mineral acres involved in the BRP transaction, we have not completed an analysis of the reserve quantity and quality for each mineral that was acquired. As a result, the reserves held by BRP are not included in the statistical information in this Form 10-K. We plan to complete a review of the BRP reserves by the end of 2011.

We have engaged Marshall Miller and Associates, Inc. and Stagg Resource Consultants, Inc. to conduct reserve studies of our existing properties. When we began this process, we focused primarily on reserves that were owned at the time. However, as a result of the extensive nature of our reserve holdings and the large number of acquisitions that we have completed, some of the more recent studies have been on properties that were subsequently acquired. These studies will be 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.

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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.

Coal Transportation and Processing Revenues

We own preparation plants and related coal handling facilities. Similar to our coal royalty structure, the throughput fees are based on a percentage of the ultimate sales price for the coal that is processed. These facilities generated $9.6 million in coal processing revenues for 2010.

In addition to our preparation plants, we own coal handling and transportation infrastructure in West Virginia, Ohio and Illinois. For the year ended December 31, 2010, we recognized $14.6 million in revenue from these assets. For the assets other than the loadout facility at the Shay No. 1 mine in Illinois, which we lease to a Cline affiliate, we operate the coal handling and transportation infrastructure and have subcontracted out that responsibility to third parties.

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 an estimated 228 million tons of aggregate reserves located in a number of states across the country. During 2010, our lessees produced 4.4 million tons of aggregates, and our aggregate royalties were $4.2 million.

Oil and Gas Properties

In 2010, we derived approximately 3% of our total revenues from oil and gas royalties in various states.

Significant Customers

In 2010, we had total revenues of $62.4 million from The Cline Group, $42.9 million from Massey Energy Company and $36.2 million from Alpha Natural Resources. Each of these lessees represented more than 10% of our total revenues. The loss of one or all of these lessees could have a material adverse effect on us. In addition, the closure or loss of revenue from Cline s Williamson mine 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 us.

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 additional measures required under U.S. Environmental Protection Agency (or EPA) laws and 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 the final Clean Air Interstate Rule (or CAIR), which would permanently cap nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. CAIR required these states to achieve the required emission reductions by requiring power plants to either participate in an EPA-administered cap-and-trade program that caps emission in two phases, or by meeting an individual state emissions budget through measures established by the state. 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, the CAIR was challenged and the Court of Appeals for the D.C. Circuit vacated the CAIR on July 11, 2008. The vacatur caused significant uncertainty regarding state implementing regulations that were based on the CAIR. Upon request for reconsideration, the Court on December 23, 2008, revised its remedy to a remand to EPA without providing a response deadline. The EPA proposed a revised rule on August 2, 2010, and received thousands of comments on the proposal. The rulemaking is expected to be finalized in July of 2011. Accordingly, all state regulations that were based on the CAIR are still in effect, but we are unable to predict the outcome of EPA s response to the remand and, therefore, unable to predict any effect on NRP.

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In March 2005, the EPA finalized the Clean Air Mercury Rule (or CAMR), which establishes a two-part, nationwide cap on mercury emissions from coal-fired power plants beginning in 2010. The CAMR was to be lieu of source-specific maximum achievable control technology -based limits on hazardous air pollutant (HAP) emissions, including mercury, from such sources. The CAMR was vacated in early 2008 by the Court of Appeals for the D.C. Circuit. EPA is in the process of developing MACT standards, and is now under a court order to propose those rules by March 2011 and take final action on that proposal by November 2011. The limits imposed by those rules, if adopted, may limit demand for or otherwise restrict sales of our lessors coal, which would reduce royalty revenues.

Other continued tightening of the already stringent regulation of emissions is likely, such as EPA s revision to the national ambient air quality standard for sulfur dioxide finalized June 22, 2010, and a similar proposal announced for ozone on January 6, 2010 but now expected to be revised no earlier than July of 2011. 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-fueled power plants.

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 EPA issued a Finding of Failure to Submit plans on January 15, 2009, which could trigger Federal plan implementation. EPA has taken no enforcement action against states to finalize implementation plans. Nonetheless, this program may restrict construction of new coal-fired power plants where emissions are projected to reduce visibility in protected areas. In addition, this program may require certain existing coal-fired power plants to install emissions control equipment to reduce haze-causing emissions such as sulfur dioxide, nitrogen oxide and particulate matter.

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 asserted, and Congress is considering legislation to delay or repeal EPA s actions, but we cannot predict the outcome of these efforts. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, including coal-fired electric power plants, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas 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, 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 alternatives fuels and generation systems, as well as increase litigation risk for and so discourage development of coal-fired power plants.

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In addition, EPA is under a consent decree by which it must propose by July 2011 and take final action by May 2012 on new source performance standards to govern GHG emissions from electric generating units, certainly including those fired by coal. The decree also represents EPA s agreement to consider adopting a GHG limitation program governing existing sources, as well, which EPA may attempt to use to establish a cap-and-trade-like system on emissions of power plants GHG emissions.

Other pending cases regarding GHGs may affect the market for coal. For example, in *AEP v. Connecticut*, the Second Circuit Court of Appeals held that States and private plaintiffs may maintain actions under federal common law alleging that five electric utilities have created a public nuisance by contributing to global warming, and may seek injunctive relief capping the utilities CO_2 emissions at judicially-determined levels. However, the Supreme Court granted certiorari in December 2010 in this case, and argument has not yet been scheduled. An adverse outcome for the defendants in this case or other similar cases could cause additional similar litigation and could adversely affect the demand for our coal.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs, primarily through GHG cap and trade programs. Most proposed cap and trade programs work by requiring major sources of emissions, such as coal-fired electric power plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

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 (or SMCRA) and similar state statutes 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, and require mine operators to post performance bonds to ensure compliance with any reclamation obligations. 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 approved reclamation plan. In addition, higher and better uses of the reclaimed property are encouraged. Regulatory authorities 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 (or 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 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.

Some products 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 NPDES program for regulating the concentrations of pollutants in discharges of waste and storm water; and the § 404 program administered by the Army Corps of Engineers for regulating the placement of the overburden and fill material into waters, including wetlands. The unpermitted discharge of pollutants such as from spill or leak incidents is prohibited. The Clean Water Act and regulations implemented thereunder also prohibit discharges of fill material and certain other activities in wetlands unless authorized by an appropriately issued permit.

Our lessees used to obtain general permits from the Corps of Engineers authorizing the construction of valley fills for the disposal of overburden from mining operations. These general permits, known as Nationwide Permit 21 permits, provided a streamlined permit mechanism, but are now no longer available for surface mining operations. The Corps rescinded the Nationwide Permit 21 permit in March 2009.

Regardless of the outcome of the Corps decision about any continuing use of Nationwide Permit 21, it does not prevent our lessees from seeking an individual permit under § 404 of the Clean Water Act, nor does it restrict an operation from utilizing another version of the nationwide permit authorized for small underground coal mines that must construct fills as part of their mining operations. Nevertheless, such changes will 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. Moreover, such individual permits are also subject to challenge.

In 2007, two decisions by the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Strock* complicated the ability of our lessees both to obtain individual permits from the Corps of Engineers without performing a full environmental impact statement and to construct in-stream sediment ponds to control sediment from their excess spoil valley fills. The first decision, dated March 23, 2007 rescinded four individual permits issued to Massey Energy Company subsidiaries as a result of the Corps failure to properly evaluate the impacts of filling on small headwater streams and to ensure such impacts were appropriately minimized with mitigation efforts. This order has had the effect of slowing the flow of new fill permits from the Corps Huntington, West Virginia, District Office.

The second order, dated June 13, 2007, ruled that discharges of sediment from valley fills into sediment ponds constructed in-stream to collect and treat that sediment must meet the same standards as are applied to discharges from these sediment ponds. Because of the rugged terrain in central Appalachia, often the only practicable location for these ponds is in streams. The effect of the ruling is not yet clear, but it may require our lessees to disturb substantially more surface area to construct sediment structures out of the stream channels. A similar lawsuit (*Kentucky Waterways Alliance, Inc. v. United States Army Corps of Engineers,* Civil Action No. 3:07-cv-00677 (W.D. Ky. 2007)) was filed in the Western District of Kentucky and may affect future permitting by the Louisville, Kentucky District Office as well.

The Fourth Circuit reversed both orders on February 13, 2009, but the plaintiffs then asked the United States Supreme Court to review the decision. Theoretically, that ruling should have eased a backlog of individual permit applications. However, starting in 2009, EPA put in place a series of policies for mines in central Appalachia which have had the effect of slowing the issuance of both § 404 fill permits by the Corps and NPDES permits by State agencies. These policies, among other things, seek to impose limits on a specific conductance (conductivity) and sulfate at levels which 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 the subject to challenge in federal court in Washington, D.C. in *National Mining Association (NMA) v. Jackson.* That Court recently denied a request by NMA for a preliminary injunction after concluding that industry had not shown sufficient concrete harm to warrant the injunction. However, the Court rejected EPA s motion to dismiss the complaint and determined that NMA is likely to prevail on its claims that EPA s policies constitute unlawful rulemaking and fill outside of EPA s statutory authority.

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 $0.07/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 which 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. In *The West Virginia Highlands Conservancy, Plaintiff, v. Dirk Kempthorne, Secretary of the Department of the Interior, et al., Defendants, and the West Virginia Coal Association, Intervenor/Defendan*t, Civil Action No. 2:00-cv-1062 (United States District Court for the Southern District of West Virginia), an environmental group is claiming that the SRF is underfunded and that the Federal Office of Surface Mining (OSM) has an obligation under the Federal Surface Mining Act to ensure that the SRF funds are increased to cover the supposed shortfall. On March 23, 2007, the plaintiff moved to reopen this long inactive case on the grounds that a recommendation of the state s Special Reclamation Advisory Council regarding the establishment of a $175 million trust fund for water treatment at future bond forfeiture sites has not been approved. A one-year increase in the reclamation tax was enacted in the 2008 Legislative Session. Following this legislative action, the plaintiff moved the Court to defer ruling on its motion to reopen the case until it is determined whether the increase will be re-enacted and whether it will be sufficient if West Virginia Department of Environmental Protection (WVDEP) is required to obtain National Pollution Discharge Elimination System (NPDES) permits at 21 bond forfeiture sites relief sought in two separate citizens suits pending against WVDEP. In a May 15, 2008 Order, the Court denied plaintiff s motion to reopen without prejudice, denied the plaintiff s motion to defer, except insofar as it sought denial of the motion to reopen without prejudice, and retained the case on the inactive docket of the Court. In a companion case, *West Virginia Highlands Conservancy v. Huffman,* Civil Action No. 1:07-cv-87 (United States District Court, Northern District of West Virginia), the Court granted summary judgment on January 14, 2009 and required the WVDEP to obtain NPDES permits for bond forfeiture sites in the northern part of West Virginia. The WVDEP, joined by other states appealed this decision to the Fourth Circuit. By ruling of November 8, 2010, the Fourth Circuit affirmed the district court s opinion, and we understand WVDEP is now applying for NPDES permits at bond forfeiture sites. That ruling will have the effect of increasing the monies drawn by WVDEP from the SRF.

If the Court ultimately rules that OSM has an obligation either to assume federal control of the State bonding program or to require the State to increase the money in the SRF, our lessees could be forced to bear an increase in the tax on mined coal to increase the size of the SRF.

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.

The Federal Safe Drinking Water Act (or 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.

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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. In January 2006, West Virginia passed a law imposing stringent new mine safety and accident reporting requirements and increased civil and criminal penalties for violations of mine safety laws. Similarly, on April 27, 2006, the Governor of Kentucky signed mine safety legislation that includes requirements for increased inspections of underground mines and additional mine safety equipment and authorizes the assessment of penalties of up to $5,000 per incident for violations of mine ventilation or roof control requirements.

On June 15, 2006, President Bush signed new mining safety legislation that mandates similar improvements in mine safety practices; increases civil and criminal penalties for non-compliance; requires the creation of additional mine rescue teams, and expands the scope of federal oversight, inspection and enforcement activities. Earlier, the federal Mine Safety and Health Administration announced the promulgation of new emergency rules on mine safety that took effect immediately upon their publication in the Federal Register on March 9, 2006. These rules address mine safety equipment, training, and emergency reporting requirements.

Mining Permits and Approvals. Numerous governmental permits or approvals 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. Typically, our lessees submit the necessary permit applications between 12 and 24 months before they plan to begin mining a new area. In our experience, permits generally are approved within 12 months after a completed application is submitted. In the past, our lessees have generally obtained their mining permits without significant delay. 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, 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 77 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 mineral properties 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. We consider revenues from timber and oil and gas acquired as part of the acquisition of our mineral reserves to be incidental to our business focus and those revenues constitute less than 10% of our total revenues and assets.

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

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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;
- the proximity to and capacity of transportation facilities;
- weather conditions; and
- the effect of worldwide energy conservation measures.

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.

Our royalty revenues are largely dependent on our lessees level of production from our mineral reserves. 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.

There have been several recent lawsuits filed in Central Appalachia that will potentially make it much more difficult for our lessees to obtain permits to mine our coal. The most likely impact of the litigation will be to increase both the cost to our lessees of acquiring permits and the time that it will take for them to receive the permits. These conditions may increase our lessees cost of mining and delay or halt production at particular mines for varying lengths of time or permanently. Any interruptions to the production of coal from our reserves may reduce our coal royalty revenues.

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 2010, approximately 32% of the coal production and 38% 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 close.

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 U.S. Environmental Protection Agency, or 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 asserted, and Congress is considering legislation to delay or repeal EPA s actions, but we cannot predict the outcome of these efforts. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act. The EPA recently adopted various rules under the Clean Air Act that have the effect of requiring permits for new and modified sources of greenhouse gas emissions. The principal effect of these rules will be to require proposed projects to build or modify certain large stationary sources, including coal-fired electric power plants, to undergo best available control technology reviews for greenhouse gases, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas 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. On December 21, 2010, EPA signed a consent decree in which it agreed to propose by July 26, 2011 additional rules to limit GHG emissions from new and existing electric generating units, and to take final action on that proposal by July 26, 2012. If adopted, the new source rules would apply to all affected sources on which construction commenced after the proposal date.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as coal-fired electric power plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require consumers of coal to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the coal we produce.

Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that the Earth s climate is constantly changing, and climate change can have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and

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results of operations. In addition, several lawsuits have been filed in which the plaintiffs assert common law causes of action, including that emissions of GHGs constitute a nuisance against certain entities, including in one of the cases, Natural Resource Partners. Although the case against Natural Resource Partners has been dismissed, another case involving similar issues but in which Natural Resource Partners is not a defendant, *American Electric Power v. Connecticut*, will be reviewed and decided by the U.S. Supreme Court in 2011. An adverse outcome for the defendants in this case or other similar cases could adversely affect the demand for our coal.

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. In 2009, the EPA announced an intent to increase enforcement of violations of the Clean Water Act under its Clean Water Act Action Plan. In 2010, pursuant to the Clean Water Action Plan, EPA developed guidance that may result in increased scrutiny and enforcement relating to discharges of pollutants governed by National Pollution Discharge Elimination, or NPDES, permits, or their state equivalent. EPA may develop further guidance and programs under the Clean Water Action Plan that may result in increased scrutiny and enforcement of actions covered by the Clean Water Act. 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 the Cline Group, we derive a greater percentage of our revenues from a smaller number of lessees.

In 2010, we derived over 20% of our revenues from the Cline Group, 14% from Massey Energy Company and 12% from Alpha Natural Resources. Cline s Williamson mine alone was responsible for approximately 10% of our revenues in 2010. 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. In addition, Alpha and Massey recently announced an agreement to merge their two companies, subject to the usual approvals and conditions, including shareholder approval. 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.

We may not be able to expand and our business will be adversely affected if we are unable to replace or increase our reserves, obtain other mineral reserves through acquisitions or effectively integrate new assets into our existing business.

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 is dependent in part on our ability to access the capital markets. In addition, if we are unable to successfully integrate the companies, businesses or properties we are able to acquire, our royalty revenues may decline and we could experience a material adverse effect on our business, financial condition or results of operations.

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If we acquire additional reserves, 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.

We may not be able to obtain long-term financing on acceptable terms, which would limit our ability to make acquisitions.

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.

Some of our lessees may be adversely impacted by the instability of the credit markets.

Many of our lessees finance their activities through cash flow from operations, debt, the use of commercial paper or new equity. The lack of availability of debt or equity financing may result in a significant reduction in our lessees spending related to development of new mines or expansion of existing mines on our properties. It may also impact our lessees ability to pay current obligations and continue ongoing operations on our properties. Any significant reductions in spending related to our lessees operations could have a material adverse effect on our revenues and ability to pay our quarterly distributions.

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:

- 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 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

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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.

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 growing coal infrastructure business exposes us to risks that we do not experience in the royalty business.

Over the past three years, we have acquired several coal preparation plants, load-out facilities and beltlines. These facilities are subject to mechanical and operational breakdowns that could halt or delay the transportation and processing of coal, and therefore decrease our revenues. In addition, we have assumed the capital and operating risks associated with the transportation infrastructure at two mines. Although we have sub-contracted out this work to a third party, we could experience increased costs as well as increased liability exposure associated with operating these facilities.

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.

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 662/3% 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

- 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 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 arms 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 federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we are so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for 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 pay 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 a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

In addition, current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, legislation was proposed in a prior session of Congress that would have eliminated partnership tax treatment for certain publicly traded partnerships. Although such legislation would not have applied to us as proposed, it could be reintroduced or amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Moreover, any modification to the federal income tax

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laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact an investment in our common units. At the state level, because of widespread state budget deficits and other reasons, several states are 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.

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 with 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 with 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 liability that results from 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 decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis in those units, even if the price you receive is less than your original cost. Furthermore, a 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 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.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises 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 at the highest applicable tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

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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.