NATURAL RESOURCE PARTNERS LP
Form 10-K
February 28, 2007

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, 2006

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

(713) 751-7507
(Registrant s Telephone Number, Including Area Code)

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

Title of Each Class	Name Of Each Exchange On Which Registered
Common Units representing limited partnership interests	New York Stock Exchange
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 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 Units outstanding, for this purpose, as if they were affiliates of the registrant) was approximately $649.7 million for the Common Units and $225.9 million for the Subordinated Units on June 30, 2006 based on a price of $54.20 per unit for the Common Units and $50.94 per unit for the Subordinated Units. These prices are the respective closing prices of the Units as reported on the New York Stock Exchange on that date.

As of February 27, 2007, there were 25,976,795 Common Units outstanding, 5,676,817 Subordinated Units outstanding and 541,956 Class B Units outstanding. The Class B Units are not publicly traded.

DOCUMENTS INCORPORATED BY REFERENCE.

None.

Table of Contents

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

These forward-looking statements are made based upon management s current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements.

You should not put undue reliance on any forward-looking statements. Please read Item 1A. Risk Factors for important factors that could cause our actual results of operations or our actual financial condition to differ.

PART I

Item 1. *Business*

Natural Resource Partners L.P. is a limited partnership formed in April 2002, and we completed our initial public offering in October 2002. We engage principally in the business of owning and managing coal properties in the three major coal-producing regions of the United States: Appalachia, the Illinois Basin and the Western United States. As of December 31, 2006, we owned or controlled approximately 2.1 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 minimum payments. As of December 31, 2006, our coal reserves were subject to 180 leases with 70 lessees. In 2006, our lessees produced 52.1 million tons of coal from our properties and our coal royalty revenues were $147.8 million.

In 2006 we added two new businesses: coal infrastructure and ownership of aggregate reserves that are leased to operators in exchange for royalty payments similar to our coal royalty business. Neither of these businesses currently contribute a large percentage of our total revenues, but we anticipate that we will grow these businesses in the future.

Partnership Structure and Management

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We own our subsidiaries through a wholly owned operating company, NRP (Operating) LLC. NRP (GP) LP, our general partner, has sole responsibility for conducting our business and for managing our operations. Because our general partner is a limited partnership, its general partner, GP Natural Resource Partners LLC, conducts its business and operations, and the board of directors and officers of GP Natural Resource Partners LLC makes decisions on our behalf. Robertson Coal Management LLC, a limited liability company wholly owned by Corbin J. Robertson, Jr., owns all of the membership interest in GP Natural Resource Partners LLC. Subject to the Investor Rights Agreement with Adena Minerals, LLC, Mr. Robertson is entitled to nominate nine directors, five of whom must be independent directors, to the board of directors of GP Natural Resource Partners LLC. Mr. Robertson has delegated the right to nominate two of the directors, one of whom must be independent, to Adena Minerals. Pending the appointment of an additional independent director by Adena, we currently have eight directors, four of whom are independent.

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

The senior executives and other officers who manage the WPP Group assets also manage us. They are employees of Western Pocahontas Properties and Quintana Minerals Corporation, another company controlled by Mr. Robertson, and they allocate varying percentages of their time to managing our operations. Neither our general partner, GP Natural Resource Partners LLC, nor any of their affiliates receive any management fee or other compensation in connection with the management of our business, but they are entitled to be reimbursed for all direct and indirect expenses incurred on our behalf.

Our operations headquarters are located at 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 coal mine operators granting them the right to mine and sell coal reserves from our property in exchange for a royalty payment. A typical lease has a 5- to 10-year base term, with the lessee having an option to extend the lease for additional terms. Leases often include the right to renegotiate rents and royalties for the extended term.

Under our standard lease, lessees calculate royalty and wheelage payments due us and are required to report tons of coal removed or hauled across our property as well as the sales prices of coal. Therefore, to a great extent, amounts reported as royalty and wheelage revenue are based upon the reports of our lessees. 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.

Recent Acquisitions

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

2007 Acquisitions

Dingess-Rum. On January 16, 2007, we acquired 92 million tons of coal reserves and approximately 33,700 acres of surface and timber in Logan, Clay and Nicholas Counties in West Virginia from Dingess-Rum Properties, Inc. As consideration for the acquisition, we issued 2,400,000 common units to Dingess-Rum in a private placement.

Cline. On January 4, 2007, we acquired 49 million tons of coal reserves in Williamson County, Illinois and Mason County, West Virginia that are leased to affiliates of The Cline Group. In addition, we acquired transportation assets and related infrastructure at those mines. As consideration for the transaction we issued 3,913,080 common units and 541,956 Class B units in a private placement. Through its affiliate Adena Minerals, LLC, The Cline Group has also received a 22% interest in our general partner and in the incentive distribution rights of NRP in return for providing NRP with the exclusive right to acquire additional reserves, royalty interests and certain transportation infrastructure relating to future mine developments by The Cline Group. Simultaneous with the closing of this transaction, we signed a definitive agreement to purchase the reserves and transportation infrastructure at Cline s Gatling Ohio complex. This transaction will close upon commencement of coal production, which is currently expected to occur in 2008. At the time of closing, NRP will issue Adena 2,280,000 additional Class B units, and the general partner of NRP will issue Adena an additional 9% interest in the general partner and the incentive distribution rights.

Table of Contents

2006 Acquisitions

Quadrant. On December 29, 2006, we acquired an estimated 70 million tons of aggregate reserves located in DuPont, Washington for $23.5 million in cash and assumed a utility local improvement obligation of approximately $3.0 million. Of these reserves, approximately 25 million tons are currently permitted. We will pay an additional $7.5 million when the remaining tons are permitted. If the permit is not obtained by December 2016, the unpermitted tons will revert back to Quadrant. We funded this acquisition with cash and borrowings under our credit facility.

Bluestone. On December 18, 2006, we acquired approximately 20 million tons of low vol metallurgical coal reserves that are located above our Pinnacle reserves in Wyoming County, West Virginia for $20 million. We funded this acquisition with borrowings under our credit facility.

D.D. Shepherd. On December 1, 2006, we acquired nearly 25,000 acres of land containing in excess of 80 million tons of coal reserves for $110 million. The property is located in Boone County, West Virginia adjacent to other NRP property and consists of both metallurgical and steam coal reserves, gas reserves, surface and timber. We funded this acquisition with borrowings under our credit facility.

Red Fox. On September 1, 2006, we acquired the Red Fox preparation plant and coal handling facility located in McDowell County, West Virginia for approximately $8.1 million, of which $4.1 million was paid at closing and the remainder was paid during the third and fourth quarters as construction was completed. This acquisition was the second under our memorandum of understanding with Taggart Global, LLC (formerly Sedgman USA, LLC). The plant will handle an estimated 20 million tons of coal reserves during its life. The initial $4.1 million payment paid at closing was funded through cash and borrowings under our credit facility and the remaining payments were funded with cash.

Coal Mountain. On August 24, 2006, we acquired the Coal Mountain preparation plant, handling facility and rail load-out facility located in Wyoming County, West Virginia for $16.1 million under our memorandum of understanding with Taggart Global. We expect that approximately 35 million tons of coal will be processed through this facility during its life. We paid for the facilities with cash and with borrowings under our credit facility as construction was completed in phases during the third and fourth quarters.

Williamson Development. On January 20, 2006 and August 15, 2006, we closed the second and third phases of the Williamson Development acquisition in Illinois for $35 million each. We funded the January 20, 2006 acquisition with proceeds from the issuance of senior notes and the August 15, 2006 acquisition with borrowings under our credit facility.

Allegany County, Maryland. On June 29, 2006, we acquired 3.3 million tons of coal in Allegany County, Maryland for $5.5 million in cash.

Indiana Reserves. On May 26, 2006, we acquired 16.3 million tons of coal reserves and an overriding royalty interest on an additional 2.4 million tons for $10.85 million in cash. These reserves are located in Pike, Warrick and Gibson Counties in Indiana.

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, 2006, 2005 and 2004. 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)		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
Area						
Appalachia						
Northern	$ 10,231	$ 11,306	$ 7,084	$ 1.92	$ 1.89	$ 1.70
Central	100,487	93,008	76,583	3.14	2.84	2.34
Southern	20,469	25,089	14,874	3.83	4.01	2.86
Total Appalachia	131,187	129,403	98,541	3.07	2.87	2.34
Illinois Basin	5,325	4,288	3,852	1.85	1.54	1.23
Northern Powder River Basin	11,240	8,446	4,063	1.72	1.46	1.30
Total	$ 147,752	$ 142,137	$ 106,456	$ 2.84	$ 2.65	$ 2.20

The following table sets forth production data and reserve information for the properties that we owned or controlled for the years ending December 31, 2006, 2005 and 2004. 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, 2006		
	2006	**2005**	**2004**	**Underground**	**Surface**	**Total**
	(Tons in thousands)					
Area						
Appalachia						
Northern	5,329	5,977	4,179	399,641	7,804	407,445
Central	31,991	32,790	32,702	1,138,728	107,077	1,245,804
Southern	5,347	6,263	5,208	159,660	35,987	195,647
Total Appalachia	42,667	45,030	42,089	1,698,028	150,868	1,848,896
Illinois Basin	2,877	2,781	3,138	103,819	19,194	123,013

Northern Powder River Basin	6,548	5,795	3,130		125,323	125,323
Total	52,092	53,606	48,357	1,801,848	295,384	2,097,232

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, 2006, approximately 36% of our reserves were compliance coal. Unless otherwise indicated, we present the quality of the coal throughout this Form 10-K on an as-received basis, which assumes 6% moisture for Appalachian reserves, 12% moisture for Illinois Basin reserves and 25% moisture for Northern Powder River Basin reserves. We own both steam and metallurgical coal reserves in Northern, Central and Southern Appalachia, and we own steam coal

Table of Contents

reserves in the Illinois Basin and the Northern Powder River Basin. In 2006, approximately 28% of the production and 33% of the coal royalty revenues from our properties were from metallurgical coal.

The following table sets forth our estimate of the sulfur content, the typical quality of our coal reserves and the type of coal in each area as of December 31, 2006.

Sulfur Content, Typical Quality and Type of Coal

		Sulfur Content				Typical Quality		Type of Coal	
		Low	Medium	High					
rea	**Compliance Coal(1)**	**(less than 1.0%)**	**(1.0% to 1.5%)**	**(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	25,824	329,742	407,445	13,083	2.77	397,883	9,562
entral	598,239	931,001	274,660	40,143	1,245,804	13,042	0.87	791,413	454,391
outhern	110,795	141,531	41,891	12,224	195,647	13,635	0.90	147,753	47,894
otal Appalachia	752,333	1,124,412	342,375	382,110	1,848,896			1,337,049	511,847
inois Basin		701	5,147	117,165	123,013	11,605	2.48	123,013	
orthern Powder iver Basin		125,323			125,323	8,800	0.65	125,323	
otal	752,333	1,250,436	347,522	499,274	2,097,232			1,585,385	511,847

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

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

In 2005, we engaged several independent engineering firms to conduct reserve studies of our existing properties. However, as a result of the extensive nature of our reserve holdings and the large number of acquisitions that we consummate on an annual basis, this study will be an ongoing process. As of December 31, 2006, these studies had been completed with respect to approximately 44% of the tons we owned when we began the process, and a study is currently ongoing with respect to another 20% of the initial reserves. In connection with acquisitions, we have either commissioned new studies or relied on reports done prior to the acquisition. In addition to these studies, we base our estimates of reserve information on engineering, economic and geological data assembled and analyzed by our internal geologists and engineers. There are numerous uncertainties inherent in estimating the quantities and qualities of recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves depend upon a number of variable factors and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. 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.

Table of Contents

Coal Transportation and Processing Revenues

In the second half of 2006, we acquired two preparation plants and coal handling facilities under our memorandum of understanding with Taggart Global. Together with a third coal preparation plant and rail load-out facility that we acquired in Greenbrier County, West Virginia in 2005, these facilities generated approximately $1.5 million in revenues in 2006. We do not operate the preparation plants, but receive a fee for coal processed through them.

Similar to our coal royalty structure, the throughput fees are based on a percentage of the ultimate sales price for the coal that is processed through the facilities.

In addition to our preparation plants, as part of the January 2007 Cline transaction, we acquired coal handling and transportation infrastructure associated with the Gatling mining complex in West Virginia and beltlines and rail load-out facilities associated with Williamson Energy s Pond Creek No. 1 mine in Illinois. We also entered into an agreement to purchase the transportation infrastructure as well as the reserves at Cline s Gatling Ohio complex. This complex is located in Meigs County, Ohio directly across the river from Cline s West Virginia operation. In contrast to our typical royalty structure, we are operating the coal handling and transportation infrastructure and have subcontracted out that responsibility to third parties. We anticipate that these assets will contribute significant revenues to NRP in future years.

Aggregates Royalty Revenues, Reserves and Production

In December 2006, we acquired an estimated 70 million tons of aggregate reserves located in DuPont, Washington for $23.5 million in cash and assumed a utility local improvement obligation of approximately $3.0 million. Of these reserves, approximately 25 million tons are currently permitted. We will pay an additional $7.5 million when the remaining tons are permitted, provided, however, that if they are not permitted by December 2016, the title to the remaining tons will revert back to Quadrant. The acquisition was effective as of December 1, 2006 and for the month of December we received $0.6 million in royalty revenues on 412,000 tons of production.

Oil, Gas and Timber Properties

For the year ended December 31, 2006, we derived approximately 5% of our total revenues from oil, gas and timber royalties in Kentucky, Virginia and Tennessee. The 2006 revenues include approximately $3.5 million related to the sale of substantially all of our then-existing timber properties. Subsequent to that sale we acquired approximately 24,000 acres of timber rights in the D.D. Shepard acquisition in December 2006 and another 31,000 acres of timber rights in the Dingess-Rum acquisition in January 2007. Nevertheless, we do not own the oil, gas or timber rights on the vast majority of our properties, and do not expect to receive material oil, gas or timber revenues in 2007.

Significant Customers

In 2006, Alpha Natural Resources, Inc. and its various subsidiaries, as lessees, collectively provided approximately 14% of our total revenues. Although the loss of Alpha as a lessee could have a material adverse effect on us, we do not believe that the loss of a single mine on any of our properties would have a material adverse effect on us. No other lessee contributed more than 10% of our total revenues in 2006.

Competition

We face 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 64% in 2005. 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 and Environmental Matters

General. Our lessees are obligated to conduct mining operations in compliance with all applicable federal, state and local laws and regulations. These laws and regulations include matters involving the discharge of materials into the environment, employee health and safety, mine permits and other licensing requirements, reclamation and restoration of mining properties after mining is completed, management of materials generated by mining operations, surface subsidence from underground mining, water pollution, legislatively mandated benefits for current and retired coal miners, air quality standards, protection of wetlands, plant and wildlife protection, limitations on land use, storage of petroleum products and substances which are regarded as hazardous under applicable laws and management of electrical equipment containing PCBs. Because of extensive and comprehensive regulatory requirements, violations during mining operations are not unusual in the industry and, notwithstanding compliance efforts, we do not believe violations by our lessees can be eliminated entirely. However, to our knowledge none of the violations to date, nor the monetary penalties assessed, have been material to our lessees. We do not currently expect that future compliance will have a material effect on us.

While it is not possible to quantify the costs of compliance by our lessees with all applicable federal, state and local laws and regulations, those costs have been and are expected to continue to be significant. The lessees post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. We do not accrue for such costs because our lessees are contractually liable for all costs relating to their mining operations, including the costs of reclamation and mine closure. Although the lessees typically accrue adequate amounts for these costs, their future operating results would be adversely affected if they later determined these accruals to be insufficient. Compliance with these laws and regulations has substantially increased the cost of coal mining for all domestic coal producers.

In addition, the utility industry, which is the most significant end-user of coal, is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for coal mined by our lessees. The possibility exists that new legislation or regulations may be adopted that have a significant impact on the mining operations of our lessees or their customers ability to use coal and may require our lessees or their customers to change operations significantly or incur substantial costs that could impact us.

Air Emissions. The Federal Clean Air Act and corresponding state and local laws and regulations affect all aspects of our business. The Clean Air Act directly impacts our lessees coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, on sources that emit various hazardous and non-hazardous air pollutants. The Clean Air Act also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants. There have been a series of federal rulemakings that are focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technology and additional measures required under U.S. Environmental Protection Agency (or EPA) laws and regulations will make it more costly to operate coal-fired power plants and, depending on the requirements of individual state implementation plans, could make coal a less attractive fuel alternative in the planning and building of power plants in the future. Any reduction in coal s share of power generating capacity could negatively impact our lessees ability to sell coal, which would have a material effect on our coal royalty revenues.

The EPA s Acid Rain Program, provided in Title IV of the Clean Air Act, regulates emissions of sulfur dioxide from electric generating facilities. Sulfur dioxide is a by-product of coal combustion. Affected facilities purchase or are otherwise allocated sulfur dioxide emissions allowances, which must be surrendered annually in an amount equal to a facility s sulfur dioxide emissions in that year. Affected facilities may sell or trade excess allowances to other facilities that require additional allowances to offset their sulfur dioxide emissions. In addition to purchasing or trading for additional sulfur dioxide allowances, affected power facilities can satisfy the requirements of the

Table of Contents

EPA s Acid Rain Program by switching to lower sulfur fuels, installing pollution control devices such as flue gas desulphurization systems, or scrubbers, or by reducing electricity generating levels.

The EPA has promulgated rules, referred to as the NOx SIP Call, that require coal-fired power plants and other large stationary sources in 21 eastern states and Washington D.C. to make substantial reductions in nitrogen oxide emissions in an effort to reduce the impacts of ozone transport between states. Additionally, in March 2005, the EPA issued the final Clean Air Interstate Rule (or CAIR), which will permanently cap nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. beginning in 2009 and 2010, respectively. CAIR requires these states to achieve the required emission reductions by requiring power plants to either participate in an EPA-administered cap-and-trade program that caps emission in two phases, or by meeting an individual state emissions budget through measures established by the state.

In March 2005, the EPA finalized the Clean Air Mercury Rule (or CAMR), which establishes a two-part, nationwide cap on mercury emissions from coal-fired power plants beginning in 2010. While currently the subject of extensive controversy and litigation, if fully implemented, CAMR would permit states to implement their own mercury control regulations or participate in an interstate cap-and-trade program for mercury emission allowances.

The EPA has adopted new, more stringent national air quality standards for ozone and fine particulate matter. As a result, some states will be required to amend their existing state implementation plans to attain and maintain compliance with the new air quality standards. For example, in December 2004, the EPA designated specific areas in the United States as in non-attainment with the new national ambient air quality standard for fine particulate matter. In November 2005, the EPA published proposed rules addressing how states would implement plans to bring applicable non-attainment regions into compliance with the new air quality standard. Under the EPA s proposed rulemaking, states would have until April 2008 to submit their implementation plans to the EPA for approval. Because coal mining operations and coal-fired electric generating facilities emit particulate matter, our lessees mining operations and their customers could be affected when the new standards are implemented by the applicable states.

In June 2005, the EPA announced final amendments to its regional haze program originally developed in 1999 to improve visibility in national parks and wilderness areas. As part of the new rules, affected states must develop implementation plans by December 2007 that, among other things, identify facilities that will have to reduce emissions and comply with stricter emission limitations. This program may restrict construction of new coal-fired power plants where emissions are projected to reduce visibility in protected areas. In addition, this program may require certain existing coal-fired power plants to install emissions control equipment to reduce haze-causing emissions such as sulfur dioxide, nitrogen oxide and particulate matter.

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

Carbon Dioxide Emissions. The Kyoto Protocol to the United Nations Framework Convention on Climate Change calls for developed nations to reduce their emissions of greenhouse gases to five percent below 1990 levels by 2012. Carbon dioxide, which is a major byproduct of the combustion of coal and other fossil fuels, is subject to the Kyoto Protocol. The Kyoto Protocol went into effect on February 16, 2005 for those nations that ratified the treaty.

In 2002, the United States withdrew its support for the Kyoto Protocol As the Kyoto Protocol becomes effective, there will likely be increasing international pressure on the United States to adopt mandatory restrictions on carbon dioxide emissions. The United States Congress has considered bills in the past that would regulate domestic carbon dioxide emissions, but such bills have not yet received sufficient Congressional support for passage into law. Several states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired electric generating facilities. For example, in December 2005, seven northeastern states agreed to implement a regional cap-and-trade program to stabilize carbon dioxide emissions from regional power plants beginning in 2009.

It is possible that future federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, which could negatively impact our lessees coal sales, and thereby have an adverse effect on our coal royalty revenues.

Surface Mining Control and Reclamation Act of 1977. The Surface Mining Control and Reclamation Act of 1977 (or SMCRA) and similar state statutes impose on mine operators the responsibility of reclaiming the land and compensating the landowner for types of damages occurring as a result of mining operations, and require mine operators to post performance bonds to ensure compliance with any reclamation obligations. Regulatory authorities may attempt to assign the liabilities of our coal lessees to us if any of these lessees are not financially capable of fulfilling those obligations. In conjunction with mining the property, our coal lessees are contractually obligated under the terms of our leases to comply with all state and local laws, including SMCRA, with obligations including the reclamation of the mined areas by grading, shaping and reseeding the soil. Upon completion of the mining, reclamation generally is completed by seeding with grasses or planting trees for use as pasture or timberland, as specified in the approved reclamation plan.

Hazardous Materials and Waste. The Federal Comprehensive Environmental Response, Compensation and Liability Act (or CERCLA or the Superfund law), and analogous state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources.

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

Water Discharges. Our lessees operations can result in discharges of pollutants into waters. The Clean Water Act and analogous state laws and regulations impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States. The unpermitted discharge of pollutants such as from spill or leak incidents is prohibited. The Clean Water Act and regulations implemented thereunder also prohibit discharges of fill material and certain other activities in wetlands unless authorized by an appropriately issued permit.

Our lessees mining operations are strictly regulated by the Clean Water Act, particularly with respect to the discharge of overburden and fill material into waters, including wetlands. Recent federal district court decisions in West Virginia, and related litigation filed in federal district court in Kentucky, have created uncertainty regarding the future ability to obtain certain general permits authorizing the construction of valley fills for the disposal of overburden from mining operations. A July 2004 decision by the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Bulen* enjoined the Huntington District of the U.S. Army Corps of Engineers from issuing further permits pursuant to Nationwide Permit 21, which is a general permit issued by the U.S. Army Corps of Engineers to streamline the process for obtaining permits under Section 404 of the Clean Water Act. While the decision was vacated by the Fourth Circuit Court of Appeals in November 2005, a similar lawsuit filed in federal district court in Kentucky seeks to enjoin the issuance of permits pursuant to Nationwide Permit 21 by the Louisville District of the U.S. Army Corps of Engineers. In the event that such lawsuits prove to be successful in adjoining jurisdictions, some of our lessees may be required to apply for individual discharge permits pursuant to Section 404 of the Clean Water Act in areas where they would have otherwise utilized Nationwide Permit 21. Such a change could result in delays in our lessees obtaining the required mining permits to conduct their operations, which could in turn have an adverse effect on our coal royalty revenues. Moreover, such individual permits are also subject to challenge.

The Clean Water Act also requires states to develop anti-degradation policies to ensure non-impaired waterbodies in the state do not fall below applicable water quality standards. These and other regulatory developments may restrict our lessees ability to develop new mines, or could require our lessees to modify existing operations, which could have an adverse effect on our coal royalty revenues.

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

Mine Health and Safety Laws. The operations of our lessees are subject to stringent health and safety standards that have been imposed by federal legislation since the adoption of the Mine Health and Safety Act of 1969. The Mine Health and Safety Act of 1969 resulted in increased operating costs and reduced productivity. The Mine Safety and Health Act of 1977, which significantly expanded the enforcement of health and safety standards of the Mine Health and Safety Act of 1969, imposes comprehensive health and safety standards on all mining operations. In addition, as part of the Mine Health and Safety Acts of 1969 and 1977, the Black Lung Acts require payments of benefits by all businesses conducting current mining operations to coal miners with black lung or pneumoconiosis and to some beneficiaries of miners who have died from this disease.

Recent mining accidents in West Virginia and Kentucky have received national attention and instigated responses at the state and national level that have resulted in increased scrutiny of current safety practices and procedures at all mining operations, particularly underground mining operations. In January 2006, West Virginia passed a law imposing stringent new mine safety and accident reporting requirements and increased civil and criminal penalties for violations of mine safety laws. Similarly, on April 27, 2006, Kentucky Governor Ernie Fletcher signed mine safety legislation that includes requirements for increased inspections of underground mines and additional mine safety equipment and authorizes the assessment of penalties of up to $5,000 per incident for violations of mine ventilation or roof control requirements.

On June 15, 2006 the President signed new mining safety legislation that mandates similar improvements in mine safety practices; increases civil and criminal penalties for non-compliance; requires the creation of additional mine rescue teams, and expands the scope of federal oversight, inspection and enforcement activities. Earlier, the federal Mine Safety Health Administration announced the promulgation of new emergency rules on mine safety that took effect immediately upon their publication in the Federal Register on March 9, 2006. These rules address mine safety equipment, training, and emergency reporting requirements. Implementing and complying with these new laws and regulations could adversely affect our lessees coal production and could therefore have an adverse affect on our coal royalty revenues and our ability to make distributions.

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. In connection with obtaining these permits and approvals, our lessees may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production of coal may have upon the environment. The requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators, including our lessees, must submit a reclamation plan for reclaiming the mined property, upon the completion of mining operations. Typically, our lessees submit the necessary permit applications between 12 and 24 months before they plan to begin mining a new area. In our experience, permits generally are approved within 12 months after a completed application is submitted. In the past, our lessees have generally obtained their mining permits without significant delay. Our lessees have obtained or applied for permits to mine a majority of the reserves that are

12

Table of Contents

currently planned to be mined over the next five years. Our lessees are also in the planning phase for obtaining permits for the additional reserves planned to be mined over the following five years. However, there are no assurances that they will not experience difficulty in obtaining mining permits in the future.

Employees and Labor Relations

We do not have any employees. To carry out our operations, affiliates of our general partner employ approximately 55 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

We conduct all of our operations in a single segment the ownership and leasing of mineral properties and related transportation and processing infrastructure. All of our owned properties are subject to leases, and revenues are earned based on the volume of minerals extracted, processed or transported. We consider revenues from timber and oil and gas acquired as part of the acquisition of our mineral reserves to be incidental to our business focus and those revenues constitute less than 10% of our total revenues and assets. We anticipate that these assets will continue to be incidental to our primary business in the future.

Website Access To Company Reports

Our internet address is *www.nrplp.com.* We make available free of charge on or through our internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. Also included on our website are our Code of Business Conduct and Ethics and our Corporate Governance Guidelines adopted by our Board of Directors and the charters for our Audit Committee, Conflicts Committee and Compensation, Nominating and Governance Committee. Also, copies of our annual report, our Code of Business Conduct and Ethics, our Corporate Governance Guidelines and our committee charters will be made available upon written request.

Item 1A. *Risk Factors*

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 credit 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.

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.

Table of Contents

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.

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.

According to the U.S. Department of Energy, 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. In addition, in recent years there has been significant political discussion of the connection between the emission of greenhouse gases and global warming. The environmental lobby is applying substantial pressure on utilities to limit the construction of new coal-fired generation plants in favor of alternative sources of energy. To the extent that these efforts are successful, it could reduce the demand for our coal.

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.

Table of Contents

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

Our coal royalty revenues are largely dependent on our lessees level of production from our coal reserves. The level of our lessees production is subject to operating conditions or events beyond their or our control including:

- the inability to acquire necessary permits or mining or surface rights;
- changes or variations in geologic conditions, such as the thickness of the coal deposits and the amount of rock embedded in or overlying the coal deposit;
- changes in governmental regulation of the coal industry or the electric utility industry;
- mining and processing equipment failures and unexpected maintenance problems;
- interruptions due to transportation delays;
- adverse weather and natural disasters, such as heavy rains and flooding;
- labor-related interruptions; and
- fires and explosions.

These conditions may increase our lessees cost of mining and delay or halt production at particular mines for varying lengths of time or permanently. Any interruptions to the production of coal from our reserves may reduce our coal royalty revenues.

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

Our lessees may incur substantial costs and liabilities under increasingly strict federal, state and local environmental, health and safety 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.

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;

Table of Contents

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.

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.

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 2006, approximately 28% of the coal production and 33% of the coal royalty revenues from our properties were from 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.

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

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

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

Our reserve estimates may vary substantially from the actual amounts of coal our lessees may be able to economically recover from our reserves. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. Estimates of coal reserves necessarily depend upon a number of variables and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. These factors and assumptions relate to:

- future coal prices, operating costs, capital expenditures, severance and excise taxes, and development and reclamation costs;

future mining technology improvements;

the effects of regulation by governmental agencies; and

geologic and mining conditions, which may not be fully identified by available exploration data and may differ from our experiences in areas where our lessees currently mine.

Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and these variations may be material. As a result, you should not place undue reliance on our coal reserve data that is included in this report.

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

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

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

AFG-Southwest PA. The AFG property is located in Washington County, Pennsylvania. We acquired this property in November 2005. In 2006, 3.0 million tons were produced from this property. We lease this property to Conrhein Coal Company, a subsidiary of Consol Energy. Coal is produced from an underground mine and is transported by belt to a preparation plant operated by the lessee. Coal is shipped by both the CSX and Norfolk Southern railways to utility customers, such as American Electric Power and Allegheny Energy.

Kingwood. The Kingwood property is located in Preston County, West Virginia. In 2006, 1.3 million tons were produced from this property. We lease this property to Kingwood Mining Company, LLC, a subsidiary of Alpha Natural Resources L.P. Coal is produced from an underground mine. It is transported by belt to a preparation plant operated by the lessee. Coal is shipped primarily by CSX railroad to utilities such as Allegheny Power, Mirant and VEPCO.

Sincell. The Sincell property is located in Garrett County, Maryland. In 2006, 728,000 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.

Gatling. The Gatling property is located in Mason County, West Virginia. We acquired the property in January 2007 as part of the larger Cline transaction. Coal from this property will be mined from an underground mine and transported via belt line to a preparation plant on the property. Clean coal will be transported via beltline either directly to the customer or to a barge loading facility. Production on the property began in the fourth quarter of 2006.

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

Central Appalachia

D.D. Shepard. The D.D. Shepard property is located in Boone County, West Virginia. This property is primarily leased to a subsidiary of Peabody Energy. We acquired the property effective December 1, 2006, and 486,000 tons were produced from this property in December. Both steam and metallurgical coal is produced by the lessees from underground and surface mines. Coal is transported from the mines via belt or truck to preparation plants on the property. Coal is shipped via the CSX railroad to customers such as Appalachian Power.

VICC/Alpha. The VICC/Alpha property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. In 2006, 6.7 million tons were produced from this property. We primarily 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 2006, 5.3 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 2006, 2.2 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 2006, 2.5 million tons were produced from this property. We lease the property to Ark Land Company, a subsidiary of Arch Coal, Inc. Production comes from underground mines and is transported primarily by beltline to a preparation plant on adjacent property and shipped on the Norfolk Southern or CSX railroads to utility customers such as Georgia Power and the Tennessee Valley Authority.

Pardee. The Pardee property is located in Letcher County, Kentucky and Wise County Virginia. In 2006, 2.0 million tons were produced from this property. We lease the property to Ark Land Company, a subsidiary of Arch Coal, Inc. Production comes from underground and surface mines and is transported by truck or beltline to a preparation plant on the property and shipped primarily on the Norfolk Southern railroad to utility customers such as Georgia Power and the Tennessee Valley Authority and metallurgical customers such as Algoma Steel and Arcelor.

VICC/Kentucky Land. The VICC/Kentucky Land property is located primarily in Perry, Leslie and Pike Counties, Kentucky. In 2006, 4.0 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.

Dingess-Rum. The Dingess-Rum property is located in Logan, Clay and Nicholas Counties, West Virginia. This property is leased to subsidiaries of Massey Energy and Magnum Coal. We acquired this property effective January 1, 2007. Both steam and metallurgical coal are produced underground and surface mines and transported by belt or truck to preparation plants on the property. Coal is shipped via the CSX railroad to steam customers such as American Electric Power, Dayton Power and Light, Detroit Edison and to various export metallurgical customers.

Table of Contents

The map below 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 2006, 3.4 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.

Illinois Basin

Hocking-Wolford/Cummings. The Hocking-Wolford property and the Cummings property are both located in Sullivan County, Indiana. In 2006, 1.4 million tons were produced from the properties. Both properties are under common lease to Black Beauty Coal Company, an affiliate of Peabody Energy. Production is currently from a surface mine, and coal is shipped by truck and railroad to customers such as Public Service of Indiana and Indianapolis Power and Light.

Sato. The Sato property is located in Jackson County, Illinois. In 2006, 1.1 million tons were produced from the property. The property is under lease to Knight Hawk Coal LLC an independent coal producer. Production is currently from a surface mine, and coal is shipped by truck and railroad to various Midwest and southeast utilities.

Williamson Development. The Williamson Development property is located in Franklin and Williamson Counties, Illinois. In mid-2006, we completed the final phase of the acquisition of this property and production began at the mine in the fourth quarter of 2006. In 2006, 66,000 tons were produced from the mine in the initial startup phase. Production is from an underground mine which will eventually use a longwall to produce coal. Production is shipped primarily via CN railroad to customers such as Cinergy. Also, as part of the Cline acquisition we acquired acreage adjacent to the Williamson Development property that will be developed in conjunction with the same mine producing on the Williamson Development property.

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

Northern Powder River Basin

Western Energy. The Western Energy property is located in Rosebud and Treasure Counties, Montana. In 2006, 6.5 million tons were produced from our property. Western Energy Company, a subsidiary 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 2.1 billion tons of proven and probable coal reserves that we owned or controlled as of December 31, 2006, 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.

Table of Contents

Item 3. *Legal Proceedings*

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

Item 4. *Submission of Matters to a Vote of Security Holders*

None.

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 20, 2007, there were an estimated 23,900 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, 2005 to December 31, 2006, and the quarterly cash distribution declared and paid with respect to each quarter per common unit.

	Price Range		Cash
NRP	**High**	**Low**	**Distributions**
2005			
First Quarter	$ 63.14	$ 48.00	$ 0.6875
Second Quarter	$ 61.05	$ 49.00	$ 0.7125
Third Quarter	$ 68.95	$ 56.78	$ 0.7375
Fourth Quarter	$ 62.70	$ 49.47	$ 0.7625
2006			
First Quarter	$ 57.16	$ 50.50	$ 0.7900
Second Quarter	$ 58.95	$ 51.20	$ 0.8200
Third Quarter	$ 59.20	$ 48.20	$ 0.8500
Fourth Quarter	$ 59.98	$ 49.50	$ 0.8800

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 20, 2007, there were an estimated 3,400 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.

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, 2006, 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.

	Price Range		Cash
NSP	**High**	**Low**	**Distributions**
2005			

Third Quarter (from August 10, 2005)	$ 59.20	$ 51.22	$ 0.7375
Fourth Quarter	$ 57.95	$ 47.70	$ 0.7625
2006			
First Quarter	$ 55.40	$ 48.30	$ 0.7900
Second Quarter	$ 56.40	$ 48.80	$ 0.8200
Third Quarter	$ 56.75	$ 47.56	$ 0.8500
Fourth Quarter	$ 58.89	$ 48.40	$ 0.8800

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

Table of Contents

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. 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 will be converted into common units.

On November 14, 2005, 25% of the subordinated units converted into common units. On November 14, 2006, another 331/3% of the subordinated units outstanding on that date or 25% of the original outstanding 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 November 14, 2007. Following the conversion in November 2007, NSP units will no longer exist and all subordinated units will have been converted into NRP units.

In connection with the Adena Minerals transaction, we issued 541,956 Class B units to Adena in January 2007. The Class B units are a new class of limited partnership interests in NRP that will be converted to regular common units upon the approval of our unitholders (other than Adena and its affiliates). The Class B Units are subordinate to the regular common units, but senior to the subordinated units, with respect to cash distributions (and in liquidation) and will be entitled to 110% of the cash distributions per common unit if they have not been converted to common units six months following the closing of the transactions contemplated by the Second Contribution Agreement (relating to Cline s Gatling, Ohio complex) with Adena or September 30, 2008, whichever occurs first. The Class B Units are not listed for trading on the New York Stock Exchange.

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.

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, 2006, 2005, 2004, 2003 and 2002, and for the years ended December 31, 2006, 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 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 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.

Table of Contents

NATURAL RESOURCE PARTNERS L.P.

	For the years ended December 31, 2006	2005	2004	2003	From commencement of operations (October 17, 2002) through December 31, 2002
	(In thousands, except per unit and per ton data)				
Income Statement Data:					
Revenues:					
Coal royalties	$ 147,752	$ 142,137	$ 106,456	$ 73,770	$ 11,532
Aggregate royalties	538				
Coal processing fees	1,452				
Oil and gas royalties	4,220	3,180	1,907	1,675	
Property taxes	5,971	6,516	5,349	5,069	1,047
Minimums recognized as revenue	2,082	1,709	1,763	2,033	872
Override royalties	957	2,144	3,222	1,022	226
Other	7,701	3,367	2,735	1,897	216
Total revenues	170,673	159,053	121,432	85,466	13,893
Expenses:					
Depreciation, depletion and amortization	29,695	33,730	30,077	24,483	4,526
General and administrative	15,520	12,319	11,503	8,923	1,059
Property, franchise and other taxes	8,122	8,142	6,835	5,810	1,296
Coal royalty and override payments	1,560	3,392	2,045	1,299	397
Total expenses	54,897	57,583	50,460	40,515	7,278
Income from operations	115,776	101,470	70,972	44,951	6,615
Interest expense	(16,423)	(11,044)	(11,192)	(7,696)	(200)
Interest income	2,737	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	$ 102,090	$ 91,839	$ 58,994	$ 36,907	$ 6,415
Balance Sheet Data (at period end):					
Total assets	$ 939,493	$ 684,996	$ 599,926	$ 531,676	$ 392,719
Deferred revenue	20,654	14,851	15,847	15,054	13,252
Long-term debt	454,291	221,950	156,300	192,650	57,500
Total liabilities	503,806	259,088	190,734	223,518	74,085

Partners capital	435,687	425,908	409,192	308,158	318,634
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$ 138,843	$ 121,675	$ 90,847	$ 64,528	$ 6,738
Investing activities	(257,714)	(105,702)	(77,733)	(142,511)	(57,449)
Financing activities	137,224	(10,385)	4,669	94,550	58,463
Other Data:					
Royalty coal tons produced by lessees	52,092	53,606	48,357	44,344	7,314
Average gross coal royalty per ton	$ 2.84	$ 2.65	$ 2.20	$ 1.66	$ 1.58
Aggregate tons produced by lessee	412				
Average gross aggregate royalty per ton	$ 1.31				
Basic and diluted net income per limited partner unit:					
Common	$ 3.48	$ 3.39	$ 2.29	$ 1.59	$ 0.28
Subordinated	$ 3.48	$ 3.39	$ 2.29	$ 1.59	$ 0.28
Weighted average number of units outstanding:					
Common	17,183	14,345	13,447	11,354	11,354
Subordinated	8,158	10,996	11,354	11,354	11,354
Distributions per limited partner unit:					
Common	$ 3.340	$ 2.9000	$ 2.4750	$ 2.1450	$ 0.4234
Subordinated	$ 3.340	$ 2.9000	$ 2.4750	$ 2.1450	$ 0.4234

Table of Contents

WESTERN POCAHONTAS PROPERTIES LIMITED PARTNERSHIP

		For the Period From January 1, through October 16, 2002(1) (In thousands, except per ton data)
Income Statement Data:		
Revenues:		
Coal royalties	$	17,261
Timber royalties		2,774
Gain on sale of property		92
Property taxes		1,221
Other		1,219
Total revenues		22,567
Expenses:		
General and administrative		2,291
Taxes other than income		1,438
Depreciation, depletion and amortization		3,544
Total expenses		7,273
Income from operations		15,294
Other income (expense):		
Interest expense		(4,786)
Interest income		114
Reversionary interest		(561)
Net income	$	10,061
Cash Flow Data:		
Net cash flow provided by (used in):		
Operating activities	$	8,676
Investing activities		(35,028)
Financing activities		27,899
Other Data:		
Royalty coal tons produced by lessees		9,572
Average gross coal royalty per ton	$	1.80

(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) (In thousands, except per ton data)
Income Statement Data:		
Revenues:		
Coal royalties	$	5,895
Lease and easement income		474
Gain on sale of property		
Property taxes		61
Other		71
Total revenues		6,501
Expenses:		
General and administrative		417
Taxes other than income		69
Depreciation, depletion and amortization		1,979
Total expenses		2,465
Income from operations		4,036
Other income (expense):		
Interest expense		(1,877)
Interest income		115
Net income	$	2,274
Cash Flow Data:		
Net cash flow provided by (used in):		
Operating activities	$	3,725
Investing activities		
Financing activities		(4,069)
Other Data:		
Royalty coal tons produced by lessees		4,970
Average gross coal royalty per ton	$	1.19

(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) (In thousands, except per ton data)	
Income Statement Data:		
Revenues:		
Coal royalties	$	1,434
Gain on sale of property		
Property taxes		20
Other		53
Total revenues		1,507
Expenses:		
General and administrative		52
Taxes other than income		42
Depreciation, depletion and amortization		138
Total expenses		232
Income from operations		1,275
Other income (expense):		
Interest expense		(97)
Interest income		24
Reversionary interest		(104)
Net income	$	1,098
Cash Flow Data:		
Net cash flow provided by (used in):		
Operating activities	$	867
Investing activities		
Financing activities		(474)
Other Data:		
Royalty coal tons produced by lessees		479
Average gross coal royalty per ton	$	2.99

(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) (In thousands, except per ton data)
Income Statement Data:		
Revenues:		
Coal royalties	$	14,768
Other royalties		1,349
Property taxes		1,179
Total revenues		17,296
Direct costs and expenses:		
Depletion		4,889
Property taxes		1,179
Other expense		528
Total expenses		6,596
Excess (deficit) of revenues over direct costs and expenses	$	10,700
Cash Flow Data:		
Direct cash flow from contributed properties	$	15,181
Other Data:		
Royalty coal tons produced by lessees		8,791
Average gross coal royalty per ton	$	1.68

(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, 2006, we owned or controlled approximately 2.1 billion tons of proven and probable coal reserves in eleven states. For the year ended December 31, 2006, approximately 57% of the coal produced from our properties came from underground mines and approximately 43% came from surface mines. As of December 31, 2006, approximately 60% of our reserves were low sulfur coal. Included in our low sulfur reserves is compliance coal, which constitutes approximately 36% of our reserves.

We lease coal reserves to experienced mine operators under long-term leases that grant the operators the right to mine and sell coal from our reserves in exchange for royalty payments. As of December 31, 2006, our reserves were subject to 180 leases with 70 lessees. For the year ended December 31, 2006, our lessees produced 52.1 million tons of coal generating $147.8 million in coal royalty revenues from our properties and our total revenues were $170.7 million. 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.

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 those future periods. We do not recognize these minimum coal royalties as revenue until the applicable recoupment period has expired or they are recouped through production. Until recognized as revenue, these minimum royalties are recorded as deferred revenue, a liability on our balance sheet.

Coal royalty revenues from our Appalachian properties represented 89% of our total coal royalty revenues for the year ended December 31, 2006, 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. Coal prices for both metallurgical and steam coal increased during 2005 and 2006, and as our lessees older contracts have rolled over during the last two years, we have received substantially higher royalties from our leases. Our revenue per ton from that region increased to an average of $3.07 per ton for the year ended December 31, 2006 from an average of $2.87 per ton for the same period of 2005. However, because prices have generally stabilized over the last year 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 an increase in the cost of mining coal, increased customer stockpiles, 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.

For the year ended December 31, 2006, approximately 33% of our coal royalty revenues and 28% 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 2007 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 export markets.

In addition to coal royalty revenues, we generated approximately 14% of our revenues for each of the years ended December 31, 2006 and 2005 from rentals; royalties on oil and gas and coalbed methane leases; timber; overriding royalty arrangements; coal processing fees; and wheelage payments, which are toll payments for the right to transport third-party coal over or through our property.

We have recently acquired aggregate reserves near DuPont, Washington and coal processing and transportation infrastructure in West Virginia and Illinois. Although neither acquisition contributed materially to our 2006 revenues, we anticipate that both businesses will contribute significant revenues in 2007, and we hope to grow both businesses into meaningful complements to our coal royalty business.

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

Our distributable cash flow represents cash flow from operations less actual principal payments and cash reserves set aside for 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,		
	2006	2005	2004
Cash flow from operations	$ 138,843	$ 121,675	$ 90,847
Less scheduled principal payments	(9,350)	(9,350)	(9,350)
Less reserves for future principal payments	(9,600)	(9,400)	(9,400)
Add reserves used for scheduled principal payments	9,400	9,400	9,400
Distributable cash flow	$ 129,293	$ 112,325	$ 81,497

Acquisitions

Recent Acquisitions

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

2007 Acquisitions

Dingess-Rum. On January 16, 2007, we acquired 92 million tons of coal reserves and approximately 33,700 acres of surface and timber in Logan, Clay and Nicholas Counties in West Virginia from Dingess-Rum Properties, Inc. As consideration for the acquisition, we issued 2,400,000 common units to Dingess-Rum.

Cline. On January 4, 2007, we acquired 49 million tons of reserves in Williamson County, Illinois and Mason County, West Virginia that are leased to affiliates of The Cline Group. In addition, we acquired transportation assets and related infrastructure at those mines. As consideration for the transaction we issued 3,913,080 common units and 541,956 Class B units representing limited partner interests in NRP. Through its affiliate Adena Minerals, LLC, The Cline Group received a 22% interest in our general partner and in the incentive distribution rights of NRP in return for providing NRP with the exclusive right to acquire additional reserves, royalty interests and certain transportation infrastructure relating to future mine developments by The Cline Group. Simultaneous with the closing of this transaction, we signed a definitive agreement to purchase the coal reserves and transportation infrastructure at Cline s Gatling Ohio complex. This transaction will close upon commencement of coal production, which is currently expected to occur in 2008. At the time of closing, NRP will issue Adena 2,280,000 additional Class B units, and the general partner of NRP will issue Adena an additional 9% interest in the general partner and the incentive distribution rights.

2006 Acquisitions

Quadrant. On December 29, 2006, we acquired an estimated 70 million tons of high quality aggregate reserves located in DuPont, Washington for $23.5 million in cash and assumed a utility local improvement obligation of approximately $3.0 million. Of these reserves, approximately 25 million tons are currently permitted. We will pay an additional $7.5 million when the remaining tons are permitted. If the permit is not obtained by December 2016, the unpermitted tons will revert back to Quadrant. We funded this acquisition with cash and borrowings under our credit facility.

Bluestone. On December 18, 2006, we acquired approximately 20 million tons of low vol metallurgical coal reserves that are located above our Pinnacle reserves in Wyoming County, West Virginia for $20 million. We funded this acquisition with borrowings under our credit facility.

D.D. Shepherd. On December 1, 2006, we acquired nearly 25,000 acres of land containing in excess of 80 million tons of coal reserves for $110 million. The property is located in Boone County, West Virginia adjacent to other NRP property and consists of both metallurgical and steam coal reserves, gas reserves, surface and timber. We funded this acquisition with borrowings under our credit facility.

Red Fox. On September 1, 2006, we acquired the Red Fox preparation plant and coal handling facility located in McDowell County, West Virginia for approximately $8.1 million, of which $4.1 million was paid at closing and the remainder was paid during the third and fourth quarters as construction was completed. This acquisition was the second under our memorandum of understanding with Taggart Global, LLC (formerly Sedgman USA, LLC). The plant will handle an estimated 20 million tons of coal reserves during its life. The initial $4.1 million payment paid at closing was funded through cash and borrowings under our credit facility and the remaining payments were funded with cash.

Coal Mountain. On August 24, 2006, we acquired the Coal Mountain preparation plant, handling facility and rail load-out facility located in Wyoming County, West Virginia for $16.1 million under our memorandum of understanding with Taggart Global. We expect that approximately 35 million tons of coal will be processed through this facility during its life. We paid for the facilities with cash and with borrowings under our credit facility as construction was completed in phases during the third and fourth quarters.

Williamson Development. On January 20, 2006 and August 15, 2006, we closed the second and third phases of the Williamson Development acquisition in Illinois for $35 million each. We funded the January 20, 2006 acquisition with proceeds from the issuance of senior notes and the August 15, 2006 acquisition with borrowings under our credit facility.

Allegany County, Maryland. On June 29, 2006, we acquired 3.3 million tons of coal in Allegany County, Maryland for $5.5 million in cash.

Indiana Reserves. On May 26, 2006, we acquired 16.3 million tons of coal reserves and an overriding royalty interest on an additional 2.4 million tons for $10.85 million in cash. These reserves are located in Pike, Warrick and Gibson Counties in Indiana.

Disposition

Virginia Timber Properties. For the year ended December 31, 2006, we received total proceeds of $7.1 million and recorded a total gain of $3.5 million related to transactions involving the sale of timber and related surface acreage located on our property in Wise and Dickenson Counties, Virginia.

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, we reflect these minimum royalties as deferred revenue, a liability on the balance sheet.

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

Coal Processing Fees. We recognize coal processing fees on the basis of tons of coal processed through the facilities by our lessees and the corresponding revenue from those sales. Generally, the lessees of the coal processing facilities make payments to us based on the greater of a percentage of the gross sales price or a fixed price per ton of coal that is processed and sold from the facilities. The lessees are also subject to minimum monthly, quarterly or annual payments. These minimum royalties are generally recoupable over a specified period of time if sufficient royalties are generated from coal processing 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. The coal processing leases are structured so that the lessees are responsible for operating and maintenance expenses associated with the facilities.

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. We initially record the minimum payments as deferred revenue and recognize them 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 mineral properties on a units-of-production basis by lease, based upon minerals mined in relation to the net cost of the mineral properties and estimated proved and probable tonnage in those properties. We estimate proven and probable mineral reserves with the assistance of third-party mining consultants, and we use estimation techniques and recoverability assumptions. We update our estimates of mineral reserves periodically and this may result in material adjustments to mineral reserves and depletion rates that we recognize prospectively. Historical revisions have not been material. Timberlands are stated at cost less depletion. We determine the cost of the timber harvested based on the volume of timber harvested in relation to the amount of estimated net merchantable volume by geographic areas. We estimate our timber inventory using statistical information and data obtained from physical measurements and other information gathering techniques. We update these estimates annually, which may result in adjustments of timber volumes and depletion rates that we recognize prospectively. Changes in these estimates have no effect on our cash flow.

Impact of Adoption of FAS 123R

We adopted Statement of Financial Accounting Standards No. 123R *Share-Based Payment,* effective January 1, 2006 using the modified prospective approach. Prior to 2006, awards under our Long Term Incentive Plan were accounted for on the intrinsic method under the provisions of APB No. 25. FAS 123R provides that grants must be accounted for using the fair value method, which requires us to estimate the fair value of the grant and charge the estimated fair value to expense over the service or vesting period of the grant. In addition, FAS 123R requires that we include estimated forfeitures in our periodic computation of the fair value of the liability and that the fair value be recalculated at each reporting date over the service or vesting period of the grant. FAS 123R required us to recognize the 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 previously recorded. Included in operating costs and expenses was a one time charge of $661,000 which represents the cumulative effect of adopting FAS 123R as of January 1, 2006. This adjustment had the impact of reducing net income per limited partner unit for the year ended December 31, 2006 by $0.02. Application of FAS 123R to prior periods did not materially impact amounts previously presented.

Table of Contents

Results of Operations

	For the Years Ended December 31,		
	2006	2005	2004
	(In thousands, except per ton data)		
Revenues:			
Coal royalties	$ 147,752	$ 142,137	$ 106,456
Aggregate royalties	538		
Coal processing fees	1,452		
Oil and gas royalties	4,220	3,180	1,907
Property taxes	5,971	6,516	5,349
Minimums recognized as revenue	2,082	1,709	1,763
Override royalties	957	2,144	3,222
Other	7,701	3,367	2,735
Total revenues	170,673	159,053	121,432
Expenses:			
Depreciation, depletion and amortization	29,695	33,730	30,077
General and administrative	15,520	12,319	11,503
Property, franchise and other taxes	8,122	8,142	6,835
Coal royalty and override payments	1,560	3,392	2,045
Total expenses	54,897	57,583	50,460
Income from operations	115,776	101,470	70,972
Other income (expense):			
Interest expense	(16,423)	(11,044)	(11,192)
Interest income	2,737	1,413	349
Loss on early extinguishment of debt			(1,135)
Net income	$ 102,090	$ 91,839	$ 58,994
Other Data:			
Coal Royalties			
Appalachia			
Northern	$ 10,231	$ 11,306	$ 7,084
Central	100,487	93,008	76,583
Southern	20,469	25,089	14,874
Total Appalachia	131,187	129,403	98,541
Illinois Basin	5,325	4,288	3,852
Northern Powder River Basin	11,240	8,446	4,063
Total	$ 147,752	$ 142,137	$ 106,456
Production (tons)			
Appalachia			
Northern	5,329	5,977	4,179

Central	31,991	32,790	32,702
Southern	5,347	6,263	5,208
Total Appalachia	42,667	45,030	42,089
Illinois Basin	2,877	2,781	3,138
Northern Powder River Basin	6,548	5,795	3,130
Total	52,092	53,606	48,357
Average gross royalty			
Appalachia			
Northern	$ 1.92	$ 1.89	$ 1.70
Central	3.14	2.84	2.34
Southern	3.83	4.01	2.86
Total Appalachia	3.07	2.87	2.34
Illinois Basin	1.85	1.54	1.23
Northern Powder River Basin	1.72	1.46	1.30
Total	$ 2.84	$ 2.65	$ 2.20
Aggregate Royalties			
Royalty revenues	$ 538		
Production	412		
Average gross royalty	$ 1.33		

Year ended December 31, 2006 compared with year ended December 31, 2005

Revenues. For the year ended December 31, 2006, total revenues were $170.7 million compared to $159.1 million for the same period in 2005, an increase of $11.6 million or 7%. Coal royalty revenues were $147.8 million on 52.1 million tons of coal produced, compared to $142.1 million in coal royalty revenues on 53.6 million tons of coal produced for the year ended December 31, 2005, representing a 4% increase in coal royalty revenues and a 3% decrease in production. Coal royalty revenues comprised approximately 87% and 89% of our total revenues for each of the years ended December 31, 2006 and 2005.

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

Appalachia. As a result of higher prices in the Central Appalachia region, coal royalty revenues in Appalachia for the year ended December 31, 2006 were $131.2 million compared to $129.4 million for the same period in 2005, an increase of $1.8 million or 1%. For the year ended December 31, 2006, production in Appalachia was 42.7 million tons compared to 45.0 million tons for the same period in 2005, a decrease of 2.3 million tons or 5%. The Appalachian results by region are set forth below.

Northern Appalachia. Coal royalty revenues decreased 10% from $11.3 million for the year ended December 31, 2005 to $10.2 million for the year ended December 31, 2006. Production decreased 12% from 6.0 million tons to 5.3 million tons over the same periods. The property we acquired in June 2006 in Allegany County, Maryland generated coal royalty revenues of $576,000 and production of 222,000 tons. The other significant differences are described below.

AFG Properties production increased from 1.5 million tons to 3.0 million tons and coal royalty revenues increased from $2.7 million to $5.5 million. The increased tonnage was due to a greater proportion of production from the longwall unit being on our property.

Sincell production decreased from 2.6 million tons to 728,000 tons and coal royalty revenues decreased from $4.7 million to $1.2 million. The decreased tonnage was due to a mine exhausting its longwall mineable reserves.

Stony River production decreased from 343,000 tons to 17,000 tons and coal royalty revenues decreased from $851,000 to $55,000 due to the lessee idling production during bankruptcy proceedings.

Central Appalachia. Production from our Central Appalachia properties decreased 2% from 32.8 million tons for the year ended December 31, 2005 to 32.0 million tons for the year ended December 31, 2006. However, as a result of higher prices, our coal royalty revenues from these properties increased 8% from $93.0 million to $100.4 million over those same periods. The property we acquired in December 2006 in the D.D. Shepard transaction generated coal royalty revenues of $2.1 million and production of 486,000 tons. In addition to the D.D. Shepard acquisition, the results in Central Appalachia are a combination of increases and decreases over a number of other properties, the most significant of which are described below.

VICC/Kentucky Land production increased from 2.6 million tons to 4.0 million tons and coal royalty revenues increased from $8.8 million to $13.9 million. The increased production was due to an increase in tonnage from mines moving onto the property and production from recently negotiated new leases that more than offset mines moving off the property.

VICC/Alpha production increased from 5.1 million tons to 5.3 million tons and coal royalty revenues increased from $17.2 million to $20.5 million. The tonnage increase was due to slightly improved production from the mines on the property.

Plum Creek properties production increased from 573,000 tons to 1.5 million tons and coal royalty revenues increased from $1.5 million to $4.2 million. The increased production and coal royalty revenues were due primarily to new mines in West Virginia increasing production on the properties over their earlier startup levels.

Lynch production increased from 5.1 million tons to 5.3 million tons and coal royalty revenues increased from $11.5 million to $13.8 million. The tonnage increase was due to a new mine starting on the property.

Table of Contents

Pardee production increased from 1.7 million tons to 2.0 million tons and coal royalty revenues increased from $6.5 million to $7.7 million. The increased tonnage was due to a greater proportion of production from the mines being on our property.

Eunice production decreased from 2.6 million tons to 738,000 tons and coal royalty revenues decreased from $6.7 million to $2.5 million due to a mine exhausting its longwall mineable reserves and a greater proportion of production from a surface mine coming from adjacent property.

Pinnacle production decreased from 2.9 million tons to 2.2 million tons and coal royalty revenues decreased from $10.8 million to $7.8 million. The decreases were primarily due to coal being produced from adjacent property and slightly lower prices being received by our lessee.

Eastern Kentucky Property production decreased from 552,000 tons to 56,000 tons and coal royalty revenues decreased from $1.9 million to $236,000. The decreased production was due to the lessee temporarily idling the operation during the year. A new lessee resumed production on the property in the fourth quarter of 2006.

Southern Appalachia. Our coal royalty revenues in Southern Appalachia decreased 18% from $25.1 million for the year ended December 31, 2005 to $20.5 million for the year ended December 31, 2006, as production decreased 16% from 6.3 million tons to 5.3 million tons over the same period. The following properties contributed to this decrease.

Twin Pines/Drummond production decreased from 685,000 tons to 591,000 tons and coal royalty revenues decreased from $6.1 million to $3.5 million. The decrease in coal royalty revenues was partially due to a temporary royalty reduction in the first half of the year and a lower per ton royalty being paid under the terms of the lease at one mine, as well as a temporary idling of another mine.

BLC Properties production decreased from 3.8 million tons to 3.4 million tons and coal royalty revenues decreased from $12.7 million to $11.9 million. The decrease was due to slightly reduced production and some temporary royalty reduction to one lessee to encourage mining in some areas of difficult geology.

Oak Grove production decreased from 1.7 million tons to 1.3 million tons and coal royalty revenues decreased from $6.2 million to $5.1 million. The decreases were due to lower production from the mine.

Illinois Basin. Production in the Illinois Basin increased 4% from 2.8 million tons for the year ended December 31, 2005 to 2.9 million tons for the year ended December 31, 2006 and coal royalty revenues increased 23% from $4.3 million for the year ended December 31, 2005 to $5.3 million for the year ended December 31, 2006. During the fourth quarter of 2006, production began from a mine on the property we acquired in 2005 and 2006, described formerly as the Steelhead property and now known as the Williamson property. During the fourth quarter, the mine produced 66,000 tons and generated coal royalty revenues of $171,000 in its initial startup phase. The other significant variances are described below.

Sato/Trico production remained nearly constant at 1.4 million tons and coal royalty revenues increased from $2.4 million to $3.0 million. The increase in coal royalty revenues was due to higher sales prices received by our lessee.

Hocking Wolford/Cummings production remained nearly constant at 1.4 million tons and coal royalty revenues increased from $1.9 million to $2.2 million. The increased coal royalty revenues were due to higher sales prices received by our lessee.

Northern Powder River Basin. Production from our Western Energy property increased 0.7 million tons or 12% from 5.8 million tons to 6.5 million tons and coal royalty revenues increased $2.8 million or 33% from $8.4 million to $11.2 million. These increases were due to the typical variations in production resulting from the checkerboard ownership pattern and additional royalty revenues attributable to a positive price adjustment received by a lessee during the third quarter.

Other revenues. Included in other revenues are three related sales of timber and surface acreage located on our property in Wise and Dickenson Counties, Virginia. We received proceeds from the sales of $7.1 million, resulting in a gain of $3.5 million.

Table of Contents

Operating costs and expenses. For the year ended December 31, 2006, total expenses were $54.9 million, compared to $57.6 million for 2005, representing a decrease of $2.7 million, or 5%. Included in total expenses are:

Depletion and amortization of $29.7 million for the year ended December 31, 2006 compared to $33.7 million for the same period in 2005, representing a decrease of $4.0 million. Fluctuations in depletion are dependent on the depletion rates where coal is mined, which can cause total depletion to be lower in periods where production is actually up;

General and administrative expenses of $15.5 million for the year ended December 31, 2006, compared to $12.3 million for the year ended December 31, 2005, an increase of $3.2 million, or 26%. The increase in general and administrative expenses is attributable to additional expenses required to manage a larger portfolio of properties as well as an increase in incentive compensation accrual partially attributable to the adoption of FAS 123R. We also had an increase in the allowance for doubtful accounts of $0.8 million during the year ended December 31, 2006;

Property, franchise and other taxes were even at $8.1 million for the years ended December 31, 2006 and 2005. Due to acquisitions, property taxes increased about $0.2 million while franchise taxes decreased about the same amount.

Interest Expense. For the year ended December 31, 2006, interest expense was $16.4 million compared to $11.0 million for 2005, an increase of $5.4 million. This increase is attributed to the issuance of senior notes during the third quarter of 2005 and the first quarter of 2006, as well as significantly higher outstanding balances on our credit facility, which was used to fund acquisitions.

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 did 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.

Table of Contents

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 the same percentage of revenue 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.

Related Party Transactions

Partnership Agreement

Our general partner does not receive any management fee or other compensation for its management of Natural Resource Partners L.P. However, in accordance with our partnership agreement, we reimburse our general partner and its affiliates for expenses incurred on our behalf. All direct general and administrative expenses are charged to us as incurred. We also reimburse indirect general and administrative costs, including certain legal, accounting, treasury, information technology, insurance, administration of employee benefits and other corporate services incurred by our general partner and its affiliates. Cost reimbursements due our general partner may be substantial and will reduce our cash available for distribution to unitholders. The reimbursements to our general partner for services performed by Western Pocahontas Properties and Quintana Minerals Corporation totaled $4.0 million in 2006, $3.7 million in 2005 and $3.8 million in 2004. For additional information, please read Certain Relationships and Related Transactions, and Director Independence Omnibus Agreement.

The Cline Group

On January 4, 2007, we acquired from Adena Minerals, LLC four entities that own approximately 49 million tons of coal reserves in West Virginia and Illinois that are leased to active mining operations, as well as associated transportation and infrastructure assets at those mines. The reserves consist of 37 million tons at Adena s Gatling mining operation in Mason County, West Virginia and 12 million tons adjacent to reserves currently owned by us at Adena affiliate Williamson Energy s Pond Creek No. 1 mine in Southern Illinois. In consideration therefor, Adena received 3,913,080 common units and 541,956 Class B units representing limited partner interests in NRP and a 22% interest in our general partner and in our outstanding incentive distribution rights. Adena is an affiliate of The

Cline Group, a private coal company that controls over 3 billion tons of coal reserves in the Illinois and Northern Appalachian coal basins.

Second Contribution Agreement. At the closing, we executed a Second Contribution Agreement, pursuant to which we agreed to acquire from Adena two entities that own coal reserves in Meigs County, Ohio and associated transportation infrastructure. As consideration, Adena will receive 2,280,000 Class B Units (unless we have received unitholder approval to convert the Class B Units to common units, in which case Adena will receive 2,280,000 common units), as well as an additional 9% interest in the general partner and our outstanding incentive distribution rights. The transactions contemplated by the Second Contribution Agreement are expected to close, subject to customary closing conditions, upon commencement of production of the Ohio coal reserves, which is currently expected to occur in 2008.

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

Investor Rights Agreement. Also at the closing, NRP and certain affiliates and Adena executed an Investor Rights Agreement pursuant to which Adena was granted certain management rights. Specifically, Adena has the right to name two directors (one of which will be independent) to the board of directors of our managing general partner so long as Adena beneficially owns either 5% of our limited partnership interest or 5% of our general partner s limited partnership interest and so long as certain rights under our managing general partner s LLC Agreement have not been exercised by Adena or Corbin J. Robertson, Jr. Adena nominated J. Matthew Fifield, Managing Director of Adena, to serve as one of the two directors and anticipates nominating an independent director in the near future. The independent director will be appointed to at least one committee for which such director meets the applicable qualifications. Adena will also have the right, pursuant to the terms of the Investor Rights Agreement, to withhold its consent to the sale or other disposition of any entity or assets contributed by the Cline entities to NRP.

Quintana Energy Partners, L.P.

In 2006, Corbin J. Robertson, Jr. formed Quintana Energy Partners L.P., or QEP, a private equity fund focused on investments in the energy business. In connection with the formation of QEP, our general partner s board of directors adopted a conflicts policy that establishes the opportunities that will be pursued by NRP and those that will be pursued by QEP. QEP s governance documents reflect the guidelines set forth in NRP s conflicts policy. For a more detailed description of this policy, please see Item 13. Certain Relationships and Related Transactions, and Director Independence in this Form 10-K.

In February 2007, QEP acquired a 43% membership interest in Taggart Global, LLC, including the right to nominate two members of Taggart s 5-person board of directors. NRP currently has a memorandum of understanding with Taggart Global pursuant to which the two companies have agreed to jointly pursue the development of coal handling and preparation plants. NRP will own and lease the plants to Taggart Global, which will design, build and operate the plants. The lease payments are based on the sales price for the coal that is processed through the facilities. In 2006, NRP and Taggart Global jointly developed two such plants in West Virginia.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

We satisfy our working capital requirements with cash generated from operations. Since our initial public offering, we have financed our property acquisitions with available cash, borrowings under our revolving credit facility, and the issuance of our senior notes and additional common and Class B 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, 2006, 2005 and 2004 was $138.8 million, $121.7 million and $90.8 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 December 31, 2006, 2005 and 2004 was $257.7 million, $105.7 million and $77.7 million, respectively. In each of those years, substantially all of our investing activities consisted of acquiring coal reserves and other mineral rights. In the third quarter of 2005, we also acquired a coal preparation plant and rail loadout facility for $6 million and in the third quarter of 2006, we acquired two more coal preparation plants and related handling facilities totaling $24.2 million. In December 2006, we acquired aggregate reserves for $23.5 million. In 2006, we sold non-core timberlands for gross proceeds totaling $7.1 million.

Net cash generated from financing activities for the years ended December 31, 2006 and 2005 was $137.2 million and $4.7 million, respectively, while we used $10.4 million in cash for financing activities for the year ended December 31, 2005. All of the loan proceeds from our credit facility were used to fund our acquisitions. We issued $50 million in senior notes in each of 2006 and 2005 and used those proceeds to pay down our credit facility. We also made $9.35 million in principal payments on our senior notes in each of the three year periods. In 2004, we used $100.1 million of the proceeds from the sale of 5.25 million of our common units to redeem 2.6 million common units held by Arch Coal, and we used the balance of the proceeds, or $102.5 million, to pay down our credit facility. We also paid cash distributions to our partners totaling $92.4 million, $75.2 million and $60.4 million for each of the years ending December 31, 2006, 2005 and 2004, respectively.

Contractual Obligations and Commercial Commitments

At December 31, 2006, our debt consisted of:

$214 million outstanding under our $300 million revolving credit facility that matures in October 2010;

$35 million of 5.55% senior notes due 2013;

$61.85 million of 4.91% senior notes due 2018;

$100 million of 5.05% senior notes due 2020;

$2.9 million of a 5.31% utility local improvement obligation due 2021; and

$50.1 million of 5.55% senior notes due 2023.

In December 2006, we increased the limit under our credit facility to $300 million pursuant to the accordion feature in the credit agreement. We may prepay all loans at any time without penalty. Indebtedness under the our 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

Table of Contents

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.

Our credit facility 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. 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, 2006 (in millions):

	Payments Due by Period(1)						
Contractual Obligations	**Total**	**2007**	**2008**	**2009**	**2010**	**2011**	**Thereafter**
Long-term debt (including current maturities)	$ 556.10	$ 22.26	$ 29.47	$ 28.59	$ 241.70	$ 26.83	$ 207.25

(1) The amounts indicated in the table include principal and interest due on our senior notes, as well as the utility local improvement obligation related to our property in DuPont, Washington. The table also includes the $214 million outstanding principal balance at December 31, 2006 under our credit facility, which matures in October 2010.

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, 2006, 2005 and 2004.

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, 2006. 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.

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

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

Commodity Price Risk

We are dependent upon the efficient marketing of the coal mined by our lessees. Our lessees sell the coal under various long-term and short-term contracts as well as on the spot market. In previous years, a large portion of these sales were under long-term contracts. We estimate that 80% of our coal is currently sold by our lessees under coal supply contracts that have terms of one year or more. Current conditions in the coal industry may make it difficult for our lessees to extend existing contracts or enter into supply contracts with terms of one year or more. Our lessees failure to negotiate long-term contracts could adversely affect the stability and profitability of our lessees operations and adversely affect our coal royalty revenues. If more coal is sold on the spot market, coal royalty revenues may become more volatile due to fluctuations in spot coal prices.

Interest Rate Risk

Our exposure to changes in interest rates results from our current borrowings under our credit facility, which are subject to variable interest rates based upon LIBOR or the federal funds rate plus an applicable margin. Management intends to monitor interest rates and may enter into interest rate instruments to protect against increased borrowing costs. At December 31, 2006, we had $214 million outstanding in variable interest debt. If interest rates were to increase by 1%, annual interest expense would increase $2.1 million, assuming the same principal amount remained outstanding during the year.

Item 8. *Financial Statements and Supplementary Data*

INDEX TO FINANCIAL STATEMENTS

NATURAL RESOURCE PARTNERS L.P.

CONSOLDATED 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, 2006 and 2005, and the related consolidated statements of income, partners capital and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Natural Resource Partners L.P. at December 31, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, Natural Resource Partners L.P. adopted Statement of Financial Accounting Standards No. 123R Share-Based Payment .

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, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2007 expressed an unqualified opinion thereon.

Ernst & Young LLP

Houston, Texas
February 27, 2007

Table of Contents

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(In thousands, except for unit information)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 66,044	$ 47,691
Accounts receivable, net of allowance for doubtful accounts	23,357	21,946
Accounts receivable affiliate	21	6
Other	1,411	833
Total current assets	90,833	70,476
Land	17,781	14,123
Plant and equipment, net	29,615	5,924
Coal and other mineral rights, net	798,135	590,459
Loan financing costs, net	2,197	2,431
Other assets, net	932	1,583
Total assets	$ 939,493	$ 684,996
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 1,041	$ 677
Accounts payable affiliate	105	88
Current portion of long-term debt	9,542	9,350
Accrued incentive plan expenses current portion	5,418	1,105
Property, franchise and other taxes payable	4,330	4,138
Accrued interest	3,846	1,534
Total current liabilities	24,282	16,892
Deferred revenue	20,654	14,851
Accrued incentive plan expenses	4,579	5,395
Long-term debt	454,291	221,950
Partners capital:		
Common units (outstanding: 19,663,715 in 2006, 16,825,307 in 2005)	338,912	292,990
Subordinated units (outstanding: 5,676,817 in 2006, 8,515,228 in 2005)	83,772	123,114
General partner s interest	12,138	10,024
Holders of incentive distribution rights	1,616	582
Accumulated other comprehensive loss	(751)	(802)
Total partners capital	435,687	425,908

Total liabilities and partners capital	$ 939,493	$ 684,996

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,		
	2006	2005	2004
	(In thousands, except per unit data)		
Revenues:			
Coal royalties	$ 147,752	$ 142,137	$ 106,456
Aggregate royalties	538		
Coal processing fees	1,452		
Oil and gas royalties	4,220	3,180	1,907
Property taxes	5,971	6,516	5,349
Minimums recognized as revenue	2,082	1,709	1,763
Override royalties	957	2,144	3,222
Other	7,701	3,367	2,735
Total revenues	170,673	159,053	121,432
Operating costs and expenses:			
Depreciation, depletion and amortization	29,695	33,730	30,077
General and administrative	15,520	12,319	11,503
Property, franchise and other taxes	8,122	8,142	6,835
Coal royalty and override payments	1,560	3,392	2,045
Total operating costs and expenses	54,897	57,583	50,460
Income from operations	115,776	101,470	70,972
Other income (expense)			
Interest expense	(16,423)	(11,044)	(11,192)
Interest income	2,737	1,413	349
Loss on early extinguishment of debt			(1,135)
Net income	$ 102,090	$ 91,839	$ 58,994
Net income attributable to:(1)			
General partner	$ 9,717	$ 4,491	$ 1,705
Holders of incentive distribution rights	$ 4,133	$ 1,429	$ 281
Limited partners	$ 88,240	$ 85,919	$ 57,008
Basic and diluted net income per limited partner unit:			
Common	$ 3.48	$ 3.39	$ 2.29
Subordinated	$ 3.48	$ 3.39	$ 2.29

Weighted average number of units outstanding:			
Common	17,183	14,345	13,447
Subordinated	8,158	10,996	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)	Total
	Units	Amounts	Units	Amounts	Amounts	Amounts		
			(In thousands, except unit data)					
alance at ecember 31, 2003	11,353,658	$ 143,956	11,353,658	$ 158,633	$ 6,474	$	$ (905)	$ 308,158
suance 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 ecember 31, 2004	13,986,906	$ 243,814	11,353,658	$ 157,324	$ 8,802	$ 105	$ (853)	$ 409,192
ubordinated units onverted to common	2,838,430	39,873	(2,838,430)	(39,873)				
edemption of actional 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
ubordinated units onverted to common	2,838,411	40,775	(2,838,411)	(40,775)				
edemption of actional units upon onversion of ubordinated units	(3)							
istributions to nitholders		(54,220)		(27,440)	(7,603)	(3,099)		(92,362
et income for the year nded December 31, 006		59,367		28,873	9,717	4,133		102,090
oss on interest hedge							51	51
omprehensive income							51	102,141
alance at ecember 31, 2006	19,663,715	$ 338,912	5,676,817	$ 83,772	$ 12,138	$ 1,616	$ (751)	$ 435,687

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

Table of Contents

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	2006	2005	2004
	(In thousands)		
Cash flows from operating activities:			
Net income	$ 102,090	$ 91,839	$ 58,994
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	29,695	33,730	30,077
Non-cash interest charge	349	318	932
Loss on early extinguishment of debt			1,135
Gain on sale of timber assets	(3,471)		
Change in operating assets and liabilities:			
Accounts receivable	(1,426)	(6,869)	(4,093)
Other assets	(579)	(47)	236
Accounts payable and accrued liabilities	381	84	(47)
Accrued interest	2,312	1,268	(415)
Deferred revenue	5,803	(996)	793
Accrued incentive plan expenses	3,497	1,670	2,574
Property, franchise and other taxes payable	192	678	661
Net cash provided by operating activities	138,843	121,675	90,847
Cash flows from investing activities:			
Acquisition of land, plant and equipment, coal and other mineral rights	(264,765)	(105,702)	(77,733)
Proceeds from sale of timber assets	7,051		
Net cash used in investing activities	(257,714)	(105,702)	(77,733)
Cash flows from financing activities:			
Proceeds from loans	254,000	125,000	75,500
Deferred financing costs	(64)	(861)	(969)
Repayment of loans	(24,350)	(59,350)	(111,850)
Distributions to partners	(92,362)	(75,173)	(60,393)
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)
Redemption of fractional units upon conversion of subordinated units		(1)	
Net cash (used in) provided by financing activities	137,224	(10,385)	4,669
Net increase in cash	18,353	5,588	17,783
Cash at beginning of period	47,691	42,103	24,320

Cash at end of period	$	66,044	$	47,691	$	42,103
Supplemental cash flow information:						
Cash paid during the period for interest	$	13,734	$	9,459	$	10,603
Non-cash financing activities:						
Utility improvement obligation acquired	$	2,883				

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

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Organization

Natural Resource Partners L.P. (the Partnership), a Delaware limited partnership, was formed in April 2002. The general partner of the Partnership is NRP (GP) LP, a Delaware limited partnership, whose general partner is GP Natural Resource Partners LLC, a Delaware limited liability company. The Partnership engages principally in the business of owning and managing coal properties in the three major coal-producing regions of the United States: Appalachia, the Illinois Basin and the Western United States. As of December 31, 2006, the Partnership owned or controlled approximately 2.1 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 its operating assets are owned by, its subsidiaries. The Partnership owns its subsidiaries through a wholly owned operating company, NRP (Operating) LLC. NRP (GP) LP, the general partner of the Partnership, has sole responsibility for conducting its business and for managing its operations. Because its general partner is a limited partnership, its general partner, GP Natural Resource Partners LLC, conducts its business and operations, and the board of directors and officers of GP Natural Resource Partners LLC makes decisions on its behalf. Robertson Coal Management LLC, a limited liability company wholly owned by Corbin J. Robertson, Jr., owns all of the membership interest in GP Natural Resource Partners LLC. Mr. Robertson is entitled to nominate all seven of the directors, four 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.

Accounts Receivable

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

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

when it becomes aware of a specific customer s inability to meet its financial obligations to the Partnership, such as in the case of bankruptcy filings or deterioration in the lessee s operating results or financial position, the Partnership records a specific reserve for bad debt to reduce the related receivable to the amount it reasonably believes is collectible. If circumstances related to specific lessees change, the Partnership s estimates of the recoverability of receivables could be further adjusted.

Land, Coal and Mineral Rights

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

Plant and Equipment

Plant and equipment which consists of coal preparation plants and rail loadout facilities 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.

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 $235.4 million and $197.6 million at December 31, 2006 and 2005, 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 $214.0 million in outstanding debt under the credit facility at December 31, 2006.

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

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Aggregate Royalties. Aggregate royalty revenues are recognized on the basis of tons of aggregate sold by the Partnership s lessees and the corresponding revenue from those sales. Generally, the aggregate 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 aggregate they sell, subject to a minimum annual payment.

Coal Processing Fees. Coal processing fees are recognized on the basis of tons of coal processed through the facilities by the Partnership s lessees and the corresponding revenue from those sales. Generally, the lessees of the coal processing facilities make payments to us based on the greater of a percentage of the gross sales price or a fixed price per ton of coal that is processed and sold from the facilities. The lessees are also subject to minimum monthly, quarterly or annual payments. These minimum royalties are generally recoupable over a specified period of time if sufficient royalties are generated from coal processing 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. The coal processing leases are structured in a manner so that the lessees are responsible for operating and maintenance expenses associated with the facilities.

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 payments are initially recorded as deferred revenue when received and recognized as revenue 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

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

Partnership s income is ultimately sustained by the taxing authorities.

Share-Based Payment

The Partnership adopted Statement of Financial Accounting Standards No. 123R *Share-Based Payment,* effective January 1, 2006 using the modified prospective approach. Prior to 2006, awards under our Long Term Incentive Plan were accounted for on the intrinsic method under the provisions of APB No. 25. FAS 123R provides

Table of Contents

NATURAL RESOURCE PARTNERS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)