NATURAL RESOURCE PARTNERS LP
Form 10-K
February 27, 2006

Table of Contents

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, 2005

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
Subordinated 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, or a non-accelerated filer

o Large Accelerated Filer þ Accelerated Filer o Non-accelerated Filer

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 $609.0 million on June 30, 2005 based on a price of $57.99 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on that date. The Subordinated Units were not publicly traded on June 30, 2005.

As of February 27, 2006, there were 16,825,307 Common Units outstanding and 8,515,228 Subordinated Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE.
None.

TABLE OF CONTENTS

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, acquisitions and dispositions, expected commencement dates of coal mining, projected quantities of future coal production by our lessees producing coal from our reserves, projected demand or supply for coal 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.

Table of Contents

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, 2005, we owned or controlled approximately two billion tons of proven and probable coal reserves in eleven states. 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 a minimum payment. As of December 31, 2005, our reserves were subject to 176 leases with 67 lessees. In 2005, our lessees produced 53.6 million tons of coal from our properties and our coal royalty revenues were $142.1 million.

Partnership Structure and Management

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We own our subsidiaries through a wholly owned operating company, NRP (Operating) LLC. NRP (GP) LP, our general partner, has sole responsibility for conducting our business and for managing our operations. Because our general partner is a limited partnership, its general partner, GP Natural Resource Partners LLC, conducts its business and operations, and the board of directors and officers of GP Natural Resource Partners LLC makes decisions on our behalf. Robertson Coal Management LLC, a limited liability company wholly owned by Corbin J. Robertson, Jr., owns all of the membership interest in GP Natural Resource Partners LLC. Mr. Robertson is entitled to nominate all seven of the directors, three of whom must be independent directors, to the board of directors of GP Natural Resource Partners LLC.

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 Limited Partnership, 85% of the general partner of Great Northern Properties Limited Partnership 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 Limited Partnership and Quintana Minerals Corporation, a 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 P.O. Box 2827, 1035 Third Avenue, Suite 300, Huntington, West Virginia 25727 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 are principally engaged in the business of owning and managing coal reserves. As an owner of coal reserves, we typically are not responsible for operating mines but instead enter into leases with third-party coal mine operators granting them the right to mine coal reserves on the owner s 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 often include the right to renegotiate rents and royalties for the extended term.

Table of Contents

Under our standard lease, third-party 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. If permitted by the terms of the lease, 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 coal prices, lessees supply contracts and, to a lesser extent, fluctuations in the spot market prices for coal. 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 when coal production commences.

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 health care legacy costs, black lung benefits and workmen s compensation costs, associated with operating the mines. We typically pay property taxes and then are reimbursed by the lessee for the taxes on the 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 in 2005

AFG. On November 21, 2005, we completed the acquisition of 179 million tons of coal reserves in Ohio and Pennsylvania for $29 million.

Area F/Lexington. In two separate transactions on September 26, 2005, we acquired approximately 25 million tons of owned coal reserves and an overriding royalty on approximately 14 million tons of leased coal reserves in Randolph, Upshur and Barbour Counties in north central West Virginia for $13.5 million.

Dolphin. On September 22, 2005, we acquired a coal preparation plant and rail load-out facility in Greenbrier County, West Virginia for $6 million. We do not operate the preparation plant but receive a fee for coal processed through it. The facilities primarily process coal produced from our Plum Creek properties.

Williamson Development (formerly Steelhead). On June 1, 2005, we signed a definitive agreement to purchase interests in approximately 144 million tons in the Illinois Basin for $105 million in three separate transactions. Ultimately, we will acquire approximately 60% of the reserves in fee and will receive an override on the remaining tons. On July 11, 2005, we closed the first of the three transactions for $35 million. The acquisition included approximately 47.5 million tons, of which approximately 75% are owned in fee. We received an override on the remaining tons. On January 20, 2006, we closed the second phase of this transaction for $35 million. We expect to close on the third and final phase in mid-2006.

Plum Creek. On March 3, 2005, we completed an acquisition of coal reserves from Plum Creek Timber Company, Inc. for $21.25 million. This property consists of approximately 85 million tons of coal reserves located on approximately 175,000 acres in Virginia, West Virginia and Kentucky.

Table of Contents

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, 2005, 2004 and 2003. Coal royalty revenues were generated from the properties in each of the areas as follows:

	Coal Royalty Revenues for the Years Ended December 31, (In thousands)			Average Coal Royalty Revenue Per Ton for the Years Ended December 31, ($ per ton)		
	2005	2004	2003	2005	2004	2003
Area						
Appalachia						
Northern	$ 11,306	$ 7,084	$ 5,341	$ 1.89	$ 1.70	$ 1.43
Central	93,008	76,583	55,071	2.84	2.34	1.77
Southern	25,089	14,874	3,443	4.01	2.86	3.05
Total Appalachia	129,403	98,541	63,855	2.87	2.34	1.77
Illinois Basin	4,288	3,852	3,566	1.54	1.23	1.18
Northern Powder River Basin	8,446	4,063	6,349	1.46	1.30	1.20
Total	$ 142,137	$ 106,456	$ 73,770	$ 2.65	$ 2.20	$ 1.66

The following table sets forth production data and reserve information for the properties that we own or control for the years ending December 31, 2005, 2004, and 2003. 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, 2005		
	2005	2004	2003	Underground	Surface	Total
	(Tons in thousands)					
Area						
Appalachia						
Northern	5,977	4,179	3,736	399,840	4,832	404,672
Central	32,790	32,702	31,135	1,118,276	111,543	1,229,819
Southern	6,263	5,208	1,127	162,376	37,767	200,143
Total Appalachia	45,030	42,089	35,998	1,680,492	154,142	1,834,634
Illinois Basin	2,781	3,138	3,034	40,052	21,794	61,846
Northern Powder River Basin	5,795	3,130	5,312		131,871	131,871

Total	53,606	48,357	44,344	1,720,544	307,807	2,028,351

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, 2005, approximately 35% of our reserves were compliance coal. Unless otherwise indicated, we present the quality of the coal throughout this Form 10-K on an as-received basis, which assumes 6% moisture for Appalachian reserves, 12% moisture for Illinois Basin reserves and 25% moisture for Northern Powder River Basin reserves. We own both steam and metallurgical coal reserves in Northern, Central and Southern

Table of Contents

Appalachia, and we own steam coal reserves in the Illinois Basin and the Northern Powder River Basin. In 2005, approximately 31% of the coal royalty revenues from our properties was 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, 2005.

Sulfur Content, Typical Quality and Type of Coal

		Sulfur Content				Typical Quality		Type of Coal	
rea	Compliance Coal(1)	Low (less than 1.0%)	Medium (1.0% to 1.5%)	High (Greater than 1.5%)	Total	Heat Content (Btu per Pound)	Sulfur (%)	Steam	Metallurgica
		(Tons in thousands)						(Tons in thousands)	
ppalachia									
orthern	43,300	51,879	27,356	325,438	404,673	13,112	2.43	395,111	9,562
entral	544,018	839,189	323,383	67,246	1,229,818	12,963	0.91	825,027	404,791
outhern	113,678	144,615	42,995	12,533	200,143	13,631	0.90	150,337	49,806
otal Appalachia	700,996	1,035,683	393,733	405,218	1,834,634	13,069	1.25	1,370,475	464,159
inois Basin			6,983	54,863	61,846	12,124	2.50	61,846	
orthern Powder ver Basin		131,871			131,871	8,800	0.65	131,871	
otal	700,996	1,167,554	400,716	460,080	2,028,351	12,762	1.25	1,564,192	464,159

(1) Compliance coal meets the sulfur dioxide emission standards imposed by Phase II of the Clean Air Act without blending with other coals or using sulfur dioxide reduction technologies. Compliance coal is a subset of low sulfur coal and is, therefore, also reported within the amounts for low sulfur coal.

(2) For purposes of this table, we have defined metallurgical coal reserves as reserves located in those seams that historically have been of sufficient quality and characteristics to be able to be used in the steel making process. Some of the reserves in the metallurgical category can also be used as steam coal.

We base our estimates of reserve information on engineering, economic and geological data assembled and analyzed by our internal geologists and engineers. This information is periodically reviewed by third party consultants. 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. 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 decreased royalties from lower than expected production by our lessees.

Oil, Gas and Timber Properties

For the year ended December 31, 2005, we derived less than 2% of our total revenues from oil, gas and timber, which are located in Kentucky, Virginia and Tennessee. We do not own the oil, gas or timber rights on the vast majority of the properties.

Table of Contents

Significant Customers

We have three lessees who each provided more than 10% of our total revenue in 2005: Alpha Natural Resources, Inc., Arch Coal, Inc. and PinnOak Resources LLC. Each of these companies has several different mines on our properties. While the loss of any one of these lessees would have a material adverse effect on us, we do not believe that the loss of any single mine would have a material adverse effect on us.

Competition

We face significant competition from other land companies and from coal producers 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 2004. 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 environmental and government regulations, technological developments and the availability and the cost of generating power from alternative fuel sources, including nuclear, natural gas, oil and hydroelectric power.

Regulation

The coal mining industry is subject to regulation by federal, state and local authorities on matters such as:

- employee health and safety;
- mine permits and other licensing requirements;
- reclamation and restoration of mining properties after mining is completed;
- water pollution;
- management of materials generated by mining operations;
- the discharge of materials into the environment;
- surface subsidence from underground mining;
- air quality standards;
- legislatively mandated benefits for some current and retired coal miners;
- protection of wetlands;
- endangered plant and wildlife protection;
- limitations on land use;

storage of petroleum products and substances that are regarded as hazardous under applicable laws; and

management of electrical equipment containing polychlorinated biphenyls, or PCBs.

In addition, the electricity generation 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. New legislation or regulations may be adopted or enforcement of existing laws could change, either of which may have a significant impact on the mining operations of our lessees or their customers ability to use coal. Potential regulation may require our lessees or their customers to change operations significantly or incur substantial costs.

Table of Contents

Our lessees are obligated to conduct mining operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements, violations during mining operations are not unusual in the industry and, notwithstanding compliance efforts, we do not believe violations by our lessees can be eliminated completely. While we expect the current regulatory and legislative environment to add significantly to our lessees costs and to adversely impact their productivity, we do not at this time expect that future compliance costs will have a material adverse effect on us, our unitholders or our quarterly distributions.

While it is not possible to quantify the expenditures incurred by our lessees to maintain compliance with all applicable federal and state laws, those costs have been and are expected to continue to be significant. Our lessees post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. Compliance with these laws substantially increases the cost of coal mining for all domestic coal producers.

Specific Regulatory and Litigation Matters

Surface Mining Control and Reclamation Act. SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of deep mining. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of mining activities. In conjunction with mining the property, our lessees are contractually obligated under the terms of their leases to comply with all laws, including SMCRA and similar state and local laws.

SMCRA also requires our lessees to submit a bond or otherwise financially secure the performance of their reclamation obligations. The earliest a reclamation bond can be completely released is five years after reclamation is complete. In addition, the Abandoned Mine Lands Act, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to reclaim mines closed before 1977. Since our lessees are responsible for these obligations and any related liabilities, we do not accrue the estimated costs of reclamation or mine closing, and we do not pay the tax described above.

Under SMCRA, responsibility for unabated violations, unpaid civil penalties and unpaid reclamation fees of independent mine lessees and other third parties could potentially be imputed to other companies that are deemed to have owned or controlled the mine operator. Sanctions against the owner or controller are quite severe and can incl civil penalties, reclamation fees and reclamation costs. We are not aware of any currently pending or asserted claims against us asserting that we own or control our lessees. We believe our lessees are generally in compliance with all operational, reclamation and closure requirements under their SMCRA permits.

West Virginia Antidegradation Policy. In January 2002, a number of environmental groups and individuals filed suit in the U.S. District Court for the Southern District of West Virginia to challenge the EPA s approval of West Virginia s antidegradation implementation policy. Under the federal Clean Water Act, state regulatory authorities must conduct an antidegradation review before approving permits for the discharge of pollutants into waters that have been designated as high quality by the state. Antidegradation review involves public and intergovernmental scrutiny of permits and requires permittees to demonstrate that the proposed activities are justified in order to accommodate significant economic or social development in the area where the waters are located. In *Ohio Valley Environmental Coalition v. Whitman*, the court vacated the EPA s approval of West Virginia s antidegradation implementation policy that exempted current holders of National Pollutant Discharge Elimination System (NPDES) permits and Section 404 permits, among other parties, from the antidegradation-review process. On March 29, 2004, EPA Region III sent a letter to the West Virginia Department of Environmental Protection that approved portions of the state s antidegradation program, denied approval of portions pending further study, and recommended removal of certain language in the state s regulations. The West Virginia Department of Environmental Protection is proceeding with a review. Our lessees are current NPDES or Section 404 permit holders that had been exempt from antidegradation review under the former policy. With exemptions not in place, our lessees that discharge into waters that have been designated as high quality by the state may experience delays in the issuance or reissuance of Clean Water Act permits, or these permits may be denied. Delay in issuance of or denial of these permits increases the costs of coal production and could potentially reduce our royalty revenues.

Massey Energy Settlement. In January 2006, Massey Energy agreed to a settlement with the West Virginia Department of Environmental Protection relating to a number of lawsuits and enforcement actions against Massey and its subsidiaries. In connection with the settlement, Marfork Coal, a Massey subsidiary that mines coal on our Dorothy-Sarita and Eunice properties, agreed to shut down its operations for a total of six days. In 2005, we received $4.7 million in coal royalty revenues from Marfork Coal, and we do not expect this settlement to have a material impact on our coal royalty revenues.

Mine Health and Safety Laws. Stringent safety and health standards have been imposed on the coal mining industry by federal legislation since the adoption of the Mine Health and Safety Act of 1969. The Mine Health and Safety Act of 1969 also 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 safety and health standards on all mining operations. In addition, as part of the Mine Health and Safety Acts of 1969 and 1977, the Black Lung Act requires payments of benefits by all businesses conducting current mining operations to coal miners with black lung and to some survivors of miners who die from this disease. Because the regulatory requirements imposed by mine worker health and safety laws are comprehensive and ongoing in nature, non-compliance cannot be eliminated completely. We believe our lessees have made all payments under the Black Lung Act and are generally in compliance with all applicable mine health and safety laws.

Clean Air Act. The federal Clean Air Act and similar state and local laws, which regulate emissions into the air, affect coal mining and processing operations primarily through permitting and emissions control requirements. The Clean Air Act also indirectly affects coal mining operations by extensively regulating the emissions from coal-fired industrial boilers and power plants, which are the largest end-users of our coal. These regulations can take a variety of forms, as explained below.

The Clean Air Act imposes obligations on the Environmental Protection Agency, or EPA, and the states to implement regulatory programs that will lead to the attainment and maintenance of EPA-promulgated ambient air quality standards, including standards for sulfur dioxide, particulate matter, nitrogen oxides and ozone. Owners of coal-fired power plants and industrial boilers have been required to expend considerable resources to comply with these ambient air standards. Significant additional emissions control expenditures will be needed in order to meet the current national ambient air standards.

Numerous legal and regulatory actions have been initiated over the years under the Clean Air Act, the outcome of which could adversely affect coal mining and coal-fired power plants. In January 2005, legislation was re-introduced in Congress outlining the Bush administration s Clear Skies Initiative, which calls for dramatic decreases in sulfur, nitrogen oxide, and mercury emissions from power plants. If emissions standards from power plants are required to be lowered under the act, it could result in a decrease in coal demand.

If Clear Skies is not passed, EPA has announced an intention to take alternative action and finalize the Clean Air Interstate Rule (CAIR), and a related rule to reduce mercury emissions, under the existing Clean Air Act. The CAIR would mandate reductions in sulfur dioxide and nitrogen oxides in 29 states and the District of Columbia while the mercury rule would require mercury emissions reductions on a national basis. EPA is seeking to lower mercury emissions at new and existing sources by requiring the use of Maximum Achievable Control Technology (MACT), or, in the alternative, by implementing a nationwide cap and trade program. Should either or both of these proposed rules become final, additional costs may be associated with operating coal-fired power generation facilities that may make coal a less attractive fuel source.

Clean Water Act. Section 301 of the Clean Water Act prohibits the discharge of a pollutant from a point source into navigable waters except in accordance with a permit issued under either Section 402 or Section 404 of the Clean Water Act. Navigable waters are broadly defined to include streams, even those that are not navigable in fact, and may include wetlands.

All mining operations in Appalachia generate excess material that must be placed in fills in adjacent valleys and hollows. Likewise, coal refuse disposal areas and coal processing slurry impoundments are located in valleys and hollows. Almost all of these areas contain intermittent or perennial streams, which are considered navigable waters. An operator must secure a Clean Water Act permit before filling such streams. For approximately the past twenty-five years, operators have secured Section 404 fill permits to authorize the filling of navigable waters with material from various forms of coal mining. Operators have also obtained permits under Section 404 for the construction of slurry impoundments although the use of these impoundments, including discharges from them, requires permits under Section 402. Our leases require our lessees to obtain all necessary permits required under the Clean Water Act. To our knowledge, our lessees have obtained all permits required under the Clean Water Act and equivalent state laws.

In March 2002, the Army Corps of Engineers issued Nationwide Permit 21 under Section 404 to allow mining companies to discharge into fills without obtaining individual permits under the Clean Water Act. The legality of that permitting scheme was challenged in a lawsuit filed in October 2003 by the Ohio Valley Environmental Coalition and several other citizens groups. This lawsuit, *Ohio Valley Environmental Coalition v. Bulen*, was the latest in a series of lawsuits filed in the United States District Court for the Southern District of West Virginia by citizens groups challenging the legality of various aspects of the regulatory scheme for the permitting of surface coal mining, especially mountaintop removal coal mining and valley fills. Although the first two lawsuits were successful at the district court level, the Fourth Circuit Court of Appeals overturned both decisions.

In Ohio Valley Environmental Coalition v. Bulen, plaintiffs alleged that a nationwide permit cannot lawfully be issued under Section 404 for the surface mining of coal and that the Corps of Engineers failed to comply with the requirements of the National Environmental Policy Act in the adoption of Nationwide Permit 21. In July 2004, the district court enjoined the Corps of Engineers from issuing future authorizations under Nationwide Permit 21in the Southern District of West Virginia. With respect to the eleven specific mining sites challenged by the plaintiffs, the Corps of Engineers was ordered to suspend those authorizations for valley fills and surface impoundments on which construction had not commenced as of July 8, 2004. In a subsequent order in August 2004, the district court clarified that the Corps of Engineers must suspend all existing authorizations under Nationwide Permit 21 for valley fills and surface impoundments in the Southern District of West Virginia on which construction had not commenced as of July 8, 2004. In November 2005, the Fourth Circuit Court of Appeals overturned the decision of the district court, finding that the Corps of Engineers had not violated the Clean Water Act in its issuance and application of Nationwide Permit 21. The Fourth Circuit remanded the case back to the district court.

In January 2005, a lawsuit was filed in Eastern District of Kentucky on similar grounds challenging the legality of Nationwide Permit 21. In March 2005, the plaintiffs filed a motion for summary judgment requesting the court to (1) issue a declaratory judgment that Nationwide Permit 21 violates Section 404 of the Clean Water Act and (2) issue an injunction prohibiting the Corps from issuing further authorizations pursuant to Nationwide Permit 21 in Kentucky. The motion also requested the court to suspend those authorizations for valley fills on which the placement of mining spoil in streams had not commenced as of the date of filing of the motion. In June 2005, the judge transferred the case from the Lexington Division to the Pikeville Division, and oral arguments have recently concluded. We will continue to monitor this litigation and its impact on the development of our coal reserves.

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. We do not hold any mining permits. Under our leases, our lessees are responsible for obtaining and maintaining all permits. 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. Regulations also provide that a mining permit can be refused or revoked if an officer, director or a shareholder with a 10% or greater interest in the entity is affiliated with another entity that has outstanding permit violations. Thus, past or ongoing violations of federal and state mining laws could provide a basis to revoke existing permits and to deny the issuance of additional permits.

Table of Contents

In order to obtain mining permits and approvals from state regulatory authorities, mine operators, including our lessees, must submit a reclamation plan for restoring the mined property to its prior condition, productive use or other permitted condition upon the completion of mining operations. Typically our lessees submit the necessary permit applications between 12 and 18 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 our reserves that are currently planned to be mined over the next five years. Our lessees are in the planning phase for obtaining permits for the reserves planned to be mined over the subsequent five years. We cannot assure you, however, that they will not experience difficulty in obtaining mining permits in the future.

As a consequence of potential future legislation and administrative regulations that may emphasize the protection of the environment, the activities of mine operators, including our lessees, may be more closely regulated. Legislation and regulations, as well as future interpretations of existing laws, may also require substantial increases in equipment expenditures and operating costs, as well as delays, interruptions or the termination of operations. We cannot predict the possible effect of such regulatory changes.

Under some circumstances, substantial fines and penalties, including revocation or suspension of mining permits, may be imposed under the laws described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws.

Framework Convention on Global Climate Change. The United States and more than 160 other nations are signatories to the 1992 United Nations Framework Convention on Global Climate Change that is intended to limit or capture emissions of greenhouse gases such as carbon dioxide and methane. In December 1997, in Kyoto, Japan, the signatories to the convention established a potentially binding set of emissions targets for developed nations. In March 2001, the Bush Administration withdrew its support for the Kyoto Protocol, and the United States is not subject to its requirements. However, other countries have ratified the protocol, which will enter into force and require developing nations subject to it to reduce greenhouse gas emissions over a five-year period from 2008 to 2012. As an alternative to the Kyoto Protocol, in February 2002, the Bush administration announced a new approach to climate change, proposing voluntary actions to reduce the greenhouse gas intensity of the U.S. Greenhouse gas intensity measures the ratio of greenhouse gas emissions, such as carbon dioxide, to economic output. The Bush Administration continues to pursue this voluntary approach. Moreover, future regulation of greenhouse gases could occur either pursuant to future U.S. treaty obligations or pursuant to statutory or regulatory changes under the Clean Air Act. Additionally, states, such as New Jersey and Maine, independently regulate emissions of certain greenhouse gases. Efforts to control greenhouse gas emissions could result in reduced demand for coal if electric power generators switch to lower carbon sources of fuel. These restrictions or uncertainties could have a material adverse effect on our business.

Comprehensive Environmental Response, Compensation and Liability Act. CERCLA and similar state laws affect coal mining operations by, among other things, imposing cleanup requirements for threatened or actual releases of hazardous substances that may endanger public health or welfare or the environment. Under CERCLA and similar state laws, joint and several liability may be imposed on waste generators, site owners and lessees and others regardless of fault or the legality of the original disposal activity. Although the EPA excludes most wastes generated by coal mining and processing operations from the hazardous waste laws, such wastes can, in certain circumstances, constitute hazardous substances for the purposes of CERCLA. In addition, the disposal, release or spilling of some products used by coal companies in operations, such as chemicals, could implicate the liability provisions of the statute. Thus, coal mines on lands that we currently own or have previously owned, and sites to which our lessees sent waste materials, may be subject to liability under CERCLA and similar state laws. In particular, we may be liable under CERCLA or similar state laws for the cleanup of hazardous substance contamination at sites where we own surface rights. We cannot assure you that we or our lessees will not become involved in future proceedings, litigation or investigations or that these liabilities will not be material.

Endangered Species. The federal Endangered Species Act and counterpart state legislation protects species threatened with possible extinction. Protection of endangered species may have the effect of prohibiting or delaying our lessees from obtaining mining permits and may include restrictions on timber harvesting, road building and other mining or silvicultural activities in areas containing the affected species. A number of species indigenous to our properties are protected under the Endangered Species Act. Based on the species that have been identified to date and the current application of applicable laws and regulations, however, we do not believe there are any species protected under the Endangered Species Act that would materially adversely affect our lessees ability to mine coal from our properties in accordance with current mining plans. There can be no assurance, however, that additional species on our properties will not receive protected status under the Endangered Species Act or that currently protected species will not be discovered within our properties.

Other Environmental Laws Affecting Our Lessees. Our lessees are required to comply with numerous other federal, state and local environmental laws in addition to those previously discussed. These additional laws include the Resource Conservation and Recovery Act, the Safe Drinking Water Act, the Toxic Substance Control Act and the Emergency Planning and Community Right-to-Know Act. We believe that our lessees are in substantial compliance with all applicable environmental laws.

Employees and Labor Relations

We do not have any employees. To carry out our operations, affiliates of our general partner employ approximately 47 employees who directly support our operations. None of these employees are subject to a collective bargaining agreement. Some of the employees of our lessees and sub-lessees are subject to collective bargaining agreements.

Segment Information

Pursuant to SFAS No. 131, Disclosure About Segments of an Enterprise and Related Information, we are not required to disclose separate segment information because the materiality of timber and oil and gas do not meet the test for segment disclosure.

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 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, the 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***

We may not have sufficient cash from operations to pay the minimum quarterly distribution following establishment of cash reserves and payment of fees and expenses, including payments to our general partner.

The amount of cash we can distribute on our units principally depends upon the amount of royalties we receive from our lessees, which will fluctuate from quarter to quarter based on, among other things:

- the amount of coal our lessees are able to produce from our properties;
- the price at which our lessees are able to sell coal; and

prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors that include:

- the level of our operating costs;
- the level of our general and administrative costs;
- the costs of acquisitions, if any;
- our debt service requirements;
- fluctuations in our working capital;
- the level of capital expenditures we make;
- restrictions on distributions contained in our debt instruments;
- our ability to borrow under our working capital facility to pay distributions; and
- the amount of cash reserves established by our general partner in its sole discretion in the conduct of our business.

You should also be aware that our ability to pay quarterly distributions depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and we may not make distributions during periods when we record net income.

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

The prices our lessees receive for their coal depend upon factors beyond their or our control, including:

- the supply of and demand for domestic and foreign coal;
- weather conditions;
- the proximity to and capacity of transportation facilities;
- worldwide economic conditions;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels; and
- the effect of worldwide energy conservation measures.

A substantial or extended decline in coal prices could materially and adversely affect us in two ways. First, lower prices may reduce the quantity of coal that may be economically produced from our properties. This, in turn, could reduce our coal royalty revenues and the value of our coal reserves. Second, even if production is not reduced, the royalties we receive on each ton of coal sold may be reduced.

Our lessees 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;

Table of Contents

- 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.

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.

We depend on a limited number of primary operators for a significant portion of our coal royalty revenues, and the loss of or reduction in production from any of our major operators could reduce our coal royalty revenues.

If reductions in production by these operators are implemented on our properties and sustained, our revenues may be substantially affected. Additionally, if a lessee were to experience financial difficulty, the lessee might not be able to pay its royalty payments or continue its operations, which could materially reduce our coal royalty revenues.

We may not be able to terminate our leases, and we may experience delays and be unable to replace lessees that do not make royalty payments.

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.

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;
- credit risk of their customers;

permitting;

insurance and surety bonding;

acquisition of surface rights and other mineral estates;

employee wages;

coal transportation arrangements;

compliance with applicable laws, including environmental laws;

negotiations and relations with unions; and

mine closure and reclamation.

Adverse developments in the coal industry could reduce our coal royalty revenues and, due to our lack of asset diversification, could substantially reduce our total revenues.

Our coal royalty business generates substantially all of our revenues. Due to our lack of asset diversification, an adverse development in the coal industry would have a significantly greater impact on our financial condition and results of operations than if we owned more diverse assets.

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 2005, approximately 27% of the coal production from our properties was metallurgical coal. The steel industry has increasingly relied on electric arc furnaces or pulverized coal processes to make steel. These processes do not use coke. If this trend continues, the amount of metallurgical coal that our lessees mine could continue to decrease. Additionally, 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 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, these mines may not be economically viable and may close.

We may not be able to expand and our business will be adversely affected if we are unable to replace or increase our reserves or obtain other mineral reserves through acquisitions.

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. 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.

Any change in fuel consumption patterns by electric power generators resulting in a decrease in the use of coal could result in lower coal production by our lessees, which would reduce our coal royalty revenues.

Domestic electric power generation accounts for approximately 90% of domestic coal consumption. The amount of coal consumed for domestic electric power generation is affected primarily by the overall demand for electricity, the price and availability of competing fuels for power plants such as natural gas, nuclear, fuel oil and hydroelectric power and environmental and other governmental regulations. We expect new power plants will be built to produce electricity. Some of these new power plants will be fired by natural gas because of lower construction costs compared to coal-fired plants and because natural gas is a cleaner burning fuel. The increasingly stringent requirements of the federal Clean Air Act may result in more electric power generators shifting from coal to natural-gas-fired power plants.

Table of Contents

Competition within the coal industry may adversely affect the ability of our lessees to sell coal, and excess production capacity in the industry could put downward pressure on coal prices.

Our lessees compete with numerous other coal producers in various regions of the United States for domestic sales. During the mid-1970s and early 1980s, increased demand for coal attracted new investors to the coal industry, spurred the development of new mines and resulted in additional production capacity throughout the industry, all of which led to increased competition and lower coal prices. Any increases in coal prices could also encourage the development of expanded capacity by new or existing coal producers. Any resulting overcapacity could reduce coal prices and therefore reduce our coal royalty revenues.

Competition from coal with lower production costs shipped east from western coal mines has resulted in increased competition for coal sales from the Appalachian region and the Illinois Basin. This competition could result in a decrease in market share for our lessees operating in these regions and a decrease in our coal royalty revenues.

The amount of coal exported from the United States has declined over the last few years due to adverse economic conditions in Asia and the higher relative cost of U.S. coal due to the strength of the U.S. dollar. This decline could cause competition among coal producers in the United States to intensify, potentially resulting in additional downward pressure on coal prices.

Conversely, the amount of coal imported into the United States over the last few years has increased. This increase is mostly due to the economic and environmental advantages of some imported coal. A continued increase in imported coal could result in less of our coal being mined and sold and reduce our coal royalty revenues. Additionally, lower priced imported coal could result in lower coal prices that would reduce our coal royalty revenues.

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.

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 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.

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

Table of Contents

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.

Our lessees work forces could become increasingly unionized in the future.

Some of the mines on our properties are operated by unionized employees of our lessees or their affiliates. Our lessees employees could become increasingly unionized in the future. Some labor unions active in our lessees areas of operations are attempting to organize the employees of some of our lessees. If some or all of our lessees non-unionized operations were to become unionized, it could adversely affect their productivity, increase costs and increase the risk of work stoppages. In addition, our lessees operations may be adversely affected by work stoppages at unionized companies, particularly if union workers were to orchestrate boycotts against our lessees operations. Any further unionization of our lessees employees could adversely affect the stability of production from our reserves and 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 and endangered species 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. 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.

New environmental legislation, new regulations and new interpretations of existing environmental laws, including regulations governing permitting requirements and the protection of endangered species, 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.

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.

Table of Contents

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

None.

Item 2. ***Properties***

Major Coal Properties

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

Northern Appalachia

Sincell. The Sincell property is located in Garrett County, Maryland. In 2005, 2.6 million tons were produced from this property. We lease this property to Mettiki Coal, LLC, a subsidiary of Alliance Resource Partners L.P. Coal is produced from an underground mine and a surface mine. It is transported by belt or 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 2005, 1.5 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.

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

Table of Contents

Table of Contents

Central Appalachia

VICC/Alpha. The VICC/Alpha property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. In 2005, 6.5 million tons were produced from this property. We lease this property to Alpha Land and Reserves, LLC. 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.

Lynch. The Lynch property is located in Harlan and Letcher Counties, Kentucky. In 2005, 5.1 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.

Pinnacle Property. The Pinnacle property is located in Wyoming and McDowell Counties, West Virginia. This property is leased to PinnOak Resources, LLC. In 2005, 2.9 million tons were produced from this property. Metallurgical coal is produced from two underground mines and transported by belt or truck to a preparation plant operated by the lessee. Coal is shipped via the Norfolk Southern railroad to customers such as U.S. Steel, National Steel, and is exported to a number of customers located in Europe.

Lone Mountain. The Lone Mountain property is located in Harlan County, Kentucky. In 2005, 2.6 million tons were produced from this property. We lease the property to Ark Land Company, a subsidiary of publicly held 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.

Eunice. The Eunice property is located in Raleigh and Boone Counties, West Virginia. In 2005, 2.6 million tons were produced from this property. We lease the property to Boone East Development Co., a subsidiary of publicly held Massey Energy Company. Boone East Development, through affiliates, conducts two operations on the property, a surface operation and an underground longwall mine. These operations extend onto adjacent reserves and will also eventually extend onto a portion of our nearby Y&O property. Coal production from this operation is generally transported by beltline and processed at two preparation plants located off the property. The preparation plants ship metallurgical and steam coal on the CSX railroad to customers such as American Electric Power, Cinergy, Louisville Gas & Electric, Virginia Electric Power, AK Steel and U.S. Steel.

VICC/Kentucky Land. The VICC/Kentucky Land property is located primarily in Perry, Leslie and Pike Counties, Kentucky. In 2005, 2.5 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.

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

Table of Contents

Southern Appalachia

BLC Properties. The BLC properties are located in Kentucky, Tennessee, and Alabama. In 2005, 3.8 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.

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

Table of Contents

Illinois Basin

Hocking-Wolford/Cummings. The Hocking-Wolford property and the Cummings property are both located in Sullivan County, Indiana. In 2005, 1.4 million tons were produced from our property. Both properties are under common lease to Black Beauty Coal Company, an affiliate of publicly held Peabody Energy. 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.

Williamson Development. On June 1, 2005, we signed a definitive agreement to purchase interests in approximately 144 million tons in the Illinois Basin in three separate transactions. Ultimately, we will acquire approximately 60% of the reserves in fee and will receive an override on the remaining tons. We closed the first of the three transactions on July 11, 2005, and on January 20, 2006, we closed the second phase of this transaction. We expect to close on the third and final phase in mid-2006. We expect production to begin in the second half of 2006, with significant production starting in 2007.

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

Table of Contents

Northern Powder River Basin

Western Energy. The Western Energy property is located in Rosebud and Treasure Counties, Montana. In 2005, 5.8 million tons were produced from our property. Western Energy Company, a subsidiary of publicly held 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.

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

Title to Property

Of the approximately two billion tons of proven and probable coal reserves to which we had rights as of December 31, 2005, we owned approximately 99% of the reserves in fee. We lease approximately 18.5 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.

Item 3. ***Legal Proceedings***

In February 2006, NRP was dismissed from the pending flood litigation trial in West Virginia that we had disclosed in previous public filings. We are involved, from time to time, in various other 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.

Table of Contents

PART II

Item 5. ***Market for Registrant s Common and Subordinated 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 9, 2006, there were an estimated 20,000 beneficial owners 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, 2004 to December 31, 2005, and the quarterly cash distribution declared and paid with respect to each quarter per common unit.

NRP

	Price Range		Cash
	High	Low	Distributions
2004			
First Quarter	$ 43.53	$ 35.50	$ 0.5750
Second Quarter	$ 38.98	$ 34.30	$ 0.6000
Third Quarter	$ 40.50	$ 37.31	$ 0.6375
Fourth Quarter	$ 57.98	$ 40.00	$ 0.6625
2005			
First Quarter	$ 63.14	$ 48.00	$ 0.6875
Second Quarter	$ 61.05	$ 49.00	$ 0.7125
Third Quarter	$ 68.95	$ 57.30	$ 0.7375
Fourth Quarter	$ 62.70	$ 49.47	$ 0.7625

In addition to common units, we have also issued subordinated units that are listed and traded on the NYSE under the symbol NSP . As of February 9, 2006, there were an estimated 3,900 beneficial owners of our subordinated units. The computation of the approximate number of unitholders is based upon a broker survey. The subordinated units were issued as part of our initial public offering in October 2002 and receive a quarterly distribution only after sufficient funds have been paid to the common units, as described below. The subordinated units were held privately until August 2005, when a large holder of subordinated units sold 4,200,000 of its subordinated units in a public offering. Subsequently, this unitholder sold the remainder of its subordinated units in several block trades in December 2005. Other than its subordinated units that converted into common units in November 2005 as described below, the WPP Group still owns all of the subordinated units it received in the initial public offering.

The following table sets forth the high and low sales prices per subordinated unit, as reported on the New York Stock Exchange Composite Transaction Tape from August 10, 2005, the first day of trading, to December 31, 2005, and the quarterly cash distribution declared and paid with respect to each quarter per subordinated unit. In addition to the data in the table, prior to going public, the subordinated units received the same distributions every quarter as the common units.

NSP

	Price Range High	Price Range Low	Cash Distributions
2005			
Third Quarter (from August 10, 2005)	$ 59.20	$ 51.22	$ 0.7375
Fourth Quarter	$ 57.95	$ 47.70	$ 0.7625

During the subordination period, the holders of our common units are entitled to receive a minimum quarterly distribution of $0.5125 per unit prior to any distribution of available cash to holders of our subordinated units. The subordination period is defined generally as the period that will end on the first day of any quarter beginning after September 30, 2007 if (1) we have distributed at least the minimum quarterly distribution on all outstanding units in each of the immediately preceding three consecutive, non-overlapping four-quarter periods and (2) our adjusted operating surplus, as defined in our partnership agreement, during such periods equals or exceeds the amount that would have been sufficient to enable us to distribute the minimum quarterly distribution on all outstanding units on a fully diluted basis and the related distribution on the 2% general partner interest during those periods. In addition, 25% of the initial outstanding subordinated units may convert to common units on a one-for-one basis after September 30, 2006, if we meet the tests set forth in our partnership agreement. If the subordination period ends, the common units will no longer be entitled to arrearages, the rights of the holders of subordinated units will no longer be subordinated to the rights of the holders of common units and the subordinated units may be converted into common units.

On November 14, 2005, 25% of the subordinated units converted into common units. Providing that the minimum quarterly distribution has been earned and paid to both the common and subordinated units for the preceding 12 quarters, the remaining NSP subordinated units will convert into NRP common units automatically on the following schedule:

331/3% of the current outstanding subordinated units (25% of the original outstanding subordinated units) following the payment of the distribution related to the third quarter of 2006 (mid-November 2006).

All of the remaining subordinated units will convert to NRP common units following the payment of the distribution related to the third quarter of 2007 (mid-November 2007).

Following the conversion in mid-November 2007, NSP units will no longer exist and all subordinated units will have been converted into NRP units.

Our general partner and affiliates of our general partner are entitled 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

		Marginal Percentage Interest in Distributions		
	Total Quarterly Distribution Target Amount	**Unitholders**	**General Partner**	**Holders of Incentive Distribution Rights**
Minimum Quarterly Distribution	$0.5125	98%	2%	
First Target Distribution	$0.5125 up to $0.5625	98%	2%	
Second Target Distribution	above $0.5625 up to $0.6625	85%	2%	13%
Third Target Distribution	above $0.6625 up to $0.7625	75%	2%	23%
Thereafter	above $0.7625	50%	2%	48%

We must distribute all of our cash on hand at the end of each quarter, less 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. 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.

Table of Contents

Item 6. *Selected Financial Data*

SELECTED HISTORICAL FINANCIAL DATA

The following tables show selected historical financial data for Natural Resource Partners L.P. and our predecessors (Western Pocahontas Properties Limited Partnership, Great Northern Properties Limited Partnership, New Gauley Coal Corporation and the Arch Coal Contributed Properties, collectively known as predecessors), in each case for the periods and as of the dates indicated. We derived the selected historical financial data for Natural Resource Partners L.P. as of December 31, 2005, 2004, 2003 and 2002, and for the years ended December 31, 2005, 2004 and 2003 and the period from commencement of operations (October 17, 2002) through December 31, 2002 from the audited financial statements of Natural Resource Partners L.P. We derived the selected historical financial data for the members of the WPP Group (see page 2) for the period from January 1 through October 16, 2002 and as of and for the year ended December 31, 2001 from the audited financial statements of the WPP Group, and we derived the selected historical financial data for the Arch Coal Contributed Properties for the period from January 1 through October 16, 2002 and as of and for the year ended December 31, 2001 from the audited financial statements of the Arch Coal Contributed Properties.

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. The tables should be read together with Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations. While substantially all of the producing coal-related assets and operations of the WPP Group were contributed to us, some assets and liabilities were retained by the WPP Group.

NATURAL RESOURCE PARTNERS L.P.

	For the Years Ended December 31, 2005	2004	2003	From Commencement of Operations (October 17, 2002) through December 31, 2002	For the Year Ended December 31, 2001
	(In thousands, except per unit and per ton data)				
Income Statement Data:					
Revenues:					
Coal royalties	$ 142,137	$ 106,456	$ 73,770	$ 11,532	(1)
Property taxes	6,516	5,349	5,069	1,047	
Minimums recognized as revenue	1,709	1,763	2,033	872	
Override royalties	2,144	3,222	1,022	226	
Other	6,547	4,642	3,572	216	
Total revenues	159,053	121,432	85,466	13,893	
Expenses:					
Depreciation, depletion and amortization	33,730	30,077	24,483	4,526	
General and administrative	12,319	11,503	8,923	1,059	
Property, franchise and other taxes	8,142	6,835	5,810	1,296	
Coal royalty and override payments	3,392	2,045	1,299	397	
Total expenses	57,583	50,460	40,515	7,278	
Income from operations	101,470	70,972	44,951	6,615	
Interest expense	(11,044)	(11,192)	(7,696)	(200)	
Interest income	1,413	349	206		
Loss from early extinguishment of debt		(1,135)			
Loss on sale of assets			(55)		
Loss from interest rate hedge			(499)		
Net income	$ 91,839	$ 58,994	$ 36,907	$ 6,415	
Balance Sheet Data (at period end):					
Total assets	$ 684,996	$ 599,926	$ 531,676	$ 392,719	
Deferred revenue	14,851	15,847	15,054	13,252	
Long-term debt	221,950	156,300	192,650	57,500	
Total liabilities	259,088	190,734	223,518	74,085	

Partners capital		425,908		409,192		308,158		318,634
Cash Flow Data:								
Net cash flow provided by (used in):								
Operating activities	$	121,675	$	90,847	$	64,528	$	6,738
Investing activities		(105,702)		(77,733)		(142,511)		(57,449)
Financing activities		(10,385)		4,669		94,550		58,463
Other Data:								
Royalty coal tons produced by lessees		53,606		48,357		44,344		7,314
Average gross coal royalty per ton	$	2.65	$	2.20	$	1.66	$	1.58
Basic and diluted net income per limited partner unit:								
Common	$	3.39	$	2.29	$	1.59	$	0.28
Subordinated	$	3.39	$	2.29	$	1.59	$	0.28
Weighted average number of units outstanding:								
Common		14,345		13,447		11,354		11,354
Subordinated		10,996		11,354		11,354		11,354
Distributions per limited partner unit:								
Common	$	2.9000	$	2.4750	$	2.1450	$	0.4234
Subordinated	$	2.9000	$	2.4750	$	2.1450	$	0.4234

(1) No financial data is presented for this period because Natural Resource Partners L.P. was not formed until April 9, 2002 and did not commence operations until October 17, 2002.

Table of Contents

WESTERN POCAHONTAS PROPERTIES LIMITED PARTNERSHIP

	For the Period from January 1, through October 16, 2002(1)	For the Year Ended December 31, 2001
	(In thousands, except per ton data)	
Income Statement Data:		
Revenues:		
Coal royalties	$ 17,261	$ 15,458
Timber royalties	2,774	3,691
Gain on sale of property	92	3,125
Property taxes	1,221	1,184
Other	1,219	2,512
Total revenues	22,567	25,970
Expenses:		
General and administrative	2,291	2,981
Taxes other than income	1,438	1,457
Depreciation, depletion and amortization	3,544	1,369
Total expenses	7,273	5,807
Income from operations	15,294	20,163
Other income (expense):		
Interest expense	(4,786)	(3,966)
Interest income	114	270
Reversionary interest	(561)	(1,924)
Net income	$ 10,061	$ 14,543
Balance Sheet Data (at period end):		
Total assets		$ 88,224
Deferred revenue		7,916
Long-term debt		47,716
Total liabilities		68,055
Partners capital		20,169
Cash Flow Data:		
Net cash flow provided by (used in):		
Operating activities	$ 8,676	$ 13,056
Investing activities	(35,028)	2,685
Financing activities	27,899	(15,434)
Other Data:		

Royalty coal tons produced by lessees	9,572	10,309
Average gross coal royalty per ton	$ 1.80	$ 1.50

(1) Up to the date of contribution of assets to Natural Resource Partners L.P.

Table of Contents

GREAT NORTHERN PROPERTIES LIMITED PARTNERSHIP

	For the Period from January 1 through October 16, 2002(1)	For the Year Ended December 31, 2001
	(In thousands, except per ton data)	
Income Statement Data:		
Revenues:		
Coal royalties	$ 5,895	$ 7,457
Lease and easement income	474	787
Gain on sale of property		439
Property taxes	61	88
Other	71	31
Total revenues	6,501	8,802
Expenses:		
General and administrative	417	611
Taxes other than income	69	110
Depreciation, depletion and amortization	1,979	2,144
Total expenses	2,465	2,865
Income from operations	4,036	5,937
Other income (expense):		
Interest expense	(1,877)	(3,652)
Interest income	115	307
Net income	$ 2,274	$ 2,592
Balance Sheet Data (at period end):		
Total assets		$ 70,236
Deferred revenue		1,034
Long-term debt		47,125
Total liabilities		50,110
Partners capital		20,126
Cash Flow Data:		
Net cash flow provided by (used in):		
Operating activities	$ 3,725	$ 3,677
Investing activities		475
Financing activities	(4,069)	(4,564)
Other Data:		

Royalty coal tons produced by lessees	4,970	8,509
Average gross coal royalty per ton	$ 1.19	$ 0.88

(1) Up to the date of contribution of assets to Natural Resource Partners L.P.

Table of Contents

NEW GAULEY COAL CORPORATION

	For the Period from January 1 through October 16, 2002(1)	For the Year Ended December 31, 2001
	(In thousands, except per ton data)	
Income Statement Data:		
Revenues:		
Coal royalties	$ 1,434	$ 1,609
Gain on sale of property		25
Property taxes	20	28
Other	53	61
Total revenues	1,507	1,723
Expenses:		
General and administrative	52	41
Taxes other than income	42	45
Depreciation, depletion and amortization	138	212
Total expenses	232	298
Income from operations	1,275	1,425
Other income (expense):		
Interest expense	(97)	(132)
Interest income	24	15
Reversionary interest	(104)	(85)
Net income	$ 1,098	$ 1,223
Balance Sheet Data (at period end):		
Total assets		$ 4,625
Deferred revenue		3,601
Long-term debt		1,584
Total liabilities		5,391
Stockholders deficit		(766)
Cash Flow Data:		
Net cash flow provided by (used in):		
Operating activities	$ 867	$ 1,323
Investing activities		(175)
Financing activities	(474)	(1,091)
Other Data:		

Royalty coal tons produced by lessees		479		718
Average gross coal royalty per ton	$	2.99	$	2.24

(1) Up to the date of contribution of assets to Natural Resource Partners L.P.

Table of Contents

ARCH COAL CONTRIBUTED PROPERTIES

	For the Period from January 1 through October 16, 2002(1)	Year Ended December 31, 2001
	(In thousands, except per ton data)	
Income Statement Data:		
Revenues:		
Coal royalties	$ 14,768	$ 18,415
Other royalties	1,349	1,363
Property taxes	1,179	1,033
Total revenues	17,296	20,811
Direct costs and expenses:		
Depletion	4,889	6,382
Property taxes	1,179	1,033
Other expense	528	283
Total expenses	6,596	7,698
Excess (deficit) of revenues over direct costs and expenses	$ 10,700	$ 13,113
Balance Sheet Data (at period end):		
Total assets		$ 90,733
Deferred revenue		10,409
Total liabilities		11,180
Net assets purchased		79,553
Cash Flow Data:		
Direct cash flow from contributed properties	$ 15,181	$ 19,836
Other Data:		
Royalty coal tons produced by lessees	8,791	11,281
Average gross coal royalty per ton	$ 1.68	$ 1.63

(1) Up to the date of contribution of assets to Natural Resource Partners L.P.

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 historical financial statements.

Executive Overview

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. Coal produced from our properties is burned in electric power plants located east of the Mississippi River and in Montana and Minnesota. As of December 31, 2005, we owned or controlled approximately two billion tons of proven and probable coal reserves in eleven states. For the year ended December 31, 2005, approximately 61% of the coal produced from our properties came from underground mines and approximately 39% came from surface mines. As of December 31, 2005, approximately 57% of our reserves were low sulfur coal. Included in our low sulfur reserves is compliance coal, which constitutes approximately 35% of our reserves.

We 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. As of December 31, 2005, our reserves were subject to 176 leases with 67 lessees. For the year ended December 31, 2005, our lessees produced 53.6 million tons of coal generating $142.1 million in coal royalty revenues from our properties and our total revenue was $159.1 million.

Our revenue and profitability are dependent on our lessees ability to mine and market our coal reserves. Generally, our lessees make payments to us based on the greater of a percentage of the gross sales price or a fixed price 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 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.

Most of our coal is produced by large companies, many of which are publicly traded, with professional and sophisticated 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.

Coal royalty revenues from our Appalachian properties represented 91% of our total coal royalty revenues for the year ended December 31, 2005, and thus a significant portion of our total revenue is dependent upon Appalachian coal prices. Coal prices are based on supply and demand, specific coal characteristics, economics of alternative fuel, and overall domestic and international economic conditions. Our lessees located in Appalachia have recently experienced a greater demand for coal, and coal prices for both metallurgical and steam coal for those producers increased during 2004 and 2005. Towards the end of the second quarter of 2004, our Appalachian lessees began to enter into new coal sales contracts at the higher prices. As their older contracts have continued to rollover during the last 15 months, we have received substantially higher royalties from our leases, and our revenue per ton from that region has increased to an average of $2.87 per ton for the year ended December 31, 2005 from an average of $2.34 per ton for the same period of 2004. However, because prices have generally stabilized over the last six months and our lessees will have fewer contracts that will rollover into substantially higher prices, we expect that our coal royalty revenue per ton will not continue to increase at this pace over the next year. In addition, in spite of the higher prices, most of our lessees have not appreciably increased production due to a number of constraints, including a shortage of labor, permitting issues and rail transportation problems. As a result, we believe that a larger percentage of our future revenue growth will come from acquisitions of new reserves.

Table of Contents

For the year ended December 31, 2005, approximately 31% of our coal royalty revenues and 27% of the related production were from metallurgical coal, which was sold to steel companies in the eastern United States, South America, Europe and Asia. Prices of metallurgical coal have been substantially higher over the last two years and we expect them to remain at historically high levels in 2006 as well. Metallurgical coal, because of its unique chemical characteristics, is usually priced higher than steam coal. The current pricing environment for U.S. metallurgical coal is strong in both the domestic and seaborne export markets.

In addition to coal royalty revenues, we generated approximately 6% of our revenues for the years ended December 31, 2005 and 2004, respectively, from rentals; royalties on oil and gas and coalbed methane leases; timber; overriding royalty arrangements; and wheelage payments, which are toll payments for the right to transport third-party coal over or through our property.

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 critical 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.

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

Reconciliation of GAAP Net Cash Provided by Operating Activities to Non-GAAP Distributable Cash Flow

	For the years ended December 31,		
	2005	**2004**	**2003**
Cash flow from operations	$ 121,675	$ 90,847	$ 64,528
Less scheduled principal payments	(9,350)	(9,350)	
Less reserves for future principal payments	(9,400)	(9,400)	(4,700)
Add reserves used for scheduled principal payments	9,400	9,400	
Distributable cash flow	$ 112,325	$ 81,497	$ 59,828

Acquisitions

2005 Acquisitions

AFG. On November 21, 2005, we completed the acquisition of 179 million tons of coal reserves in Ohio and Pennsylvania for $29 million.

Area F/Lexington. In two separate transactions on September 26, 2005, we acquired approximately 25 million tons of owned coal reserves and an overriding royalty on approximately 14 million tons of leased coal reserves in Randolph, Upshur and Barbour Counties in north central West Virginia for $13.5 million.

Dolphin. On September 22, 2005, we acquired a coal preparation plant and rail load-out facility in Greenbrier County, West Virginia for $6 million. We do not operate the preparation plant but receive a fee for coal processed through it. The facilities primarily process coal produced from our Plum Creek properties.

Williamson Development (formerly Steelhead). On June 1, 2005, we signed a definitive agreement to purchase interests in approximately 144 million tons in the Illinois Basin for $105 million in three separate transactions. Ultimately, we will acquire approximately 60% of the reserves in fee and will receive an override on the remaining tons. On July 11, 2005, we closed the first of the three transactions for $35 million. On January 20, 2006, we closed the second phase of this transaction for $35 million. We expect to close on the third and final phase in mid-2006.

Plum Creek. On March 3, 2005, we completed an acquisition of coal reserves from Plum Creek Timber Company, Inc. for $21.25 million. This property consists of approximately 85 million tons of coal reserves located on approximately 175,000 acres in Virginia, West Virginia and Kentucky.

2004 Acquisitions

Clinchfield. In September 2004, we purchased a tract of coal reserves from Clinchfield Coal Company in Dickenson County, Virginia for $0.4 million. This property adjoins other property we own and represents approximately 0.8 million tons. We have subsequently combined this property with other properties under an existing lease to a subsidiary of Alpha Natural Resources.

Pardee Minerals. In May 2004, we purchased a tract of coal reserves from Pardee Minerals LLC in Wise County, Virginia for $1.6 million. This property adjoins other property we own and represents approximately 1.0 million tons. As a part of this transaction, we took an assignment of a coal lease under which a subsidiary of Alpha Natural Resources is the lessee.

Appolo. In February 2004, we purchased two tracts of property from Appolo Fuels, Inc. in Bell County, Kentucky for $2.5 million. This property adjoins the properties purchased in the BLC acquisition and represents approximately 2.5 million tons. As a part of this transaction, an older below market lease affecting approximately 2.5 million additional tons of adjacent reserves was renegotiated to current royalty rates.

BLC Properties. In January 2004, we purchased all of the mineral interests of BLC Properties LLC for $73.0 million. This acquisition included coal, oil and gas and other mineral rights on approximately 270,000 acres that contain approximately 176 million tons of coal reserves. We lease these reserves to eight different lessees. The transaction also included oil and gas and other mineral rights on approximately 205,000 additional acres. The properties are located in Kentucky, Tennessee, West Virginia, Virginia, and Alabama. BLC retained a 35% non-participating royalty interest in the oil and gas and other mineral rights.

2003 Acquisitions

Eastern Kentucky Reserves. In November 2003, we acquired coal reserves and related interests in eastern Kentucky from a number of private sellers for $18.8 million. The acquisition included approximately 21 million tons of coal reserves, an additional royalty interest in approximately 8 million tons of coal reserves on contiguous property, and the right to collect a wheelage fee on 10 million tons of coal. We lease some of these reserves to Appalachian Fuels.

PinnOak Resources. In July 2003, we acquired approximately 79 million tons of coal reserves and an overriding royalty interest on additional coal reserves from subsidiaries of PinnOak Resources, LLC for $58.0 million. We lease these reserves to other subsidiaries of PinnOak Resources. PinnOak Resources produces low volatile metallurgical coal from these longwall mines and has onsite preparation plants. The properties consist of coal reserves located at two mine complexes: the Pinnacle mine in Pineville, West Virginia and the Oak Grove mine near Birmingham, Alabama.

Alpha Natural Resources Reserves. In April 2003, we acquired approximately 295,000 mineral acres containing approximately 353 million tons of coal reserves from two subsidiaries of Alpha Natural Resources, LLC for $53.6 million. We leased most of these reserves to two Alpha subsidiaries and seven other operators. The properties are located in Virginia adjacent to the coal properties that we acquired from El Paso Corporation in December 2002, which are operated by another subsidiary of Alpha Natural Resources, LLC.

Alpha Natural Resources Royalty Interest. In February 2003, we purchased an overriding royalty interest in the coal reserves that we purchased from El Paso Corporation in December 2002 from a subsidiary of Alpha Natural Resources LLC for $11.9 million.

Critical Accounting Policies

Coal Royalties. We recognize coal royalty revenues on the basis of tons of coal sold by our lessees and the corresponding revenue from those sales. Generally, the lessees make payments to us based on the greater of a percentage of the gross sales price or a fixed price per ton of 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 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 carried as deferred revenue, a liability on the balance sheet.

Timber Royalties. We sell timber on a contract basis under which independent contractors harvest and sell the timber and, from time to time, in a competitive bid process involving sales of standing timber on individual parcels. We recognize timber revenues when the timber has been sold or harvested by the independent contractors. Title and risk of loss pass to the independent contractors when they harvest the timber.

Oil and Gas Royalties. We recognize oil and gas royalties on the basis of volume of hydrocarbons sold by lessees and the corresponding revenue from those sales. Generally, the lessees make payments to us based on a percentage of the selling price. Some leases are subject to minimum annual payments or delay rentals. The minimum annual payments that are recoupable are generally recoupable over certain periods. The minimum payments are initially recorded as deferred revenue and recognized either when the lessee recoups the minimum payments 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 coal properties on a units-of-production basis by lease, based upon coal mined in relation to the net cost of the mineral properties and estimated proved and probable tonnage in those properties. We estimate proven and probable coal reserves with the assistance of third-party mining consultants, and we use estimation techniques and recoverability assumptions. Our estimates of coal reserves are updated periodically and may result in material adjustments to coal reserves and depletion rates that are recognized 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 are recognized prospectively. Changes in these estimates have no effect on our cash flow.

LTIP Awards and New Accounting Standards

Statement of Financial Accounting Standards No. 123R *Accounting for Stock-Based Compensation,* revised in 2004, superseded APB No. 25. Awards under our Long Term Incentive Plan have been accounted for on the intrinsic method under the provisions of APB No. 25. FAS 123R, effective for the first quarter of 2006, requires us to recognize a cumulative effect of the accounting change at the date of adoption based on the difference between the fair value of the unvested awards and the intrinsic value recorded. Additionally, FAS 123R provides that grants after the effective date must be accounted for using the fair value method which will require us to estimate the fair value of the grant using an accepted method and charge the estimated fair value to expense over the service or vesting period of the grant. FAS 123R requires that the fair value be recalculated at each reporting date over the service or vesting period of the grant. Use of the fair value method as compared with the intrinsic method, will not change the total expense to be reflected for a grant but it may impact the period in which expense is reflected by increasing expense in one period based upon the fair value calculation and lowering expense in a different period. We are in the process of evaluating the impact of FAS 123R and expect to adopt it in the first quarter of 2006 using the modified prospective method.

Table of Contents

Results of Operations

Natural Resource Partners L.P.

	For the Years Ended December 31,		
	2005	2004	2003
	(In thousands, except per ton data)		
Revenues:			
Coal royalties	$ 142,137	$ 106,456	$ 73,770
Property taxes	6,516	5,349	5,069
Minimums recognized as revenue	1,709	1,763	2,033
Override royalties	2,144	3,222	1,022
Other	6,547	4,642	3,572
Total revenues	159,053	121,432	85,466
Expenses:			
Depreciation, depletion and amortization	33,730	30,077	24,483
General and administrative	12,319	11,503	8,923
Property, franchise and other taxes	8,142	6,835	5,810
Coal royalty and override payments	3,392	2,045	1,299
Total expenses	57,583	50,460	40,515
Income from operations	101,470	70,972	44,951
Other income (expense):			
Interest expense	(11,044)	(11,192)	(7,696)
Interest income	1,413	349	206
Loss on early extinguishment of debt		(1,135)	
Loss on sale of oil and gas properties			(55)
Loss from interest rate hedge			(499)
Net income	$ 91,839	$ 58,994	$ 36,907
Other Data:			
Coal Royalties			
Appalachia			
Northern	$ 11,306	$ 7,084	$ 5,341
Central	93,008	76,583	55,071
Southern	25,089	14,874	3,443
Total Appalachia	129,403	98,541	63,855
Illinois Basin	4,288	3,852	3,566
Northern Powder River Basin	8,446	4,063	6,349
Total	$ 142,137	$ 106,456	$ 73,770

Production (tons)			
Appalachia			
Northern	5,977	4,179	3,736
Central	32,790	32,702	31,135
Southern	6,263	5,208	1,127
Total Appalachia	45,030	42,089	35,998
Illinois Basin	2,781	3,138	3,034
Northern Powder River Basin	5,795	3,130	5,312
Total	53,606	48,357	44,344
Average gross royalty			
Appalachia			
Northern	$ 1.89	$ 1.70	$ 1.43
Central	2.84	2.34	1.77
Southern	4.01	2.86	3.05
Total Appalachia	2.87	2.34	1.77
Illinois Basin	1.54	1.23	1.18
Northern Powder River Basin	1.46	1.30	1.20
Total	$ 2.65	$ 2.20	$ 1.66

Year ended December 31, 2005 compared to year ended December 31, 2004

Revenues. For the year ended December 31, 2005, total revenues were $159.1 million compared to $121.4 million for the same period in 2004, an increase of $37.7 million or 31%. Coal royalty revenues were $142.1 million, on 53.6 million tons of coal produced, for the year ending December 31, 2005, and represented 89% of total revenue. For the year ended December 31, 2004, coal royalty revenues were $106.5 million, on 48.4 million tons produced, and represented 87% of total revenue.

Coal royalty revenues. Coal royalty revenues increased to $142.1 million in 2005 from $106.5 million in 2004, an increase of $35.6 million or 33%. Coal production increased to 53.6 million tons from 48.4 million in 2004, an increase of 5.2 million tons or 11%. The substantial increase in coal royalty revenues was primarily due to the significantly higher sales prices realized by our lessees in 2005. In addition, approximately 2.1 million tons and $4.2 million of the increase in coal royalty revenues generated during the year ended December 31, 2005 were attributable to acquisitions we made in 2005. All of these acquisitions were in Appalachia, with the exception of the Williamson Development acquisition, which will not contribute any production or coal royalty revenue until the second half of 2006.

The following is a breakdown of our major coal producing regions:

Appalachia. Coal royalty revenues in Appalachia in 2005 were $129.4 million compared to $98.5 million in 2004, an increase of $30.9 million, or 31%. In 2005, production in Appalachia was 45.0 million tons compared to 42.1 million tons in 2004, an increase of 2.9 million tons, or 7%. The Appalachia results by region are set forth below.

Northern Appalachia. Primarily, as a result of the acquisition of the AFG properties in 2005 and higher prices, our coal royalty revenue increased 59% from $7.1 million for the year ended December 31, 2004 to $11.3 million for the year ended December 31, 2005. Production increased 43% from 4.2 million tons to 6.0 million tons over the same periods. The AFG acquisition generated coal royalty revenue of $2.7 million and production of 1.5 million tons. In addition to the AFG acquisition, the following property was a significant contributor to the variance:

> *Sincell* production increased from 1.6 million tons to 2.6 million tons and coal royalty revenues increased from $2.8 to $4.7 million. The increased tonnage was due to the longwall unit being on our property for a greater portion of the year.

Central Appalachia. Primarily, due to higher prices, coal royalty revenue increased 21% from $76.6 million for the year ended December 31, 2004 to $93 million for the year ended December 31, 2005, while production only slightly increased from 32.7 million tons to 32.8 million tons for the same periods. The results in Central Appalachia include a combination of increases and decreases over several properties, the most significant of which are described below.

In addition to higher coal prices and acquisitions, the properties that had significant increases in production and coal royalty revenues were:

> *Pinnacle* production increased from 1.8 million tons to 2.9 million tons and coal royalty revenues increased from $6.0 million to $10.8 million. The increased tonnage was due to the mine resuming production after being idle for a portion of the year in 2004.
>
> *Lynch* production increased from 4.5 million tons to 5.1 million tons and coal royalty revenues increased from $8.7 million to $11.5 million. The increased tonnage was due to lessees starting new mines and some mines moving onto the property.

VICC/Kentucky Land production increased from 2.3 million tons to 2.5 million tons and coal royalty revenues increased from $5.5 million to $8.2 million. The increased tonnage was due to a net increase in tonnage from mines moving onto the property that more than offset some mines moving off the property.

Eunice production increased from 2.0 million tons to 2.6 million tons and coal royalty revenues increased from $4.1 million to $6.7 million. The increased tonnage was due to higher production by the longwall unit on the property.

Kingston production increased from 1.1 million tons to 1.7 million tons and coal royalty revenues increased from $2.2 million to $4.6 million. The increased tonnage was due to a new surface mine starting on the property.

Pardee production increased from 1.4 million tons to 1.7 million tons and coal royalty revenues increased from $4.7 million to $6.5 million. The increased tonnage was due to increased production from the surface mines on the property.

These increases were partially offset by decreases in production and coal royalty revenues from our West Fork property. Production decreased from 2.7 million tons to nearly zero and coal royalty revenues decreased from $8.0 million to nearly zero as longwall mining was completed on the property.

Southern Appalachia. Primarily due to higher prices, coal royalty revenues increased 68% from $14.9 million for the year ended December 31, 2004 to $25.1 million for the year ended December 31, 2005, while production increased from 5.2 million tons to 6.3 million tons for the same periods. The following properties contributed significantly to the variance:

BLC production increased from 3.5 million tons to 3.8 million tons and coal royalty revenues increased from $9.5 million to $12.7 million. The increased tonnage was due to a mine being on our property for a greater portion of the year and improved production at some of the mines on our property.

Oak Grove production increased from 1.4 million tons to 1.7 million tons and coal royalty revenues increased from $3.1 million to $6.2 million. The increased tonnage was due to improved production from the mine.

Twin Pines production increased from 358,000 tons to 572,000 tons and coal royalty revenues increased from $2.2 million to $5.1 million. The increased tonnage was due to the lessee increasing production at the mine.

Illinois Basin. Coal royalty revenues increased 11% from $3.9 million for the year ended December 31, 2004 to $4.3 million for the year ended December 31, 2005, while production decreased 11% from 3.1 million tons to 2.8 million tons for the same periods. The property that had an increase in coal royalty revenues is described below:

Sato production increased from 963,000 tons to 1.1 million tons and coal royalty revenues increased from $1.4 million to $1.9 million. The increased tonnage was due to the lessee increasing production at the mine.

Northern Powder River Basin. Coal royalty revenue increased 105% from $4.1 million to $8.4 million and production increased 87% from 3.1 million tons to 5.8 million tons over the same period. This increase was due to the typical variations in production resulting from the checkerboard ownership pattern and from higher sales prices being received by our lessee. Included in our coal royalty revenues for the year ended December 31, 2004 is a one-time settlement of $170,000, or $0.08 per ton, resulting from an arbitration award our lessee received from a third party.

Expenses. Total expenses were $57.6 million, or 36%, of total revenues for the year ended December 31, 2005, compared to $50.5 million, or 42%, of total revenues for the year ended December 31, 2004. Depreciation, depletion and amortization represented 59% of the total expenses for both 2005 and 2004. Although depreciation, depletion and amortization was consistent for the periods discussed, it can vary depending on where the coal production occurs and fluctuations in depletion rates. General and administrative expenses were approximately 21% and 23% of total expenses for the year ended December 31, 2005 and 2004, excluding accruals for incentive compensation of $3.0 million in 2005 and $3.5 million in 2004. The accruals for incentive compensation decreased as a result of the change in the price of our common units between years. Property, franchise and other taxes were $8.1 million, or 14%, of total expenses for 2005 and $6.8 million, or 13%, of total expenses for 2004. Property and franchise taxes increased due to the acquisitions made during 2005. Coal royalty and override payments were $3.4 million or 6% of total expenses for 2005 and $2.0 million or 4% of total expenses for 2004. The increase in coal royalty and override payments is a direct result of the increase in coal prices.

Other Income (Expense). Interest expense was $11.0 million for 2005 compared with $11.2 million for 2004, a decrease of $0.2 million. This decrease is attributed to lower borrowings under our credit facility and the repayment of a portion of our senior notes during 2005. Interest income increased from 2004 as a result of the investment of surplus cash. Other expense for 2004 includes a one-time charge of $1.1 million for the early extinguishment of debt in connection with our new credit facility.

Year ended December 31, 2004 compared to year ended December 31, 2003

Revenues. For the year ended December 31, 2004, total revenues were $121.4 million compared to $85.5 million for the same period in 2003, an increase of $35.9 million or 42%. Coal royalty revenues were $106.5 million, on 48.4 million tons of coal produced, for the year ending December 31, 2004, and represented 88% of total revenue. For the year ended December 31, 2003, coal royalty revenues were $73.8 million, on 44.3 million tons produced, and represented 86% of total revenue. Of the $35.9 million increase in total revenues, coal royalty revenues increased $32.7 million or 44% and override revenues increased $2.2 million or 215%. There was also an increase in wheelage revenue of $0.5 million or 35%, and modest increases in property tax reimbursements, rental income, oil and gas revenue and other totaling approximately $0.5 million or 9%.

Coal royalty revenues. Coal royalty revenues increased to $106.5 million in 2004 from $73.8 million in 2003, an increase of $32.7 million or 44%. Coal production increased to 48.4 million tons from 44.3 million in 2003, an increase of 4.1 million tons or 9%. The substantial increase in coal royalty revenues is primarily due to the significantly higher sales prices realized by our lessees in 2004.

The following is a breakdown of our major coal producing regions:

Appalachia. Coal royalty revenues in Appalachia in 2004 were $98.5 million compared to $63.9 million in 2003, an increase of $34.6 million, or 54%. In 2004, production in Appalachia was 42.1 million tons compared to 36.0 million tons in 2003, an increase of 6.1 million tons, or 17%. In addition, approximately 3.6 million tons and $9.8 million of the increase in coal royalty revenues generated during the year ended December 31, 2004 were attributable to the acquisitions made subsequent to December 31, 2003. All of these acquisitions were in Appalachia. The Appalachia results by region are set forth below.

Northern Appalachia. Coal royalty revenues increased 34% from $5.3 million for the year ended December 31, 2003 to $7.1 million for the year ended December 31, 2004. Production increased 11% from 3.8 million tons to 4.2 million tons over the same periods. The following properties were a significant contributor to the variance:

> *Sincell* production increased from 95,000 tons to 1.6 million tons and coal royalty revenues increased from $119,000 to $2.8 million. These increases were due to production moving onto our property.
>
> *Davis Lumber* production decreased from 464,000 tons to 46,000 tons and coal royalty revenues decreased from $632,000 to $106,000. These decreases were due to a previously active mine exhausting its reserves.

Central Appalachia. Primarily due to higher prices, coal royalty revenues increased 39% from $55.1 million for the year ended December 31, 2003 to $76.6 million for the year ended December 31, 2004, while production increased from 31.1 million tons to 32.7 million tons for the same periods. The results in Central Appalachia include a combination of increases and decreases over several properties, the most significant of which are described below.

In addition to higher coal prices and acquisitions, the properties that had significant increases in production and coal royalty revenues were:

Pinnacle production increased from 830,000 tons to 1.8 million tons and coal royalty revenues increased from $1.8 million to $6.0 million. The mine operated on our property for two months in 2003 before ceasing production due to a ventilation disruption. The mine resumed production in late April 2004.

Lynch production increased from 2.9 million tons to 4.5 million tons and coal royalty revenues increased from $4.7 million to $8.7 million. These increases were due in part to new mines being opened on the property.

Y&O production increased from 133,000 tons to 696,000 tons and coal royalty revenues increased from $262,000 to $1.3 million. These increases were due to mines moving onto the property.

These increases were partially offset by decreases in production and coal royalty revenues from our Boone-Lincoln and Chesapeake Minerals properties. On our Boone-Lincoln property, production decreased from 547,000 tons to 127,000 tons and coal royalty revenues decreased from $993,000 to $253,000. These decreases were due to a greater proportion of production occurring on adjacent property. On our Chesapeake Minerals property, production decreased from 475,000 tons to 136,000 tons and coal royalty revenues decreased from $942,000 to $366,000. These decreases were due to the depletion of reserves at one mine and a greater proportion of production occurring on adjacent property.

Southern Appalachia. Primarily as a result of our acquisition of the BLC property in 2004, coal royalty revenues increased 332% from $3.4 million for the year ended December 31, 2003 to $14.9 million for the year ended December 31, 2004, while production increased from 1.1 million tons to 5.2 million tons for the same periods. In addition to the BLC property, the following property contributed significantly to the variance:

Oak Grove production increased from 775,000 tons to 1.4 million tons and coal royalty revenues increased from $1.7 million to $3.1 million. These production increases were due to owning the property for the entire year of 2004 versus six months in 2003.

Illinois Basin. On our Sato property, production increased from 909,000 tons to 963,000 tons and coal royalty revenues increased from $1.2 million to $1.4 million. These increases were due to slightly higher production and higher prices being realized by the lessee.

Northern Powder River Basin. Production from our Western Energy property decreased from 4.3 million tons to 3.1 million tons and coal royalty revenues decreased from $5.4 million to $4.1 million. This decrease was due to the typical variations in production resulting from the checkerboard ownership pattern. On our Big Sky property production decreased from 983,000 tons to zero and coal royalty revenues decreased from $903,000 to zero as operations were idled at the Big Sky mine. Included in our coal royalty revenues for the year ended December 31, 2004 is a one-time settlement of $170,000, or $0.08 per ton, resulting from an arbitration award between our lessee and a third party.

Expenses. Total expenses were $50.5 million, or 42%, of total revenues for the year ended December 31, 2004, compared to $40.5 million, or 47%, of total revenues for the year ended December 31, 2003. Depreciation, depletion and amortization represented 60% of the total expenses for both 2004 and 2003. Although depreciation, depletion and amortization was consistent for the periods discussed, it can vary depending on where the coal production occurs and fluctuations in depletion rates. General and administrative expenses were approximately 16% of total expenses in both years, excluding accruals for incentive compensation of $3.4 million in 2004 and $2.8 million in 2003. The accruals for incentive compensation reflect additional units granted during the year as well as the increase in the unit price at year end. Property, franchise and other taxes were $6.8 million, or 13%, of total expenses for 2004 and $5.8 million, or 14%, of total expenses for 2003, this increase is a reflection of additional properties acquired during the year. Coal royalty and override payments were $2.0 million or 4% of total expenses for 2004 and $1.3 million or 3% of total expenses for 2003. The increase in coal royalty and override payments is a direct result of the increase in coal prices.

Other Income (Expense). Interest expense was $11.2 million for 2004 compared with $7.7 million for 2003. This increase in interest expense is a result of our $175 million senior debt being outstanding for a full year in 2004. Interest income increased from 2003 as a result of the investment of surplus cash. Other expense includes a one-time charge of $1.1 million for the early extinguishment of debt in connection with our new credit facility. In 2003, a $0.5 million expense was related to the hedge of interest rates on the issuance of the senior notes as well as a loss on the sale of oil and gas properties of $0.1 million incurred upon disposition of these properties in the fourth quarter.

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, 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. 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 $3.7 million in 2005, $3.8 million in 2004 and $2.9 million in 2003. For additional information, please read Certain Relationships and Related Transactions Omnibus Agreement.

First Reserve Corporation

Prior to August 2005, First Reserve controlled a partnership that held 4,796,920 subordinated units. In connection with this investment, First Reserve had a contractual right to appoint two members to our board of directors. Following the public sale of these subordinated units in 2005, First Reserve relinquished this contractual right. However, one of the two First Reserve appointees, Steve Smith, has remained on our board. Mr. Smith is an independent director and serves on our audit committee. Alex Krueger, the other director appointed by First Reserve, resigned from the board in December 2005. He is a managing director at First Reserve, which during 2005 had investments in two of our lessees, Alpha Natural Resources and Foundation Coal Holdings. Because Mr. Krueger also served on the boards of directors of Alpha and Foundation during 2005, we have summarized below our relationships with each of these companies.

Alpha Natural Resources. We have entered into a number of coal mining leases with Alpha through a combination of new leases entered into upon our purchase of the Alpha property and through leases we had with entities that Alpha acquired.

The Alpha leases in general have terms of five to ten years with the ability to renew the leases for subsequent terms of five to ten years, until the earlier to occur of: (1) delivery of notice that the lessee will not renew the lease or (2) all mineable and merchantable coal has been mined. The leases provide for payments to us based on the higher of a percentage of the gross sales price or a fixed minimum per ton of coal sold from the properties, with minimum annual payments. Under the Alpha leases minimum royalty payments are credited against future production royalties.

Coal royalty revenues earned under these leases for the year ended December 31, 2005 totaled $20.0 million, representing 14% of our total coal royalty revenues. If no production had taken place in 2005, minimum recoupable royalties of $4.7 million would have been payable under the leases. At December 31, 2005 we had accounts receivable outstanding of $1.5 million with Alpha Natural Resources.

We believe the production and minimum royalty rates contained in the Alpha leases are consistent with current market royalty rates.

Foundation Coal Holdings, Inc. Foundation Coal Holdings, Inc. controls our lessee on the Kingston and Plum Creek properties in West Virginia, which contained approximately 6.7 million tons of proven and probable reserves as of December 31, 2005.

The leases have terms of five to ten years with the ability to renew the lease for subsequent terms of five years unless the lessee gives notice it will not renew the lease. The lease provides for payments to us based on the higher of a percentage of the gross sales price or a fixed minimum per ton of coal sold from the properties, with annual minimum payments. Under the leases minimum royalty payments are credited against future production royalties. We believe the production and minimum royalty rates contained in the leases are consistent with current market royalty rates.

Coal royalty revenues earned under the leases for the year ended December 31, 2005 totaled $4.6 million, representing 3% of our coal royalty revenues. If no production had taken place in 2005, minimum recoupable royalties of $260,000 would have been payable under the lease. At December 31, 2005, we had accounts receivable outstanding of $0.4 million with Foundation Coal Holdings, Inc.

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 the use of available cash, through borrowings under our revolving credit facility, and through the issuance of our senior notes and additional common units. We believe that cash generated from our operations, combined with the availability under our credit facility and the proceeds from the issuance of debt and equity, will be sufficient to fund working capital, capital expenditures and future acquisitions. Our ability to satisfy any debt service obligations, fund planned capital expenditures, make acquisitions and pay distributions to our unitholders will depend upon our ability to access the capital markets, as well as our future operating performance, which will be affected by prevailing economic conditions in the coal industry and financial, business and other factors, some of which are beyond our control. For a more complete discussion of factors that will affect cash flow we generate from our operations, please read Item 1A. Risk Factors. Our capital expenditures, other than for acquisitions, have historically been minimal.

Net cash provided by operations for the years ended December 31, 2005, 2004 and 2003 was $121.7 million, $90.8 million and $64.5 million, respectively. Substantially all of our cash provided by operations since inception has been generated from coal royalty revenues.

Net cash used in investing activities for the years ended December 31, 2005, 2004 and 2003 was $105.7 million, $77.7 million and 142.5 million, respectively. The 2005 results include the acquisition of coal reserves from Plum Creek Timber Company, Inc. for $21.2 million, the acquisition of coal reserves from Williamson Development for $35.1 million, the acquisition of a coal preparation plant and loadout facility from Dolphin for $6.0 million, the acquisition of the Area F/Lexington coal reserves for $13.6 million and the acquisition of our AFG properties for $29.4 million. Net cash used in investing activities for 2004 include the acquisitions of coal reserves from BLC, Apollo, Pardee Minerals and Clinchfield. Acquisitions in 2003 include the Alpha Natural Resources reserves and overriding royalty interest, PinnOak Resources and Eastern Kentucky reserves.

Net cash used in financing activities for the year ended December 31, 2005 was $10.4 million compared to net cash provided by financing activities of $4.7 million for the same period a year ago. For the year ended December 31, 2005, we borrowed $75.0 million on our revolving credit facility to fund acquisitions, and repaid $50.0 million with the issuance of new senior notes. In addition to the repayment of the revolving credit facility, we paid $9.4 million in principal payments on our senior notes and we paid distributions to our partners of $75.2 million. During the year ended December 31, 2004, results include $200.4 million in net proceeds from our equity offering in March 2004, a $2.1 million capital contribution from our general partner to maintain its 2% general partner interest, as well as $75.5 million in proceeds from borrowings on our credit facility. We used $102.5 million of the net proceeds from the equity offering to pay the outstanding balance on our credit facility and $100.1 million to redeem 2.6 million common units owned by Arch Coal. We also paid $9.4 million in principal payments on our senior notes along with distributions to our partners totaling $60.4 million. Cash provided by financing activities for the year ended December 31, 2003 was $94.5 million. During 2003, we received proceeds from borrowings of $317.1 million, which includes $142.1 million under our revolving credit facility and $175.0 million from the issuance of our senior unsecured notes. These borrowings were partially offset by repayments of debt on our revolving credit facility of $172.6 million. We paid $0.9 million to settle an interest rate hedge entered into in connection with issuance of our senior notes and $2.5 million for debt issuance costs. During 2003, we also paid cash distributions of $46.5 million to our partners.

Contractual Obligations and Commercial Commitments

At December 31, 2005, our debt consisted of:

- $25 million outstanding under our $175 million revolving credit facility that matures in October 2010;
- $53.4 million of 5.55% senior notes due 2023, with a 10-year average life;
- $67.9 million of 4.91% senior notes due 2018, with a 7.5-year average life;
- $35 million of 5.55% senior notes due 2013, with a 9-year average life; and
- $50 million of 5.05% senior notes due 2020, with a 9-year average life.

The $50 million of 5.05% senior notes due 2020 were issued on July 19, 2005. The proceeds from the issuance of these senior notes were used to repay borrowings under the revolving credit facility. We issued an additional $50 million of senior notes in January 2006. We used the proceeds of the issuance to fund the second phase of the Williamson Development acquisition for $35 million and used the excess cash to repay borrowings under our revolving credit facility.

In November 2005, we completed an extension of our $175 million revolving credit facility for an additional year and improved its pricing. We retained the option to increase the limit up to $300 million. The amendment extends the term of the credit facility by one year to 2010 with two separate options to extend for one additional year each. The amendment also lowers the borrowing costs and commitment fees.

Our obligations under the new 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 1.00% or the prime rate as announced by the agent bank; or
- at a rate equal to LIBOR plus an applicable margin ranging from .75% to 2.00%.

We incur a commitment fee on the unused portion of the revolving credit facility at a rate ranging from 0.15% to 0.40% per annum.

The credit agreement contains covenants requiring us to maintain:

- a ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the credit agreement) 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, 2005 (in millions):

	Payments Due by Period(1)						
Contractual Obligations	**Total**	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**
Long-term debt (including current maturities)	$ 360.36	$ 21.14	$ 21.92	$ 29.13	$ 28.26	$ 27.39	$ 232.52

(1) The amounts indicated in the table include principal and interest due on our senior notes.

Shelf Registration

On December 23, 2003, we and our operating subsidiaries jointly filed a $500 million universal shelf registration statement with the Securities and Exchange Commission for the proposed sale of debt and equity securities. Securities issued under this registration statement may be in the form of common units representing limited partner interests in Natural Resource Partners or debt securities of NRP or any of our operating subsidiaries. The registration statement also covers, for possible future sales, up to 673,715 common units held by Great Northern Properties Limited Partnership. In November 2004, Great Northern Properties sold 300,000 common units in a private placement.

Approximately $290.2 million is available under our shelf registration statement. The securities may be offered from time to time directly or through underwriters at amounts, prices, interest rates and other terms to be determined at the time of any offering. The net proceeds from the sale of securities from the shelf will be used for future acquisitions and other general corporate purposes, including the retirement of existing debt. We did not and will not receive any proceeds from the sale of common units by Great Northern Properties.

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, 2003, 2004 and 2005.

Environmental

The operations our lessees conduct on our properties are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. As an owner of surface interests in some properties, we may be liable for certain environmental conditions occurring at 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, 2005. 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 our lessees reclamation obligations. We were also indemnified by Western Pocahontas Properties Limited Partnership, Great Northern Properties Limited Partnership, New Gauley Coal Corporation and Arch Coal, Inc., jointly and severally, until October 17, 2005 against environmental and tax liabilities attributable to the ownership and operation of the assets contributed to us prior to the closing of the initial public offering. During 2005, we notified Western Pocahontas Properties Limited Partnership that we had been named in the pending flood litigation in West Virginia and were reserving our rights under the indemnity. In February 2006, we were dismissed from this litigation and we expect no further claims against the indemnity. The environmental indemnity is limited to a maximum of $10.0 million.

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 as discussed below:

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. In previous years, a large portion of these sales were under long term contracts. 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. We estimate that 80% of our coal is sold by our lessees under coal supply contracts that have 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 revolving credit facility, which are subject to variable interest rates based upon LIBOR or the federal funds rate plus an applicable margin. Management intends to monitor interest rates and may enter into interest rate instruments to protect against increased borrowing costs. At December 31, 2005, we had $25 million outstanding in variable interest debt. If interest rates were to increase by 100 basis points, annual interest expense would increase $250,000, assuming the same principal amount remained outstanding during the year.

Table of Contents

Item 8. *Financial Statements and Supplementary Data*

INDEX TO FINANCIAL STATEMENTS

Table of Contents

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, 2005 and 2004, and the related consolidated statements of income, partners capital and cash flows for each of the three years in the period ended December 31, 2005. 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 also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Natural Resource Partners L.P. at December 31, 2005 and 2004, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, 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), the effectiveness of Natural Resource Partners L.P. s internal control over financial reporting as of December 31, 2005, 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 23, 2006 expressed an unqualified opinion thereon.

Ernst & Young LLP

Houston, Texas
February 23, 2006

Table of Contents

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2004
	(In thousands, except for unit information)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 47,691	$ 42,103
Accounts receivable	21,946	15,058
Accounts receivable affiliate	6	25
Other	833	786
Total current assets	70,476	57,972
Land	14,123	13,721
Plant and equipment, net	5,924	
Coal and other mineral rights, net	590,459	523,844
Loan financing costs, net	2,431	1,837
Other assets, net	1,583	2,552
Total assets	$ 684,996	$ 599,926
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable	$ 677	$ 576
Accounts payable affiliate	88	105
Current portion of long-term debt	9,350	9,350
Accrued incentive plan expenses current portion	1,105	1,559
Property, franchise and other taxes payable	4,138	3,460
Accrued interest	1,534	266
Total current liabilities	16,892	15,316
Deferred revenue	14,851	15,847
Accrued incentive plan expenses	5,395	3,271
Long-term debt	221,950	156,300
Partners capital:		
Common units (outstanding: 16,825,307 in 2005, 13,986,906 in 2004)	292,990	243,814
Subordinated units (outstanding: 8,515,228 in 2005, 11,353,658 in 2004)	123,114	157,324
General partner s interest	10,024	8,802
Holders of incentive distribution rights	582	105
Accumulated other comprehensive loss	(802)	(853)
Total partners capital	425,908	409,192

Total liabilities and partners capital	$	684,996	$	599,926

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

Table of Contents

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31, 2005	2004	2003
	(In thousands, except per unit data)		
Revenues:			
Coal royalties	$ 142,137	$ 106,456	$ 73,770
Property taxes	6,516	5,349	5,069
Minimums recognized as revenue	1,709	1,763	2,033
Override royalties	2,144	3,222	1,022
Other	6,547	4,642	3,572
Total revenues	159,053	121,432	85,466
Operating costs and expenses:			
Depreciation, depletion and amortization	33,730	30,077	24,483
General and administrative	12,319	11,503	8,923
Property, franchise and other taxes	8,142	6,835	5,810
Coal royalty and override payments	3,392	2,045	1,299
Total operating costs and expenses	57,583	50,460	40,515
Income from operations	101,470	70,972	44,951
Other income (expense) Interest expense	(11,044)	(11,192)	(7,696)
Interest income	1,413	349	206
Loss from sale of oil and gas properties			(55)
Loss from interest rate hedge			(499)
Loss on early extinguishment of debt		(1,135)	
Net income	$ 91,839	$ 58,994	$ 36,907
Net income attributable to:(1)			
General partner	$ 4,491	$ 1,705	$ 738
Holders of incentive distribution rights	$ 1,429	$ 281	
Limited partners	$ 85,919	$ 57,008	$ 36,169
Basic and diluted net income per limited partner unit:			
Common	$ 3.39	$ 2.29	$ 1.59
Subordinated	$ 3.39	$ 2.29	$ 1.59
Weighted average number of units outstanding:			
Common	14,345	13,447	11,354

Subordinated	10,996	11,354	11,354

(1) Net Income is allocated among the limited partners, the general partner and holders of the incentive distribution rights (IDRs) based upon their pro rata share of distributions. The IDRs are allocated 65% to the general partner and the remaining 35% to affiliates of the general partner. The IDRs allocated to the general partner are included in the net income attributable to the general partner.

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

Table of Contents

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)					
alance at December 31, 2002	11,353,658	$ 148,646	11,353,658	$ 163,322	$ 6,666			$ 318,634
istributions to nitholders		(22,774)		(22,774)	(930)			(46,478
et income for the year nded December 31, 003		18,084		18,085	738			36,907
oss on interest hedge, et							(905)	(905
omprehensive income							(905)	36,002
alance at December 31, 2003	11,353,658	$ 143,956	11,353,658	$ 158,633	$ 6,474	$	$ (905)	$ 308,158
ssuance of units to the ublic, net of offering nd other costs	5,250,000	200,355						200,355
edemption of common nits, net	(2,616,752)	(100,121)						(100,121
dditional contribution y the General Partner					2,147			2,147
istributions to nitholders		(31,730)		(26,963)	(1,524)	(176)		(60,393
et income for the year nded December 31, 004		31,354		25,654	1,705	281		58,994
oss on interest hedge							52	52
omprehensive income							52	59,046
alance at December 31, 2004	13,986,906	$ 243,814	11,353,658	$ 157,324	$ 8,802	$ 105	$ (853)	$ 409,192
	2,838,430	39,873	(2,838,430)	(39,873)				

ubordinated units onverted to common edemption of ractional units upon onversion of ubordinated units	(29)	(1)						(1
istributions to nitholders		(39,162)		(31,790)	(3,269)	(952)		(75,173
et income for the year nded December 31, 005		48,466		37,453	4,491	1,429		91,839
oss on interest hedge							51	51
omprehensive income							51	91,890
alance at ecember 31, 2005	16,825,307	$ 292,990	8,515,228	$ 123,114	$ 10,024	$ 582	$ (802)	$ 425,908

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,		
	2005	2004	2003
	(In thousands)		
Cash flows from operating activities:			
Net income	$ 91,839	$ 58,994	$ 36,907
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	33,730	30,077	24,483
Non-cash interest charge	318	932	908
Loss on early extinguishment of debt		1,135	
Loss on sale of oil and gas properties			55
Change in operating assets and liabilities:			
Accounts receivable	(6,869)	(4,093)	(1,947)
Other assets	(47)	236	(811)
Accounts payable and accrued liabilities	84	(47)	(674)
Accrued interest	1,268	(415)	481
Deferred revenue	(996)	793	1,802
Accrued incentive plan expenses	1,670	2,574	2,256
Property, franchise and other taxes payable	678	661	1,068
Net cash provided by operating activities	121,675	90,847	64,528
Cash flows from investing activities:			
Acquisition of coal and other mineral rights	(99,683)	(77,733)	(142,541)
Acquisition of plant and equipment	(6,019)		
Proceeds from sale of oil and gas properties			30
Net cash used in investing activities	(105,702)	(77,733)	(142,511)
Cash flows from financing activities:			
Proceeds from loans	125,000	75,500	317,100
Deferred financing costs	(861)	(969)	(2,541)
Repayment of loans	(59,350)	(111,850)	(172,600)
Distributions to partners	(75,173)	(60,393)	(46,478)
Contributions by general partner		2,147	
Proceeds from sale of 5,250,000 common units, net of transaction costs		200,355	
Redemption of 2,616,752 common units, net		(100,121)	
Settlement of hedge included in accumulated other comprehensive loss			(931)
Redemption of fractional units upon conversion of subordinated units	(1)		

Net cash (used in) provided by financing activities	(10,385)	4,669	94,550
Net increase in cash	5,588	17,783	16,567
Cash at beginning of period	42,103	24,320	7,753
Cash at end of period	$ 47,691	$ 42,103	$ 24,320
Supplemental cash flow information:			
Cash paid during the period for interest	$ 9,459	$ 10,603	$ 5,778

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, 2005, the Partnership owned or controlled approximately two billion tons of proven and probable coal reserves (unaudited) in eleven states. 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.

The Partnership s operations are conducted through, and our operating assets are owned by, our subsidiaries. The Partnership owns 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. Mr. Robertson is entitled to nominate all seven of the directors, three of whom must be independent directors, to the board of directors of GP Natural Resource Partners LLC.

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.

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

The Partnership considers all highly liquid short-term investments with an original maturity of three months or less to be cash equivalents.

Land, Coal and Mineral Rights

Coal mineral rights owned and leased are recorded at cost and 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.

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Plant and Equipment

Plant and equipment consists of a coal preparation plant and rail loadout facility are recorded at cost and are being depreciated on a straight-line basis over their useful life.

Asset Impairment

If facts and circumstances suggest that a long-lived 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. Historical credit losses incurred by the Partnership on receivables have not been significant.

Fair Value of Financial Instruments

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 current assets and current liabilities approximates their fair value due to their short-term nature. The fair market value of the Partnership s long-term debt was estimated to be $197.6 million and $159.1 million at December 31, 2005 and 2004, respectively, for the senior notes. The fair values of the senior notes represent management s best estimate based on other financial instruments with similar characteristics.

Since the Partnership s credit facility has variable rate debt, its fair value approximates its carrying amount. The Partnership had $25.0 million in outstanding debt under the credit facility at December 31, 2005.

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 Royalties. Coal royalty revenues are recognized on the basis of tons of coal sold by the Partnership s lessees and the corresponding revenue from those sales. Generally, the coal 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 coal they sell, subject to minimum annual or quarterly payments.

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 coal royalty 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.

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. The minimum annual payments that are recoupable are generally recoupable over certain periods. The minimum

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

payments are initially recorded as deferred revenue and recognized either when the lessee recoups the minimum payments 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. The lessees are typically 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

The Partnership is not a federal taxpaying entity, as the individual partners are responsible for reporting their pro rata share of the Partnership s federal taxable income or loss. 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.

LTIP Awards and New Accounting Standards

Statement of Financial Accounting Standards No. 123R *Accounting for Stock-Based Compensation,* revised in 2004, superseded APB No. 25. Awards under our Long Term Incentive Plan have been accounted for on the intrinsic method under the provisions of APB No. 25. FAS 123R, effective for the first quarter of 2006, requires us to recognize a cumulative effect of the accounting change at the date of adoption based on the difference between the fair value of the unvested awards and the intrinsic value recorded. Additionally, FAS 123R provides that grants after the effective date must be accounted for using the fair value method which will require us to estimate the fair value of the grant using the Black-Scholes or another method and charge the estimated fair value to expense over the service or vesting period of the grant. FAS 123R requires that the fair value be recalculated at each reporting date over the service or vesting period of the grant. Use of the fair value method as compared with the intrinsic method will not change the total expense to be reflected for a grant but it may impact the period in which expense is reflected by increasing expense in one period based upon the fair value calculation and lowering expense in a different period. The Partnership is in the process of evaluating the impact of the adoption of FAS 123R and expect to adopt it in the first quarter of 2006 using the modified prospective method.

3. Plant and Equipment

The Partnership s plant and equipment consist of the following:

	December 31, 2005	December 31, 2004
	(In thousands)	
Plant and equipment at cost	$ 6,019	$
Accumulated depreciation	95	

Net book value	$ 5,924	$

	For the Years Ended December 31,		
	2005	2004	2003
	(In thousands)		
Total depreciation expense on plant and equipment	$ 95	$	$

55

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Coal and Other Mineral Rights

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

	December 31, 2005	December 31, 2004
	(In thousands)	
Coal and other mineral rights	$ 734,242	$ 634,960
Less accumulated depletion and amortization	143,783	111,116
Net book value	$ 590,459	$ 523,844

	For the Years Ended December 31, 2005	2004	2003
	(In thousands)		
Total depletion and amortization expense on coal interests	$ 32,667	$ 29,093	$ 23,538

5. Long-Term Debt

Long-term debt consists of the following:

	December 31, 2005	December 31, 2004
	(In thousands)	
$175 million floating rate revolving credit facility, due October 2010	$ 25,000	$
5.55% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2023	53,400	56,700
4.91% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2018	67,900	73,950
5.55% senior notes, with semi-annual interest payments in June and December, maturing June 2013	35,000	35,000
5.05% senior notes, with semi-annual interest payments in January and July, with scheduled principal payments beginning July 2008, maturing in July 2020	50,000	
Total debt	231,300	165,650

Less current portion of long term debt	(9,350)	(9,350)
Long-term debt	$ 221,950	$ 156,300

Principal payments due in:

2006	$ 9,350
2007	9,350
2008	17,042
2009	17,042
2010	42,042
Thereafter	136,474
	$ 231,300

56

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Partnership s obligations under the credit facility are unsecured but are guaranteed by its operating subsidiaries. Indebtedness under the revolving credit facility bears interest, at the Partnership s option, at either:

the higher of the federal funds rate plus an applicable margin ranging from .00% to 1.00% or the prime rate as announced by the agent bank; or

at a rate equal to LIBOR plus an applicable margin ranging from 0.75% to 2.00%.

At December 31, 2005, the weighted average interest rate on the outstanding advances was 7.25%. The Partnership incurs a commitment fee on the unused portion of the revolving credit facility at a rate ranging from 0.15% to 0.40% per annum.

The credit agreement also contains covenants requiring the Partnership 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 the Partnership has 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.

The Partnership also has outstanding $206.3 million in unsecured senior notes which are guaranteed by its operating subsidiaries. Proceeds from the issuance of the senior notes were used to repay borrowings under the Partnership s revolving credit facility and for related expenses. The terms under the senior notes require that the Partnership maintain a fixed charge coverage ratio of not less than 3.50 to 1.0 and a limit on consolidated debt to consolidated EBITDA of not more than 4.0 to 1.0.

The Partnership was in compliance with all terms under its long-term debt as of December 31, 2005.

6. 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 and is allocated in the same ratio as quarterly cash distributions are made. Net income per unit attributable to limited partners is computed by dividing net income attributable to limited partners, after deducting the general partner s 2% interest and incentive distributions, by the weighted-average number of limited partnership units outstanding. Basic and diluted net income per unit attributable to limited partners are the same since the Partnership has no potentially dilutive securities outstanding.

7. Related Party Transactions

Quintana Minerals Corporation, a company controlled by Corbin J. Robertson, Jr., Chairman and CEO of GP Natural Resource Partners LLC, provided certain administrative services to the Partnership and charged it for direct costs related to the administrative services. Total expenses charged to the Partnership under this arrangement were $0.8 million, $1.1 million, and $0.8 million for the years ending December 31, 2005, 2004 and 2003, respectively. These costs are reflected in general and administrative expenses in the accompanying statements of income. At December 31, 2005 and 2004, the Partnership also had accounts payable to affiliates of $0.1 million, which includes general and administrative expense payable to Quintana Minerals Corporation.

Western Pocahontas Properties provides certain administrative services for the Partnership. Total expenses charged to the Partnership under this arrangement were $2.6 million, $2.7 million, and $2.2 million for the

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

years ending December 31, 2005, 2004 and 2003, respectfully. These costs are reflected in general and administrative expenses in the accompanying statements of income.

First Reserve Corporation

Prior to August 2005, First Reserve Corporation controlled a partnership that held 4,796,920 subordinated units. In connection with this investment, First Reserve had a contractual right to appoint two members to the Partnership s board of directors. Following the public sale of these subordinated units in 2005, First Reserve relinquished this contractual right. However, one of the two First Reserve appointees, Steve Smith, has remained on the Partnership s board. Mr. Smith is an independent director and serves on our audit committee. Alex Krueger, the other director appointed by First Reserve, resigned from the board in December 2005. Mr. Krueger is a managing director at First Reserve, which during 2005 had investments in two of the Partnership s lessees, Alpha Natural Resources and Foundation Coal Holdings. Because Mr. Krueger also served on the boards of directors of Alpha and Foundation during 2005, the Partnership s relationships with each of these companies are summarized below.

Alpha Natural Resources. The Partnership has entered into a number of coal mining leases with Alpha through a combination of new leases entered into upon its purchase of the Alpha property and through leases it had with entities that Alpha acquired.

The Alpha leases in general have terms of five to ten years with the ability to renew the leases for subsequent terms of five to ten years, until the earlier to occur of: (1) delivery of notice that the lessee will not renew the lease or (2) all mineable and merchantable coal has been mined. The leases provide for payments to the Partnership based on the higher of a percentage of the gross sales price or a fixed minimum per ton of coal sold from the properties, with minimum annual payments. Under the Alpha leases minimum royalty payments are credited against future production royalties.

Coal royalty revenues earned under these leases for the year ended December 31, 2005 totaled $20.0 million, representing 14% of the Partnership s total coal royalty revenues. If no production had taken place in 2005, minimum recoupable royalties of $4.7 million would have been payable under the leases. At December 31, 2005, the Partnership had accounts receivable outstanding of $1.5 million with Alpha Natural Resources.

The Partnership believes the production and minimum royalty rates contained in the Alpha leases are consistent with current market royalty rates.

Foundation Coal Holdings, Inc. Foundation Coal Holdings, Inc. controls the Partnership s lessee on the Kingston and Plum Creek properties in West Virginia, which contained approximately 6.7 million tons of proven and probable reserves as of December 31, 2005.

The leases have terms of five to ten years with the ability to renew the lease for subsequent terms of five years unless the lessee gives notice it will not renew the lease. The lease provides for payments to us based on the higher of a percentage of the gross sales price or a fixed minimum per ton of coal sold from the properties, with annual minimum payments. Under the leases minimum royalty payments are credited against future production royalties. The Partnership believes the production and minimum royalty rates contained in the leases are consistent with current market royalty rates.

Coal royalty revenues earned under the leases for the year ended December 31, 2005 totaled $4.6 million, representing 3% of our coal royalty revenues. If no production had taken place in 2005, minimum recoupable royalties of $260,000 would have been payable under the lease. At December 31, 2005, the Partnership had accounts receivable outstanding of $0.4 million with Foundation Coal Holdings, Inc.

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Commitments and Contingencies

Legal

The Partnership is involved, from time to time, in various other legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, the Partnership s 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 coal leases require the lessee to comply with all applicable laws and regulations, including environmental laws and regulations. Lessees post reclamation bonds assuring that reclamation will be completed as required by the relevant permit, and substantially all of the leases require the lessee to indemnify the Partnership against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. The Partnership has neither incurred, nor is aware of, any material environmental charges imposed on it related to its properties for the period ended December 31, 2005. The Partnership is not associated with any environmental contamination that may require remediation costs.

9. Major Lessees

The Partnership has three lessees that generated in excess of ten percent of total revenues for 2005. Revenues from major lessees that exceeded 10% of total revenues in any one of the last three years are as follows:

	For the Years Ended December 31,					
	2005		2004		2003	
	Revenues	Percent	Revenues	Percent	Revenues	Percent
			(Dollars in thousands)			
Lessee A	$ 18,220	11.5%	$ 13,770	11.3%	$ 9,532	11.2%
Lessee B	$ 13,452	8.5%	$ 9,542	7.9%	$ 8,774	10.3%
Lessee C	$ 2,105	1.3%	$ 10,340	8.5%	$ 8,879	10.4%
Lessee D	$ 19,966	12.6%	$ 18,705	15.4%	$ 15,102	17.7%
Lessee E	$ 17,056	10.7%	$ 9,146	7.5%	$ 1,256	1.5%

10. Incentive Plans

Prior to the Partnership s initial public offering, GP Natural Resource Partners LLC adopted the Natural Resource Partners Long-Term Incentive Plan (the Long-Term Incentive Plan) for employees and directors of GP Natural

Resource Partners LLC and 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.

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A phantom unit entitles the grantee to receive the fair market value of a common unit in cash upon vesting. The fair market value is determined by taking the average closing price over the last 20 trading days prior to the vesting date. The compensation committee may make grants under the Long-Term Incentive Plan to employees and directors containing such terms as it determines, including the period over which the phantom units will vest. Phantom units 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, the grantee s phantom units will be automatically forfeited unless and to the extent the compensation committee provides otherwise. In February 2005, the board of directors of GP Natural Resource Partners LLC granted to directors and key employees 57,696 additional phantom units that vest in February 2009. There were 211,931 phantom units outstanding at December 31, 2005.

GP Natural Resource Partners LLC adopted the Natural Resource Partners Annual Incentive Compensation Plan (the Annual Incentive Plan) in October 2002. The Annual Incentive Plan is designed to enhance the performance of GP Natural Resource Partners LLC s and its affiliates key employees by rewarding them with cash awards for achieving annual financial and operational performance objectives. The compensation committee in its discretion may determine individual participants and payments, if any, for each year. The board of directors of GP Natural Resource Partners LLC may amend or change the Annual Incentive Plan at any time. The Partnership reimburses GP Natural Resource Partners LLC for payments and costs incurred under the Annual Incentive Plan.

The Partnership accrued expenses to be reimbursed to its general partner of $3.0 million, $3.5 million and $2.2 million for the years ended December 31, 2005, 2004 and 2003 related to these plans. In connection with the Long-Term Incentive Plans, cash payments of $1.3 million, $0.9 million and $0.2 million were paid for the years ended December 31, 2005, 2004 and 2003.

11. Subsequent Events

Senior Notes

On January 19, 2006, the Partnership issued an additional $50 million of senior unsecured notes in a private placement. Proceeds were used to repay $15 million of borrowings under the Partnership s existing revolving credit facility. The remainder of the proceeds were used to finance the second phase of the three-phase acquisition of interests in 144 million tons of coal reserves in the Illinois Basin from Williamson Development Company.

Acquisition

On January 20, 2006, the Partnership closed the second of three separate transactions to acquire coal reserves in the Illinois Basin from Williamson Development LLC. The second transaction for $35 million was funded with senior notes issued in a private placement.

Distributions

On February 14, 2006, the Partnership paid a quarterly distribution of $0.7625 per unit to all holders of common and subordinated units. The distribution represented a $0.025 per unit increase over the previous quarter.

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Supplemental Financial Data

Selected Quarterly Financial Information

2005	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Unaudited) (In thousands, except per unit data)			
Total revenues	$ 36,247	$ 41,697	$ 38,735	$ 42,374
Operating income	22,673	27,211	23,962	27,624
Net income	$ 20,447	$ 24,972	$ 21,465	$ 24,955
Basic and diluted net income per limited partner unit:				
Common	$ 0.77	$ 0.92	$ 0.79	$ 0.91
Subordinated	$ 0.77	$ 0.92	$ 0.79	$ 0.91
Weighted average number of units outstanding, Basic and diluted:				
Common	13,987	13,987	13,987	15,407
Subordinated	11,354	11,354	11,354	9,934

2004	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues	$ 26,362	$ 29,497	$ 34,221	$ 31,352
Operating income	14,537	17,751	21,984	16,700
Net income	$ 11,174	$ 15,128	$ 19,368	$ 13,324
Basic and diluted net income per limited partner unit:				
Common	$ 0.47	$ 0.58	$ 0.74	$ 0.50
Subordinated	$ 0.47	$ 0.58	$ 0.74	$ 0.50
Weighted average number of units outstanding, Basic and diluted:				
Common	11,816	13,987	13,987	13,987
Subordinated	11,354	11,354	11,354	11,354

2003	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues	$ 18,070	$ 21,839	$ 23,539	$ 22,018
Operating income	8,501	11,973	12,833	11,644
Net income	$ 7,973	$ 10,183	$ 10,112	$ 8,639

Basic and diluted net income per limited partner unit:				
Common	$ 0.34	$ 0.44	$ 0.44	$ 0.37
Subordinated	$ 0.34	$ 0.44	$ 0.44	$ 0.37
Weighted average number of units outstanding, Basic and diluted:				
Common	11,354	11,354	11,354	11,354
Subordinated	11,354	11,354	11,354	11,354

Table of Contents

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, 2005. 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 disclosure.

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 our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2005 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, 2005.

Management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included below in this Item 9A.

Attestation Report of Independent Registered Public Accounting Firm

The Partners of Natural Resource Partners L.P.

We have audited management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting, that Natural Resource Partners L.P. maintained effective internal control over financial reporting as of December 31, 2005, 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. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of 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, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, 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, management s assessment that Natural Resource Partners L.P. maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Natural Resource Partners L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, 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, 2005 and 2004, and the related consolidated statements of income, partners capital equity, and cash flows for each of the three years in the period ended December 31, 2005 and our report dated February 23, 2006, expressed an unqualified opinion thereon.

Ernst & Young LLP

Houston, Texas
February 23, 2006

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

None.

PART III

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

As a master limited partnership we do not employ any of the people responsible for the management of our properties. Instead, we reimburse our managing general partner, GP Natural Resource Partners LLC, for its services. All directors and officers are elected by our managing general partner. 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.

Name	Age	Position with the General Partner
Corbin J. Robertson, Jr.	58	Chairman of the Board and Chief Executive Officer
Nick Carter	59	President and Chief Operating Officer
Dwight L. Dunlap	52	Chief Financial Officer and Treasurer
Kevin F. Wall	49	Vice President and Chief Engineer
Kathy E. Hager	54	Vice President Investor Relations
Wyatt L. Hogan	34	Vice President, General Counsel and Secretary
Kevin J. Craig	37	Vice President, Business Development
Kenneth Hudson	51	Controller
Robert T. Blakely	64	Director
David M. Carmichael	67	Director
Robert B. Karn III	64	Director
S. Reed Morian	59	Director
W. W. Scott, Jr.	60	Director
Stephen P. Smith	45	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 Chairman of the Board of Quintana Maritime Limited, the Baylor College of Medicine and of the Cullen Trust for Higher Education and on the boards of the American Petroleum Institute, the National Petroleum Council, the Texas Medical Center and the World Health and Golf Association.

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.

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 Vice President and Chief Engineer of GP Natural Resource Partners LLC. Mr. Wall has served as Vice President Engineering for 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 and is a past president of the West Virginia Society of Professional Engineers.

Kathy E. Hager is Vice President Investor Relations of GP Natural Resource Partners LLC. Ms. Hager 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. Hager has served on the local board of directors of the National Investor Relations Institute and has 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.

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. 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.

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 and 2004. 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.

Robert T. Blakely joined the Board of Directors of GP Natural Resource Partners LLC in January 2003. He currently serves as Executive Vice President and Chief Financial Officer of Fannie Mae. From mid-2003 through January 2006, he was Executive Vice President and Chief Financial Officer of MCI, Inc. From mid-2002 through mid-2003, he served 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 previously served as Executive Vice President and Chief Financial Officer of Lyondell Chemical from 1999 through 2002, Executive Vice President and Chief Financial Officer of Tenneco, Inc. from 1981 until 1999 as well as a Managing Director at Morgan Stanley. He served a four-year term on the Financial Accounting Standards Advisory Council and currently serves as a trustee of Cornell University, where he serves as a member of the Executive Committee of the Board. 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 and Tom Brown, Inc. from 1997 until 2004. He also currently serves as a trustee of the Texas Heart Institute.

Table of Contents

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 has worked for Dixie Chemical Company since 1971 and has served as its Chairman and Chief Executive Officer since 1981. 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 is the Senior Vice President and Treasurer of American Electric Power Company, Inc. 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.

Board Attendance and Executive Sessions

The Board of Directors met eight times in 2005. During that period, each director attended 80% or more of the aggregate number of meetings of the Board and the committees on which he served, and average attendance was 96%. Pursuant to our Corporate Governance Guidelines, the non-management directors meet in executive session at least quarterly. In addition, if the Board of Directors determines that any non-management directors are not independent under criteria established by the New York Stock Exchange, an executive session comprised solely of independent directors will be held at least once a year. During 2005, our non-management directors met in executive session four times. The presiding director of these meetings was rotated among the four independent directors on the Board.

Independence of Directors

The Board of Directors has determined that Messrs. Blakely, Carmichael, Karn and Smith are independent under the standards set forth in Section 303.01(B)(2)(a) and (3) of the New York Stock Exchange s listing standards and under Item 7(d)(3)(iv) of Schedule 14A under the Securities Exchange Act of 1934. Although we have a majority of independent directors, 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

66

directors, please write to: Chairman of the Audit Committee, NRP Board of Directors, 601 Jefferson Street, Suite 3600, Houston, TX 77002. The Board has three committees staffed solely by independent directors.

Audit Committee:

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

* Determined to be Audit Committee Financial Experts pursuant to Item 401(h) of Regulation S-K.

Compensation, Nominating and Governance Committee:

David M. Carmichael	Chairman
Robert T. Blakely	Member
Robert B. Karn, III	Member

Conflicts Committee:

Robert T. Blakely	Chairman
David M. Carmichael	Member
Robert B. Karn, III	Member

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 2005, 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 recommended to the Board of Directors the engagement of Ernst & Young LLP as our independent auditors for the year ended December 31, 2005 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 under Statement on Auditing Standards No. 61, as amended by Statement on Auditing Standards No. 90 (communications 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 3600T of the Public Company Accounting Oversight Board, which has adopted on an interim basis Independence Standards Board Standard No. 1 (independence discussions with audit committees), and considered with the auditors whether the provision of non-audit services provided by them to the partnership during 2005 was compatible with the auditors independence.

Table of Contents

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 2005, 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 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, 2005, for filing with the Securities and Exchange Commission.

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

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 2005, with the exception of Mr. Robertson, who 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, including our Chief Executive Officer, Chief Financial Officer and Controller, and that 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 2005, 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.

Table of Contents

Item 11. ***Executive Compensation***

We have no executive officers, but we reimburse affiliates of the general partner for compensation paid to the general partners executive officers in connection with managing us. The following table sets forth amounts reimbursed to affiliates of our general partner for compensation expense in 2003, 2004 and 2005.

Summary Compensation Table

Name and Principal Position	Year	Salary	Bonus	Other Annual Compensation(1)	LTIP Payouts
Corbin J. Robertson, Jr., Chairman of the Board and CEO	2005	$	$	$ 24,000	$ 215,546
	2004			5,000	145,213
	2003				
Nick Carter, President and Chief Operating Officer	2005	$ 252,200	$ 180,000	$ 58,872	$ 107,803
	2004	242,500	180,000	37,866	72,613
	2003	232,800	140,000	33,626	
Dwight L. Dunlap, Chief Financial Officer and Treasurer	2005	$ 167,270	$ 80,000	$ 45,888	$ 67,244
	2004	160,240	75,000	29,641	45,289
	2003	148,500	50,000	24,998	
Kevin F. Wall, Vice President and Chief Engineer	2005	$ 123,500	$ 70,000	$ 36,661	$ 49,434
	2004	118,750	60,000	25,649	33,304
	2003	114,000	50,000	22,040	
Kenneth Hudson, Controller	2005	$ 102,600	$ 64,000	$ 26,567	$ 40,558
	2004	98,800	54,000	15,679	27,324
	2003	95,000	45,000	12,191	

(1) 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. Also includes cash compensation paid by the general partner to each named executive officer. The general partner may distribute to the executive officers up to 7.5% of any cash it receives with respect to its incentive distribution rights. We do not reimburse the general partner for any of the payments with respect to the incentive distribution rights.

Corbin J. Robertson Jr., Chairman of the Board and CEO, did not receive any salary, bonus or other compensation during 2005, 2004 or 2003, except for his LTIP payments and incentive distribution rights from the General Partner.

Compensation of Directors

Each non-employee director receives an annual retainer of $20,000, payable quarterly, plus $1,000 for attending board and committee meetings. In addition, the Chairman of the Audit Committee receives $6,000 annually and the Chairmen of the Conflicts and Compensation, Nominating and Governance Committees receive $2,000 annually. In February 2005, each of the non-employee directors received a grant of 1,350 phantom units, which will vest in February 2009. On October 18, 2005, upon the vesting of a portion of their phantom units granted in 2003, Messrs. Carmichael, Karn, Scott, Morian, Smith and Krueger each received a cash payment of $83,150, representing the market value of their vested phantom units. On January 23, 2006, Mr. Blakely received a cash payment of $72,884 upon the vesting of a portion of his phantom units.

Long-Term Incentive Plan

Prior to our initial public offering, GP Natural Resource Partners LLC adopted the Natural Resource Partners Long-Term Incentive Plan for employees and directors of GP Natural Resource Partners LLC and its affiliates who perform services for us. 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.

A phantom unit entitles the grantee to receive the fair market value in cash of a common unit upon the vesting of the phantom unit. The fair market value is determined by the average closing price of the common units over the 20 trading days prior to vesting. The compensation committee may make grants under the Long-Term Incentive Plan to employees and directors containing such terms as the compensation committee determines. The compensation committee will determine the period over which the phantom units granted to employees and directors will vest. In addition, the phantom units will 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, the grantee s phantom units will be automatically forfeited unless and to the extent the compensation committee provides otherwise. The following table shows the vesting schedule for the outstanding phantom units that have been awarded to our named executive officers and members of our board of directors.

Long-Term Incentive Plan Phantom Units Vesting in:(1)

	2006	2007	2008	2009	2010
Directors					
Corbin J. Robertson, Jr.	3,667	23,525	8,840	10,000	10,000
Robert Blakely	1,358	1,350	1,350	1,350	1,350
David Carmichael		1,350	1,350	1,350	1,350
Bob Karn		1,350	1,350	1,350	1,350
S. Reed Morian		1,350	1,350	1,350	1,350
Stephen Smith		1,350	1,350	1,350	1,350
W. W. Scott, Jr.		1,350	1,350	1,350	1,350
Named Executive Officers					
Nick Carter	1,833	11,762	4,420	5,000	5,000
Dwight L. Dunlap	1,143	7,337	3,120	3,500	3,500
Kevin F. Wall	841	5,396	2,340	2,500	2,600
Kenneth Hudson	690	4,426	1,820	2,000	2,100

(1) The number of units granted is not subject to minimum thresholds, targets or maximum payout conditions.

Annual Incentive Plan

The general partner also adopted the Natural Resource Partners Annual Incentive Compensation Plan in October 2002. The annual incentive plan is designed to enhance the performance of GP Natural Resource Partners LLC and its affiliates key employees by rewarding them with cash awards for achieving annual financial and operational performance objectives. The compensation committee in its discretion may determine individual participants and payments, if any, for each fiscal year. The board of directors of GP Natural Resource Partners LLC may amend or change the annual incentive plan at any time. We reimburse GP Natural Resource Partners LLC for payments and costs incurred under the plan.

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

The following table sets forth, as of February 27, 2006 the amount and percentage of our common and subordinated units beneficially held by (1) each person known to us to beneficially own 5% or more of the

Table of Contents

stock, (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)	Subordinated Units	Percentage of Subordinated Units(1)	Percentage of Total Units
Corbin J. Robertson, Jr.(3)	4,799,270	28.5%	4,080,504	47.9%	35.0%
Western Pocahontas Properties Limited Partnership (4) (5)	4,466,107	26.5%	3,923,824	46.1%	33.1%
Great Northern Properties Partnership(5)	652,731	3.9%	837,048	9.8%	5.9%
Neuberger Berman Inc.(6)			558,249	6.6%	2.2%
Nick Carter	5,398				
Dwight L. Dunlap	4,000				
Kevin F. Wall	500				
Kathy E. Hager	4,377				
Wyatt L. Hogan(7)	500				
Kenneth Hudson	500				
Kevin J. Craig					
Robert T. Blakely					
David M. Carmichael	5,000				
Robert B. Karn III	2,500				
S. Reed Morian	10,000				
W. W. Scott, Jr.	5,310				
Stephen P. Smith					
Directors and Officers as a Group	4,837,355	28.8%	4,080,504	47.9%	35.2%

* Less than one percent.

(1) Based upon 16,825,307 common units issued and outstanding. Unless otherwise noted, beneficial ownership is less than 1%.

(2) Based upon 8,515,228 subordinated units issued and outstanding. Unless otherwise noted, beneficial ownership is less than 1%.

(3) Mr. Robertson may be deemed to beneficially own the 4,466,107 common units and 3,923,824 subordinated units owned by Western Pocahontas Properties Limited Partnership, and 178,333 common units and 156,680 subordinated units owned by New Gauley Coal Corporation. Also included are 69,530 common units held by William K. Robertson 1992 Management Trust and 69,530 units held by Frances C. Robertson 1992 Management Trust, both of which Mr. Robertson is the trustee, and has voting control, but not direct ownership. Also included are 15,770 common units held by Barbara Robertson, Mr. Robertson s spouse. Mr. Robertson s address is 601 Jefferson Street, Suite 3600, Houston, Texas 77002.

(4) These units may be deemed to be beneficially owned by Mr. Robertson.

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

(6) Includes 456,579 subordinated units over which Neuberger Berman has sole voting and shared dispositive power and 101,670 subordinated units that are for individual client accounts and over which Neuberger Berman has shared dispositive power but no voting power. The address of Neuberger Berman Inc. is 605 Third Avenue, New York, NY 10158.

(7) Of these common units, 250 common units are owned by the Anna Margaret Hogan 2002 Trust and 250 common units are owned by the Alice Elizabeth Hogan 2002 Trust. Mr. Hogan is a trustee of each of these trusts.

Table of Contents

Item 13. *Certain Relationships and Related Transactions*

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, as holders of all of the subordinated units, 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 $0.7625 on all of our outstanding units for four quarters, our general partner would receive distributions of approximately $1.7 million on its 2% general partner interest and our affiliates would receive distributions of approximately $16.2 million on their common units and $15.0 million on their subordinated units. In addition, our general partner and affiliates of our general partner would receive an aggregate of approximately $4.7 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

Table of Contents

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.

Indemnification

Under the omnibus agreement, the WPP Group and Arch Coal, jointly and severally, agreed to indemnify us for (1) three years after the closing of the initial public offering against environmental liabilities associated with the properties contributed to us and occurring before the closing date of the initial public offering and (2) all tax liabilities attributable to the ownership or operation of the partnership assets prior to the closing of the initial public offering. The environmental indemnity will be limited to a maximum amount of $10.0 million. Liabilities resulting from a change in law after the closing of the offering are excluded from the environmental indemnity. Prior to the expiration of the indemnity in October 2005, we delivered a notice to Western Pocahontas Properties Limited Partnership reserving our rights under the indemnity with respect to the pending flood litigation in West Virginia.

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.

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 and its 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.

Table of Contents

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 or accelerate the right to convert subordinated units.

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 any subordinated units held by our general partner or the incentive distribution rights; or
- hastening the expiration of the subordination period.

For example, in the event we have not generated sufficient cash from our operations to pay the minimum quarterly distribution on our common units and subordinated 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, its affiliates and the employees of our subsidiaries. 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.

Table of Contents

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 and in the omnibus agreement, affiliates of our general partner will not be prohibited from engaging in activities in which they compete directly with us. Please read Omnibus Agreement.

Item 14. ***Principal Accountant Fees and Services***

The Audit Committee of the Board of Directors of GP Natural Resource Partners LLC recommended and we engaged Ernst & Young LLP to audit our accounts and assist with tax work for fiscal 2005 and 2004. Fees (including out-of-pocket costs) incurred from Ernst & Young LLP for services for fiscal years 2005 and 2004 totaled $0.7 million and $0.7 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:

	2005	**2004**
Audit Fees (1)	$ 403,633	$ 454,811
Audit-Related Fees		
Tax Fees (2)	274,840	244,694
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. Audit fees also include $88,200 of fees related to FRC-WPP NRP Investment L.P. s sale of subordinated units in a public offering in August 2005. FRC-WPP NRP Investment L.P. paid the fee to Ernst & Young out of the proceeds of the sale. We did not incur any of the fees or expenses associated with the sale.

(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.

Table of Contents

The SEC s rules establish two different approaches to pre-approving services, which the SEC considers to be equally valid. Proposed services may either be pre-approved without consideration of specific case-by-case services by the Audit Committee (general pre-approval) or require the specific pre-approval of the Audit Committee (specific pre-approval). The Audit Committee believes that the combination of these two approaches in this Policy will result in an effective and efficient procedure to pre-approve services performed by the independent auditor. As set forth in this Policy, unless a type of service has received general pre-approval, it will require specific pre-approval by the Audit Committee if it is to be provided by the independent auditor. Any proposed services exceeding pre-approved cost levels or budgeted amounts will also require specific pre-approval by the Audit Committee.

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

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

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

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

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

II. Delegation

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

III. Audit Services

The annual Audit services engagement terms and fees will be subject to the specific pre-approval of the Audit Committee. Audit services include the annual financial statement audit (including required quarterly reviews), subsidiary audits, 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.

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.

Table of Contents

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
3.1	Second Amended and Restated Agreement of Limited Partnership of NRP (GP) LP, dated as of December 22, 2003 (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-3, dated December 23, 2003, File No. 333-111532).
3.2	Third Amended and Restated Limited Liability Company Agreement of GP Natural Resource Partners LLC, dated as of December 22, 2003 (incorporated by reference to Exhibit 3.2 to the Registration Statement on Form S-3, dated December 23, 2003, File No. 333-111532).
4.1	First Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of October 17, 2002 (incorporated by reference to Exhibit 3.2 of the Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-31465).
4.2	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of December 8, 2003 (incorporated by reference to Exhibit 4.2 to the Registration Statement on Form S-3, dated December 23, 2003, File No. 333-111532).
4.3	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of August 2, 2005 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on August 3, 2005).
4.4	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of August 2, 2005 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on October 20, 2005).
4.5	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).
4.6	Form of Indenture of Natural Resource Partners L.P. (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-3, dated December 23, 2003, File No. 333-111532).
4.7	Form of Indenture of NRP (Operating) LLC (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-3, dated December 23, 2003, File No. 333-111532).
4.8	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).
4.9	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).
4.10	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).
4.11	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).
4.12	Form of Series A Note (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed June 23, 2003).
4.13	Form of Series B Note (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed June 23, 2003).
4.14	Form of Series C Note (incorporated by reference to Exhibit 4.4 to the Current Report on Form 8-K filed June 23, 2003).

Exhibit Number	Description
4.15	Investor Rights Agreement, dated as of December 22, 2003, among FRC-WPP NRP Investment L.P., Natural Resource Partners L.P., NRP (GP) LP and GP Natural Resource Partners LLC (incorporated by reference to Exhibit 4.13 to the Registration Statement on Form S-3, dated December 23, 2003, File No. 333-111532).
4.16	Amendment No. 1 to Investor Rights Agreement, dated June 24, 2005, by and among FRC-WPP NRP Investment L.P., Natural Resource Partners L.P., NRP (GP) LP and GP Natural Resource Partners LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on June 28, 2005).
10.1	Credit Agreement, dated as of October 29, 2004, by and among NRP (Operating) LLC, as Borrower, Citibank, N.A., as Administrative Agent, the Banks and WBRD LLC and ACIN LLC, as Guarantors (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the period ended September 30, 2004, File No. 001-31465).
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10.4	Natural Resource Partners Long-Term Incentive Plan, as amended and restated (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-31465).
10.5	First Amendment to the Natural Resource Partners Long-Term Incentive Plan dated December 8, 2003 (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-31465).
10.6	Second Amendment to the Natural Resource Partners Long-Term Incentive Plan (incorporated by reference to the Current Report on Form 8-K, filed on December 13, 2004).
10.7	Form of Phantom Unit Agreement (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the period ended September 30, 2004, File No. 001-31465).
10.8	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).
10.9	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).
10.10	Purchase and Sale Agreement dated November 6, 2002, by and among El Paso CGP Company, Coastal Coal Company, LLC, Coastal Coal West Virginia LLC, ANR Western Coal Development Company and CSTL LLC (incorporated by reference to Exhibit 10.8 to the Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-31465).
10.11	First Amendment to Purchase and Sale Agreement dated December 4, 2002 (incorporated by reference to Exhibit 10.9 to the Annual Report on Form 10-K for the year ended December 31, 2002,

	File No. 001-31465).
10.12	Purchase and Sale Agreement, dated April 9, 2003, between Alpha Land and Reserves, LLC and CSTL LLC (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the period ended June 30, 2003, File No. 001-31465).
10.13	Purchase and Sale Agreement, dated June 30, 2003, by and among PinnOak Resources, LLC, Pinnacle Land Company, LLC, Oak Grove Land Company, LLC and WPP LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed July 14, 2003).

Table of Contents

Exhibit Number	Description
10.14	Purchase and Sale Agreement by and between BLC Properties LLC and WPP LLC, dated December 22, 2003 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 5, 2004, File No. 001-31465).
10.15	Form of Coal Mining Lease between Alpha Natural Resources, LLC and WPP LLC (incorporated by reference to Exhibit 10.18 to the Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-31465).
10.18	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).
10.19*	Assignment, Waiver and Amendment Agreement, dated January 20, 2006, by and among Williamson Development Company, LLC, ACIN LLC and WPP LLC.
21.1*	List of subsidiaries of Natural Resource Partners L.P.
23.1*	Consent of Ernst & Young LLP
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

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned and thereunto duly authorized.

Natural Resource Partners L.P.
By: NRP (GP) LP, its general partner

By: GP NATURAL RESOURCE PARTNERS LLC,

its general partner

Date: February 27, 2006

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

Date: February 27, 2006

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

Date: February 27, 2006

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

Date: February 27, 2006

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

Date: February 27, 2006

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

Date: February 27, 2006

By: /s/ Robert B. Karn III
Robert B. Karn III
Director

Date: February 27, 2006

By: /s/ S. Reed Morian
S. Reed Morian
Director

Date: February 27, 2006

By: /s/ W.W. Scott,

W.W. Scott, Jr.
Director

Date: February 27, 2006

By: /s/ Stephen P. Smith
Stephen P. Smith
Director

83

Table of Contents

Exhibit Index

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3.1	Second Amended and Restated Agreement of Limited Partnership of NRP (GP) LP, dated as of December 22, 2003 (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-3, dated December 23, 2003, File No. 333-111532).
3.2	Third Amended and Restated Limited Liability Company Agreement of GP Natural Resource Partners LLC, dated as of December 22, 2003 (incorporated by reference to Exhibit 3.2 to the Registration Statement on Form S-3, dated December 23, 2003, File No. 333-111532).
4.1	First Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of October 17, 2002 (incorporated by reference to Exhibit 3.2 of the Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-31465).
4.2	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of December 8, 2003 (incorporated by reference to Exhibit 4.2 to the Registration Statement on Form S-3, dated December 23, 2003, File No. 333-111532).
4.3	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of August 2, 2005 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on August 3, 2005).
4.4	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of August 2, 2005 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on October 20, 2005).
4.5	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).
4.6	Form of Indenture of Natural Resource Partners L.P. (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-3, dated December 23, 2003, File No. 333-111532).
4.7	Form of Indenture of NRP (Operating) LLC (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-3, dated December 23, 2003, File No. 333-111532).
4.8	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).
4.9	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).
4.10	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).
4.11	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).
4.12	Form of Series A Note (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed June 23, 2003).
4.13	Form of Series B Note (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed June 23, 2003).
4.14	Form of Series C Note (incorporated by reference to Exhibit 4.4 to the Current Report on Form 8-K filed June 23, 2003).
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