NATURAL RESOURCE PARTNERS LP
Form 10-K
February 27, 2009

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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, 2008 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 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 $1.6 billion on June 30, 2008 based on a price of $41.20 per unit, which was the closing price of the Common Units as reported on the daily composite list for transactions on the New York Stock Exchange on that date.

As of February 27, 2009, there were 64,891,136 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 and managing coal properties in the three major coal-producing regions of the United States: Appalachia, the Illinois Basin and the Western United States. As of December 31, 2008, we owned or controlled approximately 2.1 billion tons of proven and probable coal reserves. We do not operate any mines, but lease coal reserves to experienced mine operators under long-term leases that grant the operators the right to mine our coal 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 of coal sold, in addition to minimum payments. As of December 31, 2008, our coal reserves were subject to 201 leases with 73 lessees. In 2008, our lessees produced 60.6 million tons of coal from our properties and our coal royalty revenues were $226.3 million.

Beginning in 2006, we added two new businesses: coal infrastructure and ownership of aggregate reserves that are leased to operators in exchange for royalty payments similar to our coal royalty business. During 2008, our lessees produced 4.8 million tons of aggregates and our aggregate royalties were $9.1 million, which includes a $2.8 million bonus payment under the terms of one of our leases. Coal processing fees and coal transportation fees added $8.8 million and $11.7 million, respectively.

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.

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

The senior executives and other officers who manage the WPP Group assets also manage us. They are employees of Western Pocahontas Properties and Quintana Minerals Corporation, another company 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 are located at 5260 Irwin Road, Huntington, West Virginia 25705 and the telephone number is (304) 522-5757. Our principal executive offices are located at 601 Jefferson Street, Suite 3600, Houston, Texas 77002 and our phone number is (713) 751-7507.

Coal Royalty Business

Coal royalty businesses principally own and manage coal reserves. As an owner of coal reserves, we typically are not responsible for operating mines, but instead enter into leases with coal mine operators granting them the right to mine and sell coal 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 removed or hauled across our property as well as the sales prices of coal. Therefore, to a great extent, amounts reported as royalty and wheelage 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 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.

Coal royalty revenues are affected by changes in long-term and spot coal prices, 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. 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 coal is 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 coal production by our lessees due to the weather s negative impact on production and transportation.

Acquisitions

We are a growth-oriented company and have closed 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.

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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, 2008, 2007 and 2006. 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,		
	2008	2007	2006	2008	2007	2006
	(In thousands)			($ per ton)		
Area						
Appalachia						
Northern	$ 17,074	$ 16,664	$ 10,231	$ 2.94	$ 2.29	$ 1.92
Central	156,109	117,820	100,487	4.34	3.29	3.14
Southern	19,839	17,832	20,469	4.64	3.87	3.83
Total Appalachia	193,022	152,316	131,187	4.19	3.19	3.07
Illinois Basin	21,695	7,963	5,325	2.61	2.15	1.85
Northern Powder River Basin	11,533	11,064	11,240	1.85	1.90	1.72
Total	$ 226,250	$ 171,343	$ 147,752	$ 3.74	$ 2.99	$ 2.84

The following table sets forth production data and reserve information for the properties that we owned or controlled for the years ending December 31, 2008, 2007 and 2006. 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, 2008		
	2008	2007	2006	Underground	Surface	Total
	(Tons in thousands)					
Area						
Appalachia						
Northern	5,799	7,270	5,329	458,246	6,946	465,192
Central	35,967	35,835	31,991	1,057,324	146,374	1,203,698
Southern	4,273	4,603	5,347	156,285	33,296	189,581
Total Appalachia	46,039	47,708	42,667	1,671,855	186,616	1,858,471
Illinois Basin	8,313	3,709	2,877	109,247	15,574	124,821
Northern Powder River Basin	6,218	5,815	6,548		113,290	113,290

Total	60,570	57,232	52,092	1,781,102	315,480	2,096,582

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, 2008, approximately 59% of our reserves were low sulfur coal and 38% 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

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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 2008, approximately 22% of the production and 30% 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, 2008.

Sulfur Content, Typical Quality and Type of Coal

		Sulfur Content				Typical Quality		Type of Coal	
		Low	Medium	High		Heat Content	Sulfur		
rea	Compliance Coal(1)	(less than 1.0%)	(1.0% to 1.5%)	(greater than 1.5%)	Total	(Btu per pound)	(%)	Steam	Metallurgica
	(Tons in thousands)							(Tons in thousands)	
ppalachia									
orthern	43,253	51,832	23,993	389,367	465,192	13,012	2.75	455,630	9,562
entral	646,230	943,600	231,443	28,655	1,203,698	13,385	.87	789,253	414,445
outhern	106,972	137,514	40,454	11,613	189,581	13,641	.90	144,103	45,478
otal Appalachia	796,455	1,132,946	295,890	429,635	1,858,471		1.34	1,388,986	469,485
inois Basin		59	3,693	121,069	124,821	11,777	2.49	124,821	
orthern Powder ver Basin		113,290			113,290	8,800	.65	113,290	
otal	796,455	1,246,295	299,583	550,704	2,096,582			1,627,097	469,485

(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.

In 2005, we engaged Marshall Miller and Associates, Inc. and Stagg Resource Consultants, Inc. to conduct reserve studies of our existing properties. However, as a result of the extensive nature of our reserve holdings and the large number of acquisitions that we have completed, these studies will be an ongoing process. As of December 31, 2008, studies had been completed with respect to approximately 59% of the tons we owned when we began the process, and we anticipate completing studies on an additional 10% to 20% of those reserves by the end of 2009. In connection with acquisitions, we have either commissioned new studies or relied on recent reports done 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.

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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 $8.8 million in coal processing revenues for 2008.

In addition to our preparation plants, we own coal handling and transportation infrastructure associated with the Gatling mining complex in West Virginia and beltlines and rail load-out facilities associated with the Pond Creek No. 1 mine in Illinois. For the year ended December 31, 2008, we recognized $11.7 million in revenue from these assets. In contrast to our typical royalty structure, we are operating the coal handling and transportation infrastructure and have subcontracted out that responsibility to third parties.

Aggregates Royalty Revenues, Reserves and Production

We own an estimated 59 million tons of aggregate reserves located in DuPont, Washington. Of these reserves, approximately 14 million tons are currently permitted. If the remaining tons are not permitted by December 2016, the title to those tons will revert back to the seller of the reserves. In addition, we own a small number of aggregate reserves in West Virginia. During 2008, our lessees produced 4.8 million tons of aggregates and our aggregate royalties were $9.1 million, which includes a $2.8 million bonus payment under the terms of one of our leases.

Oil and Gas Properties

In 2008, we derived approximately 2.7% of our total revenues from oil and gas royalties in Kentucky, Virginia and Tennessee.

Significant Customers

In 2008, Alpha Natural Resources, Inc. and its various subsidiaries, as lessees, collectively provided approximately 11% of our total revenues. Although the loss of Alpha as a lessee could have a material adverse effect on us, we do not believe that the loss of a single mine on any of our properties would have a material adverse effect on us. No other lessee contributed more than 10% of our total revenues in 2008.

Competition

We face competition from other land companies, coal producers, as well as 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 undergone significant consolidation since 1976. The top ten producers have increased their share of total domestic coal production from 38% in 1976 to 65% in 2007. 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

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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 technology 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 1997, the EPA promulgated a rule, referred to as the NOx SIP Call, that required coal-fired power plants and other large stationary sources in 21 eastern states and Washington D.C. to make substantial reductions in nitrogen oxide emissions in an effort to reduce the impacts of ozone transport between states. Additionally, in March 2005, the EPA issued the final Clean Air Interstate Rule (or CAIR), which, if it remains in effect, will permanently cap nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. beginning in 2009 and 2010, respectively. CAIR will require 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. 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 Federal District Court of Appeals for the D.C. Circuit vacated the CAIR on July 11, 2008. *North Carolina v. EPA*, No. 05-1244 (D.C. Cir. Jul. 11, 2008). The vacatur caused significant uncertainty regarding state implementing regulations that were based on the CAIR. Upon request for reconsideration, though, the Court on December 23, 2008, subsequently revised its remedy to a remand to EPA without providing a response deadline. 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 vacated in early 2008 by the Federal Court of Appeals for the District of Columbia Circuit in *State of New Jersey v. EPA*, No. 05-1097 (D.C. Cir. Feb. 8, 2008) and the appeal process has not concluded. However, if fully implemented, CAMR would permit states to implement their own mercury control regulations or participate in an interstate cap-and-trade program for mercury emission allowances.

The EPA adopted new, more stringent national air quality standards for fine particulate matter in 2005 and ozone in 2008. As a result, some states will be required to amend their existing state implementation plans to attain and maintain compliance with the new air quality standards. For example, in December 2004, the EPA designated specific areas in the United States as non-attainment areas, meaning that the designated areas failed to meet the new national ambient air quality standard for fine particulate matter. In May of 2007, EPA published a final rule requiring that each State having a nonattainment area submit to EPA by April 5, 2008, an attainment demonstration and adopt regulations ensuring that the area will attain the standards as expeditiously as practicable, but no later than 2015. The same process is being played out with respect to the new ozone standard, but with later attainment dates. Because coal mining operations and coal-fired electric generating facilities emit particulate matter, our lessees mining operations and their customers could be affected when the new standards are implemented by the applicable states.

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 (74 Fed. Reg. 2392), which could trigger Federal plan implementation. 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 Emissions. In the mid-1990 s, the Kyoto Protocol to the United Nations Framework Convention on Climate Change called for developed nations to reduce their emissions of greenhouse gases to five percent below 1990 levels by 2012. Carbon dioxide, which is a major byproduct of the combustion of coal and other fossil fuels, is subject to the Kyoto Protocol. The Kyoto Protocol went into effect on February 16, 2005 for those nations that ratified the treaty. The United States has not ratified the Kyoto Protocol.

Nonetheless, the United States Congress has begun considering multiple bills that would regulate domestic carbon dioxide emissions, but no such bill has yet received sufficient Congressional support for passage into law. 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. For example, in December 2005, seven northeastern states agreed to implement a regional cap-and-trade program to stabilize carbon dioxide emissions from regional power plants beginning in 2009. 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 impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States. 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 mining operations are strictly regulated by the Clean Water Act, particularly with respect to the discharge of overburden and fill material into waters, including wetlands. Recent federal district court decisions in West Virginia, and related litigation filed in federal district court in Kentucky, have created uncertainty regarding the future ability to obtain certain general permits authorizing the construction of valley fills for the disposal of overburden from mining operations. A July 2004 decision by the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Bulen* enjoined the Huntington District of the U.S. Army Corps of Engineers from issuing further permits pursuant to Nationwide Permit 21, which is a general permit issued by the U.S. Army Corps of Engineers to streamline the process for obtaining permits under Section 404 of the Clean Water Act. While the decision was reversed and remanded to district court by the Fourth Circuit Court of Appeals in November 2005, the district court is currently considering additional challenges to Nationwide Permit 21. Additionally, a similar lawsuit filed in federal district court in Kentucky seeks to enjoin the issuance of permits pursuant to Nationwide Permit 21 by the Louisville

District of the U.S. Army Corps of Engineers. In the event that such lawsuits prove to be successful, some of our lessees may be required to apply for individual discharge permits pursuant to Section 404 of the Clean Water Act in areas where they would have otherwise utilized Nationwide Permit 21. Such a change 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 order will not take effect until a mandate is issued by that Court. A mandate will not issue for at least 14 days and could be delayed by a request for reconsideration. Thereafter, the original plaintiffs have 90 days in which to ask the United States Supreme Court to review the decision. If the Fourth Circuit decision stands, then a backlog of permits pending before the Corps of Engineers may ease.

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 WVDEP is required to obtain 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 has indicated that it intends to appeal this decision following the entry of final orders expected in March 2009.

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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.

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 69 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. We anticipate that these assets will continue to be incidental to our primary business in the future. Please see Item 8. Financial Statements and Supplementary Data for financial information regarding our segment.

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 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

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 coal, our future success and growth depend, in part, upon our ability to acquire additional coal reserves or other mineral reserves that are economically recoverable. If we are unable to replace or increase our coal reserves or acquire other mineral reserves on acceptable terms, our royalty revenues will decline as our reserves are depleted. Our ability to acquire additional coal reserves or other mineral reserves is dependent in part on our ability to access the capital markets, which could be difficult given the deterioration of the credit and 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.

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.

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

Primarily as a result of the recent downturn in the global economy, coal prices have declined significantly from the highs reached in 2008. The prices our lessees receive for their coal depend upon other 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 ability to make acquisitions and pay distributions to our unitholders depends, in part, upon our ability to access the capital markets. We may not be able to obtain long-term financing on acceptable terms or obtain funding under our current credit facility because of the deterioration of the credit and capital markets.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. The debt and equity capital markets have been distressed. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions have made, and will likely continue to make it difficult to obtain funding.

In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers. In addition, we may be unable to obtain adequate funding under our current credit facility because our lending counterparties may be unwilling or unable to meet their funding obligations.

Due to these factors, 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.

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 2008, approximately 22% of the coal production and 30% 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 steel industry has increasingly relied on electric arc furnaces or pulverized coal processes to make steel. If this trend continues, the amount of metallurgical coal that our lessees mine could decrease.

Some of our lessees may be adversely impacted by the current deterioration in the credit markets.

Many of our lessees finance their activities through cash flow from operations, the incurrence of debt, the use of commercial paper or the issuance of equity. Recently, there has been a significant deterioration in the credit markets and the availability of credit. 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.

Increased regulation of greenhouse gas emissions could cause a reduction in the use of coal as a fuel source, which could result in lower coal production by our lessees and reduce our coal royalty revenues.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide, may be contributing to warming of the Earth s atmosphere. Combustion of fossil fuels, such as coal results in the emission of carbon dioxide into the atmosphere. The U.S. Congress is considering legislation to reduce emissions of greenhouse gases. President Obama has expressed support for legislation to restrict or regulate emissions of greenhouse gases. More than one-third of the states already have begun implementing legal measures to reduce emissions of greenhouse gases. In addition, the Supreme Court s holding in 2007 in *Massachusetts, et al. v. EPA* that greenhouse gases including carbon dioxide fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources such as power plants. In July 2008, EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the Clean Air Act, in response to the Court s decision in *Massachusetts*. Although the notice did not propose any specific new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. In addition, there have been an increasing number of challenges and objections to permits for the construction of new coal-fired power plants based on concerns over greenhouse gas emissions, and permits for several proposed new coal-fired power plants have been denied or delayed.

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 reduced demand for coal and some customers switching to alternative sources of fuel, which could have a material adverse effect on our business, financial condition, and results of operations. In addition, increased difficulty or inability of our customers to obtain permits for construction of new or expansion of existing coal-fired power plants could adversely affect demand for our coal and have an adverse effect on our business and results of operation.

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

Our coal royalty revenues are largely dependent on our lessees level of production from our coal 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 coal deposits and the amount of rock embedded in or overlying the coal deposit;

changes in governmental regulation of 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 coal royalty revenues could be adversely affected.

There have been several recent lawsuits filed 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.

Our lessees are subject to federal, state and local laws and regulations that may limit their ability to produce and sell coal 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 coal 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 coal royalty revenues.

If our lessees do not manage their operations well, their production volumes and our coal 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 coal mined;
- mine plans, including the amount to be mined and the method of mining;
- processing and blending coal;
- 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;

coal transportation arrangements;

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compliance with applicable laws, including environmental laws; and

mine closure and reclamation.

A failure on the part of one of our lessees to make coal 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 coal 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 coal 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 coal mined from our properties.

Transportation costs represent a significant portion of the total delivered cost of coal for the customers of our lessees. Increases in transportation costs could make coal a less competitive source of energy or could make coal 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 coal producers in other parts of the country.

Our lessees depend upon railroads, barges, trucks and beltlines to deliver coal 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 coal to their customers. Our lessees transportation providers may face difficulties in the future that may impair the ability of our lessees to supply coal to their customers, resulting in decreased coal royalty revenues to us.

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

Coal supply contracts do not generally require operators to satisfy their obligations to their customers with coal mined from specific reserves. Several factors may influence a lessee s decision to supply its customers with coal 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 coal specifications. If a lessee satisfies its obligations to its customers with coal from properties we do not own or lease, production on our properties will decrease, and we will receive lower coal 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 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 coal 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 coal 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 coal 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 coal 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 coal 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

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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.

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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.

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 has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be 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 laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact of 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.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you will be 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 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 units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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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 effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt 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 units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our 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. If the IRS were to challenge this 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 units are loaned to a short seller to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a short seller to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those 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 to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We will adopt certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

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 our partnership for federal income tax purposes.

We will be considered to have terminated 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. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal 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 fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

As a result of investing in our common units, you may become 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 will likely be subject to other taxes, including foreign, 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 will likely be required to file foreign, 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, foreign, 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

Beaver Creek. The Beaver Creek property is located in Grant and Tucker Counties, West Virginia. In 2008, 2.5 million tons were produced from this property. This property includes the reserves which were acquired in our Mettiki acquisition in 2007. 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.

AFG-Southwest PA. The AFG property is located in Washington County, Pennsylvania. We acquired this property in November 2005. In 2008, 1.1 million tons were produced from this property. We lease this property to Conrhein Coal Company, a subsidiary of Consol Energy. Coal is produced from an underground mine and is transported by belt to a preparation plant operated by the lessee. Coal is shipped by both the CSX and Norfolk Southern railways to utility customers, such as American Electric Power and Allegheny Energy.

Kingwood. The Kingwood property is located in Preston County, West Virginia. In 2008, 898,000 tons were produced from this property. We lease this property to Kingwood Mining Company, LLC, a subsidiary of Alpha Natural Resources L.P. Although our lease is still in effect, in December 2008 Alpha announced that it was closing its mine on the Kingwood property.

Gatling. The Gatling property is located in Mason County, West Virginia. We acquired the property in January 2007 as part of the larger Cline transaction. In 2008, 629,000 tons were produced from the property. Coal from this property is mined from an underground mine and transported via belt line to a preparation plant on the property. Clean coal is transported via beltline either directly to American Electric Power or to a barge loading facility.

The map on the following page shows the location of our properties in Northern Appalachia.

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Central Appalachia

VICC/Alpha. The VICC/Alpha property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. In 2008, 5.9 million tons were produced from this property. We primarily lease this property to Alpha Land and Reserves, LLC, a subsidiary of Alpha Natural Resources, Inc. Production comes from both underground and surface mines and is trucked to one of four preparation plants. Coal is shipped via both the CSX and Norfolk Southern railroads to utility and metallurgical customers. Major customers include American Electric Power, Southern Company, Tennessee Valley Authority, VEPCO and U.S. Steel and to various export metallurgical customers.

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. We acquired the property in 2006. In 2008, 5.0 million tons were produced from the property. Both steam and metallurgical coal are produced by the lessees from

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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 customers such as AEP and to various export metallurgical customers.

Lynch. The Lynch property is located in Harlan and Letcher Counties, Kentucky. In 2008, 4.9 million tons were produced from this property. We primarily lease the property to Resource Development, LLC, an independent coal producer. 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.

Dingess-Rum. The Dingess-Rum property is located in Logan, Clay and Nicholas Counties, West Virginia. This property is leased to subsidiaries of Massey Energy and Patriot Coal. We acquired this property in 2007. In 2008, 4.5 million tons were produced from the property. Both steam and metallurgical coal are produced from underground and surface mines and 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 2008, 2.9 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.

Pardee. The Pardee property is located in Letcher County, Kentucky and Wise County Virginia. In 2008, 2.3 million tons were produced from this property. We lease the property to Ark Land Company, 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.

Lone Mountain. The Lone Mountain property is located in Harlan County, Kentucky. In 2008, 2.2 million tons were produced from this property. We lease the property to Ark Land Company, 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.

The map on the following page shows the location of our properties in Central Appalachia.

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Southern Appalachia

BLC Properties. The BLC properties are located in Kentucky, Tennessee, and Alabama. In 2008, 3.2 million tons were produced from these properties. We lease this property 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.

Oak Grove. The Oak Grove property is located in Jefferson County, Alabama. In 2008, 959,000 tons were produced from this property. We lease the property to Oak Grove Resources, LLC, 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.

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

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Illinois Basin

Williamson Development. The Williamson Development property is located in Franklin and Williamson Counties, Illinois. The property is under lease to an affiliate of the Cline Group, and in 2008, 5.5 million tons were mined on the property. This production is from a longwall mine. Production is shipped primarily via CN railroad to customers such as Duke and to various export customers.

Hocking-Wolford/Cummings. The Hocking-Wolford property and the Cummings property are both located in Sullivan County, Indiana. In 2008, 1.4 million tons were produced from the properties. Both properties are under common lease to Black Beauty Coal Company, an affiliate of Peabody Energy Corporation. Production is currently from a surface mine, and coal is shipped by truck and railroad to customers such as Public Service of Indiana and Indianapolis Power and Light.

Sato. The Sato property is located in Jackson County, Illinois. In 2008, 938,000 tons were produced from the property. The property is under lease to Knight Hawk Coal LLC, an independent coal producer. Production is currently from a surface mine, and coal is shipped by truck and railroad to various Midwest and southeast utilities.

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

Northern Powder River Basin

Western Energy. The Western Energy property is located in Rosebud and Treasure Counties, Montana. In 2008, 6.2 million tons were produced from our property. Western Energy Company, a subsidiary of Westmoreland Coal Company, has two coal leases on the property. Western Energy produces coal 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.

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

Title to Property

Of the approximately 2.1 billion tons of proven and probable coal reserves that we owned or controlled as of December 31, 2008, we owned approximately 99% of the reserves in fee. We lease approximately 2 million tons, or 1% of our reserves, 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.

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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. *Submission of Matters to a Vote of Security Holders*

None.

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 New York Stock Exchange (NYSE) under the symbol NRP . As of February 11, 2009, there were approximately 28,300 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 New York Stock Exchange Composite Transaction Tape from January 1, 2007 to December 31, 2008, and the quarterly cash distribution declared and paid with respect to each quarter per common unit. All historical trading prices that occurred prior to April 18, 2007 have been adjusted to reflect the two-for-one unit split that occurred on that date.

	Price Range		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2007					
First Quarter	$ 33.89	$ 28.18	$ 0.4550	05/01/2007	05/14/2007
Second Quarter	$ 38.94	$ 31.60	$ 0.4650	08/01/2007	08/14/2007
Third Quarter	$ 43.00	$ 26.38	$ 0.4750	11/01/2007	11/14/2007
Fourth Quarter	$ 35.61	$ 29.71	$ 0.4850	02/01/2008	02/14/2008
2008					
First Quarter	$ 33.99	$ 24.61	$ 0.4950	05/01/2008	05/14/2008
Second Quarter	$ 41.65	$ 28.42	$ 0.5150	08/01/2008	08/14/2008
Third Quarter	$ 41.20	$ 22.75	$ 0.5250	11/03/2008	11/14/2008
Fourth Quarter	$ 25.99	$ 12.66	$ 0.5350	02/05/2009	02/13/2009

Our general partner holds 65% of our incentive distribution rights (IDRs) and the remaining IDRs are held by affiliates of our general partner. The IDRs entitle the holders to incentive distributions if the amount we distribute with respect to any quarter exceeds the specified target levels shown below:

Percentage Allocations of Available Cash from Operating Surplus

	Total Quarterly Distribution Target	Marginal Percentage Interest in Distributions Paid		
	Amount	Unitholders	General Partner	Holders of IDRs
Minimum Quarterly Distribution	$0.25625	98%	2%	
First Target Distribution	$0.25625 up to $0.28125	98%	2%	
Second Target Distribution	above $0.28125 up to $0.33125	85%	2%	13%

Third Target Distribution	above $0.33125 up to $0.38125	75%	2%	23%
Thereafter	above $0.38125	50%	2%	48%

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Cash Distributions to Partners

	General Partner	Limited Partners	Other Holders of IDRs	Total Distributions
		(In thousands)		
2006				
Distributions	$ 1,847	$ 81,660	$	$ 83,507
IDR Distributions	5,756		3,099	8,855
Total Distributions	7,603	81,660	3,099	92,362
2007				
Distributions	2,939	118,858		121,797
IDR Distributions	16,404		8,832	25,236
Total Distributions	19,343	118,858	8,832	147,033
2008				
Distributions	3,426	131,080		134,506
IDR Distributions	23,921		12,880	36,801
Total Distributions	$ 27,347	$ 131,080	$ 12,880	$ 171,307

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 minimum quarterly distribution. Provisions of our credit facility and note purchase agreement may restrict our ability to make distributions under certain limited circumstances. In general, we intend to increase our cash distributions in the future assuming we are able to increase our available cash from operations and through acquisitions, provided there is no adverse change in operations, economic conditions and other factors. However, we cannot guarantee that future distributions will continue at such levels.

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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. 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.

	For the Years Ended December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
	(In thousands, except per unit and per ton data)				
Income Statement Data:					
Revenues:					
Coal royalties and related revenues	$ 259,271	$ 185,896	$ 152,243	$ 145,990	$ 111,441
Aggregate royalties	9,119	7,434	538		
Oil and gas royalties	7,902	4,930	4,220	3,180	1,907
Property taxes	9,800	10,285	5,971	6,516	5,349
Other	5,573	6,440	7,701	3,367	2,735
Total revenues	291,665	214,985	170,673	159,053	121,432
Expenses:					
Depreciation, depletion and amortization	64,254	51,391	29,695	33,730	30,077
General and administrative	13,922	20,048	15,520	12,319	11,503
Property, franchise and other taxes	13,558	13,613	8,122	8,142	6,835
Other	2,924	1,634	1,560	3,392	2,045
Total expenses	94,658	86,686	54,897	57,583	50,460
Income from operations	197,007	128,299	115,776	101,470	70,972
Other, net	(27,001)	(25,800)	(13,686)	(9,631)	(11,978)
Net income	$ 170,006	$ 102,499	$ 102,090	$ 91,839	$ 58,994
Balance Sheet Data (at period end):					
Land, equipment, coal and other mineral rights, net	$ 1,174,067	$ 1,222,094	$ 845,531	$ 610,506	$ 537,565
Total assets	1,301,340	1,320,031	939,493	684,996	599,926
Long-term debt	478,822	496,057	454,291	221,950	156,300
Partners capital	743,341	744,591	435,687	425,908	409,192
Other Data:					
Royalty coal tons produced by lessees	60,570	57,232	52,092	53,606	48,357
Average gross coal royalty revenue per ton	$ 3.74	$ 2.99	$ 2.84	$ 2.65	$ 2.20
Aggregate tons produced by lessee	4,791	5,698	412		

Average gross aggregate royalty revenue per ton	$	1.31	$	1.19	$	1.11				
Basic and diluted net income per limited partner unit	$	1.97	$	1.26	$	1.74	$	1.70	$	1.15
Weighted average number of units outstanding		64,891		64,505		50,682		50,682		49,602
Distributions per limited partner unit	$	2.070	$	1.880	$	1.670	$	1.450	$	1.238

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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 coal properties in the three major coal-producing regions of the United States: Appalachia, the Illinois Basin and the Western United States. As of December 31, 2008, we owned or controlled approximately 2.1 billion tons of proven and probable coal reserves, and 59% of our reserves were low sulfur coal. We lease coal reserves to experienced mine operators under long-term leases that grant the operators the right to mine and sell coal from our reserves in exchange for royalty payments.

Our revenue and profitability are dependent on our lessees ability to mine and market our coal 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. However, over the long term, our coal royalty revenues are affected by changes in the market price of coal.

In our coal royalty business, our lessees make payments to us based on the greater of a percentage of the gross sales price or a fixed royalty per ton of coal they sell, subject to minimum monthly, quarterly or annual payments. These minimum royalties are generally recoupable over a specified period of time (usually three to five years) if sufficient royalties are generated from coal production in those future periods. We do not recognize these minimum coal 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.

In addition to coal royalty revenues, we generated approximately 22% of our 2008 revenues from other sources, compared to 20% in 2007. The increase represents our commitment to continuing to diversify our sources of revenue. These other sources include: aggregate royalties; coal processing and transportation fees; rentals; royalties on oil and gas; overriding royalties; wheelage payments and timber.

Current Market Conditions and our Liquidity

Our business model depends in large part on our ability to make acquisitions and finance those acquisitions through the issuance of long-term debt or equity in the capital markets. As of December 31, 2008, we had in excess of $250 million in available capacity under our existing credit facility, as well as approximately $90 million in cash. Following our Macoupin acquisition in January 2009, we had $169 million in available capacity under the facility, and have committed to fund another $60 million as certain performance milestones are met in connection with the development of the Shay No. 1 mine in Illinois. Our credit facility does not mature until March 2012. In addition, because we amortize substantially all of our long-term debt, we have no need to pay off or refinance any debt obligations in 2009, other than our regularly scheduled principal payments. However, given the number of potential acquisitions that we evaluate on a regular basis, we could use up this capacity in a short period of time. In the past, we have been able to pay down our credit line by issuing equity or long-term senior notes at attractive interest rates.

As a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, and refused to refinance existing debt at maturity at all or on similar terms. Although the lenders under our credit facility have indicated to us that they intend to honor their commitments, we are aware of some cases in which lenders have refused to provide funding to borrowers in spite of existing commitments.

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.

Current Results and Outlook

As of December 31, 2008, our reserves were subject to 201 leases with 73 lessees. For the year ended December 31, 2008, our lessees produced 60.6 million tons of coal generating $226.3 million in coal royalty revenues from our properties, and our total revenues were $291.7 million.

Global and domestic prices for physical delivery of coal by our lessees remained high during most of 2008, resulting in a substantial increase in our royalty per ton in Appalachia and the Illinois Basin compared to the same period in 2007. In recent months, however, commodity prices, including coal prices, have declined in the financial markets, and we expect to see lower prices for coal that is not contracted in 2009. As of the end of 2008, our lessees had contracted to sell approximately 90% of their steam coal in 2009 and approximately 60% of their metallurgical coal. We also expect that some metallurgical coal customers will decline to take delivery of contracted tons in 2009, which could ultimately result in a decline in production from our properties.

Even though coal royalty revenues from our Appalachian properties represented 66% of our total revenues in 2008, this percentage has continued to decline and we are diligently working to diversify our holdings by expanding our presence in the Illinois Basin, where our coal royalty revenues nearly tripled over 2007. Through our relationship with the Cline Group, we expect our Illinois assets to contribute even more significantly to our total revenues in 2009.

In addition, in 2008 we benefited from our significant exposure to metallurgical coal. Approximately 30% of our coal royalty revenues and 22% of the related production during 2008 were from metallurgical coal, which is used in the production of steel. The U.S. coal market, especially for Appalachian metallurgical coal, is being impacted by the global economic slowdown and it is difficult to determine how this will impact coal production from our properties or the prices that our lessees receive for the sale of the coal.

In addition to the issues being created by the current economy, the political, legal and regulatory environment is becoming increasingly difficult for the coal industry. The recent judicial decisions by the Southern District of West Virginia regarding permits issued under Section 404 of the Clean Water Act in West Virginia, together with a similar lawsuit filed in Kentucky, have created substantial regulatory uncertainty. If these cases have adverse outcomes, it could have long-term negative implications for the future of all coal mining in Appalachia, which would impact our coal royalty revenues derived from that region. The Fourth Circuit reversed both orders on February 13, 2009, but the order will not take effect until a mandate is issued by that Court. A mandate will not issue for at least 14 days and could be delayed by a request for reconsideration. Thereafter, the original plaintiffs have 90 days in which to ask the United States Supreme Court to review the decision. If the Fourth Circuit decision stands, then a backlog of permits pending before the Corps of Engineers may ease.

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 distributable cash flow represents cash flow from operations less actual principal payments and cash reserves set aside for future 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.

Reconciliation of GAAP Net cash provided by operating activities to Non-GAAP Distributable cash flow

	For the Years Ended December 31,		
	2008	2007	2006
Net cash provided by operating activities	$ 229,956	$ 168,153	$ 138,843
Less scheduled principal payments	(17,234)	(9,350)	(9,350)
Less reserves for future principal payments	(17,235)	(13,388)	(9,600)
Add reserves used for scheduled principal payments	17,234	9,400	9,400
Distributable cash flow	$ 212,721	$ 154,815	$ 129,293

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.

Macoupin. On January 27, 2009, we acquired coal reserves and infrastructure assets related to the Shay No. 1 mine in Macoupin County, Illinois for $143.7 million from Macoupin Energy, LLC, an affiliate of the Cline Group. Upon closing, we paid $83.7 million and will make three subsequent payments of $20 million each in 2009 based upon performance measures associated with the development of a new mine.

Coal Properties. In October 2008, we acquired an overriding royalty for $5.5 million from Coal Properties Inc. This overriding royalty agreement is for coal reserves located in the states of Illinois and Kentucky.

Mid-Vol Coal Preparation Plant. In April 2008, we completed construction of a coal preparation plant and coal handling infrastructure under our memorandum of understanding with Taggart Global USA, LLC. The total cost to build the facilities was $12.7 million.

Licking River Preparation Plant. In March 2008, we signed an agreement for the construction of a coal preparation plant facility under our memorandum of understanding with Taggart Global USA, LLC. The cost for the facility, located in Eastern Kentucky, is estimated to be approximately $8.7 million, of which $8.4 million had been paid as of December 31, 2008 for construction costs incurred to date.

Massey Energy. In December 2007, we acquired an overriding royalty interest from Massey Energy for $6.6 million. The override relates to low-vol metallurgical coal reserves that are being produced from the Pinnacle Mine in West Virginia.

National Resources. In December 2007, we acquired approximately 17.5 million tons of high quality low-vol metallurgical coal reserves in Wyoming and McDowell Counties in West Virginia from National Resources, Inc., a subsidiary of Bluestone Coal. Total consideration for this purchase was $27.2 million.

Cheyenne Resources. In August 2007, we acquired a rail load-out facility and rail spur from Cheyenne Resources for $5.5 million. This facility is located in Perry County, Kentucky.

Mettiki. In April 2007, we acquired approximately 35 million tons of coal reserves in Grant and Tucker Counties in Northern West Virginia in exchange for 500,000 common units and approximately $10.2 million in cash. The assets were acquired from Western Pocahontas Properties Limited Partnership under our omnibus agreement. Western Pocahontas Properties has retained an overriding royalty interest on approximately 16 million tons of non-permitted reserves, which will be offered to us at the time those reserves are permitted.

Westmoreland. In February 2007, we acquired an overriding royalty from Westmoreland Coal Company for $12.7 million on 225 million tons of coal that are being mined by a subsidiary of Peabody Energy in the Powder River Basin. The reserves are located in the Rocky Butte Reserve in Wyoming.

Dingess-Rum. In January 2007, we acquired 92 million tons of coal reserves and approximately 33,700 acres of surface and timber in Logan, Clay and Nicholas Counties in West Virginia from Dingess-Rum Properties, Inc. As consideration for the acquisition, we issued 4,800,000 common units to Dingess-Rum.

Cline. On January 2007, we acquired 49 million tons of coal reserves in Williamson County, Illinois and Mason County, West Virginia that are leased to affiliates of The Cline Group. In addition, we acquired transportation assets and related infrastructure at those mines. As consideration for the transaction we issued 8,910,072 units representing limited partner interests in NRP.

Critical Accounting Policies

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

Coal Processing and Transportation Fees. Coal processing fees are recognized on the basis of tons of coal processed through the facilities by the Partnership s lessees and the corresponding revenue from those sales. Generally, the lessees of the coal 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 coal processing leases are structured in a manner so that the lessees are responsible for operating and maintenance expenses associated with the facilities. Coal 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 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. The deferred revenue attributable to the minimum payment is recognized as revenues either when the lessee recoups the minimum payment through production or when the period during which the lessee is allowed to recoup the minimum payment expires.

Depreciation and Depletion. 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 estimate proven and probable mineral reserves with the assistance of third-party mining consultants, and we use estimation techniques and recoverability assumptions. We update our estimates of mineral reserves periodically and this may result in material adjustments to mineral reserves and depletion rates that we recognize prospectively. Historical revisions have not been material. Timberlands are stated at cost less depletion. We determine the cost of the timber harvested based on the volume of timber harvested in relation to the amount of estimated net merchantable volume by geographic areas. We estimate our timber inventory using statistical information and data obtained from physical measurements and other information gathering techniques. We update these estimates annually, which may result in adjustments of timber volumes and depletion rates that we recognize prospectively. Changes in these estimates have no effect on our cash flow.

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 awards under our Long-Term Incentive Plan under Financial Accounting Standards Board Statement No. 123R, Share Based Payment. FAS 123R 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, FAS 123R 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 September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements.* This statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value methods. This statement does not require any new fair value measurements. Instead, it provides for increased consistency and comparability in fair value measurements and for expanded disclosure surrounding the fair value measurements whenever other standards require (or permit) the measurement of assets or liabilities at fair value. This statement is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. Accordingly, we adopted SFAS No. 157 on January 1, 2008. The adoption of this statement did not have a material impact our financial position, results of operations or cash flows. In February 2008, the FASB issued FASB Staff Position No. 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for one year for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

In February 2007, the FASB issued Statement No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. The standard provides companies with an option to report selected financial assets and liabilities at fair value and establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. We did not elect the fair value option for any financial assets or financial liabilities as of January 1, 2008, the effective date of the standard.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations*. The statement establishes principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree. The statement also provides guidance for recognizing and measuring the goodwill acquired in the business combination and determines what information to disclose to enable users of the financial statement to evaluate the nature and financial effects of the business combination. SFAS No. 141R is effective for financial statements issued for fiscal years beginning after December 15, 2008. Accordingly, any business combinations we complete in 2009 or thereafter will be recorded and disclosed following the new standard. We expect SFAS No. 141R to have an impact our consolidated financial statements when we complete a business combination, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of the acquisitions we consummate after the effective date.

In December 2007, the FASB issued SFAS No. 160, *Non-controlling Interests in Consolidated Financial Statements,* which provides guidance for accounting and reporting of non-controlling (minority) interests in consolidated financial statements. The statement is effective for fiscal years and interim periods within fiscal years beginning on or after December 15, 2008. At the current time, we do not hold minority interests in subsidaries, therefore we expect that SFAS No. 160 will have no impact on our financial condition or results of operations.

In March 2008, the FASB issued EITF No. 07-4, which considers whether the incentive distribution rights, or IDRs, of a master limited partnership represent a participating security when considered in the calculation of earnings per unit under the two-class method. The EITF considers whether the partnership

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agreement contains any contractual limitations concerning distributions to IDR holders that would impact the amount of earnings to allocate to the IDR holders for each reporting period. If distributions are contractually limited to the IDR holders share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the IDR holders. In addition, the EITF presents alternative methods for inclusion of IDRs in the earnings per unit computation. When cash distributions exceed net income for the period, net income should be reduced by the distributions made to the holders of the general partner interest, the holders of the limited partner interests and IDR holders for the period. The provisions of EITF No. 07-4 are effective for fiscal years beginning after December 15, 2008. We are currently evaluating the requirements of EITF No. 07-4 to determine the impact, if any, on our consolidated financial statements.

In June 2008, the FASB issued Staff Position (FSP) No. EITF No. 03-6-1 Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities. This FSP affects entities that accrue cash dividends on share-based payment awards during the awards service period when the dividends do not need to be returned if the employees forfeit the award. The FSP requires that all outstanding unvested share-based payment awards that contain rights to nonforfeitable dividends participate in undistributed earnings with common shareholders and are considered participating securities. Because the awards are considered participating securities, the issuing entity is required to apply the two-class method of computing basic and diluted earnings per share. The provisions of FSP No. EITF No. 03-6-1 are effective for fiscal years beginning after December 15, 2008. We are currently evaluating the requirements of FSP No. EITF 03-6-1, to determine the impact and do not expect this to have any impact on our consolidated financial statements.

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Results of Operations

Summary of 2008 and 2007 Royalties and Production

	For the Years Ended December 31, 2008	For the Years Ended December 31, 2007	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data)			
Coal royalties				
Appalachia				
Northern	$ 17,074	$ 16,664	$ 410	2%
Central	156,109	117,820	38,289	32%
Southern	19,839	17,832	2,007	11%
Total Appalachia	193,022	152,316	40,706	27%
Illinois Basin	21,695	7,963	13,732	172%
Northern Powder River Basin	11,533	11,064	469	4%
Total	$ 226,250	$ 171,343	$ 54,907	32%
Production (tons)				
Appalachia				
Northern	5,799	7,270	(1,471)	(20)%
Central	35,967	35,835	132	<1%
Southern	4,273	4,603	(330)	(7)%
Total Appalachia	46,039	47,708	(1,669)	(3)%
Illinois Basin	8,313	3,709	4,604	124%
Northern Powder River Basin	6,218	5,815	403	7%
Total	60,570	57,232	3,338	6%
Average gross royalty revenue per ton				
Appalachia				
Northern	$ 2.94	$ 2.29	$ 0.65	28%
Central	4.34	3.29	1.05	32%
Southern	4.64	3.87	.77	20%
Total Appalachia	4.19	3.19	1.00	31%
Illinois Basin	2.61	2.15	.46	21%
Northern Powder River Basin	1.85	1.90	(.05)	(3)%
Combined average gross royalty revenue per ton	3.74	2.99	.75	25%
Aggregates				
Royalty revenues	$ 6,275	$ 6,778	$ (503)	(7)%
Aggregate Bonus Royalty	$ 2,844	$ 656	$ 2,188	334%
Production	4,791	5,698	(907)	(16)%
Average gross royalty revenue per ton	$ 1.31	$ 1.19	$ 0.12	10%

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Coal Royalty Revenues and Production

Coal royalty revenues comprised approximately 78% and 80% of our total revenue for the years ended December 31, 2008 and 2007, respectively. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. Primarily as result of higher coal prices, coal royalty revenues increased by $40.7 million in 2008, even though production was slightly lower than in 2007. The decline in production was primarily the result of a longwall mine in Northern Appalachia that had a substantial percentage of its production come from adjacent property.

Illinois Basin. Coal royalty revenues were $13.7 million higher in 2008 and production was 4.6 million tons higher. As a result of a full year of operation at our Williamson property, coal royalty revenues attributable to that property were $15.8 million for the year ended December 31, 2008 compared to $2.6 million for 2007. Similarly, production attributable to that property was 5.5 million tons for 2008 compared to 1.0 million tons in 2007.

Northern Powder River Basin. The increase in both coal royalty revenues of $0.5 million and production of 0.4 million tons on our Western Energy property was due to the normal variations that occur due to the checkerboard nature of our ownership.

Aggregates Royalty Revenues and Production

In December 2006, we acquired aggregate reserves located in DuPont, Washington. For the year ended December 31, 2008 and 2007, we recorded $6.3 million and $6.8 million, respectively in royalty revenues from aggregates and had production of 4.8 million tons and 5.7 million tons for each of these years. Nearly all of this production and revenue is attributable to the aggregate reserves in DuPont, Washington. In 2008 we received a bonus royalty payment of $2.8 million compared to $0.7 million in 2007.

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Summary of 2007 and 2006 Royalties and Production

	For the Years Ended December 31, 2007	For the Years Ended December 31, 2006	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data)			
Coal royalties				
Appalachia				
Northern	$ 16,664	$ 10,231	$ 6,433	63%
Central	117,820	100,487	17,333	17%
Southern	17,832	20,469	(2,637)	(13)%
Total Appalachia	152,316	131,187	21,129	16%
Illinois Basin	7,963	5,325	2,638	50%
Northern Powder River Basin	11,064	11,240	(176)	(2)%
Total	$ 171,343	$ 147,752	$ 23,591	16%
Production (tons)				
Appalachia				
Northern	7,270	5,329	1,941	36%
Central	35,835	31,991	3,844	12%
Southern	4,603	5,347	(744)	(14)%
Total Appalachia	47,708	42,667	5,041	12%
Illinois Basin	3,709	2,877	832	29%
Northern Powder River Basin	5,815	6,548	(733)	(11)%
Total	57,232	52,092	5,140	10%
Average gross royalty revenue per ton				
Appalachia				
Northern	$ 2.29	$ 1.92	$ 0.37	19%
Central	3.29	3.14	0.15	5%
Southern	3.87	3.83	0.04	1%
Total Appalachia	3.19	3.07	0.12	4%
Illinois Basin	2.15	1.85	0.30	16%
Northern Powder River Basin	1.90	1.72	0.18	10%
Combined average gross royalty revenue per ton	2.99	2.84	0.15	5%
Aggregates				
Royalty revenues	$ 6,778	$ 456	$ 6,322	1386%
Aggregate Bonus Royalty	656	82	574	7%
Production	5,698	412	5,286	1283%
Average gross royalty revenue per ton	$ 1.19	$ 1.11	$ 0.08	7%

Coal Royalty Revenues and Production

Coal royalty revenues comprised approximately 80% and 87% of our total revenue for the years ended December 31, 2007 and 2006, respectively. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. As a result of higher coal prices and several large acquisitions completed since the end of 2006, both coal royalty revenues and production in Appalachia increased in 2007. The coal royalty revenues attributable to acquisitions completed in 2007 in Central Appalachia alone were $33.5 million and production attributable to those acquisitions was 9.2 million tons.

Illinois Basin. Coal royalty revenues and production attributable to our Williamson and James River acquisitions was $2.9 million and production attributable to those acquisitions was 1.2 million tons in 2007.

Northern Powder River Basin. The decrease in production on our Western Energy property was due to the normal variations that occur due to the checkerboard nature of our ownership, but was partially offset by higher prices being received by our lessee.

Aggregates Royalty Revenues and Production

In December 2006, we acquired aggregate reserves located in DuPont, Washington. For the year ended December 31, 2007, we recorded $6.8 million in royalty revenues from aggregates and had production of 5.7 million tons.

Other Operating Results for the Years Ended December 31, 2008, 2007 and 2006

Other revenues. Other revenues declined in 2008 since there were no material sales of land and timber. Included in other revenues for the year ended December 31, 2007 is a gain of $1.2 million from the sale of surface acreage in Wise County, Virginia. We received total proceeds in 2007 of $1.4 million related to this sale. During 2006, we recorded the sale of timber and related surface acreage located on our property in Wise and Dickenson Counties, Virginia. We received proceeds from the sale of $7.1 million, resulting in a gain of $3.5 million for the year ended December 31, 2006.

Operating costs and expenses. Included in total expenses are:

> Depletion and amortization of $64.3 million, $51.4 million and $29.7 million for the years ended December 31, 2008, 2007 and 2006, respectively. Fluctuations in depletion are dependent on the depletion rates where coal is mined, which can cause total depletion to be lower in periods where production is actually up. The new properties that we acquired in 2007 and at the end of 2006 are being depleted at much higher rates than our older properties, resulting in the significant increase in 2007 and 2008.
>
> General and administrative expenses of $13.9 million, $20.0 million and $15.5 million for the years ended December 31, 2008, 2007 and 2006, respectively. The increase in general and administrative expenses from 2006 to 2007 is primarily attributable to additional expenses required to manage a larger portfolio of properties as well as an increase in incentive compensation accrual partially attributable to the adoption of FAS 123R in 2006 as well as the steady increase in our unit price. During 2008, we experienced a decrease in the accrual for our long term incentive plan due to a decrease in our unit price which resulted in lower general and administrative expense for 2008.
>
> Property, franchise and other taxes of $13.6 million, $13.6 million and $8.1 million for the years ended December 31, 2008, 2007 and 2006, respectively. The significant increase in 2007 was primarily due to taxes on additional properties we have acquired. A substantial portion of our property taxes is reimbursed to us by our lessees and is reflected as property tax revenue on our statement of income.

Interest Expense. Interest expense was $28.4 million, $28.7 million and $16.4 million for the years ended December 31, 2008, 2007 and 2006, respectively. Interest expense is attributed to borrowings on our credit facility and the issuance of senior notes used to fund acquisitions in 2006 and 2007. During 2008, we did not incur any additional debt to fund acquisitions.

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 our 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. Cost reimbursements due our general partner may be substantial and will reduce our cash available for distribution to unitholders. The reimbursements to our general partner for services performed by Western Pocahontas Properties and Quintana Minerals Corporation totaled $5.6 million in 2008, $5.0 million in 2007 and $4.0 million in 2006. For additional information, please read Certain Relationships and Related Transactions, and Director Independence Omnibus Agreement.

The Cline Group

On January 4, 2007, we acquired four entities from Adena Minerals, LLC that own approximately 49 million tons of coal reserves in West Virginia and Illinois that are leased to active mining operations, as well as associated transportation and infrastructure assets at those mines. The reserves consist of 37 million tons at Adena s Gatling mining operation in Mason County, West Virginia and 12 million tons adjacent to reserves currently owned by us at Adena affiliate Williamson Energy s Pond Creek No. 1 mine in Southern Illinois. In consideration therefor, Adena received 8,910,072 units, now representing a 13.8% limited partner interest in NRP and a 22% interest in our general partner and in our outstanding incentive distribution rights. Adena is an affiliate of The Cline Group, a private coal company that controls over 3 billion tons of coal reserves in the Illinois and Northern Appalachian coal basins. In 2008 and 2007, we received $27.9 million and $12.1 million, respectively in revenues from affiliates of The Cline Group. In addition we also received $9.8 million in advance minimum royalty payments that have not been recouped. At December 31, 2008, NRP had accounts receivable from the Cline Group of $2.3 million.

Second Contribution Agreement. At the closing, we executed a Second Contribution Agreement, pursuant to which we agreed to acquire from Adena two entities that own coal reserves in Meigs County, Ohio and associated transportation infrastructure. As consideration, Adena will receive 4,560,000 common units, as well as an additional 9% interest in the general partner and our outstanding incentive distribution rights. The transactions contemplated by the Second Contribution Agreement are expected to close in the second quarter of 2009.

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

Investor Rights Agreement. Also at the closing, NRP and certain affiliates and Adena executed an Investor Rights Agreement pursuant to which Adena was granted certain management rights. Specifically, Adena has the right to name two directors (one of which will be independent) to the board of directors of our managing general partner so long as Adena beneficially owns either 5% of our limited partnership interest or 5% of our general partner s limited partnership interest and so long as certain rights under our managing general partner s LLC Agreement have not been exercised by Adena or Corbin J. Robertson, Jr. Adena nominated J. Matthew Fifield, Managing Director of Adena, and Leo A. Vecellio to serve as the two directors. Mr. Vecellio serves on our Compensation, Nominating and

Governance Committee. Adena also has the right, pursuant to the terms of the Investor Rights Agreement, to withhold its consent to the sale or other disposition of any entity or assets contributed by the Cline entities to NRP.

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, NRP s Board of Directors 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. For a more detailed description of this policy, please see Item 13. Certain Relationships and Related Transactions, and Director Independence in this Form 10-K.

In February 2007, a fund controlled by Quintana Capital acquired a 43% membership interest in Taggart Global, 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 will own and lease the plants to Taggart Global, which will design, build and operate the plants. The lease payments are based on the sales price for the coal that is processed through the facilities. NRP and Taggart Global have jointly developed four such plants in West Virginia. In 2008, NRP received $5.0 million in revenue from Taggart compared to $2.7 million in 2007. At December 31, 2008, NRP had accounts receivable from Taggart of $0.4 million.

In June 2007, a fund controlled by Quintana Capital acquired Kopper-Glo, a small coal mining company with operations in Tennessee. Kopper-Glo is an NRP lessee that paid us $1.4 million in coal royalties in 2008 and $1.9 million in 2007. At December 31, 2008, NRP had accounts receivable of $0.1 million from Kopper-Glo.

Office Building in Huntington, West Virginia

In 2008, Western Pocahontas Properties Limited Partnership completed construction of an office building in Huntington, West Virginia. On January 1, 2009, we began leasing substantially all of two floors of the building from Western Pocahontas at market rates. The terms of the lease were approved by our conflicts committee.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

We satisfy our working capital requirements with cash generated from operations. Since our initial public offering, we have financed our property acquisitions with available cash, borrowings under our revolving credit facility, and the issuance of our senior notes and additional units. Our capital expenditures, other than for acquisitions, have historically been minimal. However, given the current global financial crisis, we cannot be certain that proceeds from capital markets issuances will be available or sufficient to finance future acquisitions. 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 industry and other factors, some of which are beyond our control.

We had approximately $90 million of cash available at the end of the year and do not currently have any need to raise capital through the equity markets. Following our Macoupin acquisition in January 2009, we had $169 million in available capacity under the facility, and have committed to fund another $60 million as certain performance milestones are met in connection with the development of the Shay No. 1 mine in Illinois.

Our credit facility does not expire until 2012, and our credit ratios are well within our debt covenants for both our credit facility and our outstanding senior notes. In addition, we are amortizing substantially all of our long-term debt and have no immediate need to refinance. For a more complete discussion of factors that will affect our liquidity, please read Item 1A. Risk Factors . During 2008, we reviewed our banking relationships and our internal policies regarding deposit concentrations with specific attention to effectively managing risk in the current banking environment.

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Net cash provided by operations for the years ended December 31, 2008, 2007 and 2006 was $230.0 million, $168.2 million and $138.8 million, respectively. A significant portion of our cash provided by operations is generated from coal royalty revenues.

Net cash used in investing activities for the years December 31, 2008, 2007 and 2006 was $9.8 million, $79.6 million and $257.7 million, respectively. In each of those years, substantially all of our investing activities consisted of acquiring coal reserves and other mineral rights, but we spent $10.6 million, $16.7 million and $24.2 million in 2008, 2007 and 2006, respectively, on coal infrastructure acquisitions. Also, in December 2006, we acquired aggregate reserves for $23.5 million and sold non-core timberlands for gross proceeds totaling $7.1 million. In 2007, we sold surface acreage in Wise County, Virginia for gross proceeds of $1.4 million.

Net cash used for financing activities for the year ended December 31, 2008 and 2007 was $188.5 million and $96.2 million, respectively. Net cash generated from financing was $137.2 million for the year ended December 31, 2006. All loan proceeds from our credit facility have been used to fund acquisitions. We issued $50 million in senior notes in 2006 and $225 million in senior notes in 2007. We used those proceeds to pay down our credit facility. We also made $17.2 million in principal payments on our senior notes in 2008. We made principal payments of $9.4 million in each of the years ended December 31, 2007 and 2006. Cash distributions to our partners were $171.3 million, $147.0 million and $92.4 million for the years ended December 31, 2008, 2007 and 2006, respectively. In 2007, as a part of the Dingess-Rum and Mettiki acquisitions we received a $2.6 million cash contribution from our general partner to maintain its 2% interest.

Contractual Obligations and Commercial Commitments

Long-Term Debt

At December 31, 2008, our debt consisted of:

- $48.0 million of our $300 million floating rate revolving credit facility, due March 2012;
- $35.0 million of 5.55% senior notes due 2013;
- $49.8 million of 4.91% senior notes due 2018;
- $92.3 million of 5.05% senior notes due 2020;
- $2.5 million of 5.31% utility local improvement obligation due 2021;
- $43.5 million of 5.55% senior notes due 2023; and
- $225.0 million of 5.82% senior notes due 2024.

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 5.05% senior notes due 2020 began in July 2008, and the principal payments on the 5.82% senior notes due 2024 do not begin until March 2010. We also make annual principal and interest payments on the utility local improvement obligation.

Credit Facility. In March 2007, we completed an amendment and extension of our $300 million revolving credit facility. The amendment extends the term of the credit facility by two years to 2012 and lowers the borrowing costs and commitment fees. The amendment also includes an option to increase the credit facility up to a maximum of $450 million under the same terms. However, under current market conditions, 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 attempt to bring new lenders into the facility, but we cannot make any assurance that any new lenders would elect to participate or that the excess credit capacity will be available to us at all or on the existing terms.

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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 higher of the federal funds rate plus an applicable margin ranging from 0% to 0.50% or the prime rate as announced by the agent bank; or
- at a rate equal to LIBOR plus an applicable margin ranging from 0.45% to 1.50%.

We incur a commitment fee on the unused portion of the revolving credit facility at a rate ranging from 0.10% to 0.30% 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) of 3.75 to 1.0 for the four most recent quarters; provided however, if during one of those quarters we have made an acquisition, then the ratio shall not exceed 4.0 to 1.0 for the quarter in which the acquisition occurred and (1) if the acquisition is in the first half of the quarter, the next two quarters or (2) if the acquisition is in the second half of the quarter, the next three quarters; and
- a ratio of consolidated EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated lease operating expense) of 4.0 to 1.0 for the four most recent quarters.

Senior Notes. NRP Operating LLC issued the senior notes under a note purchase agreement. 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 note purchase agreement contains covenants requiring our operating subsidiary to:

- 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.

The following table reflects our long-term non-cancelable contractual obligations as of December 31, 2008 (in millions):

	Payments Due by Period(1)						
Contractual Obligations	**Total**	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**
Long-term debt (including current maturities)	$ 682.9	$ 41.7	$ 55.8	$ 53.4	$ 98.9	$ 83.3	$ 349.8
Rental lease	5.3	0.5	0.5	0.5	0.5	0.5	2.8
Total	$ 688.2	$ 42.2	$ 56.3	$ 53.9	$ 99.4	$ 83.8	$ 352.6

(1) The amounts indicated in the table include principal and interest due on our senior notes, as well as the utility local improvement obligation related to our property in DuPont, Washington. The table includes the $48.0 million outstanding principal balance at December 31, 2008 under our credit facility, which matures in March 2012. 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.

Two-for-One Limited Partner Unit Split

On April 18, 2007, we completed a two-for-one split of all of our limited partner units. Accordingly, all unit and per unit amounts reported reflect the split.

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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, 2008, 2007 and 2006.

Environmental

The operations our lessees conduct on our properties are subject to federal and state environmental laws and regulations. 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, 2008. 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.

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 efficient 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 80% 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 our current 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, 2008, we had $48 million outstanding in variable interest debt. If interest rates were to increase by 1%, annual interest expense would increase $480,000, assuming the same principal amount remained outstanding during the year.

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

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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, 2008 and 2007, and the related consolidated statements of income, partners capital and cash flows for each of the three years in the period ended December 31, 2008. 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, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, 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 27, 2009 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Houston, Texas
February 27, 2009

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(In thousands, except for unit information)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 89,928	$ 58,341
Restricted cash		6,240
Accounts receivable, net of allowance for doubtful accounts	31,883	27,643
Accounts receivable affiliate	1,351	1,005
Other	934	1,009
Total current assets	124,096	94,238
Land	24,343	24,343
Plant and equipment, net	67,204	61,441
Coal and other mineral rights, net	979,692	1,030,088
Intangible assets	102,828	106,222
Loan financing costs, net	2,679	3,098
Other assets, net	498	601
Total assets	$ 1,301,340	$ 1,320,031
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 861	$ 2,606
Accounts payable affiliate	365	104
Current portion of long-term debt	17,235	17,234
Accrued incentive plan expenses current portion	3,179	3,993
Property, franchise and other taxes payable	6,122	6,415
Accrued interest	6,419	6,276
Total current liabilities	34,181	36,628
Deferred revenue	40,754	36,286
Accrued incentive plan expenses	4,242	6,469
Long-term debt	478,822	496,057
Partners capital:		
Common units outstanding: 64,891,136	727,965	731,113
General partner s interest	15,148	14,177
Holders of incentive distribution rights	876	
Accumulated other comprehensive loss	(648)	(699)
Total partners capital	743,341	744,591

Total liabilities and partners capital	$ 1,301,340	$ 1,320,031

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

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NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31, 2008	2007	2006
	(In thousands, except per unit data)		
Revenues:			
Coal royalties	$ 226,250	$ 171,343	$ 147,752
Aggregate royalties	9,119	7,434	538
Coal processing fees	8,781	4,824	1,452
Transportation fees	11,656	3,984	
Oil and gas royalties	7,902	4,930	4,220
Property taxes	9,800	10,285	5,971
Minimums recognized as revenue	1,257	1,951	2,082
Override royalties	11,327	3,794	957
Other	5,573	6,440	7,701
Total revenues	291,665	214,985	170,673
Operating costs and expenses:			
Depreciation, depletion and amortization	64,254	51,391	29,695
General and administrative	13,922	20,048	15,520
Property, franchise and other taxes	13,558	13,613	8,122
Transportation costs	1,416	298	
Coal royalty and override payments	1,508	1,336	1,560
Total operating costs and expenses	94,658	86,686	54,897
Income from operations	197,007	128,299	115,776
Other income (expense)			
Interest expense	(28,356)	(28,690)	(16,423)
Interest income	1,355	2,890	2,737
Net income	$ 170,006	$ 102,499	$ 102,090
Net income attributable to:			
General partner	$ 28,318	$ 14,315	$ 9,717
Holders of incentive distribution rights	$ 13,756	$ 7,216	$ 4,133
Limited partners	$ 127,932	$ 80,968	$ 88,240
Basic and diluted net income per limited partner unit:			
Common	$ 1.97	$ 1.26	$ 1.74
Subordinated	$	$ 1.26	$ 1.74

Weighted average number of units outstanding:			
Common	64,891	54,582	34,366
Subordinated		9,923	16,316

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

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NATURAL RESOURCE PARTNERS L.P.

STATEMENT OF PARTNERS CAPITAL

	Common Units		Subordinated Units		General Partner	Holders of Incentive Distribution Rights	Accumulated Other Comprehensive Income (Loss)	
	Units	Amounts	Units	Amounts	Amounts	Amounts		Total
			(In thousands, except unit data)					
ance at cember 31, 2005	33,650,614	$ 292,990	17,030,456	$ 123,114	$ 10,024	$ 582	$ (802)	$ 425,90
bordinated units nverted to common	5,676,822	40,775	(5,676,822)	(40,775)				
demption of ctional units upon nversion of bordinated units	(6)							
tributions to itholders		(54,220)		(27,440)	(7,603)	(3,099)		(92,36
t income for the year led December 31, 06		59,367		28,873	9,717	4,133		102,09
ss on interest hedge							51	5
mprehensive income							51	102,14
ance at cember 31, 2006	39,327,430	$ 338,912	11,353,634	$ 83,772	$ 12,138	$ 1,616	$ (751)	$ 435,68
uance of units for quisitions	14,210,072	346,319			4,422			350,74
bordinated units nverted to common	11,353,634	75,444	(11,353,634)	(75,444)				
pital contribution					2,645			2,64
tributions to itholders		(98,023)		(20,835)	(19,343)	(8,832)		(147,03
t income for the year led cember 31, 2007		68,461		12,507	14,315	7,216		102,49
ss on interest hedge							52	5
mprehensive income							52	102,55
	64,891,136	$ 731,113			$ 14,177		$ (699)	$ 744,59

ance at cember 31, 2007						
tributions to tholders		(131,080)	(27,347)	(12,880)		(171,30
t income for the year led December 31, 08		127,932	28,318	13,756		170,00
ss on interest hedge					51	5
nprehensive income					51	170,05
ance at cember 31, 2008	64,891,136	$ 727,965	$ 15,148	$ 876	$ (648)	$ 743,34

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

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Cash flows from operating activities:			
Net income	$ 170,006	$ 102,499	$ 102,090
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	64,254	51,391	29,695
Non-cash interest charge	278	443	349
Gain(loss) on sale of assets	33	(1,236)	(3,471)
Change in operating assets and liabilities:			
Accounts receivable	(4,586)	(5,270)	(1,426)
Other assets	178	178	(579)
Accounts payable and accrued liabilities	(1,484)	(464)	381
Accrued interest	143	2,430	2,312
Deferred revenue	4,468	15,632	5,803
Accrued incentive plan expenses	(3,041)	465	3,497
Property, franchise and other taxes payable	(293)	2,085	192
Net cash provided by operating activities	229,956	168,153	138,843
Cash flows from investing activities:			
Acquisition of land, coal and other mineral rights	(5,500)	(58,124)	(240,517)
Acquisition or construction of plant and equipment	(10,568)	(16,695)	(24,248)
Proceeds from sale of assets		1,425	7,051
Change in restricted accounts	6,240	(6,240)	
Net cash used in investing activities	(9,828)	(79,634)	(257,714)
Cash flows from financing activities:			
Proceeds from loans		285,400	254,000
Deferred financing costs		(1,292)	(64)
Repayments of loans	(17,234)	(235,942)	(24,350)
Distributions to partners	(171,307)	(147,033)	(92,362)
Contributions by general partner		2,645	
Net cash (used in) provided by financing activities	(188,541)	(96,222)	137,224
Net increase (decrease) in cash and cash equivalents	31,587	(7,703)	18,353
Cash and cash equivalents at beginning of period	58,341	66,044	47,691
Cash and cash equivalents at end of period	$ 89,928	$ 58,341	$ 66,044

Supplemental cash flow information:						
Cash paid during the period for interest	$	27,735	$	25,771	$	13,734
Non-cash financing activities:						
Equity issued for business combinations	$		$	330,064	$	
Assets contributed by general partner in business combination				4,422		
Liability assumed in business combination				1,989		
Equity issued for assets purchased				16,255		
Utility improvement obligation acquired						2,883

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

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Organization

Natural Resource Partners L.P. (the Partnership), a Delaware limited partnership, was formed in April 2002. The general partner of the Partnership is NRP (GP) LP, a Delaware limited partnership, whose general partner is GP Natural Resource Partners LLC, a Delaware limited liability company. The Partnership engages principally in the business of owning and managing coal properties in the three major coal-producing regions of the United States: Appalachia, the Illinois Basin and the Western United States. As of December 31, 2008, the Partnership owned or controlled approximately 2.1 billion tons of proven and probable coal reserves (unaudited) . The Partnership does not operate any mines, but leases coal reserves to experienced mine operators under long-term leases that grant the operators the right to mine coal reserves in exchange for royalty payments. Lessees are generally required to make royalty payments based on the higher of a percentage of the gross sales price or a fixed price per ton of coal sold, in addition to a minimum payment.

In addition, the Partnership owns coal transportation and preparation equipment, aggregate reserves, other coal related rights and oil and gas properties on which it earns revenue.

The Partnership s operations are conducted through, and its operating assets are owned by, its subsidiaries. The Partnership owns its subsidiaries through a wholly owned operating company, NRP (Operating) LLC. NRP (GP) LP, the general partner of the Partnership, has sole responsibility for conducting its business and for managing its operations. Because its 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 its behalf. Robertson Coal Management LLC, a limited liability company wholly owned by Corbin J. Robertson, Jr., owns all of the membership interest in GP Natural Resource Partners LLC. Mr. Robertson is entitled to nominate all nine of the directors, five of whom must be independent directors, to the board of directors of GP Natural Resource Partners LLC. In connection with the Cline acquisition, Mr. Robertson delegated the right to nominate two of the directors, one of whom must be independent, to Adena Minerals, LLC, an affiliate of the Cline Group.

2. Summary of Significant Accounting Policies

Principles of Consolidation

The financial statements include the accounts of Natural Resource Partners L.P. and its wholly owned subsidiaries. Intercompany transactions and balances have been eliminated.

Reclassification

Certain reclassifications have been made to the prior year s financial statements to conform to current year classifications. The accumulated retirement obligation has been moved to accounts payable for both years.

Business Combinations

For purchase acquisitions accounted for as a business combination, the Partnership is required to record the assets acquired, including identified intangible assets and liabilities assumed at their fair value, which in many instances involves estimates based on third party valuations, such as appraisals, or internal valuations based on discounted cash flow analyses or other valuation techniques. For additional discussion concerning our valuation of intangible assets, see Note 7, Intangible Assets.

Fair Value Measurements

In September 2006, FASB released FAS 157, *Fair Value Measurements* (FAS 157) which is effective for the year ending December 31, 2008 for the Partnership. FASB 157 defines fair value, establishes a

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NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. In November 2007, FASB agreed to a one-year deferral associated with the effective date for nonfinancial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis. The Partnership is currently assessing the deferred portion of the pronouncement. As of January 1, 2008, the Partnership adopted FAS 157 for the fair value measurement of recurring items.

FAS 157 describes three levels of inputs that may be used to measure fair value:

Level 1 Quoted prices in active markets for identical assets or liabilities.

Level 2 Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.

Level 3 Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. Level 3 assets and liabilities include financial instruments whose value is determined using pricing models, discounted cash flow methodologies, or similar techniques, as well as instruments for which the determination of fair value requires significant management judgment or estimation.

The Partnership s financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and long-term debt. The carrying amount of the Partnership s financial instruments included in accounts receivable and accounts payable approximates their fair value due to their short-term nature. The Partnership s cash and cash equivalents include money market accounts and are considered a Level 1 measurement. The fair market value of the Partnership s long-term debt was estimated to be $385.5 million and $444.2 million at December 31, 2008 and 2007, respectively, for the senior notes. The fair value is estimated by management using comparable term risk-free treasury issues with a market rate component determined by current financial instruments with similar characteristics which is a Level 3 measurement. Since the Partnership s credit facility has variable rate debt, its fair value approximates its carrying amount. The Partnership had $48.0 million in outstanding debt under the credit facility at December 31, 2008.

Use of Estimates

Preparation of the accompanying financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash Equivalents and Restricted Cash

The Partnership considers all highly liquid short-term investments with an original maturity of three months or less to be cash equivalents. Restricted cash includes deposits to secure performance under contracts acquired as part of the Cline acquisition. Earnings on the restricted cash are available to the Partnership. Performance under the Cline contracts was completed in November 2008 and the funds were released from escrow at that time.

Accounts Receivable

Accounts receivable are recorded on the basis of tons of minerals sold by the Partnership s lessees in the ordinary course of business, and do not bear interest. Receivables are recorded net of the allowance for doubtful accounts in the accompanying consolidated balance sheets. The Partnership evaluates the collectibility of its accounts receivable based on a combination of factors. The Partnership regularly analyzes its lessees accounts and when it becomes aware of a specific customer s inability to meet its financial obligations to the

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Partnership, such as in the case of bankruptcy filings or deterioration in the lessee s operating results or financial position, the Partnership records a specific reserve for bad debt to reduce the related receivable to the amount it reasonably believes is collectible. Accounts are charged off when collection efforts are complete and future recovery is doubtful. If circumstances related to specific lessees change, the Partnership s estimates of the recoverability of receivables could be further adjusted.

Land, Coal and Mineral Rights

Land, coal and other mineral rights owned and leased are recorded at cost. Coal and other mineral rights are depleted on a unit-of-production basis by lease, based upon coal mined in relation to the net cost of the mineral properties and estimated proven and probable tonnage therein, or over the amortization period of the contractual rights.

Plant and Equipment

Plant and equipment consists of coal preparation plants, related coal handling facilities, and other coal processing and transportation infrastructure. Expenditures for new facilities and expenditures that substantially increase the useful life of property, including interest during construction, are capitalized and reported in the capital expenditure caption in the Consolidated Statements of Cash Flows. These assets are recorded at cost and are being depreciated on a straight-line basis over their useful lives, which range from five to forty years.

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.

Concentration of Credit Risk

Substantially all of the Partnership s accounts receivable result from amounts due from third-party companies in the coal industry. This concentration of customers may impact the Partnership s overall credit risk, either positively or negatively, in that these entities may be affected by changes in economic or other conditions. Receivables are generally not collateralized.

Deferred Financing Costs

Deferred financing costs consist of legal and other costs related to the issuance of the Partnership s revolving credit facility and senior notes. These costs are amortized over the term of the debt.

Revenues

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

Coal Processing and Transportation Fees. Coal processing fees are recognized on the basis of tons of coal processed through the facilities by the Partnership s lessees and the corresponding revenue from those sales. Generally, the lessees of the coal 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 coal processing leases are structured in a manner so that the lessees are responsible for operating and maintenance expenses associated with the facilities. Coal transportation fees are recognized on the basis of

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 are subject to minimum annual payments or delay rentals.

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

Property Taxes

The Partnership is responsible for paying property taxes on the properties it owns. Typically, the lessees are contractually responsible for reimbursing the Partnership for property taxes on the leased properties. The reimbursement of property taxes is included in revenues in the statement of income as property taxes.

Income Taxes

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

Share-Based Payment

The Partnership accounts for awards under its Long-Term Incentive Plan under Financial Accounting Standards Board Statement No. 123R, Share Based Payment. FAS 123R provides that grants must be accounted for using the fair value method, which requires the Partnership to estimate the fair value of the grant and charge or credit the estimated fair value to expense over the service or vesting period of the grant based on fluctuations in value. In addition, FAS 123R 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.

New Accounting Standard

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements.* This statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value methods. This statement does not require any new fair value measurements. Instead, it provides for increased consistency and comparability in fair value measurements and for expanded disclosure surrounding the fair value measurements whenever other standards require (or permit) the measurement of assets or liabilities at fair value. This statement is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. Accordingly, the Partnership adopted SFAS No. 157 on January 1, 2008. The adoption of this statement did not have a material impact on the Partnership s financial position, results of operations or cash flows. In February 2008, the FASB issued FASB Staff Position No. 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for one year for nonfinancial assets

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

In February 2007, the FASB issued Statement No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. The standard provides companies with an option to report selected financial assets and liabilities at fair value and establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. The Partnership did not elect the fair value option for any financial assets or financial liabilities as of January 1, 2008, the effective date of the standard.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* . The statement establishes principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree. The statement also provides guidance for recognizing and measuring the goodwill acquired in the business combination and determines what information to disclose to enable users of the financial statement to evaluate the nature and financial effects of the business combination. SFAS No. 141R is effective for financial statements issued for fiscal years beginning after December 15, 2008. Accordingly, any business combinations the Partnership completes in 2009 or thereafter will be recorded and disclosed following the new standard. The Partnership expects SFAS No. 141R to have an impact on its consolidated financial statements when it completes a business combination, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of the acquisitions the Partnership consummates after the effective date.

In December 2007, the FASB issued SFAS No. 160, *Non-controlling Interests in Consolidated Financial Statements,* which provides guidance for accounting and reporting of non-controlling (minority) interests in consolidated financial statements. The statement is effective for fiscal years and interim periods within fiscal years beginning on or after December 15, 2008. At the current time, the Partnership does not hold minority interests in subsidiaries, therefore it is expected that SFAS No. 160 will have no impact on its financial condition or results of operations.

In March 2008, the FASB issued EITF No. 07-4, which considers whether the incentive distribution rights, or IDRs, of a master limited partnership represent a participating security when considered in the calculation of earnings per unit under the two-class method. The EITF considers whether the partnership agreement contains any contractual limitations concerning distributions to IDR holders that would impact the amount of earnings to allocate to the IDR holders for each reporting period. If distributions are contractually limited to the IDR holders share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the IDR holders. In addition, the EITF presents alternative methods for inclusion of IDRs in the earnings per unit computation. When cash distributions exceed net income for the period, net income should be reduced by the distributions made to the holders of the general partner interest, the holders of the limited partner interests and IDR holders for the period. The provisions of EITF No. 07-4 are effective for fiscal years beginning after December 15, 2008. The Partnership is currently evaluating the requirements of EITF No. 07-4 to determine the impact, if any, on our consolidated financial statements.

In June 2008, the FASB issued Staff Position (FSP) No. EITF No. 03-6-1 Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities. This FSP affects entities that accrue cash dividends on share-based payment awards during the awards service period when the dividends do not need to be returned if the employees forfeit the award. The FSP requires that all outstanding unvested share-based payment awards that contain rights to nonforfeitable dividends participate in undistributed earnings with common shareholders and are considered participating securities. Because the awards are considered participating securities, the issuing entity is required to apply the two-class method of computing basic and diluted earnings per share. The provisions of FSP No. EITF No. 03-6-1 are effective for fiscal years

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

beginning after December 15, 2008. The Partnership is currently evaluating the requirements of FSP No. EITF 03-6-1, to determine the impact and it does not expect this to have any impact on our consolidated financial statements.

3. Acquisitions and Business Combinations

During the years ended December 31, 2008 and 2007, the Partnership acquired coal properties, processing and transportation facilities. The Partnership purchased these assets utilizing cash, its credit facility and the issuance of senior notes. In addition, the Partnership completed three acquisitions in 2007 that included the issuance of 14.2 million partnership units. Two of the three acquisitions consisting of the issuance of partnership units were accounted for as business combinations. The Cline transaction included the acquisition of four entities, none of which had conducted operations or generated material amounts of revenue or operating cost prior to acquisition. Total net operating losses of the four entities from startup through December 31, 2006 were $0.3 million. In the Dingess-Rum transaction, the Partnership acquired a group of assets from an entity that was formed for purposes of the transaction. That entity did not operate the assets acquired. Therefore, unaudited pro forma information of prior periods is not presented as it would not differ materially from the historic operations of the Partnership. The third acquisition, consisting of partnership units and cash, was an asset purchase of coal reserves from Western Pocahontas Properties Limited Partnership, an affiliate of the general partner.

The following table summarizes the aggregate estimated fair values of the assets acquired and liabilities assumed in 2007 for each of the transactions accounted for as a business combination:

	Dingess-Rum	Cline
	(In thousands)	
Land, plant and equipment	$ 7,935	$ 17,783
Coal and other mineral rights	105,573	98,866
Other assets		72
Intangible assets		107,557
Equity consideration	113,396	216,668
Assets contributed by General Partner		4,422
Transaction costs and liabilities assumed	112	3,188

4. Allowance for Doubtful Accounts

Activity in the allowance for doubtful accounts for the years ended December 31, 2008, 2007 and 2006 was as follows:

	2008	2007	2006
		(In thousands)	
Balance, January 1	$ 1,272	$ 906	$ 85
Provision charged to operations:			

Additions to the reserve	366	871	822
Collections of previously reserved accounts	(1,037)	(505)	(1)
Total charged (credited) to operations	(671)	366	821
Non-recoverable balances written off	(235)		
Balance, December 31	$ 366	$ 1,272	$ 906

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NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Plant and Equipment

The Partnership s plant and equipment consist of the following:

	December 31, 2008	December 31, 2007
	(In thousands)	
Plant construction in process	$ 8,524	$ 11,238
Plant and equipment at cost	68,197	54,758
Less accumulated depreciation	(9,517)	(4,555)
Net book value	$ 67,204	$ 61,441

	For the Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Total depreciation expense on plant and equipment	$ 4,965	$ 3,904	$ 556

6. Coal and Other Mineral Rights

The Partnership s coal and other mineral rights consist of the following:

	December 31, 2008	December 31, 2007
	(In thousands)	
Coal and other mineral rights	$ 1,253,314	$ 1,247,814
Less accumulated depletion and amortization	(273,622)	(217,726)
Net book value	$ 979,692	$ 1,030,088

For the Years Ended December 31,

	2008	2007 (In thousands)	2006
Total depletion and amortization expense on coal and other mineral interests	$ 55,896	$ 45,519	$ 28,487

7. Intangible Assets

In January 2007, the Partnership completed a business combination in which certain intangible assets were identified related to the royalty and lease rates of contracts acquired when compared to the estimate of current market rates for similar contracts. The estimated fair value of the above-market rate contracts was determined based on the present value of future cash flow projections related to the underlying coal reserves and transportation infrastructure acquired. Amounts recorded as intangible assets along with the balances and accumulated amortization at December 31, 2008 are reflected in the table below.

	As of December 31, 2008	
	Gross Carrying Amount	Accumulated Amortization
	(In thousands)	
Finite-lived intangible assets		
Above market transportation contracts	$ 82,276	$ 3,683
Above market coal leases	25,281	1,046
	$ 107,557	$ 4,729

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Amortization expense related to these contract intangibles was $3.4 million for the year ended December 31, 2008 and is based upon the production and sales of coal from acquired reserves and the number of tons of coal transported using the transportation infrastructure. The estimates of expense for the periods as indicated below are based on current mining plans and are subject to revision as those plans change in future periods.

Estimated amortization expense (In thousands)	
For year ended December 31, 2009	4,231
For year ended December 31, 2010	5,026
For year ended December 31, 2011	5,390
For year ended December 31, 2012	5,390
For year ended December 31, 2013	5,390

8. Long-Term Debt

Long-term debt consists of the following:

	December 31, 2008	December 31, 2007
	(In thousands)	
$300 million floating rate revolving credit facility, due March 2012	$ 48,000	$ 48,000
5.55% senior notes, with semi-annual interest payments in June and December, maturing June 2013	35,000	35,000
4.91% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2018	49,750	55,800
5.05% senior notes, with semi-annual interest payments in January and July, with scheduled principal payments beginning July 2008, maturing in July 2020	92,308	100,000
5.31% utility local improvement obligation, with annual principal and interest payments, maturing in March 2021	2,499	2,691
5.55% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2023	43,500	46,800
5.82% senior notes, with semi-annual interest payments in March and September, with scheduled principal payments beginning March 2010, maturing in March 2024	225,000	225,000
Total debt	496,057	513,291
Less current portion of long term debt	(17,235)	(17,234)
Long-term debt	$ 478,822	$ 496,057

Principal payments due in:

2009	$ 17,235
2010	32,234
2011	31,517
2012	78,801
2013	30,200
Thereafter	306,070
	$ 496,057

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NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On March 28, 2007, the Partnership completed an amendment and extension of its $300 million revolving credit facility. The amendment extends the term of the credit facility by two years to 2012 and lowers borrowing costs and commitment fees. The amendment also includes an option to increase the credit facility at least twice a year up to a maximum of $450 million under the same terms, as well as an annual option to extend the term by one year. However, under the current market conditions, the Partnership cannot be certain that its lenders will elect to participate in the accordion feature. To the extent the lenders decline to participate, the Partnership may elect to bring new lenders into the facility, but it cannot make any assurance that the excess credit capacity will be available to the Partnership or will be available under existing terms.

At both December 31, 2008 and 2007, the Partnership had $48.0 million outstanding on its revolving credit facility. The weighted average interest rate at December 31, 2008 and 2007 was 5.14% and 6.06%, respectively. The Partnership incurs a commitment fee on the undrawn portion of the revolving credit facility at rates ranging from 0.10% to 0.30% per annum. Interest capitalized as part of the construction cost of Plant and Equipment was $0.2 million in 2008.

The Partnership was in compliance with all terms under its long-term debt as of December 31, 2008.

The credit agreement contains covenants requiring us to maintain:

- a ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the credit agreement) of 3.75 to 1.0 for the four most recent quarters; provided however, if during one of those quarters we have made an acquisition, then the ratio shall not exceed 4.0 to 1.0 for the quarter in which the acquisition occurred and (1) if the acquisition is in the first half of the quarter, the next two quarters or (2) if the acquisition is in the second half of the quarter, the next three quarters; and

- a ratio of consolidated EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated lease operating expense) of 4.0 to 1.0 for the four most recent quarters.

9. Net Income Per Unit Attributable to Limited Partners

Net income per unit attributable to limited partners is based on the weighted-average number of common and subordinated units outstanding during the period. Net income is allocated in the same ratio as quarterly cash distributions are made. Further, under the terms of the partnership agreement, in periods in which distributions to the holders of incentive distribution rights are greater than their allocated income, additional net income must be allocated to the extent of any negative capital account balance. This allocation also reduces net income allocated to limited partners for purposes of computing earnings per unit. Basic and diluted net income per unit attributable to limited partners are the same since the Partnership has no potentially dilutive securities outstanding.

10. Related Party Transactions

Reimbursements to Affiliates of our General Partner

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

The reimbursements to affiliates of the Partnership s general partner for services performed by Western Pocahontas Properties and Quintana Minerals Corporation totaled $5.6 million, $5.0 million and $4.0 million for the years ended December 31, 2008, 2007 and 2006, respectively. At December 31, 2008 and 2007, the Partnership also had accounts payable to affiliates of $0.4 million and $0.1 million, respectively.

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NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Transactions with Cline Affiliates

Williamson Energy, LLC, a company controlled by Chris Cline, leases coal reserves from the Partnership, and the Partnership provides transportation services to Williamson for a fee. Mr. Cline, through another affiliate, Adena Minerals, LLC, owns a 22% interest in our general partner, as well as 8,910,072 common units. In addition to the units owned by Adena Minerals, Mr. Cline owns 40,000 units directly. At December 31, 2008, the Partnership had accounts receivable totaling $1.9 million from Williamson. For the years ended December 31, 2008 and 2007, the Partnership had total revenue of $27.9 million and $4.6 million, respectively from Williamson. In addition, the Partnership also received $2.1 million in minimum royalty payments that have not been recouped and are included as deferred revenue on the balance sheet.

Gatling, LLC, a company also controlled by Chris Cline, leases coal reserves from the Partnership and the Partnership provides transportation services to Gatling for a fee. At December 31, 2008, the Partnership had accounts receivable totaling $0.4 million from Gatling. For the years ended December 31, 2008 and 2007, the Partnership had total revenue of $4.2 million and $7.5 million, respectively from Gatling, LLC. In addition, the Partnership also received $7.7 million in advance minimum royalty payments that have not been recouped and are included as deferred revenue on the balance sheet.

Quintana Capital Group GP, Ltd.

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

In February 2007, a fund controlled by Quintana Capital acquired a significant membership interest in Taggart Global USA, LLC, including the right to nominate two members of Taggart s 5-person board of directors. The Partnership 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. The Partnership will own and lease the plants to Taggart Global, which will design, build and operate the plants. The lease payments are based on the sales price for the coal that is processed through the facilities. To date, the Partnership has acquired four facilities under this agreement with Taggart, and for the years ended December 31, 2008 and 2007, the Partnership received total revenue of $5.0 million and $2.7 million, respectively from Taggart. At December 31, 2008 and 2007, the Partnership had accounts receivable totaling $0.4 million from Taggart.

In June 2007, a fund controlled by Quintana Capital acquired Kopper-Glo, a small coal mining company with operations in Tennessee. Kopper-Glo is a Partnership lessee that paid the Partnership $1.9 million in coal royalties in 2007 and $1.4 million in 2008. At December 31, 2008 and 2007, the Partnership also had accounts receivable of $0.1 million from Kopper-Glo.

Office Building in Huntington, West Virginia

In 2008, Western Pocahontas Properties completed construction of an office building in Huntington, West Virginia. On January 1, 2009, the Partnership began leasing substantially all of two floors of the building from Western Pocahontas Properties.

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Commitments and Contingencies

Legal

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

Environmental Compliance

The operations conducted on the Partnership s properties by its lessees are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. As owner of surface interests in some properties, the Partnership may be liable for certain environmental conditions occurring at the surface properties. The terms of substantially all of the Partnership s leases require the lessee to comply with all applicable laws and regulations, including environmental laws and regulations. Lessees post reclamation bonds assuring that reclamation will be completed as required by the relevant permit, and substantially all of the leases require the lessee to indemnify the Partnership against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. The Partnership has neither incurred, nor is aware of, any material environmental charges imposed on it related to its properties as of December 31, 2008. The Partnership is not associated with any environmental contamination that may require remediation costs.

Lease

On January 1, 2009, the Partnership leased it office facilities in Huntington, WV under a lease that requires annual payments of $530,160 for each year through December 31, 2018.

12. Major Lessees

The Partnership has one lessee that generated in excess of ten percent of total revenues for 2008, 2007 and 2006. Revenues from that lessee are as follows:

	For the Years Ended December 31,					
	2008		2007		2006	
	Revenues	Percent	Revenues	Percent	Revenues	Percent
	(Dollars in thousands)					
Lessee A	$ 31,958	11.0%	$ 21,025	10.0%	$ 23,146	14.0%

13. Incentive Plans

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

Under the plan a grantee will receive the market value of a common unit in cash upon vesting. Market value is defined as the average closing price over the 20 trading days prior to the vesting date. The compensation committee may make grants under the Long-Term Incentive Plan to employees and directors

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

containing such terms as it determines, including the vesting period. Outstanding grants vest upon a change in control of the Partnership, the general partner, or GP Natural Resource Partners LLC. If a grantee s employment or membership on the board of directors terminates for any reason, outstanding grants will be automatically forfeited unless and to the extent the compensation committee provides otherwise.

A summary of activity in the outstanding grants for the year ended December 31, 2008 are as follows:

Outstanding grants at the beginning of the period	507,466
Grants during the period	171,328
Grants vested and paid during the period	(105,230)
Forfeitures during the period	(2,280)
Outstanding grants at the end of the period	571,284

Grants typically vest at the end of a four-year period and are paid in cash upon vesting. The liability fluctuates with the market value of the Partnership units and because of changes in estimated fair value determined each quarter using the Black-Scholes option valuation model. Risk free interest rates and historical volatility are reset at each calculation based on current rates corresponding to the remaining vesting term for each outstanding grant and ranged from 0.40% to 0.99% and 45.34% to 68.53%, respectively at December 31, 2008. The Partnership s historical dividend rate of 6.038% was used in the calculation at December 31, 2008. The Partnership accrued expenses related to its plans to be reimbursed to its general partner of $6.1 million and $4.3 million for the years ended December 31, 2007 and 2006, respectively. During 2008, the Partnership reversed accruals of approximately $0.3 million due to the decrease in unit price from December 31, 2007 to December 31, 2008. Included in the first quarter of 2006, was $661,000 related to the cumulative effect of the change in accounting method for the adoption of FAS 123R. In connection with the Long-Term Incentive Plans, cash payments of $3.2 million, $5.8 million and $0.8 million were paid during each of the years ended December 31, 2008, 2007, and 2006, respectively. The grant date fair value was $32.66, $34.64 and $31.06 per unit for awards in 2008, 2007 and 2006, respectively and the unaccrued cost associated with the unvested outstanding grants at December 31, 2008 was $4.9 million.

In connection with the phantom unit awards granted in February 2008, the CNG Committee also granted tandem Distribution Equivalent Rights, or DERs, which entitle the holders to receive distributions equal to the distributions paid on the Partnership s common units. The DERs have a four-year vesting period, and the Partnership will accrue the cost of the distributions over that period.

14. Subsequent Events (Unaudited)

Acquisitions

On January 27, 2009, the Partnership acquired coal reserves and infrastructure assets for $143.7 million from Macoupin Energy, LLC, an affiliate of the Cline Group. Following the Macoupin acquisition in January 2009, the Partnership had $169 million in available capacity under the credit facility, and has committed to fund another $60 million as certain performance milestones are met in connection with the development of the Shay No. 1 mine in

Illinois.

Distributions

On February 13, 2009, the Partnership paid a quarterly distribution of $0.535 per unit to all holders of common units.

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NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. Supplemental Financial Data (Unaudited)

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

2008	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues	$ 64,055	$ 75,592	$ 76,196	$ 75,822
Income from operations	40,768	47,105	53,882	55,252
Net income	$ 33,852	$ 40,353	$ 47,338	$ 48,463
Basic and diluted net income per limited partner unit	$ 0.40	$ 0.47	$ 0.55	$ 0.55
Weighted average number of units outstanding:				
Common	64,891	64,891	64,891	64,891

2007	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues	$ 50,207	$ 51,097	$ 56,366	$ 57,315
Income from operations	28,391	29,078	35,316	35,514
Net income	$ 21,881	$ 22,631	$ 28,928	$ 29,059
Basic and diluted net income per limited partner unit	$ 0.28	$ 0.28	$ 0.35	$ 0.35
Weighted average number of units outstanding:				
Common	50,893	52,925	53,537	59,214
Subordinated	11,354	11,354	11,354	5,677
Class B	1,048	607		

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Item 9. ***Changes In and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

We carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act) as of December 31, 2008. This evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of GP Natural Resource Partners LLC, our managing general partner. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and procedures are effective in producing the timely recording, processing, summary and reporting of information and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosures.

Management s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of GP Natural Resource Partners LLC, our managing general partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2008 based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2008. No changes were made to our internal control over financial reporting during the last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

Report of Independent Registered Public Accounting Firm

The Partners of Natural Resource Partners L.P.

We have audited Natural Resource Partners L.P s. internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Natural Resource Partners L.P. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control Over Financial Reporting . Our responsibility is to express an opinion on the Partnership s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Natural Resource Partners L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Natural Resource Partners L.P. as of December 31, 2008 and 2007, and the related consolidated statements of income, partners capital and cash flows for each of the three years in the period ended December 31, 2008 and our report dated February 27, 2009, expressed an unqualified opinion thereon.

Ernst & Young LLP

Houston, Texas
February 27, 2009

Item 9B. ***Other Information***

None.

PART III

Item 10. *Directors and Executive Officers of the Managing General Partner and Corporate Governance*

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

Name	Age	Position with the General Partner
Corbin J. Robertson, Jr.	61	Chairman of the Board and Chief Executive Officer
Nick Carter	62	President and Chief Operating Officer
Dwight L. Dunlap	55	Chief Financial Officer and Treasurer
Kevin F. Wall	52	Executive Vice President Operations
Wyatt L. Hogan	37	Vice President, General Counsel and Secretary
Dennis F. Coker	41	Vice President, Aggregates
Kevin J. Craig	40	Vice President, Business Development
Kenneth Hudson	54	Controller
Kathy H. Roberts	57	Vice President, Investor Relations
Robert T. Blakely	67	Director
David M. Carmichael	70	Director
J. Matthew Fifield	35	Director
Robert B. Karn III	67	Director
S. Reed Morian	62	Director
W. W. Scott, Jr.	63	Director
Stephen P. Smith	47	Director
Leo A. Vecellio, Jr.	62	Director

Corbin J. Robertson, Jr. is the Chief Executive Officer and Chairman of the Board of Directors of GP Natural Resource Partners LLC. Mr. Robertson has served as the Chief Executive Officer and Chairman of the Board of the general partners of Western Pocahontas Properties Limited Partnership since 1986, Great Northern Properties Limited Partnership since 1992 and Quintana Minerals Corporation since 1978 and as Chairman of the Board of Directors of New Gauley Coal Corporation since 1986. He also serves as a Principal with Quintana Capital Group, Chairman of the Board of the Cullen Trust for Higher Education and on the boards of the American Petroleum Institute, the National Petroleum Council, the Baylor College of Medicine and the World Health and Golf Association. In 2006, Mr. Robertson was inducted into the Texas Business Hall of Fame.

Nick Carter is the President and Chief Operating Officer of GP Natural Resource Partners LLC. He has also served as President of the general partner of Western Pocahontas Properties Limited Partnership and New Gauley Coal Corporation since 1990 and as President of the general partner of Great Northern Properties Limited Partnership from

1992 to 1998. Prior to 1990, Mr. Carter held various positions with MAPCO Coal Corporation and was engaged in the private practice of law. He is Chairman of the National Council of Coal Lessors, a past Chair of the West Virginia Chamber of Commerce and a board member of the Kentucky Coal Association, West Virginia Coal Association, Indiana Coal Council, Community Trust Bancorp, Inc.,Vigo Coal Company, Inc. and Carbo* Prill, Inc.

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Dwight L. Dunlap is the Chief Financial Officer and Treasurer of GP Natural Resource Partners LLC. Mr. Dunlap has served as Vice President and Treasurer of Quintana Minerals Corporation and as Chief Financial Officer, Treasurer and Assistant Secretary of the general partner of Western Pocahontas Properties Limited Partnership, Chief Financial Officer and Treasurer of Great Northern Properties Limited Partnership and Chief Financial Officer, Treasurer and Secretary of New Gauley Coal Corporation since 2000. Mr. Dunlap has worked for Quintana Minerals since 1982 and has served as Vice President and Treasurer since 1987. Mr. Dunlap is a Certified Public Accountant with over 30 years of experience in financial management, accounting and reporting including six years of audit experience with an international public accounting firm.

Kevin F. Wall is Executive Vice President Operations of GP Natural Resource Partners LLC. Mr. Wall was promoted to Executive Vice President Operations in December 2008. Prior to then he served as Vice President Engineering for GP Natural Resource Partners LLC, the general partner of Western Pocahontas Properties Limited Partnership since 1998 and the general partner of Great Northern Properties Limited Partnership since 1992. He has also served as the Vice President Engineering of New Gauley Coal Corporation since 1998. He has performed duties in the land management, planning, project evaluation, acquisition and engineering areas since 1981. He is a Registered Professional Engineer in West Virginia and is a member of the American Institute of Mining, Metallurgical, and Petroleum Engineers and of the National Society of Professional Engineers. Mr. Wall also serves on the Board of Directors of Leadership Tri-State as well as the Board of the Virginia Center for Coal and Energy Research and is a past president of the West Virginia Society of Professional Engineers.

Wyatt L. Hogan is Vice President, General Counsel and Secretary of GP Natural Resource Partners LLC. Mr. Hogan joined NRP in May 2003 from Vinson & Elkins L.L.P., where he practiced corporate and securities law from August 2000 through April 2003. He has also served since 2003 as the Vice President, General Counsel and Secretary of Quintana Minerals Corporation, the Secretary for the general partner of Western Pocahontas Properties Limited Partnership and as General Counsel and Secretary for the general partner of Great Northern Properties Limited Partnership. He is also member of the Board of Directors of Quintana Minerals Corporation. Prior to joining Vinson & Elkins in August 2000, he practiced corporate and securities law at Andrews & Kurth L.L.P. from September 1997 through July 2000.

Dennis F. Coker is Vice President, Aggregates of GP Natural Resource Partners LLC. Mr. Coker joined NRP in March 2008 from Hanson Building Materials America, where he had been employed since 2002, and most recently served as Director, Corporate Development. Mr. Coker has 14 years of experience in the aggregate industry, with the last nine years focused on business development activity. He currently serves as Chairman of the Young Leaders Council of the National Stone Sand and Gravel Association.

Kevin J. Craig is the Vice President of Business Development for GP Natural Resource Partners LLC. Mr. Craig joined the partnership in 2005 from CSX Transportation, where he served as Terminal Manager for the West Virginia Coalfields. He has extensive marketing and finance experience with CSX since 1996. Mr. Craig also serves as a Delegate to the West Virginia House of Delegates having been elected in 2000 and re-elected in 2002, 2004 and 2006. Prior to joining CSX, he served as a Captain in the United States Army.

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

Kathy H. Roberts is Vice President Investor Relations of GP Natural Resource Partners LLC. Ms. Roberts joined NRP in July 2002. She was the Principal of IR Consulting Associates from 2001 to July 2002 and from 1980 through

2000 held various financial and investor relations positions with Santa Fe Energy Resources, most recently as Vice President Public Affairs. She is a Certified Public Accountant. Ms. Roberts currently serves on the Board of Directors of the National Association of Publicly Traded Partnerships and has served on the local board of directors of the National Investor Relations Institute and maintained professional affiliations with various energy industry organizations. She has also served on the Executive Committee and as a National Vice President of the Institute of Management Accountants.

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Robert T. Blakely joined the Board of Directors of GP Natural Resource Partners LLC in January 2003. He currently serves as President of Performance Enhancement Group, which was formed to acquire manufacturers of high performance and racing components designed for automotive and marine-engine applications. He also served in the same capacity from mid-2002 through mid-2003. From January 2006 until August 2007, he served as Executive Vice President and Chief Financial Officer of Fannie Mae, and from August 2007 to January 2008 as an Executive Vice President at Fannie Mae. From mid-2003 through January 2006, he was Executive Vice President and Chief Financial Officer of MCI, Inc. He previously served as Executive Vice President and Chief Financial Officer of Lyondell Chemical from 1999 through 2002, Executive Vice President and Chief Financial Officer of Tenneco, Inc. from 1981 until 1999 as well as a Managing Director at Morgan Stanley. He currently serves as a Trustee of the Financial Accounting Federation and is a trustee emeritus of Cornell University. He has served on the Board of Directors and as Chairman of the Audit Committee of Westlake Chemical Corporation since August 2004.

David M. Carmichael is a member of the Board of Directors of GP Natural Resource Partners LLC. He currently is a private investor. Mr. Carmichael is the former Vice Chairman of KN Energy and the former Chairman and Chief Executive Officer of American Oil and Gas Corporation, CARCON Corporation and WellTech, Inc. He has served on the Board of Directors of ENSCO International since 2001, Cabot Oil and Gas since 2006, and Tom Brown, Inc. from 1997 until 2004. Mr. Carmichael serves on the Nominating and Governance Committee and the Compensation Committee for Cabot and on the Compensation, Nominating and Governance Committees for ENSCO. He also currently serves as a trustee of the Texas Heart Institute.

J. Matthew Fifield is a member of the Board of Directors of GP Natural Resource Partners LLC. Mr. Fifield joined NRP s Board of Directors in January 2007. He currently serves as a Managing Director of Foresight Management, LLC, a Cline Group affiliate and is responsible for business development. Since 2005, he has also served as a Managing Director of both Adena Minerals, LLC and Cline Resource & Development Company, both Cline Group affiliates. From June 2004 until joining the Cline Group, Mr. Fifield worked at RCF Management LLC, a private equity firm focusing on metals and mining. While at RCF Management, he also served as President of Basin Perlite Company from August 2005 to October 2005. Mr. Fifield received his MBA from The University of Pennsylvania s Wharton School of Business, which he attended from 2002 through 2004.

Robert B. Karn III is a member of the Board of Directors of GP Natural Resource Partners LLC. He currently is a consultant and serves on the Board of Directors of various entities. He was the partner in charge of the coal mining practice worldwide for Arthur Andersen from 1981 until his retirement in 1998. He retired as Managing Partner of the St. Louis office s Financial and Economic Consulting Practice. Mr. Karn is a Certified Public Accountant, Certified Fraud Examiner and has served as president of numerous organizations. He also currently serves on the Board of Directors of Peabody Energy Corporation and the Board of Trustees of Fiduciary Claymore MLP Opportunity Fund and Fiduciary Claymore Dynamic Equity Fund.

S. Reed Morian is a member of the Board of Directors of GP Natural Resource Partners LLC. Mr. Morian has served as a member of the Board of Directors of the general partner of Western Pocahontas Properties Limited Partnership since 1986, New Gauley Coal Corporation since 1992 and the general partner of Great Northern Properties Limited Partnership since 1992. Mr. Morian worked for Dixie Chemical Company from 1971 to 2006 and served as its Chairman and Chief Executive Officer from 1981 to 2006. He has also served as Chairman, Chief Executive Officer and President of DX Holding Company since 1989. He has served on the Board of Directors for the Federal Reserve Bank of Dallas-Houston Branch since April 2003 and as a Director of Prosperity Bancshares, Inc. since March 2005.

W. W. Scott, Jr. is a member of the Board of Directors of GP Natural Resource Partners LLC. Mr. Scott was Executive Vice President and Chief Financial Officer of Quintana Minerals Corporation from 1985 to 1999. He served as Executive Vice President and Chief Financial Officer of the general partner of Western Pocahontas Properties Limited Partnership and New Gauley Coal Corporation from 1986 to 1999. He served as Executive Vice President and Chief

Financial Officer of the general partner of Great Northern Properties Limited Partnership from 1992 to 1999. Since 1999, he has continued to serve as a director of the general partner of Western Pocahontas Properties Limited Partnership and Quintana Minerals Corporation.

Stephen P. Smith joined the Board of Directors of GP Natural Resource Partners LLC on March 5, 2004. Mr. Smith has been the Executive Vice President and Chief Financial Officer for NiSource, Inc. since June 2008. Prior to joining NiSource, he held several positions with American Electric Power Company, Inc, including Senior Vice President Shared Services from January 2008 to June 2008, Senior Vice President and Treasurer from January 2004 to December 2007, and Senior Vice President Finance from April 2003 to December 2003. From November 2000 to January 2003, Mr. Smith served as President and Chief Operating Officer Corporate Services for NiSource Inc. Prior to joining NiSource, Mr. Smith served as Deputy Chief Financial Officer for Columbia Energy Group from November 1999 to November 2000 and Chief Financial Officer for Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company from 1996 to 1999.

Leo A. Vecellio, Jr. joined the Board of Directors of GP Natural Resource Partners LLC in May 2007. Since November 2002, Mr. Vecellio has served as Chairman and Chief Executive Officer of Vecellio Group, Inc, a major aggregates producer and contractor in the Mid-Atlantic and Southeastern states. For nearly 30 years prior to that time Mr. Vecellio served in various capacities with Vecellio & Grogan, Inc., having most recently served as Chairman and Chief Executive Officer from April 1996 to November 2002. Mr. Vecellio is the former Chairman of the American Road and Transportation Builders and is a longtime member of the Florida Council of 100, as well as many other civic and charitable organizations.

Corporate Governance

Board Attendance and Executive Sessions

The Board of Directors met nine times in 2008. During that period, every director attended all of the board meetings, with the exception of Messrs. Fifield and Smith, who each missed two meetings, and Messrs. Karn and Blakely, who each missed one meeting. Pursuant to our Corporate Governance Guidelines, the non-management directors meet in executive session on a quarterly basis. During 2008, our non-management directors met in executive session four times. The presiding director of these meetings was David Carmichael, the Chairman of our Compensation, Nominating and Governance Committee, or CNG Committee. In addition, our independent directors met one time in executive session in 2008. Mr. Carmichael was the presiding director at this meeting. Interested parties may communicate with our non-management directors by writing a letter to the Chairman of the CNG Committee, NRP Board of Directors, 601 Jefferson St., Suite 3600, Houston, Texas 77002.

Independence of Directors

The Board of Directors has determined that Messrs. Blakely, Carmichael, Karn, Smith and Vecellio are independent under the standards set forth in Section 303A.02(a) of the New York Stock Exchange s listing standards. Although we had a majority of independent directors in 2008, because we are a limited partnership as defined in Section 303A of the New York Stock Exchange s listing standards, we are not required to do so. To contact the independent directors, please write to: Chairman of the Audit Committee, NRP Board of Directors, 601 Jefferson Street, Suite 3600, Houston, TX 77002. The Board has an Audit Committee, Compensation, Nominating and Governance Committee and Conflicts Committee, each of which is staffed solely by independent directors. Our Audit Committee is comprised of Robert B. Karn III, who serves as chairman, Robert T. Blakely, Stephen P. Smith and David M. Carmichael. Mr. Karn, Mr. Smith and Mr. Blakely are Audit Committee Financial Experts as determined pursuant to Item 407 of Regulation S-K.

Report of the Audit Committee

Our Audit Committee is composed entirely of independent directors. The members of the Audit Committee meet the independence and experience requirements of the New York Stock Exchange. The Committee has adopted, and annually reviews, a charter outlining the practices it follows. The charter complies with all current regulatory requirements.

During the year 2008, at each of its meetings, the Committee met with the senior members of our financial management team, our general counsel and our independent auditors. The Committee had private sessions at certain of its meetings with our independent auditors at which candid discussions of financial management, accounting and internal control issues took place.

The Committee approved the engagement of Ernst & Young LLP as our independent auditors for the year ended December 31, 2008 and reviewed with our financial managers and the independent auditors overall audit scopes and plans, the results of internal and external audit examinations, evaluations by the auditors of our internal controls and the quality of our financial reporting.

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

The Committee also discussed with the independent auditors other matters required to be discussed by the auditors with the Committee by PCAOB Auditing Standard AU Section 380, *Communication With Audit Committees.* The Committee received and discussed with the auditors their annual written report on their independence from the partnership and its management, which is made under Rule 3526, *Communication With Audit Committees Concerning Independence,* and considered with the auditors whether the provision of non-audit services provided by them to the partnership during 2008 was compatible with the auditors independence.

In performing all of these functions, the Audit Committee acts only in an oversight capacity. The Committee reviews our quarterly and annual reporting on Form 10-Q and Form 10-K prior to filing with the Securities and Exchange Commission. In 2008, the Committee also reviewed quarterly earnings announcements with management and representatives of the independent auditor in advance of their issuance. In its oversight role, the Committee relies on the work and assurances of our management, which has the primary responsibility for financial statements and reports, and of the independent auditors, who, in their report, express an opinion on the conformity of our annual financial statements with U.S. generally accepted accounting principles.

In reliance on these reviews and discussions, and the report of the independent auditors, the Audit Committee has recommended to the Board of Directors, and the Board has approved, that the audited financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2008, for filing with the Securities and Exchange Commission.

Robert B. Karn III, Chairman
Robert T. Blakely
Stephen P. Smith
David M. Carmichael

Compensation, Nominating and Governance Committee Authority

Executive officer compensation is administered by the CNG Committee, which is comprised of four members. Mr. Carmichael, the Chairman, and Mr. Karn have served on this committee since 2002, Mr. Blakely joined the committee in early 2003, and Mr. Vecellio joined the committee in 2007. The CNG Committee has reviewed and approved the compensation arrangements described in the Compensation Discussion and

Analysis section of this Form 10-K. Our board of directors appoints the CNG Committee and delegates to the CNG Committee responsibility for:

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

Our board of directors has determined that each committee member is independent under the listing standards of the New York Stock Exchange and the rules of the Securities and Exchange Commission.

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

***Section 16*(a) Beneficial Ownership Reporting Compliance**

Section 16(a) of the Securities and Exchange Act of 1934 requires directors, officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the New York Stock Exchange initial reports of ownership and reports of changes in ownership of their equity securities. These people are also required to furnish us with copies of all Section 16(a) forms that they file. Based solely upon a review of the copies of Forms 3, 4 and 5 furnished to us, or written representations from certain reporting persons that no Forms 5 were required, we believe that our officers and directors and persons who beneficially own more than ten percent of a registered class of our equity securities complied with all filing requirements with respect to transactions in our equity securities during 2008, with the exception of Messrs. Coker, Morian, Vecellio, who each filed one late Form 4.

Partnership Agreement

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

Corporate Governance Guidelines and Code of Business Conduct and Ethics

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

NYSE Certification

Pursuant to Section 303A of the NYSE Listed Company Manual, in 2008, Corbin J. Robertson, Jr. certified to the NYSE that he was not aware of any violation by the Partnership of NYSE corporate governance listing standards.

Item 11. ***Executive Compensation***

Compensation Discussion and Analysis

Overview

As a publicly traded partnership, we have a unique employment and compensation structure that is different from that of a typical public corporation. We have no employees, and our executive officers based in

Houston, Texas are employed by Quintana Minerals Corporation and our executive officers based in Huntington, West Virginia are employed by Western Pocahontas Properties Limited Partnership, both of which are our affiliates. For a more detailed description of our structure, please see Item 1. Business Partnership Structure and Management in this Form 10-K. Although our executives salaries and bonuses are paid directly by the private companies that employ them, we reimburse those companies based on the time allocated to NRP by each executive officer. Our reimbursement for the compensation of executive officers is governed by our partnership agreement.

Executive Officer Compensation Strategy and Philosophy

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

Our philosophy is that optimal alignment between our unitholders and our executive officers is best achieved by providing a greater amount of total compensation in the form of equity-based compensation rather than salary alone. Our compensation for executive officers consists of four primary components:

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

Importantly, Mr. Robertson does not receive a salary or an annual bonus in his capacity as CEO. Rather, for the reasons discussed in greater detail below, Mr. Robertson is compensated exclusively through long-term phantom unit grants awarded by the CNG Committee and the incentive distribution rights owned by our general partner and its affilitates. Mr. Robertson also directly or indirectly owns in excess of 25% of the outstanding units of NRP, and thus his interests are directly aligned with our unitholders.

In December 2008, our CNG Committee reviewed the performance of the executive officers and the amount of time expected to be spent by each NRP officer on NRP business in the coming year. All of our executive officers other than Mr. Robertson spend nearly 90% or more of their time on NRP matters and NRP bears the allocated cost of their time spent on NRP matters. Mr. Robertson has historically spent approximately 50% of his time on NRP matters. Based on its review, the CNG Committee approved the salaries for each of the executive officers other than Mr. Robertson.

In February 2009, the CNG Committee met to approve the year-end bonuses and long-term incentive awards for the executive officers. The CNG Committee considered the performance of the partnership, the performance of the individuals and the outlook for the future in determining the amounts of the awards. Because we are a partnership, tax and accounting conventions make it more costly for us to issue additional common units or options as incentive compensation. Consequently, we have no outstanding options or restricted units and have no plans to issue options or restricted units in the future. Instead, we have issued phantom units to our executive officers that are paid in cash based on the average closing price of our common units for the 20-day trading period prior to vesting. The phantom units typically vest four years from the date of grant. In connection with the phantom unit awards granted in February 2008, the CNG Committee also granted tandem Distribution Equivalent Rights, or DERs, which entitle the holders to receive distributions equal to the distributions paid on our common units. The DERs have a four-year vesting period. Through these awards, each executive officer s interest is aligned with those of our unitholders in increasing our quarterly cash distributions, our unit price and maintaining a steady growth profile for NRP.

Role of Compensation Experts

The CNG Committee engaged Korn/Ferrey International in 2008 to advise it as to the market and appropriate benchmarks for companies of NRP s size and industry. As with the consultants that the CNG Committee has utilized in the past, the CNG Committee considered the advice of the consultant as only one factor among the other items discussed in this compensation discussion and analysis. For a more detailed description of the CNG Committee and its responsibilities, please see Item 10. Directors and Executive Officers of the Managing General Partner and Corporate Governance in this Form 10-K.

Role of Our Executive Officers in the Compensation Process

Mr. Robertson and Mr. Carter provided recommendations to the CNG Committee in its evaluation of the 2008 compensation programs for our executive officers. Mr. Carter provided Mr. Robertson with recommendations relating to the executive officers, other than himself, that are based in Huntington. Mr. Robertson considered those recommendations and provided the CNG Committee with recommendations for all of the executive officers, including the Houston-based officers other than himself. Mr. Robertson and Mr. Carter relied on their personal experience in setting compensation over a number of years in determining the appropriate amounts for each employee, and considered each of the factors described elsewhere in this compensation discussion and analysis. Mr. Robertson and Mr. Carter attended the CNG Committee meetings at which the committee deliberated and approved the compensation, but were excused from the meetings when the CNG Committee discussed their compensation. No other named executive officer assumed an active role in the evaluation or design of the 2008 executive officer compensation programs.

Components of Compensation

Base Salaries

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

Annual Cash Incentive Awards

Each executive officer, other than Mr. Robertson, participated in two cash incentive programs in 2008. The first program is a discretionary cash bonus award approved in February by the CNG Committee based on the same criteria used to evaluate the annual base salaries. The bonuses awarded with respect to 2008 under this program are disclosed in the Summary Compensation Table under the Bonus column. As with the base salaries, there are no formulas or specific performance targets related to these awards.

Under the second cash incentive program, our general partner has set aside 7.5% of the cash distributions it receives on an annual basis with respect to its incentive distribution rights under our partnership agreement for awards to our executive officers, including Mr. Robertson. The cash awards that our officers receive under this plan are reviewed by the CNG Committee and taken into account when making determinations with respect to salaries, bonuses and long-term incentive awards. Because they are ultimately reimbursed by the general partner and not NRP, the incentive payments made with respect to this program do not have any

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impact on our financial statements or cash available for distribution to our unitholders. Because the cost of these awards is not borne by NRP, we have not disclosed the amounts of these awards in the Summary Compensation Table, but have included the amounts separately in a footnote to the table. We believe that these awards align the interests of our executive officers directly with our unitholders in consistently increasing our quarterly distributions.

Long-Term Incentive Compensation

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

Consistent with this approach, in January 2008 our CNG Committee recommended, and our Board approved, an amendment to our Long-Term Incentive Plan to add distribution equivalent rights as a possible award to be granted under the plan. The distribution equivalent rights are contingent rights, granted in tandem with phantom units, to receive an amount in cash equal to the cash distributions made by NRP with respect to the common units during the period in which the phantom units are outstanding.

Our CNG Committee has generally approved annual awards of phantom units that vest four years from the date of grant. The amounts disclosed in the Phantom Unit Awards column in the Summary Compensation Table represent the expense incurred by NRP in 2006, 2007 and 2008 with respect to awards granted from 2004-2008, although the forfeiture component that is deducted in the FAS 123R calculation has been added back in for purposes of the table. We have structured the phantom unit awards so that our executive officers and directors directly benefit along with our unitholders when our unit price increases, and experience reductions in the value of their incentive awards when our unit price declines. As the Summary Compensation Table indicates, the dramatic decline in the value of the units in 2008 resulted in negative accruals for the outstanding LTIP awards.

Perquisites and Other Personal Benefits

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

Quintana and Western Pocahontas also maintain 401(k) and defined contribution retirement plans. Quintana matches 100% of the first 4.5% of the employee contributions under the 401(k) plan and Western Pocahontas matches the employee contributions at a level of 100% of the first 3% of the contribution and 50% of the next 3% of the contribution. In addition, each company contributes 1/12 of each employee s base salary to the defined contribution retirement plan on an annual basis. As with the other contributions, any amounts contributed by Quintana and Western Pocahontas are reimbursed by us based on the time allocated by the employee to our business. The payments made to Messrs. Carter, Dunlap, Hogan and Wall under the defined contribution plan exceeded $10,000 in each of 2006, 2007 and 2008, but did not exceed $20,000 for any individual in any year. None of NRP, Quintana or Western Pocahontas maintain a pension plan or a defined benefit retirement plan. As noted in the Summary Compensation Table, in 2006, 2007 and 2008 we also reimbursed Quintana and Western Pocahontas for car allowances provided to Messrs. Carter, Dunlap and Wall.

Unit Ownership Requirements

We do not have any policy or guidelines that require specified ownership of our common units by our directors or executive officers or unit retention guidelines applicable to equity-based awards granted to directors or executive officers. As of December 31, 2008, our named executive officers held 205,800 phantom

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units that have been granted as compensation. In addition, Mr. Robertson directly or indirectly owns in excess of 25% of the outstanding units of NRP.

Securities Trading Policy

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

Tax Implications of Executive Compensation

Because we are a partnership, Section 162(m) of the Internal Revenue Code does not apply to compensation paid to our named executive officers and accordingly, the CNG Committee did not consider its impact in determining compensation levels in 2006, 2007 or 2008. The CNG Committee has taken into account the tax implications to the partnership in its decision to limit the long-term incentive compensation to phantom units as opposed to options or restricted units.

Accounting Implications of Executive Compensation

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

Report of the Compensation, Nominating and Governance Committee

The CNG Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management. Based on the reviews and discussions referred to in the foregoing sentence, the CNG Committee recommended to the board of directors that the Compensation Discussion and Analysis be included in our Annual Report on Form 10-K for the year ended December 31, 2008.

David M. Carmichael, Chairman
Robert B. Karn III
Robert T. Blakely
Leo A. Vecellio, Jr.

Summary Compensation Table

The following table sets forth the amounts reimbursed to affiliates of our general partner for compensation expense in 2006, 2007 and 2008 based on time allocated by each individual to Natural Resource Partners. In 2008, Messrs. Robertson, Dunlap, Carter, Hogan and Wall spent approximately 50%, 88%, 97%, 89% and 95% of their time on NRP matters.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Phantom Unit Awards(1) ($)	All Other Compensation(2) ($)	Total ($)
Corbin J. Robertson, Jr.	2008			(124,644)		(124,644)
Chairman and CEO	2007			991,308		991,308
	2006			899,387		899,387
Dwight L. Dunlap	2008	253,843	140,000	(46,489)	32,287	379,641
CFO and Treasurer	2007	219,417	100,000	326,689	31,662	677,768
	2006	176,908	100,000	298,926	28,769	604,603
Nick Carter	2008	320,100	220,000	(62,322)	37,353	515,131
President and COO	2007	291,000	200,000	495,651	36,116	1,022,767
	2006	261,900	200,000	449,683	36,116	947,699
Wyatt L. Hogan	2008	257,380	140,000	(30,376)	27,133	394,137
Vice President, General	2007	221,563	60,000	283,356	25,591	590,510
Counsel and Secretary	2006	174,018	60,000	183,384	22,237	439,639
Kevin F. Wall	2008	147,242	140,000	(21,429)	26,300	292,113
Executive Vice President	2007	133,380	75,000	245,922	23,869	478,171
Operations	2006	128,250	75,000	219,756	23,869	446,875

(1) Amounts represent the expense incurred by NRP for awards granted from 2004-2008 calculated in accordance with FAS 123R, with the exception that estimated forfeitures are not allocated to individual participants. Amounts for the year ended 2008 reflect the reversal of amounts accrued through the end of 2007 as a result of the decline in the market value of NRP s common units, upon which this element of compensation is based. The total estimated cash payments for all outstanding grants at December 31, 2008, including awards made during 2008, was $412,000 less than the estimated obligation at December 31, 2007. For a description of the assumptions made in the FAS 123R calculation, please see Note 13 in Notes to Consolidated Financial Statements on page 65 of this Form 10-K.

(2) Includes portions of automobile allowance, 401(k) matching and retirement contributions allocated to Natural Resource Partners by Quintana Minerals Corporation and Western Pocahontas Properties Limited Partnership. The payments made to Messrs. Carter, Dunlap, Hogan and Wall under the defined contribution plan exceeded $10,000 in each of 2006, 2007 and 2008, but did not exceed $20,000 for any individual in any year. The table does not include any cash compensation paid by the general partner to each named executive officer. The general partner may distribute up to 7.5% of any cash it receives with respect to its incentive distribution rights in NRP. We do not reimburse the general partner for any of the payments with respect to the incentive distribution rights, and these payments are not an expense of NRP. The table below shows the amounts paid by the general partner with respect to the incentive distribution rights that are not reimbursed by NRP.

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Individual	Year	Compensation Received from General Partner and Not Reimbursed by NRP ($)
Corbin J. Robertson, Jr.	2008	300,000
	2007	225,000
	2006	74,857
Dwight L. Dunlap	2008	216,000
	2007	150,000
	2006	57,395
Nick Carter	2008	300,000
	2007	225,000
	2006	74,857
Wyatt L. Hogan	2008	216,000
	2007	150,000
	2006	57,395
Kevin F. Wall	2008	216,000
	2007	150,000
	2006	41,795

Grants of Plan-Based Awards in 2008

Named Executive Officer	Grant Date	All Other Unit Awards: Number of Phantom Units(1) (#)	Grant Date Fair Value of Unit Awards(2) ($)
Corbin J. Robertson, Jr.	2/13/2008	20,000	724,400
Dwight L. Dunlap	2/13/2008	7,000	253,540
Nick Carter	2/13/2008	10,000	362,200
Wyatt L. Hogan	2/13/2008	7,000	253,540
Kevin F. Wall	2/13/2008	7,000	253,540

(1) The phantom units were granted in February 2008 and will vest in February 2012.

(2) Amounts represent the estimated fair value on February 22, 2008 calculated in accordance with FAS 123R.

None of our executive officers has an employment agreement, and the salary, bonus and phantom unit awards noted above are approved by the CNG Committee. Please see our disclosure in the Compensation Discussion and Analysis section of this Form 10-K for a description of the factors that the CNG Committee considers in determining the amount of each component of compensation.

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

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

As stated above in the Compensation Discussion and Analysis, we have no outstanding option grants, and do not intend to grant any options or restricted unit awards in the future. The CNG Committee regularly makes awards of phantom units on an annual basis in February. Each award of phantom units vests four years from the date of grant, so that the awards listed above will vest in February 2012.

Outstanding Awards at December 31, 2008

The table below shows the total number of outstanding phantom units held by each named executive officer at December 31, 2008. The phantom units shown below have been awarded over the last four years, with a portion of the units vesting in February in each of 2009, 2010, 2011 and 2012.

Named Executive Officer	Number of Phantom Units That Have Not Vested (#)	Market Value of Phantom Units That Have Not Vested(1) ($)
Corbin J. Robertson, Jr.	86,000	1,500,700
Dwight L. Dunlap	28,200	492,090
Nick Carter	43,000	750,350
Wyatt L. Hogan	25,400	443,230
Kevin F. Wall	23,200	404,840

(1) Based on a unit price of $17.45, the closing price for the common units on December 31, 2008.

Phantom Units Vested in 2008

The table below shows the phantom units that vested with respect to each named executive officer in 2008, along with the value realized by each individual.

Named Executive Officer	Number of Phantom Units That Vested (#)	Value Realized on Vesting ($)
Corbin J. Robertson, Jr.	17,680	530,930
Dwight L. Dunlap	6,240	187,387
Nick Carter	8,840	265,465
Wyatt L. Hogan	5,200	156,156
Kevin F. Wall	4,680	140,540

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Potential Payments upon Termination or Change in Control

None of our executive officers have entered into employment agreements with Natural Resource Partners or its affiliates. Consequently, there are no severance benefits payable to any executive officer upon the termination of their employment. The annual base salaries, bonuses and other compensation are all determined by the CNG Committee in consultation with Mr. Robertson, Mr. Carter and the full board of directors. Upon the occurrence of a change in control of NRP, our general partner or GP Natural Resource Partners LLC, the outstanding phantom unit awards held by each of our executive officers would immediately vest. The table below indicates the impact of a change in control on the outstanding equity-based awards at December 31, 2008, based on the 20-day average of the common units of $16.70 on December 31, 2008.

Named Executive Officer	Number of Phantom Units That Have Not Vested (#)	Potential Post-Employment Payments Required Upon Change in Control ($)	Potential Cash Payments Required Upon Change in Control ($)
Corbin J. Robertson, Jr.	86,000		1,436,200
Dwight L. Dunlap	28,200		470,940
Nick Carter	43,000		718,100
Wyatt L. Hogan	25,400		424,180
Kevin F. Wall	23,200		387,440

Director s Compensation for the Year Ended December 31, 2008

The table below shows the directors compensation for the year ended December 31, 2008. As with our named executive officers, we do not grant any options or restricted units to our directors.

Name	Fees Earned or Paid in Cash ($)	Phantom Unit Awards(1)(2) ($)	Total ($)
Robert Blakely	60,000	(21,351)	38,649
David Carmichael	60,000	(21,351)	38,649
J. Matthew Fifield	35,000	(21,351)	13,649
Robert Karn III	60,000	(21,351)	38,649
S. Reed Morian	35,000	(21,351)	13,649
Stephen Smith	40,000	(21,351)	18,649
W. W. Scott, Jr.	35,000	(21,351)	13,649
Leo A. Vecellio, Jr.	40,000	(18,914)	21,086

(1)

Amounts represent the expense incurred by NRP for awards granted from 2004-2008 calculated in accordance with FAS 123R, with the exception that the forfeiture deductions in the FAS 123R calculation have been added back in for purposes of the table. The negative amounts reflect the reversal of amounts accrued through the end of 2007 as a result of the decline in the market value of NRP s common units, upon which this element of compensation is based. For a description of the assumptions made in the FAS 123R calculation, please see Note 13 in Notes to Consolidated Financial Statements on page 65 of this Form 10-K.

(2) As of December 31, 2008, each director held 12,000 phantom units that vest in annual increments of 3,000 units in each of 2009, 2010, 2011 and 2012.

In 2008, the annual retainer for the directors was $35,000, and the directors did not receive any additional fees for attending meetings. Each chairman of a committee received an annual fee of $10,000 for serving as chairman, and each committee member received $5,000 for serving on a committee.

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2009 Long-Term Incentive Awards

In February 2009, the CNG Committee awarded 35,000 phantom units, 8,000 phantom units, 14,000 phantom units, 8,000 phantom units and 8,000 phantom units to each of Messrs. Robertson, Dunlap, Carter, Hogan and Wall, respectively. The phantom units included tandem distribution equivalent rights, pursuant to which the units will accrue the quarterly distributions paid by NRP on its common units. NRP will pay the amounts accrued under the distribution equivalent rights upon the vesting of the phantom units in 2013. The CNG Committee also recommended, and the Board of Directors approved, an award of 3,000 phantom units, including tandem distribution equivalent rights, to each of the members of the Board of Directors. The awards to the directors will also vest in 2013.

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended December 31, 2008, Messrs. Carmichael, Karn, Blakely and Vecellio served on the CNG Committee. None of Messrs. Carmichael, Karn, Blakely or Vecellio has ever been an officer or employee of NRP or GP Natural Resource Partners LLC. None of our executive officers serve as a member of the board of directors or compensation committee of any entity that has any executive officer serving as a member of our Board of Directors or CNG Committee.

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

The following table sets forth, as of February 27, 2009 the amount and percentage of our common units beneficially held by (1) each person known to us to beneficially own 5% or more of any class of our units, (2) by each of the directors and executive officers and (3) by all directors and executive officers as a group. Unless otherwise noted, each of the named persons and members of the group has sole voting and investment power with respect to the units shown.

Name of Beneficial Owner	Common Units	Percentage of Common Units(1)
Corbin J. Robertson, Jr.(2)	18,288,368	28.2%
Western Pocahontas Properties(3)(4)	17,279,860	26.6%
Christopher Cline(5)	8,950,072	13.8%
Adena Minerals LLC(6)	8,910,072	13.7%
Dingess-Rum Properties, Inc.(7)	4,800,000	7.4%
Nick Carter(8)	14,210	*
Dwight L. Dunlap	11,829	*
Kevin F. Wall(9)	2,500	*
Wyatt L. Hogan(10)	1,500	*
Dennis F. Coker	400	*
Kevin J. Craig	1,850	*
Kenneth Hudson	4,000	*
Kathy H. Roberts	13,000	*
Robert T. Blakely		
David M. Carmichael	10,000	*
J. Matthew Fifield		
Robert B. Karn III	5,600	*
S. Reed Morian	233,772	*
W. W. Scott, Jr.	20,620	*

Stephen P. Smith	3,552	*
Leo A. Vecellio, Jr.	20,000	*
Directors and Officers as a Group	18,631,201	28.7%

* Less than one percent.

(1) Percentages based upon 64,891,136 common units issued and outstanding. Unless otherwise noted, beneficial ownership is less than 1%.

(2) Mr. Robertson may be deemed to beneficially own the 17,279,860 common units owned by Western Pocahontas Properties Limited Partnership, and the 670,024 common units owned by New Gauley Coal Corporation. Also included are 31,540 common units held by Barbara Robertson, Mr. Robertson s spouse. Mr. Robertson s address is 601 Jefferson Street, Suite 3600, Houston, Texas 77002.

(3) These units may be deemed to be beneficially owned by Mr. Robertson. Western Pocahontas has pledged 9,728,921 units as collateral on its long term debt.

(4) The address of Western Pocahontas Properties Limited Partnership is 601 Jefferson Street, Suite 3600, Houston, Texas 77002.

(5) Mr. Cline may be deemed to beneficially own the 8,910,072 common units owned by Adena Minerals, LLC. Mr. Cline s address is 3801 PGA Boulevard, Suite 903, Palm Beach Gardens, FL 33410.

(6) The address of Adena Minerals LLC is 3801 PGA Boulevard, Suite 903, Palm Beach Gardens, FL 33410.

(7) The address of Dingess-Rum Properties, Inc. is 405 Capital Street, Suite 701, Charleston, WV 25301.

(8) Includes 210 common units held by Mr. Carter s spouse, the remaining 14,000 of these units are pledged as collateral for a personal loan.

(9) Includes 500 common units held by Mr. Wall s daughter and 500 common units held by Mr. Wall s son. Mr. Wall disclaims beneficial ownership of these securities.

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

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

Distributions and Payments to the General Partner and its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with the ongoing operation and any liquidation of Natural Resource Partners. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm s-length negotiations.

Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions 98% to the unitholders, including affiliates of our general partner and 2% to the general partner. In addition, if distributions exceed the target distribution levels, the holders of the incentive distribution rights, including our general partner, will be entitled to increasing percentages of the distributions, up to an aggregate of 48% of the distributions above the highest target level. Assuming we have sufficient available cash to pay the current quarterly distribution of $0.535 on all of our outstanding units for four quarters in 2009, our general partner would receive distributions of approximately $3.7 million on its 2% general partner interest and our affiliates would receive distributions of approximately $60.6 million on their common units. In addition in 2009, our general partner and affiliates of our general partner would receive an aggregate of approximately $44.3 million with respect to their incentive distribution rights.
Other payments to our general partner and its affiliates	Our general partner and its affiliates will not receive any management fee or other compensation for the management of our partnership. Our general partner and its affiliates will be reimbursed, however, for all direct and indirect expenses incurred on our behalf. Our general partner has the sole discretion in determining the amount of these expenses.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Omnibus Agreement

Non-competition Provisions

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

- the entering into or holding of leases with a party other than an affiliate of the GP affiliate for any GP affiliate-owned fee coal reserves within the United States; and

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

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

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

the GP affiliate was engaged in the restricted business at the closing of the offering; provided that if the fair market value of the asset or group of related assets of the restricted business subsequently exceeds $10 million, the GP affiliate must offer the restricted business to us under the offer procedures described below.

the asset or group of related assets of the restricted business have a fair market value of $10 million or less; provided that if the fair market value of the assets of the restricted business subsequently exceeds $10 million, the GP affiliate must offer the restricted business to us under the offer procedures described below.

the asset or group of related assets of the restricted business have a fair market value of more than $10 million and the general partner (with the approval of the conflicts committee) has elected not to cause us to purchase these assets under the procedures described below.

its ownership in the restricted business consists solely of a noncontrolling equity interest.

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

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

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

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

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

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

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

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

The Cline Group

On January 4, 2007, we acquired from Adena Minerals, LLC four entities that own approximately 49 million tons of coal reserves in West Virginia and Illinois that are leased to active mining operations, as well as associated transportation and infrastructure assets at those mines. The reserves consist of 37 million tons at Adena s Gatling mining operation in Mason County, West Virginia and 12 million tons adjacent to reserves currently owned by the Partnership at Adena affiliate Williamson Energy s Pond Creek No. 1 mine in Southern Illinois. In consideration therefore, Adena received 8,910,072 units representing limited partner interests in NRP and a 22% interest in our general partner and in our outstanding incentive distribution rights. Adena is an affiliate of The Cline Group, a private coal company that controls over 3 billion tons of coal reserves in the Illinois and Northern Appalachian coal basins.

Second Contribution Agreement. At the closing of the acquisition, we executed a Second Contribution Agreement, pursuant to which we agreed to acquire from Adena two entities that own coal reserves in Meigs County, Ohio and associated transportation infrastructure. As consideration, Adena will receive 4,560,000 units, as well as an additional 9% interest in the general partner and our outstanding incentive distribution rights. The transactions contemplated by the Second Contribution Agreement are expected to close in the second quarter of 2009.

Restricted Business Contribution Agreement. Also at the closing, Christopher Cline, Foresight Reserves LP and Adena (collectively, the Cline Entities) and NRP executed a Restricted Business Contribution Agreement. Pursuant to the terms of the Restricted Business Contribution Agreement, the Cline Entities and their affiliates will be obligated to offer to NRP any business owned, operated or invested in by the Cline Entities, subject to certain exceptions, that either (a) owns, leases or invests in hard minerals or (b) owns, operates, leases or invests in transportation infrastructure relating to future mine developments by the Cline Entities in Illinois. In addition, we created an area of mutual interest (the AMI) encompassing the properties

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to be acquired by us pursuant to the Contribution Agreement and the Second Contribution Agreement. During the applicable term of the Restricted Business Contribution Agreement, the Cline Entities will be obligated to contribute any coal reserves held or acquired by the Cline Entities or their affiliates within the AMI to us. In connection with the offer of mineral properties by the Cline Entities to NRP, including pursuant to the Second Contribution Agreement, the parties to the Restricted Business Contribution Agreement will negotiate and agree upon an area of mutual interest around such minerals, which will supplement and become a part of the AMI.

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

Quintana Capital Group GP, Ltd.

Corbin J. Robertson, Jr. is a principal in Quintana Capital Group GP, Ltd., which controls several private equity funds focused on investments in the energy business. In connection with the formation of Quintana Capital, NRP s Board of Directors 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. The basic tenets of the policy are set forth below.

NRP s business strategy is focused on the ownership of non-operated royalty producing coal properties in North America and the leasing of these coal reserves. In addition, NRP has extended its business into the ownership and leasing of other non-operated royalty producing extracted hard mineral properties. NRP also has added the transportation, storage and related logistics activities related to coal and other hard minerals to its business strategy. These current and prospective businesses are referred to as the NRP Businesses.

NRP s business strategy does not, and is not expected to, include oil and gas exploration or development (except for non-operated royalty interests in coal bed methane production ancillary to its coal business), investments which do not generate qualifying income for a publicly traded partnership under U.S. tax regulations, investments outside of North America and other midstream or refining businesses which do not involve coal or other hard extracted minerals, including the gathering, processing, fractionation, refining, storage or transportation of oil, natural gas or natural gas liquids. NRP s business strategy also does not, and is not expected to include, coal mining or mining for other hard minerals. The businesses and investments described in this paragraph are referred to as the Non-NRP Businesses .

For so long as Corbin Robertson, Jr. remains both an affiliate of Quintana Capital and an executive officer or director of NRP or an affiliate of its general partner, before making an investment in an NRP Business, Quintana Capital will first offer such opportunity in its entirety to NRP. NRP may elect to pursue such investment wholly for its own account, to pursue the opportunity jointly with Quintana Capital or not to pursue such opportunity. If NRP elects not to pursue an NRP Business investment opportunity, Quintana Capital may pursue the investment for its own account. Decisions in respect of such opportunities will be made for NRP by the Conflicts Committee of the Board of Directors of the general partner; provided, however, that decisions in respect of potential investments of $20 million or less may be made by an executive officer of the general partner to whom such authority is delegated by the Conflicts Committee. NRP will undertake to advise Quintana Capital of its decision regarding a potential investment opportunity within 10 business days of the identification of such opportunity to either the Conflicts Committee or such designated officer, as applicable.

Neither Quintana Capital nor Mr. Robertson will have any obligation to offer investments relating to Non-NRP Businesses to NRP and that NRP will not have any obligation to refrain from pursuing a Non-NRP Business if there is a change in its business strategy. If such a change in strategy occurs, it is expected that the Conflicts Committee would work together with Quintana Capital to adopt mutually agreed practices and procedures in order to safeguard confidential information relating to potential investments and to address any potential or actual conflicts of interest involving Quintana Capital investments or the activities of Mr. Robertson.

In February 2007, a fund controlled by Quintana Capital acquired a 43% membership interest in Taggart Global, 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 will own and lease the plants to Taggart Global, who will design, build and operate the plants. The lease payments are based on the sales price for the coal that is processed through the facilities. NRP and Taggart Global have jointly financed and developed four such plants in West Virginia.

In June 2007, a fund controlled by Quintana Capital acquired Kopper-Glo, a small coal mining company with operations in Tennessee. Kopper-Glo is an NRP lessee that paid NRP $1.4 million and $1.9 million in coal royalties in 2008 and 2007, respectively.

Office Building in Huntington, West Virginia

In 2008, Western Pocahontas Properties Limited Partnership completed construction of an office building in Huntington, West Virginia. On January 1, 2009, we began leasing substantially all of two floors of the building from Western Pocahontas Properties Limited Partnership at market rates. The terms of the lease were approved by our conflicts committee.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including the WPP Group, the Cline Group, and their affiliates) on the one hand, and our partnership and our limited partners, on the other hand. The directors and officers of GP Natural Resource Partners LLC have fiduciary duties to manage GP Natural Resource Partners LLC and our general partner in a manner beneficial to its owners. At the same time, our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and our partnership or any other partner, on the other, our general partner will resolve that conflict. Our general partner may, but is not required to, seek the approval of the conflicts committee of the board of directors of our general partner of such resolution. The partnership agreement contains provisions that allow our general partner to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. In effect, these provisions limit our general partner s fiduciary duties to our unitholders. Delaware case law has not definitively established the limits on the ability of a partnership agreement to restrict such fiduciary duties. The partnership agreement also restricts the remedies available to unitholders for actions taken by our general partner that might, without those limitations, constitute breaches of fiduciary duty.

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

- approved by the conflicts committee, although our general partner is not obligated to seek such approval and our general partner may adopt a resolution or course of action that has not received approval;

on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

fair to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

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

the relative interests of any party to such conflict and the benefits and burdens relating to such interest;

any customary or accepted industry practices or historical dealings with a particular person or entity;

generally accepted accounting practices or principles; and

such additional factors it determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

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

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

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

amount and timing of asset purchases and sales;

cash expenditures;

borrowings;

the issuance of additional units; and

the creation, reduction or increase of reserves in any quarter.

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

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

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

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

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

We reimburse our general partner and its affiliates for expenses.

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

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

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

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

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

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

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

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

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

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

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

Our general partner s affiliates may compete with us.

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

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Director Independence

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

Review, Approval or Ratification of Transactions with Related Persons

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

Pursuant to our Code of Business Conduct and Ethics, conflicts of interest are prohibited as a matter of policy, except under guidelines approved by the Board of Directors and as provided in the Omnibus Agreement, the Restricted Business Contribution Agreement, and our partnership agreement.

Item 14. *Principal Accounting Fees and Services*

The Audit Committee of the Board of Directors of GP Natural Resource Partners LLC recommended and we engaged Ernst & Young LLP to audit our accounts and assist with tax work for fiscal 2008 and 2007. Fees (including out-of-pocket costs) incurred from Ernst & Young LLP for services for fiscal years 2008 and 2007 totaled $0.8 million and $0.9 million, respectively. All of our audit, audit-related fees and tax services have been approved by the Audit Committee of our Board of Directors. The following table presents fees for professional services rendered by Ernst &Young LLP:

	2008	2007
Audit Fees(1)	$ 355,914	$ 415,241
Audit-Related Fees		
Tax Fees(2)	$ 418,783	$ 445,749
All Other Fees		

(1) Audit fees include fees associated with the annual audit of our consolidated financial statements and reviews of our quarterly financial statement for inclusion in our Form 10-Q.

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

Audit and Non-Audit Services Pre-Approval Policy

I. Statement of Principles

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

The SEC s rules establish two different approaches to pre-approving services, which the SEC considers to be equally valid. Proposed services may either be pre-approved without consideration of specific case-by-case services by the Audit Committee (general pre-approval) or require the specific pre-approval of the Audit

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Committee (specific pre-approval). The Audit Committee believes that the combination of these two approaches in this Policy will result in an effective and efficient procedure to pre-approve services performed by the independent auditor. As set forth in this Policy, unless a type of service has received general pre-approval, it will require specific pre-approval by the Audit Committee if it is to be provided by the independent auditor. Any proposed services exceeding pre-approved cost levels or budgeted amounts will also require specific pre-approval by the Audit Committee.

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

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

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

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

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

II. Delegation

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

III. Audit Services

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

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

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IV. Audit-related Services

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

V. Tax Services

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

VI. Pre-Approval Fee Levels or Budgeted Amounts

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

VII. Procedures

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

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

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PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a)(1) and (2) Financial Statements and Schedules

Please See Item 8, Financial Statements and Supplementary Data

(a)(3) Exhibits

Exhibit Number	Description
2.1	Contribution Agreement dated December 14, 2006 by and among Foresight Reserves LP, Adena Minerals, LLC, NRP (GP) LP, Natural Resource Partners L.P. and NRP (Operating) LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on December 15, 2006).
2.2	Contribution Agreement dated December 19, 2006 by and among Dingess-Rum Properties, Inc., Natural Resource Partners L.P. and WPP LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on December 20, 2006).
2.3	Second Contribution Agreement, dated January 4, 2007, by and among Foresight Reserves LP, Adena Minerals, LLC, NRP (GP) LP, Natural Resource Partners L.P. and NRP (Operating) LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on January 4, 2007).
2.4	Amendment No. 1 to Second Contribution Agreement, dated April 18, 2007, by and among Natural Resource Partners L.P., NRP (GP) LP, NRP (Operating) LLC, Foresight Reserves LP and Adena Minerals, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on April 19, 2007).
2.5	Purchase and Sale Agreement, dated April 2, 2007, by and among Natural Resource Partners L.P., WPP LLC and Western Pocahontas Properties Limited Partnership (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on April 3, 2007).
3.1	Third Amended and Restated Agreement of Limited Partnership of NRP (GP) LP, dated as of January 4, 2007 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed on January 4, 2007).
3.2	Fourth Amended and Restated Limited Liability Company Agreement of GP Natural Resource Partners LLC, dated as of January 4, 2007 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on January 4, 2007).
4.1	Third Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated April 18, 2007 (incorporated by reference to Exhibit 4.1 of the Current Report on Form 8-K filed on April 19, 2007).
4.2	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated April 7, 2008 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on April 8, 2008.
4.3	Amended and Restated Limited Liability Company Agreement of NRP (Operating) LLC, dated as of October 17, 2002 (incorporated by reference to Exhibit 3.4 of the Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-31465).
4.4	Note Purchase Agreement dated as of June 19, 2003 among NRP (Operating) LLC and the Purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed

	June 23, 2003).
4.5	First Supplement to Note Purchase Agreements, dated as of July 19, 2005 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on July 20, 2005).

Exhibit Number	Description
4.6	Second Supplement to Note Purchase Agreements, dated as of March 28, 2007 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on March 29, 2007).
4.7	First Amendment, dated as of July 19, 2005, to Note Purchase Agreements dated as of June 19, 2003 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed on July 20, 2005).
4.8	Second Amendment, dated as of March 28, 2007, to Note Purchase Agreements dated as of June 19, 2003 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed on March 29, 2007).
4.9	Subsidiary Guarantee of Senior Notes of NRP (Operating) LLC, dated June 19, 2003 (incorporated by reference to Exhibit 4.5 to the Current Report on Form 8-K filed June 23, 2003).
4.10	Form of Series A Note (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed June 23, 2003).
4.11	Form of Series B Note (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed June 23, 2003).
4.12	Form of Series C Note (incorporated by reference to Exhibit 4.4 to the Current Report on Form 8-K filed June 23, 2003).
4.13	Form of Series D Note (incorporated by reference to Exhibit 4.12 to the Annual Report on Form 10-K filed February 28, 2007).
4.14	Form of Series E Note (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed March 29, 2007).
10.1	Amended and Restated Credit Agreement, dated as of March 28, 2007, by and among NRP (Operating) LLC, as Borrower, Citibank, N.A., as Administrative Agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on March 29, 2007).
10.2	Contribution, Conveyance and Assumption Agreement by and among Western Pocahontas Properties Limited Partnership, Great Northern Properties Limited Partnership, New Gauley Coal Corporation, Ark Land Company, WPP LLC, GNP LLC, NNG LLC, ACIN LLC, Robertson Coal Management LLC, NRP (Operating) LLC, GP Natural Resource Partners LLC, NRP (GP) LP and Natural Resource Partners L.P., dated as of October 17, 2002 (incorporated by reference to Exhibit 10.2 to the Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-31465).
10.3	Natural Resource Partners Second Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on January 17, 2008).
10.4	Form of Phantom Unit Agreement (incorporated by reference to Exhibit 10.4 to the Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-31465).
10.5	Natural Resource Partners Annual Incentive Plan (incorporated by reference to Exhibit 10.4 to the Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-31465).
10.6	Omnibus Agreement dated October 17, 2002, by and among Arch Coal, Inc., Ark Land Company, Western Pocahontas Properties Limited Partnership, Great Northern Properties Limited Partnership, New Gauley Coal Corporation, Robertson Coal Management LLC, GP Natural Resource Partners LLC, NRP (GP) LP, Natural Resource Partners L.P. and NRP (Operating) LLC (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-31465).
10.7	Restricted Business Contribution Agreement, dated January 4, 2007, by and among Christopher Cline, Foresight Reserves LP, Adena Minerals, LLC, GP Natural Resource Partners LLC, NRP (GP) LP,

Natural Resource Partners L.P. and NRP (Operating) LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on January 4, 2007).

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Exhibit Number	Description
10.8	Investor Rights Agreement, dated January 4, 2007, by and among NRP (GP) LP, GP Natural Resource Partners LLC, Robertson Coal Management and Adena Minerals, LLC (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on January 4, 2007).
10.9	Purchase and Sale Agreement by and between Steelhead Development Company, LLC and ACIN LLC, dated as of May 31, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on June 1, 2005).
10.10	Assignment, Waiver and Amendment Agreement, dated January 20, 2006, by and among Williamson Development Company, LLC, ACIN LLC and WPP LLC.
10.11	Memorandum of Understanding by and between NRP (Operating) LLC and Sedgman USA, LLC, dated as of August 23, 2006 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on August 24, 2006).
21.1*	List of subsidiaries of Natural Resource Partners L.P.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of Sarbanes-Oxley.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of Sarbanes-Oxley.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350.
99.1*	Audited balance sheet of NRP (GP) LP

* Filed herewith

** Furnished herewith

SIGNATURES

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

NATURAL RESOURCE PARTNERS L.P.
By: NRP (GP) LP, its general partner

By: GP NATURAL RESOURCE

PARTNERS LLC, its general partner

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

Date: February 27, 2009

By: /s/ DWIGHT L. DUNLAP
Dwight L. Dunlap,
Chief Financial Officer and
Treasurer (Principal Financial Officer)

Date: February 27, 2009

By: /s/ KENNETH HUDSON
Kenneth Hudson
Controller
(Principal Accounting Officer)

Date: February 27, 2009

By: /s/ ROBERT T. BLAKELY
Robert T. Blakely
Director

Date: February 27, 2009

By: /s/ DAVID M. CARMICHAEL
David M. Carmichael
Director

Date: February 27, 2009

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	By: J. Matthew Fifield Director	/s/ J. MATTHEW FIFIELD
Date: February 27, 2009		
	By: Robert B. Karn III Director	/s/ ROBERT B. KARN III
Date: February 27, 2009		
	By: S. Reed Morian Director	/s/ S. REED MORIAN
Date: February 27, 2009		
	By: W.W. Scott, Jr. Director	/s/ W.W. SCOTT, JR.
Date: February 27, 2009		
	By: Stephen P. Smith Director	/s/ STEPHEN P. SMITH
Date: February 27, 2009		
	By: Leo A. Vecellio, Jr. Director	/s/ LEO A. VECELLIO, JR.
Date: February 27, 2009		