NATURAL RESOURCE PARTNERS LP
Form 10-Q
August 06, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549
FORM 10-Q

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

For the quarterly period ended June 30, 2009

OR

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

Commission file number: 001-31465
NATURAL RESOURCE PARTNERS L.P.
(Exact name of registrant as specified in its charter)

Delaware	35-2164875
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

601 Jefferson Street, Suite 3600
Houston, Texas 77002
(Address of principal executive offices)
(Zip Code)
(713) 751-7507
(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definition of accelerated filer , large accelerated filer , and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ
At August 6, 2009 there were 69,451,136 Common Units outstanding.

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Forward-Looking Statements

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

Such forward-looking statements include, among other things, statements regarding capital expenditures, acquisitions and dispositions, expected commencement dates of mining, projected quantities of future production by our lessees and projected demand for or supply of coal and aggregates that will affect sales levels, prices and royalties and other revenues 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 in this Form 10-Q and in our Form 10-K for the year ended December 31, 2008 for important factors that could cause our actual results of operations or our actual financial condition to differ.

Part I. Financial Information
Item 1. Financial Statements

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS
(In thousands)

	June 30, 2009 (Unaudited)	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 81,495	$ 89,928
Accounts receivable, net of allowance for doubtful accounts	26,293	31,883
Accounts receivable affiliate	3,906	1,351
Other	704	934
Total current assets	112,398	124,096
Land	24,343	24,343
Plant and equipment, net	71,130	67,204
Coal and other mineral rights, net	1,133,023	979,692
Intangible assets, net	163,610	102,828
Loan financing costs, net	3,120	2,679
Other assets, net	461	498
Total assets	$ 1,508,085	$ 1,301,340
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 804	$ 861
Accounts payable affiliates	175	365
Current portion of long-term debt	32,235	17,235
Accrued incentive plan expenses current portion	3,982	3,179
Property, franchise and other taxes payable	4,543	6,122
Accrued interest	10,328	6,419
Total current liabilities	52,067	34,181
Deferred revenue	49,064	40,754
Accrued incentive plan expenses	5,007	4,242
Long-term debt	606,280	478,822
Partners capital:		
Common units outstanding: (69,451,136 in 2009, 64,891,136 in 2008)	769,892	719,341
General partner s interest	14,218	13,579
Holders of incentive distribution rights	12,180	11,069
Accumulated other comprehensive loss	(623)	(648)

Total partners capital	795,667	743,341
Total liabilities and partners capital	$ 1,508,085	$ 1,301,340

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

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit data)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(Unaudited)			
Revenues:				
Coal royalties	$ 46,380	$ 60,026	$ 98,987	$ 109,178
Aggregate royalties	1,347	1,933	2,997	5,295
Coal processing fees	2,400	1,757	4,300	3,654
Transportation fees	3,489	3,361	5,585	5,010
Oil and gas royalties	953	1,933	2,446	3,378
Property taxes	2,514	3,105	5,725	5,497
Minimums recognized as revenue	67	149	290	456
Override royalties	1,336	2,006	3,884	4,505
Other	1,001	1,322	2,006	2,674
Total revenues	59,487	75,592	126,220	139,647
Operating costs and expenses:				
Depreciation, depletion and amortization	21,996	16,748	35,074	31,807
General and administrative	5,834	6,890	13,340	11,039
Property, franchise and other taxes	3,151	4,098	7,126	7,747
Transportation costs	473	408	741	529
Coal royalty and override payments	372	343	861	652
Total operating costs and expenses	31,826	28,487	57,142	51,774
Income from operations	27,661	47,105	69,078	87,873
Other income (expense):				
Interest expense	(10,675)	(7,064)	(18,754)	(14,424)
Interest income	96	312	178	756
Net income	$ 17,082	$ 40,353	$ 50,502	$ 74,205
Net income attributable to:				
General partner	$ 98	$ 611	$ 539	$ 1,116
Holders of incentive distribution rights	$ 12,180	$ 9,822	$ 23,561	$ 18,399
Limited partners	$ 4,804	$ 29,920	$ 26,402	$ 54,690
Basic and diluted net income per limited partner unit	$ 0.07	$ 0.46	$ 0.40	$ 0.84
Weighted average number of units outstanding	66,946	64,891	65,924	64,891

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

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(Unaudited)	
Cash flows from operating activities:		
Net income	$ 50,502	$ 74,205
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	35,074	31,807
Non-cash interest charge, net	1,010	235
Loss from disposition of assets		32
Change in operating assets and liabilities:		
Accounts receivable	1,865	(8,971)
Other assets	267	584
Accounts payable and accrued liabilities	(247)	429
Accrued interest	3,909	(265)
Deferred revenue	8,310	2,726
Accrued incentive plan expenses	1,568	1,078
Property, franchise and other taxes payable	(1,579)	(990)
Net cash provided by operating activities	100,679	100,870
Cash flows from investing activities:		
Acquisition of land, coal and other mineral rights	(95,641)	
Acquisition or construction of plant and equipment	(1,157)	(7,454)
Net cash used in investing activities	(96,798)	(7,454)
Cash flows from financing activities:		
Proceeds from loans	303,000	
Deferred financing costs	(661)	
Repayment of loans	(160,542)	(9,543)
Retirement of obligation related to purchase of coal reserves and infrastructure	(60,000)	
Costs associated with issuance of units	(21)	
Distributions to partners	(94,090)	(81,760)
Net cash used in financing activities	(12,314)	(91,303)
Net increase (decrease) in cash and cash equivalents	(8,433)	2,113
Cash and cash equivalents at beginning of period	89,928	58,341
Cash and cash equivalents at end of period	$ 81,495	$ 60,454

Supplemental cash flow information:

Cash paid during the period for interest	$ 13,760	$ 14,450
Non-cash investing activities:		
Equity issued for acquisitions	$ 95,910	$
Liability assumed in acquisitions	1,170	
Non-cash financing activities:		
Obligation related to purchase of coal reserves and infrastructure	59,220	

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

The accompanying unaudited consolidated financial statements have been prepared in accordance with generally accepted accounting principles for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included. Operating results for the three and six months ended June 30, 2009 are not necessarily indicative of the results that may be expected for future periods.

You should refer to the information contained in the footnotes included in Natural Resource Partners L.P. s 2008 Annual Report on Form 10-K in connection with the reading of these unaudited interim consolidated financial statements.

The Partnership engages principally in the business of owning, managing and leasing coal properties in the three major coal-producing regions of the United States: Appalachia, the Illinois Basin and the Western United States. The Partnership does not operate any mines. The Partnership leases coal reserves through its wholly owned subsidiary, NRP (Operating) LLC, (NRP Operating), to experienced mine operators under long-term leases that grant the operators the right to mine the Partnership s coal reserves in exchange for royalty payments. The Partnership s lessees are generally required to make payments to the Partnership based on the higher of a percentage of the gross sales price or a fixed royalty per ton of coal sold, in addition to a minimum payment.

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

The 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.

2. Recent Accounting Pronouncements

In September 2006, the FASB issued Statement of Financial Accounting Standard (SFAS) No. 157, Fair Value Measurements . SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. This standard eliminates inconsistencies found in various prior pronouncements but does not require any new fair value measurements. SFAS No. 157 was effective for the Partnership on January 1, 2008, but in February 2008, the FASB issued Staff Position 157-2, permitting entities to delay application of SFAS 157 to fiscal years beginning after November 15, 2008, for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). On January 1, 2009, the Partnership began applying SFAS 157 fair value requirements to nonfinancial assets and nonfinancial liabilities that are not recognized or disclosed on a recurring basis.

On April 9, 2009, the FASB issued FASB Staff Position No. FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instrument*, which amends FASB Statement No. 107, *Disclosures about Fair Value of Financial Instruments*, to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. This FSP also amends APB Opinion No. 28, *Interim Financial Reporting*, to require those disclosures in summarized financial information at interim reporting periods. This FSP is effective for interim reporting periods ending after June 15, 2009, and requires that the Partnership provide fair value footnote disclosure related to its outstanding debt quarterly but will otherwise not materially impact the financial statements. Fair value measurements are disclosed in footnote 8.

In December 2007, the FASB issued SFAS No. 141R, Business Combinations (SFAS 141(R)), which replaces SFAS 141. SFAS 141(R) establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any controlling interest; recognizes and measures goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The Partnership adopted SFAS 141(R) on January 1, 2009 and, therefore, acquisitions accounted for as business combinations that are completed by the Partnership in 2009 and thereafter will be impacted by this new standard.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51 (SFAS 160). SFAS 160 establishes new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 was effective for the Partnership on January 1, 2009. The adoption did not impact the financial statements.

In June 2008, the FASB issued Staff Position (FSP) No. EITF No. 03-06-1 Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities. This FSP affects entities that accrue cash dividends on share-based payment awards during the awards service period when the dividends do not need to be returned if the employees forfeit the award. The FSP requires that all outstanding unvested share-based payment awards that contain rights to nonforfeitable dividends participate in undistributed earnings with common shareholders and are considered participating securities. Because the awards are considered participating securities, the issuing entity is required to apply the two-class method of computing basic and diluted earnings per share. The provisions of FSP No. EITF No. 03-06-1 were effective for the Partnership on January 1, 2009, but because distributions accrued on the Partnership s share-based payment awards are subject to forfeiture, the adoption of the FSP did not impact earnings per unit.

In May 2009, the FASB issued SFAS No. 165, Subsequent Events (SFAS 165). SFAS 165 establishes general standards of accounting for and disclosure of events that occur subsequent to the balance sheet date but before financial statements are issued. SFAS 165 defines (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. Under SFAS 165, a public reporting entity shall evaluate subsequent events through the date the financial statements are issued. The Partnership adopted SFAS 165 for the quarter ended June 30, 2009. The adoption did not impact the financial position, results of operations or cash flows. As disclosed in Note 15. Subsequent Events, the Partnership evaluated subsequent events through August 6, 2009.

In June 2009, the FASB issued SFAS No. 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162 (SFAS 168). SFAS 168 establishes the Codification as the source of authoritative U.S. accounting and reporting standards recognized by the FASB for use in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP. Rules and interpretive releases of the SEC under authority of federal securities law are also sources of authoritative GAAP for SEC registrants. SFAS 168 is effective for interim and annual reporting periods after September 15, 2009. The Partnership expects that SFAS 168 will have no impact on its financial position, results of operations or cash flows.

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

3. Significant Acquisitions

Gatling Ohio - In May 2009, the Partnership completed the purchase of the membership interests in two companies from Adena Minerals, LLC, an affiliate of the Cline Group. The companies own coal reserves and infrastructure assets at Cline s Yellowbush Mine located on the Ohio River in Meigs County, Ohio. The Partnership issued 4,560,000 common units to Adena Minerals in connection with this acquisition. In addition, the general partner of Natural Resource Partners granted Adena Minerals an additional nine percent interest in the general partner.

Macoupin In January 2009, the Partnership acquired coal reserves and infrastructure assets related to the Shay No. 1 mine in Macoupin County, Illinois for $143.7 million from Macoupin Energy, LLC, an affiliate of the Cline Group.

4. Plant and Equipment

The Partnership s plant and equipment consist of the following:

	June 30, 2009	December 31, 2008
	(In thousands)	
	(Unaudited)	
Construction in process	$	$ 8,524
Plant and equipment at cost	84,732	68,197
Accumulated depreciation	(13,602)	(9,517)
Net book value	$ 71,130	$ 67,204

	Six months ended June 30, 2009	2008
	(In thousands) (Unaudited)	
Total depreciation expense on plant and equipment	$ 4,085	$ 2,184

5. Coal and Other Mineral Rights

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

	June 30, 2009	December 31, 2008
	(In thousands)	
	(Unaudited)	
Coal and other mineral rights	$ 1,423,023	$ 1,253,314
Less accumulated depletion and amortization	(290,000)	(273,622)
Net book value	$ 1,133,023	$ 979,692

	Six months ended June 30, 2009	2008
	(In thousands) (Unaudited)	
Total depletion and amortization expense on coal and other mineral rights	$ 29,443	$ 28,093

Excluding a onetime expense of $8.2 million for a terminated lease due to a mine closure, depletion decreased as a result of lower total production for the first six months of 2009.

6. Intangible Assets

Amounts recorded as intangible assets along with the balances and accumulated amortization are reflected in the table below:

	June 30, 2009		December 31, 2008	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(In thousands) (Unaudited)		(In thousands)	
Finite-lived intangible assets				
Above market transportation contracts	$ 127,169	$ 4,876	$ 82,276	$ 3,683
Above market coal leases	42,717	1,400	25,281	1,046
	$ 169,886	$ 6,276	$ 107,557	$ 4,729

As a part of the acquisition of coal reserves and transportation assets in the first half of 2009, the Partnership acquired additional above market transportation contracts valued at $44.9 million and two above market coal leases valued at $17.5 million.

Amortization expense related to contract intangibles was $0.6 million and $1.0 million and $1.5 million and $1.5 million for the three and six months ended June 30, 2009 and 2008, respectively, and is based upon the production and sales of coal from acquired reserves and the number of tons of coal transported using the transportation infrastructure. The estimates of expense for the periods as indicated below are based on current mining plans and are subject to revision as those plans change in future periods.

Estimated amortization expense (In thousands, unaudited):

For remainder of year ended December 31, 2009	$2,283
For year ended December 31, 2010	5,936
For year ended December 31, 2011	6,447
For year ended December 31, 2012	6,470
For year ended December 31, 2013	6,470
For year ended December 31, 2014	6,470

7. Long-Term Debt

Long-term debt consists of the following:

	June 30, 2009	December 31, 2008
	(In thousands)	
	(Unaudited)	
$300 million floating rate revolving credit facility, due March 2012	$	$ 48,000
5.55% senior notes, with semi-annual interest payments in June and December, maturing June 2013	35,000	35,000
4.91% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2018	43,700	49,750
8.38% senior notes, with semi-annual interest payments in March and September, with scheduled principal payments beginning March 2013, maturing in March 2019	150,000	
5.05% senior notes, with semi-annual interest payments in January and July, with scheduled principal payments beginning July 2008, maturing in July 2020	92,308	92,308
5.31% utility local improvement obligation, with annual principal and interest payments, maturing in March 2021	2,307	2,499
5.55% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2023	40,200	43,500
5.82% senior notes, with semi-annual interest payments in March and September, with scheduled principal payments beginning March 2010, maturing in March 2024	225,000	225,000
8.92% senior notes, with semi-annual interest payments in March and September, with scheduled principal payments beginning March 2014, maturing in March 2024	50,000	
Total debt	638,515	496,057
Less current portion of long term debt	(32,235)	(17,235)
Long-term debt	$ 606,280	$ 478,822

The Partnership has a $300 million revolving credit facility, and at June 30, 2009, the full amount was available under the facility. The Partnership incurs a commitment fee on the undrawn portion of the revolving credit facility at rates ranging from 0.10% to 0.30% per annum. Under an accordion feature in the credit facility, the Partnership may request its lenders to increase their aggregate commitment to a maximum of $450 million on the same terms. However, under the current financial market conditions, the Partnership cannot be certain that its lenders will elect to participate in the accordion feature. To the extent the lenders decline to participate, the Partnership may elect to bring new lenders into the facility, but it cannot make any assurance that the additional credit capacity will be available to the Partnership on the existing terms.

In March 2009, the Partnership completed a private placement of $200 million of senior unsecured notes. Two tranches of amortizing senior notes were issued: $150 million that bear interest at 8.38%; and $50 million that bear interest at 8.92%. Both tranches of the notes have semi-annual interest payments. These senior notes also provide that in the event that the Partnership s leverage ratio exceeds 3.75 to 1.00 at the end of any fiscal quarter, then in addition to all other interest accruing on these notes, additional interest in the amount of 2.00% per annum shall accrue on the notes for the two succeeding quarters and for as long thereafter as the leverage ratio remains above 3.75 to 1.00.

The Partnership was in compliance with all terms under its long-term debt as of June 30, 2009.

8. Fair Value Measurements

The Partnership discloses certain assets and liabilities using fair value as defined by FAS 157.

SFAS No. 157 describes three levels of inputs that may be used to measure fair value:

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

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

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

The Partnership s financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and long-term debt. The carrying amount of the Partnership s financial instruments included in accounts receivable and accounts payable approximates their fair value due to their short-term nature. The Partnership s cash and cash equivalents include money market accounts and are considered a Level 1 measurement. The fair market value of the Partnership s long-term debt was estimated to be $588.3 million and $385.5 million at June 30, 2009 and December 31, 2008, respectively, for the senior notes. The carrying value of the Partnership s long-term debt was $638.5 million and $496.1 million at June 30, 2009 and December 31, 2008, respectively, for the senior notes. The fair value is estimated by management using comparable term risk-free treasury issues with a market rate component determined by current financial instruments with similar characteristics which is a Level 3 measurement. Since the Partnership s credit facility has variable rate debt, its fair value approximates its carrying amount.

9. Net Income Per Unit Attributable to Limited Partners and Adoption of EITF Issue 07-04

The Partnership adopted EITF Issue 07-04: *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships* effective January 1, 2009. This EITF provides guidance related to the calculation of earnings per unit for master limited partnerships that have Incentive Distribution Rights (IDRs) as part of their equity structure. Under the Partnership Agreement, IDRs are a separate interest from that of the General Partner and therefore are a participating security. However, IDRs participate in income only to the extent of cash distributions and such distributions as required in the Partnership Agreement are considered priority distributions. Therefore distributions on the IDRs from income for the current period are subtracted from net income prior to the determination of net income allocable to limited and general partnership interests. Net income per limited partnership unit is determined based on cash distributions to those interests from income of the period increased for their share of any undistributed earnings or reduced for their share of distributions in excess of earnings for the period. As provided for in our Partnership Agreement, IDRs do not have an interest in undistributed earnings and do not share in losses of the Partnership. As required by the EITF, all prior periods have been restated to conform to the new guidance including presentation of the equity interests of IDRs as a separate component of equity. In prior periods, the IDRs owned by the General Partner were included in the equity interest of the General Partner. As the IDRs of the Partnership are not denominated in terms of shares or units, earnings for those interests on a per unit or share basis are not presented separately in the accompanying financial statements. Basic and diluted net income per unit attributable to limited partners are the same since the Partnership has no potentially dilutive securities outstanding.

10. Related Party Transactions

Reimbursements to Affiliates of its General Partner

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

The reimbursements to affiliates of the Partnership s general partner for services performed by Western Pocahontas Properties and Quintana Minerals Corporation totaled $1.7 million and $1.4 million and $3.4 million and $2.7 million for each of the three and six month periods ended June 30, 2009 and 2008, respectively.

Transactions with Cline Affiliates

Williamson Energy, LLC, a company controlled by Chris Cline, leases coal reserves from the Partnership, and the Partnership provides coal transportation services to Williamson for a fee. Mr. Cline, both individually and through another affiliate, Adena Minerals, LLC, owns a 31% interest in the Partnership s general partner and in the incentive distribution rights of the Partnership, as well as 13,510,072 common units. At June 30, 2009, the Partnership had accounts receivable totaling $3.0 million from Williamson. For the three and six month periods ended June 30, 2009 and 2008, the Partnership had total revenue of $9.4 million and $7.5 million and $15.1 million and $9.3 million, respectively, from Williamson. In addition, the Partnership has also received $1.6 million in advance minimum royalty payments that have not been recouped.

Gatling, LLC, a company also controlled by Chris Cline, leases coal reserves from the Partnership and the Partnership provides coal transportation services to Gatling for a fee. At June 30, 2009, the Partnership had accounts receivable totaling $0.2 million from Gatling. For the three and six month periods ended June 30, 2009 and 2008, the Partnership had total revenue of $0.6 million and $0.9 million, and $1.1 million and $2.1 million, respectively, from Gatling, LLC. In addition, the Partnership has also received $9.8 million in advance minimum royalty payments that have not been recouped.

In May 2009, Gatling Ohio, LLC, a company also controlled by Chris Cline, leased coal reserves from the Partnership and the Partnership began providing coal transportation services to Gatling Ohio for a fee. At June 30, 2009, the Partnership had accounts receivable totaling $0.2 million from Gatling Ohio. For the three and six month periods ended June 30, 2009, the Partnership had total revenue of $0.3 million.

Macoupin Energy, LLC, a company also controlled by Chris Cline, leases coal reserves and infrastructure from the Partnership. The Partnership recorded $0.8 million in imputed interest expense in the first quarter related to the delayed payment structure of this acquisition.

Quintana Capital Group GP, Ltd.

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

In February 2007, a fund controlled by Quintana Capital acquired a significant membership interest in Taggart Global USA, LLC, including the right to nominate two members of Taggart s 5-person board of directors. The Partnership currently has a memorandum of understanding with Taggart Global pursuant to which the two companies have agreed to jointly pursue the development of coal handling and preparation plants. The Partnership will own and lease the plants to Taggart Global, which will design, build and operate the plants. The lease payments are based on the sales price for the coal that is processed through the facilities. To date, the Partnership has acquired four facilities under this agreement with Taggart with a total cost of $46.6 million. For the three and six month periods ended June 30, 2009 and 2008, the Partnership received total revenue of $1.3 million and $1.0 million and $2.0 million and $2.0 million, respectively, from Taggart. At June 30, 2009, the Partnership had accounts receivable totaling $0.3 million from Taggart.

In June 2007, a fund controlled by Quintana Capital acquired Kopper-Glo, a small coal mining company that is one of the Partnership s lessees with operations in Tennessee. For the three and six month periods ended June 30, 2009 and 2008, the Partnership had total revenue of $0.3 million and $0.3 million and $0.8 million and $0.5 million, respectively, from Kopper-Glo, and at June 30, 2009, the Partnership had accounts receivable totaling $0.1 million from Kopper-Glo.

11. Commitments and Contingencies

Legal

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

Environmental Compliance

The operations conducted on the Partnership s properties by its lessees are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. As owner of surface interests in some properties, the Partnership may be liable for certain environmental conditions occurring at the surface properties. The terms of substantially all of the Partnership s leases require the lessee to comply with all applicable laws and regulations, including environmental laws and regulations. Lessees post reclamation bonds assuring that reclamation will be completed as required by the relevant permit, and substantially all of the leases require the lessee to indemnify the Partnership against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. The Partnership has neither incurred, nor is aware of, any material environmental charges imposed on it related to its properties as of June 30, 2009. The Partnership is not associated with any environmental contamination that may require remediation costs.

12. Major Lessees

Revenues from lessees that exceeded ten percent of total revenues for the periods are indicated below:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009		2008		2009		2008	
	Revenues	Percent	Revenues	Percent	Revenues	Percent	Revenues	Percent
	(Dollars in thousands) (Unaudited)							
Lessee A	$10,308	17.3%	$8,393	11.1%	$16,553	13.1%	$11,459	8.2%
Lessee B	4,837	8.1%	9,158	12.1%	12,145	9.6%	16,356	11.7%

13. Incentive Plans

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

Under the plan a grantee will receive the market value of a common unit in cash upon vesting. Market value is defined as the average closing price over the last 20 trading days prior to the vesting date. The CNG Committee may make grants under the Long-Term Incentive Plan to employees and directors containing such terms as it determines, including the vesting period. Outstanding grants vest upon a change in control of the Partnership, the general partner, or GP Natural Resource Partners LLC. If a grantee s employment or membership on the board of directors terminates for any reason, outstanding grants will be automatically forfeited unless and to the extent the CNG Committee provides otherwise.

A summary of activity in the outstanding grants for the first six months of 2009 are as follows:

Outstanding grants at the beginning of the period	571,284
Grants during the period	207,366
Grants vested and paid during the period	(125,052)
Forfeitures during the period	
Outstanding grants at the end of the period	653,598

Grants typically vest at the end of a four-year period and are paid in cash upon vesting. The liability fluctuates with the market value of the Partnership units and because of changes in estimated fair value determined each quarter using the Black-Scholes option valuation model. Risk free interest rates and volatility are reset at each calculation based on current rates corresponding to the remaining vesting term for each outstanding grant and ranged from 0.48% to 2.08% and 44.50% to 74.16%, respectively at June 30, 2009. The Partnership s historic distribution rate of 6.33% was used in the calculation at June 30, 2009. The Partnership recorded expenses related to its plans to be reimbursed to its general partner of $1.5 million and $3.9 million and $4.4 million and $4.0 million for the three and six month periods ended June 30, 2009 and 2008, respectively. In connection with the Long-Term Incentive Plan, payments are typically made during the first quarter of the year. Payments of $2.9 million and $3.2 million were paid during the three and six month periods ended June 30, 2009 and 2008, respectively.

In connection with the phantom unit awards granted in February 2008 and 2009, the CNG Committee also granted tandem Distribution Equivalent Rights, or DERs, which entitle the holders to receive distributions equal to the distributions paid on the Partnership s common units. The DERs are only applicable to the 2008 and 2009 awards that vest in 2012 and 2013 and, at the discretion of the CNG Committee, may be included with awards granted in the future. The DERs are payable in cash upon vesting but may be subject to forfeiture if the grantee ceases employment prior to vesting.

The unaccrued cost associated with the outstanding grants and related DERs at June 30, 2009 was $9.9 million.

14. Distributions

On May 14, 2009, the Partnership paid a cash distribution equal to $0.54 per unit to unitholders of record on May 4, 2009.

15. Subsequent Events

The following represents material events that have occurred subsequent to June 30, 2009 but prior to August 6, 2009, the date the Partnership s Form 10-Q was filed with the Securities and Exchange Commission:

Acquisitions

On July 16, 2009, the Partnership acquired approximately 121 acres of limestone reserves in Wise County, Texas from Blue Star Materials, LLC for a purchase price of $24 million. As of August 6, 2009, the Partnership had funded $12 million of the acquisition with borrowings under the Partnership s credit facility.

Distributions

On July 22, 2009, the Partnership declared a second quarter 2009 distribution of $0.54 per unit. The distribution will be paid on August 14, 2009 to unitholders of record on August 5, 2009.

Item 2. 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 and the financial statements and footnotes included in the Natural Resource Partners L.P. Form 10-K, as filed on February 27, 2009.

Executive Overview

Our Business

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

Our revenue and profitability are dependent on our lessees ability to mine and market our coal reserves. Most of our coal is produced by large companies, many of which are publicly traded, with experienced and professional sales departments. A significant portion of our coal is sold by our lessees under coal supply contracts that have terms of one year or more. However, over the long term, our coal royalty revenues are affected by changes in the market for and the market price of coal.

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

In addition to coal royalty revenues, we generated approximately 22% of our year to date and second quarter revenues from other sources in both 2008 and 2009. These other sources include: aggregate royalties; coal processing and transportation fees; rentals; royalties on oil and gas; timber; overriding royalties; and wheelage payments.

Current Market Conditions and our Liquidity

Our business model depends in large part on our ability to make acquisitions and finance those acquisitions through the issuance of long-term debt or equity in the capital markets. In March 2009, we issued $200 million of senior notes, using the proceeds to pay down our revolving credit facility and to partially fund the Macoupin acquisition. As of June 30, 2009 we had the full $300 million in available capacity under our existing credit facility, which does not mature until March 2012, as well as approximately $81 million in cash. In addition, because we amortize substantially all of our long-term debt, we have no need to pay off or refinance any debt obligations in 2009, other than our regularly scheduled principal payments.

The cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, and refused to refinance existing debt at maturity on any terms. As a result, our ability to obtain additional capital other than that available under our current credit facility may be severely restricted. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues, results of operations and quarterly distributions.

Current Results

As of June 30, 2009, our reserves were subject to 205 leases with 74 lessees. For the six months ended June 30, 2009, our lessees produced 24.3 million tons of coal generating $99.0 million in coal royalty revenues from our properties, and our total revenues were $126.2 million.

As a result of declines in production the first half of the year and declines in coal prices in the second quarter, we recorded lower than expected revenues for the periods ended June 30, 2009. The difficult economic environment and very low prices for natural gas, a competing fuel, impacted demand for coal in all regions, in particular within heavily industrialized regions where coal is the dominant generating fuel. While we do not have much visibility into the future of the coal markets, several public coal companies have indicated that they are starting to see signs of a recovery. We expect that the remainder of 2009 will be similar to the second quarter, and do not expect any material improvement in our results this year.

Even though coal royalty revenues from our Appalachian properties represented 67% of our total revenues in the first half of 2009, this percentage has continued to decline as we are diligently working to diversify our holdings by expanding our presence in the Illinois Basin. Through our relationship with the Cline Group, we expect our Illinois Basin assets to contribute even more significantly to our total revenues in the remainder of 2009 and 2010.

Because we have significant exposure to metallurgical coal, we are feeling the effects of the global reduction in demand for steel. Several of the metallurgical coal producers on our properties temporarily ceased production during the quarter. We believe that met coal prices have recently settled near a bottom and should remain steady for the remainder of the year. Approximately 28% of our coal royalty revenues and 21% of the related production during the six months ended 2009 were from metallurgical coal.

Political, Legal and Regulatory Environment

The political, legal and regulatory environment is becoming increasingly difficult for the coal industry. On Thursday, June 11, 2009, the White House Council on Environmental Quality announced a Memorandum of Understanding among the Environmental Protection Agency, Department of Interior, and the U.S. Army Corps of Engineers concerning the permitting and regulation of coal mines in Appalachia. While the Council described this memorandum as an unprecedented step[s] to reduce environmental impacts of mountaintop coal mining, the memorandum broadly applies to all forms of coal mining in Appalachia. The memorandum contemplates both short-term and long-term changes to the process for permitting and regulating coal mines in Appalachia.

These new processes will be effective in the states of Kentucky, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. The short-term actions are scheduled for implementation in 2009 and involve modifications to existing policy and guidance. The memorandum also describes a longer term process for the assessment of policy with the potential for new regulatory actions. The all-encompassing nature of the changes suggests that implementation of the memorandum will generate continued uncertainty regarding the permitting of coal mines in Appalachia for some time and inevitably will lead, at a minimum, to delays and increased costs.

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

Finally, on June 26, 2009, the U.S. House of Representatives approved adoption of the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey cap-and-trade legislation or ACESA. The purpose of ACESA is to control and reduce emissions of greenhouse gases, or GHGs, in the United States. GHGs are certain gases, including carbon dioxide and methane, that may be contributing to warming of the Earth s atmosphere and other climatic changes. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as coal.

The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. President Obama has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance permitting system that results in fewer allowances being issued each year but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or how any bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could have an adverse effect on demand for our coal.

Distributable Cash Flow

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

Our distributable cash flow represents cash flow from operations less actual principal payments and cash reserves set aside for 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
(In thousands)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	(Unaudited)			
	2009	**2008**	**2009**	**2008**
Net cash provided by operating activities	$ 57,127	$ 61,667	$ 100,679	$ 100,870
Less scheduled principal payments	(9,350)	(9,350)	(9,542)	(9,543)
Less reserves for future principal payments	(8,059)	(4,308)	(16,118)	(8,616)
Add reserves used for scheduled principal payments	9,350	9,350	9,542	9,543
Distributable cash flow	$ 49,068	$ 57,359	$ 84,561	$ 92,254

Acquisitions

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

Gatling Ohio In May 2009, we completed the purchase of the membership interest in two companies from Adena Minerals, LLC, an affiliate of the Cline Group. The companies own coal reserves and infrastructure assets, related to Cline s Yellowbush Mine located on the Ohio River in Meigs County, Ohio. We issued 4,560,000 common units to Adena Minerals in connection with this acquisition. In addition, the general partner of Natural Resource Partners granted Adena Minerals an additional nine percent interest in the general partner.

Massey Jewell Smokeless. In March 2009, we acquired from Lauren Land Company, a subsidiary of Massey Energy, the remaining four-fifths interest in coal reserves located in Buchanan County, Virginia in which we previously held a one-fifth interest. Total consideration for this purchase was $12.5 million.

Macoupin. In January 2009, we acquired coal reserves and infrastructure assets related to the Shay No. 1 mine in Macoupin County, Illinois for $143.7 million from Macoupin Energy, LLC, an affiliate of the Cline Group.

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

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

Licking River Preparation Plant. In March 2008, we signed an agreement for the construction of a coal preparation plant facility under our memorandum of understanding with Taggart Global USA, LLC. The total cost for the facility, located in Eastern Kentucky, was $8.9 million.

Results of Operations

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data) (Unaudited)			
Coal:				
Coal royalty revenues				
Appalachia				
Northern	$ 2,890	$ 4,902	$ (2,012)	(41)%
Central	30,308	42,974	(12,666)	(29)%
Southern	4,809	3,802	1,007	26%
Total Appalachia	38,007	51,678	(13,671)	(26)%
Illinois Basin	6,570	5,923	647	11%
Northern Powder River Basin	1,803	2,425	(622)	(26)%
Total	$ 46,380	$ 60,026	$ (13,646)	(23)%
Production (tons)				
Appalachia				
Northern	967	1,927	(960)	(50)%
Central	6,989	9,629	(2,640)	(27)%
Southern	798	930	(132)	(14)%
Total Appalachia	8,754	12,486	(3,732)	(30)%
Illinois Basin	1,956	2,293	(337)	(15)%
Northern Powder River Basin	1,074	1,314	(240)	(18)%
Total	11,784	16,093	(4,390)	(27)%
Average gross royalty per ton				
Appalachia				
Northern	$ 2.99	$ 2.54	$ 0.45	18%
Central	4.34	4.46	(0.12)	(3)%
Southern	6.03	4.09	1.94	47%
Total Appalachia	4.34	4.14	0.20	5%
Illinois Basin	3.36	2.58	0.78	30%
Northern Powder River Basin	1.68	1.85	(0.17)	(9)%
Combined average gross royalty per ton	3.94	3.73	0.21	6%
Aggregates:				
Royalty revenue	$ 1,047	$ 1,633	$ (586)	(36)%
Aggregate royalty bonus	$ 300	$ 300	$	
Production	791	1,238	447	(36)%
Average base royalty per ton	$ 1.32	$ 1.32	$	

Coal Royalty Revenues and Production. Coal royalty revenues comprised approximately 78% and 79% of our total revenue for the three month periods ended June 30, 2009 and 2008. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. Primarily due to lower production by our lessees in all three regions, coal royalty revenues decreased in the three month period ended June 30, 2009 compared to the same period of 2008. The lower production was due to a number of factors, including mine closures and temporary idling due to increasing costs, a difficult regulatory environment, increasingly difficult geologic conditions and some mines moving to adjacent properties. This decline in production was in part offset by a higher royalty per ton in the Northern and Southern Appalachian regions. We expect that our lessees in Appalachia will continue to experience these difficulties, which may cause future production levels to continue to decline.

Illinois Basin. Coal royalty revenues increased, despite slightly lower production. This increase was due to higher pricing on our Williamson property for the three month period ended June 30, 2009 compared to the same period for 2008. This was partially offset by another mine moving its production to adjacent property.

Northern Powder River Basin. Coal royalty revenues and production decreased on our Western Energy property due to the normal variations that occur due to the checkerboard nature of ownership.

Aggregates Royalty Revenues and Production. Aggregate production decreased during the second quarter resulting in lower royalty revenue. The lower production is mainly attributed to lower demand in the region.

Results of Operations

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data) (Unaudited)			
Coal:				
Coal royalty revenues				
Appalachia				
Northern	$ 5,933	$ 8,405	$ (2,472)	(29)%
Central	68,186	77,271	(9,085)	(12)%
Southern	9,906	9,300	606	7%
Total Appalachia	84,025	94,976	(10,951)	(12)%
Illinois Basin	10,821	8,556	2,265	26%
Northern Powder River Basin	4,141	5,646	(1,505)	(27)%
Total	$ 98,987	$ 109,178	$ (10,191)	(9)%
Production (tons)				
Appalachia				
Northern	2,066	3,264	(1,198)	(37)%
Central	14,978	18,571	(3,593)	(19)%
Southern	1,639	2,224	(585)	(26)%
Total Appalachia	18,683	24,059	(5,376)	(22)%
Illinois Basin	3,282	3,458	(176)	(5)%
Northern Powder River Basin	2,301	3,045	(744)	(24)%
Total	24,266	30,562	(6,296)	(21)%
Average gross royalty per ton				
Appalachia				
Northern	$ 2.87	$ 2.58	$ 0.29	11%
Central	4.55	4.16	0.39	9%
Southern	6.04	4.18	1.86	44%
Total Appalachia	4.50	3.95	0.55	14%
Illinois Basin	3.30	2.47	0.83	34%
Northern Powder River Basin	1.80	1.85	(0.05)	(3)%
Combined average gross royalty per ton	4.08	3.57	0.51	14%
Aggregates:				
Royalty revenue	$ 1,977	$ 3,051	$ (1,074)	(35)%
Aggregate royalty bonus	$ 1,020	$ 2,244	$ (1,224)	(55)%
Production	1,481	2,392	(911)	(38)%
Average base royalty per ton	$ 1.33	$ 1.28	$ 0.05	4%

Coal Royalty Revenues and Production. Coal royalty revenues comprised approximately 78% of our total revenue for each of the six month periods ended June 30, 2009 and 2008. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. Primarily due to lower production by our lessees, coal royalty revenues decreased in the six month period ended June 30, 2009 compared to the same period of 2008. Production was lower across all three Appalachian regions. Although production was lower, our royalty per ton increased across all regions, partially offsetting the production decline. The lower production was due to a number of factors, including mine closures and temporary idling due to increasing costs, a difficult regulatory environment, increasingly difficult geologic conditions and some mines moving to adjacent properties. We expect that our lessees in Appalachia will continue to experience these difficulties, which may cause current production levels and potentially the prices being realized by our lessees to decline.

Illinois Basin. Coal royalty revenues increased despite an overall decline in production, due to increased production from our Williamson property, which generated a higher royalty per ton, for the six month period ended June 30, 2009 compared to the same period for 2008. This was partially offset by another mine moving its production to adjacent property.

Northern Powder River Basin. Coal royalty revenues and production decreased on our Western Energy property due to the normal variations that occur due to the checkerboard nature of ownership. Near the end of the first quarter, the mine on this property experienced a brief work stoppage during the negotiation of a new labor contract. The new contract was approved in early April and the mine is back in operation.

Aggregates Royalty Revenues and Production. Aggregate production decreased during the six months ended June 30, 2009 resulting in lower royalty revenue. The lower production is mainly attributed to lower demand in the region.

Other Operating Results

Coal Processing and Transportation Revenues. We generated $2.4 million and $1.8 million and $4.3 million and $3.7 million in processing revenues for each of the three and six month periods ended June 30, 2009 and 2008. 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. Coal processed through the facilities decreased 17% for the six month period of 2009 compared to the same period of 2008, while revenue increased 17% due to increased sales prices.

In addition to our preparation plants, we own coal handling and transportation infrastructure associated with the Gatling mining complexes in West Virginia and Ohio and beltlines and rail load-out facilities associated with Williamson Energy s Pond Creek No. 1 mine in Illinois. In contrast to our typical royalty structure, we receive a fixed rate per ton for coal transported over these facilities. We operate coal handling and transportation infrastructure and have subcontracted out that responsibility to third parties. We generated transportation fees from these assets of approximately $3.5 million and $3.4 million and $5.6 million and $5.0 million for the three and six month periods ended June 30, 2009 and 2008, respectively. Production increased during 2009 due to the longwall at our Williamson property coming online in March 2008.

Oil and Gas Royalties. We generated $1.0 million and $1.9 million and $2.4 million and $3.4 million for the three and six month periods ended June 30, 2009 and 2008, respectively.

Override revenues. Override revenues were $1.3 million and $2.0 million and $3.9 million and $4.5 million for the three and six month periods ending June 30, 2009 and 2008, respectively.

Other revenues. Other revenues, primarily comprised of rent and wheelage, generated $1.0 million and $1.3 million and $2.0 million and $2.7 million for the three and six month periods ended June 30, 2009 and 2008, respectively.

Operating costs and expenses. Included in total expenses are:

Depreciation, depletion and amortization of $22.0 million and $16.7 million and $35.1 million and $31.8 million for the three and six month periods ended June 30, 2009 and 2008, respectively. Excluding a onetime expense of $8.2 million for a terminated lease due to a mine closure, depletion decreased as a result of lower total production for the first six months of 2009.

General and administrative expenses of $5.8 million and $6.9 million and $13.3 million and $11.0 million for the three and six month periods ended June 30, 2009 and 2008, respectively. The change in general and administrative expense is primarily due to accruals under our long-term incentive plan attributable to fluctuations in our unit price.

Property, franchise and other taxes have decreased slightly for both the three and six month periods ended June 30, 2009 when compared to the same period of 2008. This decrease reflects lower West Virginia and Virginia property taxes offset partially by higher Kentucky unmined mineral taxes. A substantial portion of our property taxes is reimbursed to us by our lessees and is reflected as property tax revenue on our statement of income.

Interest Expense. Interest expense was higher for the first half of 2009 when compared to the first half of 2008 due to additional debt incurred to fund acquisitions.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

We satisfy our working capital requirements with cash generated from operations. Since our initial public offering, we have financed our property acquisitions with available cash, borrowings under our revolving credit facility, and the issuance of our senior notes and additional units. However, given the current global financial crisis, we cannot be certain that proceeds from capital markets issuances will be available or sufficient to finance future acquisitions. While our ability to satisfy our debt service obligations and pay distributions to our unitholders depends in large part on our future operating performance, our ability to make acquisitions will depend on prevailing economic conditions in the financial markets as well as the coal industry and other factors, some of which are beyond our control. For a more complete discussion of factors that will affect cash flow we generate from our operations, please read Item 1A. Risk Factors. in this Form 10-Q and in our Form 10-K for the year ended December 31, 2008. Our capital expenditures, other than for acquisitions, have historically been minimal.

Net cash provided by operations for the six months ended June 30, 2009 and 2008 was $100.7 million and $100.9 million, respectively. Approximately 75% to 80% of our cash provided by operations has historically been generated from coal royalty revenues.

Net cash used in investing activities for the six months ended June 30, 2009 and 2008 was $96.8 million and $7.5 million, respectively. For the six months ended June 30, 2009 and 2008, substantially all of our investing activities consisted of acquiring coal reserves, plant and equipment and other mineral rights.

Net cash flows used in financing for the six months ended June 30, 2009 was $12.3 million. During the first half of 2009, we had proceeds from loans of $303.0 million offset by repayment of debt of $161.0 million and retirement of a $60 million obligation related to the purchase of coal reserves and infrastructure. We also paid distributions of $94.1 million. During the same period for 2008, we used $91.3 million of cash, which included a debt repayment of $9.5 million and $81.8 million for distributions to partners.

Long-Term Debt

At June 30, 2009, our debt consisted of:

- $35 million of 5.55% senior notes due 2013;
- $43.7 million of 4.91% senior notes due 2018;
- $150 million of 8.38% senior notes due 2019;
- $92.3 million of 5.05% senior notes due 2020;
- $2.3 million of 5.31% utility local improvement obligation due 2021;
- $40.2 million of 5.55% senior notes due 2023;
- $225 million of 5.82% senior notes due 2024; and
- $50 million of 8.92% senior notes due 2024.

Other than the 5.55% senior notes due 2013, which have semi-annual interest payments, all of our senior notes require annual principal payments in addition to semi-annual interest payments. The principal payments on the 5.82% senior notes due 2024 do not begin until March 2010, the principal payments of the 8.38% senior notes due in 2019 do not begin until March 2013 and the principal payments of the 8.92% senior notes do not begin until March 2014. We also make annual principal and interest payments on the utility local improvement obligation.

Credit Facility. We have a $300 million revolving credit facility, and at June 30, 2009 we had the full amount available to us under the facility. Under an accordion feature in the credit facility, we may request our lenders to increase their aggregate commitment to a maximum of $450 million on the same terms. However, under the current market conditions, we cannot be certain that our lenders will elect to participate in the accordion feature. To the extent the lenders decline to participate, we may elect to bring new lenders into the facility, but cannot make any assurance that the additional credit capacity will be available to us on existing terms.

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

- the higher of the federal funds rate plus an applicable margin ranging from 0% to 0.50% or the prime rate as announced by the agent bank; or

- at a rate equal to LIBOR plus an applicable margin ranging from 0.45% to 1.50%.

We incur a commitment fee on the unused portion of the revolving credit facility at a rate ranging from 0.10% to 0.30% per annum.

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

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

- not permit debt secured by certain liens and debt of subsidiaries to exceed 10% of consolidated net tangible assets (as defined in the note purchase agreement); and

- maintain the ratio of consolidated EBITDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated operating lease expense) at not less than 3.5 to 1.00.

In March 2009, we issued $150 million of 8.38% notes maturing March 25, 2019 and $50 million of 8.92% notes maturing March 2024. These senior notes provide that in the event that our leverage ratio exceeds 3.75 to 1.00 at the end of any fiscal quarter, then in addition to all other interest accruing on these notes, additional interest in the amount of 2.00% per annum shall accrue on the notes for the two succeeding quarters and for as long thereafter as the leverage ratio remains above 3.75 to 1.00.

Shelf Registration Statement

In addition to our credit facility, on February 27, 2009 we filed an automatically effective shelf registration statement on Form S-3 with the SEC that is available for registered offerings of common units and debt securities. The amounts, prices and timing of the issuance and sale of any equity or debt securities will depend on market conditions, our capital requirements and compliance with our credit facility and senior notes.

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.

Related Party Transactions

Reimbursements to Affiliates of our General Partner

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

The reimbursements to affiliates of our general partner for services performed by Western Pocahontas Properties and Quintana Minerals Corporation totaled $1.7 million and $1.4 million and $3.4 million and $2.7 million, for each of the three and six month periods ended June 30, 2009 and 2008, respectively.

Transactions with Cline Affiliates

Williamson Energy, LLC, a company controlled by Chris Cline, leases coal reserves from us, and we provide coal transportation services to Williamson for a fee. Mr. Cline, both individually and through another affiliate, Adena Minerals, LLC, owns a 31% interest in our general partner and the incentive distribution rights of NRP, as well as 13,510,072 common units. At June 30, 2009, we had accounts receivable totaling $3.0 million from Williamson. For the three and six month periods ended June 30, 2009 and 2008, we had total revenue of $9.4 million and $7.5 million and $15.1 million and $9.3 million, respectively, from Williamson. In addition, we have received advance minimum royalties of $1.6 million that have not been recouped.

Gatling, LLC, a company also controlled by Chris Cline, leases coal reserves from us and we provide coal transportation services to Gatling for a fee. At June 30, 2009, we had accounts receivable totaling $0.2 million from Gatling. For the three and six month periods ended June 30, 2009 and 2008, we had total revenue of $0.6 million and $0.9 million and $1.1 million and $2.1 million, respectively, from Gatling, LLC. In addition, we have received advance minimum royalty payments of $9.8 million that have not been recouped.

In May 2009, Gatling Ohio, LLC, a company also controlled by Chris Cline, leased coal reserves from us and we began providing coal transportation services to Gatling Ohio for a fee. At June 30, 2009, we had accounts receivable totaling $0.2 million from Gatling Ohio. For the three and six month periods ended June 30, 2009, we had total revenue of $0.3 million.

Macoupin Energy, LLC, a company also controlled by Chris Cline, leases coal reserves and infrastructure assets from us.

Quintana Capital Group GP, Ltd.

Corbin J. Robertson, Jr. is a principal in Quintana Capital Group GP, Ltd., which controls several private equity funds focused on investments in the energy business. In connection with the formation of Quintana Capital, NRP s Board of Directors adopted a formal conflicts policy that establishes the opportunities that will be pursued by NRP and those that will be pursued by Quintana Capital. The governance documents of Quintana Capital s affiliated investment funds reflect the guidelines set forth in NRP s conflicts policy. For a more detailed description of this policy, please see Item 13. Certain Relationships and Related Transactions, and Director Independence in our Form 10-K for the year ended December 31, 2008.

In February 2007, a fund controlled by Quintana Capital acquired a 43% membership interest in Taggart Global, including the right to nominate two members of Taggart s 5-person board of directors. NRP currently has a memorandum of understanding with Taggart Global pursuant to which the two companies have agreed to jointly pursue the development of coal handling and preparation plants. NRP will own and lease the plants to Taggart Global, which will design, build and operate the plants. The lease payments are based on the sales price for the coal that is processed through the facilities. To date, NRP has acquired four facilities under this agreement with Taggart for a total cost of $46.6 million. For the three and six months ended June 30, 2009 and 2008, total revenues were $1.3 million and $1.0 million and $2.0 million and $2.0 million, respectively, from Taggart. At June 30, 2009, we had accounts receivable totaling $0.3 million from Taggart.

In June 2007, a fund controlled by Quintana Capital acquired Kopper-Glo, a small coal mining company that is one of our lessees with operations in Tennessee. For the three and six month periods ended June 30, 2009 and 2008, we had total revenue of $0.3 million and $0.3 million and $0.8 million and $0.5 million, respectively, from Kopper-Glo, and at June 30, 2009, we had accounts receivable totaling $0.1 million.

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 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 as of June 30, 2009. We are not associated with any environmental contamination that may require remediation costs. However, our lessees regularly conduct reclamation work on the properties under lease to them. Because we are not the permittee of the operations on our properties, we are not responsible for the costs associated with these operations. In addition, West Virginia has established a fund to satisfy any shortfall in our lessees reclamation obligations.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risk, which includes adverse changes in commodity prices and interest rates as discussed below:

Commodity Price Risk

We are dependent upon the effective marketing and efficient mining of our coal reserves by our lessees. Our lessees sell coal under various long-term and short-term contracts as well as on the spot market. A large portion of these sales are under long-term contracts. As evidenced by the current market, 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. Additionally, volatility in coal prices could make it difficult to estimate with precision the value of our coal reserves and any coal reserves that we may consider for acquisition.

Interest Rate Risk

Our exposure to changes in interest rates results from our borrowings under our revolving credit facility, which are subject to variable interest rates based upon LIBOR. At June 30, 2009, we did not have any variable interest rate debt.

Item 4. Controls and Procedures

NRP carried out an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act) as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of NRP management, including the Chief Executive Officer and Chief Financial Officer of the general partner of the general partner of NRP. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and procedures are effective in providing reasonable assurance that (a) the information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms, and (b) such information is accumulated and communicated to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

No changes were made to our internal control over financial reporting during the last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

None.

Item 1A. Risk Factors

In addition to the risk factors previously disclosed in our Form 10-K for the year ended December 31, 2008, you should consider the following risk:

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for our coal.

On June 26, 2009, the U.S. House of Representatives approved adoption of the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey cap-and-trade legislation or ACESA. The purpose of ACESA is to control and reduce emissions of greenhouse gases, or GHGs, in the United States. GHGs are certain gases, including carbon dioxide and methane, that may be contributing to warming of the Earth s atmosphere and other climatic changes. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACESA, most sources of GHG emissions would be required to obtain GHG emission allowances corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACESA s overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as coal.

The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. President Obama has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance permitting system that results in fewer allowances being issued each year but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or how any bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could have an adverse effect on demand for our coal.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

None.

Item 6. Exhibits

3.1	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of NRP (GP) LP, dated as of May 20, 2009 (incorporated by reference to the Current Report on Form 8-K filed on May 21, 2009).
3.2*	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of NRP (GP) LP, dated as of June 30, 2009.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of Sarbanes-Oxley.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of Sarbanes-Oxley.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350.

* Filed herewith.

SIGNATURES

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

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

Date: August 6, 2009

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

Date: August 6, 2009

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

Date: August 6, 2009

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