SECURITIES AND EXCHANGE COMMISSION
Washington, D.C.

FORM 10-K

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

For the fiscal year ended **December 31, 2011**	Commission File Number **000-51129**

JAMES RIVER COAL COMPANY

(Exact name of registrant as specified in its charter)

Virginia	***54-1602012***
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
901 E. Byrd Street, Suite 1600	
Richmond, Virginia	***23219***
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **: (804) 780-3000**

Securities registered pursuant to Section 12(b) of the Act:	Common Stock, par value $0.01 per share Series A Participating Cumulative Preferred Stock Purchase Rights
Name of each exchange on which registered:	The Nasdaq Global Select Market
Securities registered pursuant to Section 12(g) of the Act:	None

Indicate by a check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☐ No ☑

Indicate by a check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

Yes ☐ No ☑

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 ☑ No ☐

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 ☑ No ☐

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. ☑

Indicate by a check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐ 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 ☐ No ☑

The aggregate market value of the common stock held by non-affiliates of the registrant, based upon the closing sale price of Common Stock, par value $0.01 per share, on June 30, 2011 as reported on the Nasdaq Global Market, was approximately $543.2 million (affiliates being, for these purposes only, directors, executive officers and holders of more than 10% of the registrant's Common Stock).

The number of shares of the registrant's Common Stock, par value $.01 per share, outstanding as of February 17, 2012 was 35,671,953.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the registrant's 2012 Annual Meeting of Shareholders, to be filed with the Securities and Exchange Commission (the "SEC"), are incorporated by reference into Part III of this Annual Report on Form 10-K.

FORWARD-LOOKING INFORMATION

From time to time, we make certain comments and disclosures in reports and statements, including this report, or statements made by our officers, which may be forward-looking in nature. These statements are known as "forward-looking statements," as that term is used in Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Examples include statements related to our future outlook, anticipated capital expenditures, projected cash flows and borrowings and sources of funding. We caution readers that forward-looking statements, including disclosures that use words such as "anticipate," "believe," "estimate," "expect," "goal," "intend," "may," "should," "could," "objective," "plan," "predict," "project," "target," "will," or their negatives and similar words or statements, are subject to certain risks, trends and uncertainties that could cause actual cash flows, results of operations, financial condition, cost reductions, acquisitions, dispositions, financing transactions, operations, expansion, consolidation and other events to differ materially from the expectations expressed or implied in such forward-looking statements. We have based any forward-looking statements we have made on our current expectations and assumptions about future events and circumstances that are subject to risks, uncertainties and contingencies that could cause results to differ materially from those discussed in the forward-looking statements, including, but not limited to:

- our cash flows, results of operation or financial condition;
- the consummation of acquisition, disposition or financing transactions and the effect thereof on our business;
- our ability to successfully integrate International Resource Partners LP and its related entities;
- governmental policies, regulatory actions and court decisions affecting the coal industry or our customers' coal usage;
- legal and administrative proceedings, settlements, investigations and claims;
- our ability to obtain and renew permits necessary for our existing and planned operation in a timely manner;
- environmental concerns related to coal mining and combustion and the cost and perceived benefits of alternative sources of energy;
- inherent risks of coal mining beyond our control, including weather and geologic conditions or catastrophic weather-related damage;
- our production capabilities;
- availability of transportation;
- our ability to timely obtain necessary supplies and equipment;
- market demand for coal, electricity and steel;
- competition;
- our relationships with, and other conditions affecting, our customers;
- employee workforce factors;
- our assumptions concerning economically recoverable coal reserve estimates;
- future economic or capital market conditions; and
- our plans and objectives for future operations and expansion or consolidation.

We are including this cautionary statement in this document to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf, of us. Any forward-looking statements should be considered in context with the various disclosures made by us about our businesses, including without limitation the risk factors more specifically described below in Item 1A. Risk Factors of this Annual Report on Form 10-K.

Forward-looking statements speak only as if the date they are made. We disclaim any intent or obligation to update these forward-looking statements unless required by securities law, and we caution the reader not to rely on them unduly.

JAMES RIVER COAL COMPANY

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PART I

Available Information

The Company's website address is *http://www.jamesrivercoal.com*. The Company makes available free of charge through its website its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports as soon as reasonably practicable after filing or furnishing the material to the Securities and Exchange Commission (the "SEC"). However, our website and any contents thereof should not be considered to be incorporated by reference into this document. You may read and copy documents the Company files at the SEC's public reference room at 100 F Street, NE, Washington, D.C., 20549. Please call the SEC at 1-800-SEC-0330 for information on the public reference room. The SEC maintains a website that contains annual, quarterly and current reports, proxy statements and other information that issuers (including the Company) file electronically with the SEC. The SEC's website is *http://www.sec.gov*.

In Part III of this Form 10-K, we incorporate certain information by reference from our Proxy Statement for the 2012 Annual Meeting of Shareholders. The Company expects to file the Proxy Statement with the SEC on or about March 15, 2012, and will make it available on the Company website as soon as reasonably practicable. Please refer to the Proxy Statement when it is available.

Item 1. Business

General Business

Overview

Unless the context requires otherwise, references to “we,” “us,” “our” or “the Company” are intended to mean consolidated James River Coal Company (“James River”) and its wholly-owned subsidiaries. This drafting style is suggested by the Securities and Exchange Commission and is not meant to indicate that the publicly-traded James River owns or operates any asset, business or property of any of its subsidiaries. The operations and businesses described in this filing are owned and operated, and management services provided, by distinct direct and indirect subsidiaries of James River. James River was incorporated in 1991 under the laws of the State of Virginia.

We mine, process and sell thermal and metallurgical coal through eight active mining complexes located throughout eastern Kentucky, southern West Virginia and southern Indiana. The majority of our metallurgical coal was obtained in the April 18, 2011 acquisition (the IRP Acquisition) of International Resource Partners LP and its subsidiary companies (collectively IRP). The IRP Acquisition was completed on April 18, 2011 for $516.0 million in an all-cash transaction. The base purchase price of $475.0 million was increased by the cash acquired and any working capital (as defined in the agreement) that exceeded $18.5 million. IRP did not have any debt at the time of the closing. The IRP Acquisition increases our offerings of metallurgical coal, provides us with greater access to the international seaborne coal market and expands our brokering and trading operations. We have two reportable business segments based on the coal basins in which we operate — Central Appalachia (CAPP) and the Midwest (Midwest). IRP is included in our CAPP segment. For additional information on our segments, see Note 15 to our financial statements in Item 8 herein.

As of December 31, 2011 our eight mining complexes included 25 underground mines, 12 surface mines and 14 preparation plants. As of December 31, 2011, we believe that we controlled approximately 362.8 million tons of proven and probable coal reserves. At current production levels, we believe these reserves would support greater than 30 years of production.

In 2011, our mines produced 10.3 million tons of coal (including 0.7 million tons of coal produced in our mines that are operated by contract mine operators) and we purchased another 1.6 million tons for resale. Of the 10.3 million tons produced from Company mines, approximately 63% came from underground mines, while the remaining 37% came from surface mines. In 2011, we generated revenues of $1.2 billion and had a net loss of $39.1 million. Approximately 56% of our total revenues for 2011 were generated from coal sales to electric utility customers and the remaining 44% from coal sales (including metallurgical coal) to industrial and other customers. In 2011, South Carolina Public Service Authority and Georgia Power Company were our largest customers, representing approximately 20% and 11% of our total revenues, respectively. No other customer accounted for more than 10% of our revenues.

The coal that we sell is obtained from three sources: our Company-operated mines, our mines that are operated by independent contract mine operators, and other third parties from whom we purchase coal for resale. Contract mining and coal purchased from other third parties provide flexibility to increase or decrease production based on market conditions. The table below reflects the amount and percentage of coal obtained from those sources in 2011:

	Tons (000s)	Percentage of total coal obtained by the Company
Coal produced from Company-operated mines	9,599	81.0%
Coal obtained from our mines operated by independent contractors	655	5.5%
Coal purchased from third parties	1,605	13.5%
	11,859	**100%**

Mining Methods

Our Company-operated and contractor mines produce coal using different mining methods. These methods are room and pillar underground mining and contour and point removal surface mining. These methods are described in more detail below.

Room and Pillar. In the underground room and pillar method of mining, continuous mining machines cut five to nine entries into the coal seam and connect them by driving crosscuts, leaving a series of rectangular pillars, or columns of coal, to help support the mine roof and control the flow of air. Generally, openings are driven 20 feet wide and the pillars are 40 to 100 feet wide. As mining advances, a grid-like pattern of entries and pillars is formed. When mining advances to the end of a panel, or section of the mine, retreat mining may begin. In retreat mining, as much coal as is feasible is mined from the pillars that were created in advancing the panel, allowing the roof to cave.

The coal face is cut with continuous mining machines and the coal is transported from the continuous mining machine to the mine conveyor belts using a continuous haulage system, shuttle cars or ram cars. The mine conveyor system consists of a series of conveyor belts, which transport the coal from the active face areas to the surface. Once on the surface, the coal is transported to the preparation plants where it is processed to remove any impurities. The coal is then transported to the clean coal stockpiles or silos from which it is loaded for shipment to our customers. Reserve recovery, a measure of the percentage of the total coal in place that is ultimately produced, using this method of mining typically depends on the shape of the reserve, the amount of low-cover areas, and the geological characteristics of the reserve body.

Surface Mining. Surface mining is used when coal is found close to the surface. This method involves the removal of overburden (earth and rock covering the coal) with heavy earth-moving equipment and explosives, loading out the coal, replacing the overburden and topsoil after the coal has been excavated and reestablishing vegetation and plant life and making other improvements that have local community and environmental benefit. Overburden is typically removed at our mines by either hydraulic shovels or front-end loaders which place the overburden into large trucks.

In the Central Appalachia Region (CAPP), we use the contour and highwall surface mining methods. Contour and highwall mining is used where removal of all the overburden overlying a coal seam is either uneconomical or impossible due to property control or other issues. With contour mining, a contour cut is taken along the outcrop of the seam and the coal is removed from the exposed pit. Highwall mining can then take place where the seam is exposed in the highwall. A highwall miner resembles an underground continuous miner. The highwall miner cuts entries into the coal seam up to 10 feet wide and up to 900 feet deep. The coal is transported to the surface through the augers and loaded into trucks using a loader. The contour area is then reclaimed by returning overburden to the pit and restoring the mountainside to its approximate original contour.

As of December 31, 2011, we had 12 Company-operated surface mines, 5 of which had a contract highwall miner operated in connection with the surface operations. Four of the contract highwall miners were operated by independent contractors.

Underground Mine Characteristics

Underground mines are characterized as either “drift” mines or “below drainage” mines. Drift mines are mines that are developed into the coal seam at a point where the seam intersects the surface. The area where the seam intersects the surface is commonly known as the “outcrop.” Multiple entries are developed into the coal seam and are used as airways for mine ventilation, passageways for miners and supplies, and entries for conveyor belts that transport coal from the active production areas of the mine to the surface.

In below drainage mines, the coal seam does not intersect the surface in the vicinity of the mining area. Therefore, the coal seam must be accessed through excavated passageways from the surface. These passageways typically consist of vertical shafts and angled slopes. The shafts are constructed with diameters ranging from 12 to 24 feet and are used as airways for mine ventilation and passageways for miners and supplies via elevators. The slopes, when used to house conveyor belts to transport the mined coal from the active production areas of the mine to the surface, are typically driven at an angle of less than 17 degrees from the horizontal. In addition, the slopes provide passageways for miners and supplies, and airways for mine ventilation.

As of December 31, 2011, we had 23 Company-operated underground mines and 2 contract underground mines in operation for a total of 25 mines, of which 19 were drift mines and the remaining 6 were below-drainage mines.

Mining Operations

Our coal production is conducted through seven mining complexes in the Central Appalachia Region and one mining complex in the Midwest Region. We generally do not own the land on which we conduct our mining operations. Rather, our coal reserves are controlled pursuant to leases from third party landowners. We believe that greater than 95% and 90% of our coal reserves in the Central Appalachia Region and Midwest Region, respectively, are controlled pursuant to leases from third party landowners. These leases typically convey mining rights to the coal producer in exchange for a per ton fee or royalty payment of a percentage of the gross sales price to the lessor. The average royalties (including wheelage amounts and unrecoupable royalty prepayments) for coal reserves from our producing properties were approximately 9.1% and 4.2% of produced coal revenue for the year ended December 31, 2011, in the Central Appalachia Region and the Midwest Region, respectively.

All of our operations are located on or near public highways and receive electrical power from commercially available sources. Existing facilities and equipment are maintained in good working condition and are continuously updated through capital expenditure investments.

The following table provides summary information on our mining complexes as of December 31, 2011:

	Number and Type of Mines				Quality of Shipments for the year ended 2011	
Mining Complex	Underground	Surface (S) and Highwall (HW)	Total	Tons Shipped (millions) (2)	Average Sulfur Content (%)	Average BTU Content
Central Appalachia						
Bell County	2	—	2	0.3	1.8	13,376
Bledsoe	4	1S /1HW(1)	5	1.5	1.4	12,889
Blue Diamond Buckeye (3)	2	2S /1HW(1)	4	1.2	1.0	12,642
Blue Diamond Leatherwood	4	—	4	1.4	1.0	12,905
Hampden Coal	5	1	6	1.1	0.9	13,500(4)
Laurel Mountain	—	3S /2HW(1)	3	0.8	1.1	12,117
McCoy Elkhorn	6	1S /1HW(1)	7	1.8	1.4	12,939
Midwest						
Triad Mining	2	4S	6	2.5	3.2	11,329

(1) Highwall Miner operated in conjunction with surface mining.

(2) Tons shipped include only the tons shipped from our mining complexes. Purchased tons that are not processed or shipped from our mining complexes are not included in the tons shipped. Additionally, tons shipped between locations are only included in the shipped tons from the originating location.

(3) Blue Diamond Buckeye was formerly referred to as Leeco.

(4) Hampden Coal's average BTU content of shipments in 2011 was an estimate based on the quality of the reserves as of December 31, 2010.

The following summarizes additional information concerning each of our mining complexes:

Bell County. The Bell County complex is located in Bell County in eastern Kentucky. We use room and pillar mining and mine the Jellico and Garmeada seams of coal. Coal is processed at our preparation plant and loaded into railcars via an integrated four-hour unit train loadout that is serviced by both the CSX and Norfolk Southern railroads. As of December 31, 2011, we employed 125 mining and support personnel at this complex.

Bledsoe. The Bledsoe complex is located in Leslie and Harlan counties in eastern Kentucky. Our underground mines use room and pillar mining and our surface mines use the contour and highwall mining methods. We mine the Hazard #4 and #4 Rider, and #5 seams of coal at this complex. Coal is processed at one of two preparation plants and loaded into railcars at a separate location via a four-hour unit train loadout on the CSX railroad. As of December 31, 2011, we employed 405 mining and support personnel at this complex.

Blue Diamond — Buckeye. The Buckeye complex is located in Knott and Perry counties in eastern Kentucky. Our underground mines use room and pillar mining and our surface mines use the contour and highwall mining methods. We mine the Amburgy, #7, #8, and #9 seams of coal at this complex. Coal is processed at our preparation plant and loaded into railcars via an integrated four-hour unit train loadout on the CSX railroad. As of December 31, 2011, we employed 232 mining and support personnel at this complex.

Blue Diamond — Leatherwood. The Leatherwood complex is located in Leslie, Perry and Letcher counties in eastern Kentucky. We use room and pillar mining for our underground mines. We mine the Hazard #4 and Elkhorn #3 seams of coal at this complex. Coal is processed at our preparation plant and loaded into railcars via an integrated four-hour unit train loadout on the CSX railroad. As of December 31, 2011, we employed 279 mining and support personnel at this complex.

Hampden. The Hampden Coal Complex is located in Mingo and Logan counties in southern West Virginia. The underground operations use room-and-pillar mining to produce metallurgical coal from the 2-Gas and Lower Cedar Grove seams. The surface mine produces metallurgical and steam coal from the Alma seam. Coal is processed at the Hampden Preparation Plant and loaded into railcars via 2 CSX load-outs and 1 Norfolk Southern Load-out. As of December 31, 2011, we employed approximately 433 mining and support personnel at this complex.

McCoy Elkhorn. The McCoy Elkhorn complex is located in Pike and Floyd counties in eastern Kentucky. Our underground mines use room and pillar mining and our surface mine uses the contour and highwall mining methods. Two of the underground mines and the highwall miner at the McCoy Elkhorn complex are operated by contractors. We mine the Millard, Alma, Whitesburg, Fireclay, Elkhorn #2 and Elkhorn #3 seams at this complex. Coal is processed at our three preparation plants and loaded into railcars via integrated four-hour unit train loadouts on the CSX railroad. As of December 31, 2011, we employed 413 mining and support personnel at this complex.

Laurel Mountain. The Laurel Mountain complex is located in Floyd, Johnson, Lawrence and Knott counties in eastern Kentucky. Our surface mines use both contour and highwall and area mining methods. We mine the Richardson, Skyline, Hazard #9, #8, #7, #4 Haddix, Fireclay, Whitesburg, Amburgy, and Elkhorn #3, #2, and #1 seams at this complex. Coal is processed and loaded into railcars at our twenty-four hour unit train load out facility on the CSX. As of December 31, 2011, we employed 164 mining and support personnel at this complex.

Triad. The Triad complex is located in Pike and Knox counties in southern Indiana. We use room and pillar mining to mine the Springfield seam of coal, and use the surface mine method to mine multiple seams, including the Danville, Millersburg, Hymera, Bucktown and Springfield seams. Coal is processed at one of five preparation plants (four of which our active) and loaded into trucks for delivery to the customer or by rail at our Switz City loadout. The Switz City loadout is serviced by Indiana Railroad and the Indiana Southern Railroad. As of December 31, 2011, we employed approximately 280 mining and support personnel at this complex.

Contract mining represented less than 6.0% of our coal production in the year ended December 31, 2011. Each mining complex monitors its contract mining operations and provides geological and engineering assistance to the contract mine operators. The contract mine operators generally provide their own equipment and operate the mines using their employees. Independent contract mine operators are paid a fixed rate for each ton of saleable product. We are primarily responsible for the reclamation activities involved with all contractor-operated mines. Our relationships with contract mine operators typically can be cancelled by either party without penalty by giving between 30 and 60 days notice.

Reserves

We have an ongoing mineral development drilling and exploration program on our coal properties. The purpose of the drilling and exploration program is to assist us with planning our mining activities and to better assess our coal reserves. Marshall Miller & Associates, Inc. (MM&A) prepared a detailed study of our CAPP reserves that we controlled as of March 31, 2004 based on all of our geologic information, including our then current drilling and mining data. MM&A completed their report on our CAPP reserves in June 2004. For the Triad properties, MM&A prepared a detailed study of Triad's reserves as of February 1, 2005 for the reserves obtained in the acquisition of Triad and as of April 11, 2006 for certain additional reserves acquired in the second quarter of 2006 in the Midwest. MM&A also prepared a detailed study of the reserves as of December 31, 2010 for the reserves obtained in the IRP Acquisition. We have used MM&A's March 31, 2004 study of the CAPP reserves and the December 31, 2010 study of the reserves acquired from IRP (which was based in part on previous evaluations of the properties) as the basis for our current internal estimate of our Central Appalachia reserves and MM&A's February 1, 2005 and April 11, 2006 studies as the basis for our current internal estimate of our Midwest reserves (collectively the "MM&A studies"). However, MM&A has not conducted any coal reserve study on our December 31, 2011 estimate.

The MM&A studies were planned and performed to obtain reasonable assurance of our subject demonstrated (proven plus probable) reserves. In connection with the studies, MM&A prepared reserve maps and had certified professional geologists develop estimates based on data supplied by us and using standards accepted by government and industry.

After reviewing the maps and information we supplied, MM&A prepared an independent mapping and estimate of our demonstrated reserves using methodology outlined in U.S. Geological Survey Circular 891 and SEC Industry Guide 7. MM&A developed reserve estimation criteria to assure that the basic geologic characteristics of the reserves (*e.g.*, minimum coal thickness and wash recovery, interval between deep mineable seams, mineable area tonnage for economic extraction, etc.) are in reasonable conformity with present and recent mine operation capabilities on our various properties.

We continue to have an ongoing mineral development drilling and exploration program on our coal properties. Any future negative changes in our reserves could have a material adverse impact on our depreciation, depletion and amortization expense. A material adverse impact could also lead to a charge for impairment of the value of our coal property assets.

As of December 31, 2011, we estimated that we controlled approximately 322.4 million tons of proven and probable coal reserves in Central Appalachia and 40.4 million tons of proven and probable coal reserves in the Midwest.

Reserves for these purposes are defined by SEC Industry Guide 7 as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. The reserve estimates have been prepared using industry-standard methodology to provide reasonable assurance that the reserves are recoverable, considering technical, economic and legal limitations. Although the MM&A studies found our reserves to be reasonable (notwithstanding unforeseen geological, market, labor or regulatory issues that may affect the operations), the MM&A studies did not include an economic feasibility study of our reserves. In accordance with standard industry practice, we have performed our own economic feasibility analysis for our reserves. It is not generally considered to be practical, however, nor is it standard industry practice, to perform a feasibility study for a company's entire reserve portfolio. In addition, MM&A did not independently verify our control of our properties, and has relied solely on property information supplied by us. Reserve acreage, average seam thickness, average seam density and average mine and wash recovery percentages were verified by MM&A to prepare a reserve tonnage estimate for each reserve. There are numerous uncertainties inherent in estimating quantities and values of economically recoverable coal reserves as discussed in "Critical Accounting Estimates — Coal Reserves".

The following table provides information on our mining complexes reserves (the quality information is based on the MM&A studies):

Mining Complex	Proven & Probable Reserves As of December 31, 2011 (1),(4) (millions of tons)	Approximate Overall Reserve Quality (2), (3) Estimated Years of Reserve Life Based on 2011 Production Levels	Sulfur Content (%)	Heat Value (Btu/lb.)
Central Appalachia				
Bell County	9.1	30	1.0	13,500
Bledsoe	57.4	39	1.2	13,000
Blue Diamond Buckeye (a)	50.3	40	1.2	13,200
Blue Diamond Leatherwood	75.3	55	1.1	13,700
Hampden	50.5	39	0.8	13,500
Laurel Mountain	42.4	37	1.5	12,300
McCoy Elkhorn	37.4	21	1.6	13,300
Total/Average	**322.4**	**38**	**1.2**	**13,200**
Midwest				
Triad	**40.4**	**16**	**3.2**	**12,000**

(a) Blue Diamond Buckeye was formerly referred to as Leeco.

(1) Proven reserves have the highest degree of geologic assurance and are reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings, or drill holes; (b) grade and/or quality are computed from the results of detailed sampling and (c) the sites for inspections, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established. Probable reserves have a moderate degree of geologic assurance and are reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation. This reserve information reflects recoverable tonnage on an as-received basis with 5.5% moisture.

(2) Sulfur content is expressed as the percent by weight of those constituents in the coal sample compared to the total weight of the sample being tested. Heat value is expressed as Btu per pound in the coal based on laboratory testing of coal samples. The samples are typically obtained from exploratory core borings placed at strategic locations within the coal reserve area. The samples are sent to accredited laboratories for testing under protocols established by the American Society of Testing and Materials (ASTM). The estimated overall quality values are derived by a multiple step process, including: (a) for each mine or reserve area, an arithmetic average quality (dry basis) was prepared to represent the coal tons within the area, based on samples from the area; (b) the overall quality of reserves for each mine complex was determined by performing a tonnage-weighted average of the average quality of all mine and reserve areas within the division; and (c) the resulting dry basis overall quality was converted to wet product basis to reflect its anticipated moisture content at the time of sale. The actual quality of the shipped coal may vary from these estimates due to factors such as: (a) the particle size of the coal fed to the plant; (b) the specific gravity of the float media in use at the preparation plant; (c) the type of plant circuit(s); (d) the efficiency of the plant circuit(s); (e) the moisture content of the final product; and (f) customer requirements.

(3) For the CAPP region, represents reserve quality information for our mining complexes as of March 31, 2004 for Bell County, Bledsoe, Blue Diamond Buckeye, Blue Diamond Leatherwood and McCoy and as of December 31, 2010 for Hamden and Laurel Mountain. For the Midwest region, represents weighted average reserve quality information as of February 1, 2005 and April 11, 2006, for the reserves obtained on the acquisition of the Triad mining complex and for a lease entered into during 2006, respectively. The reserve quality information is based on the MM&A studies.

(4) Represents the Company's estimate of reserves at December 31, 2011 based on additional information or reserves obtained from exploration and acquisition activities, production activities or discovery of new geologic information. We calculated the adjustments to the reserves in the same manner, and based on the same assumptions and qualifications, as used in the MM&A studies described above, but these December 31, 2011 estimates have not been reviewed by MM&A.

Processing and Transportation

Coal from each of our mine complexes is transported by conveyor belt or by truck to one of our preparation plants or directly to one of our load-outs, all of which are in close proximity to our mining operations. These preparation plants remove impurities from the run-of-mine coal (the raw coal that comes directly from the mine) and offer the flexibility to blend various coals and coal qualities to meet specific customer needs. We regularly upgrade and maintain all of our preparation plants to achieve a high level of coal cleaning efficiency and maintain the necessary capacity.

In Central Appalachia, coal consumed domestically is usually sold f.o.b. at the mine and transportation costs are normally borne by our customers. Export coal is usually sold at the loading port, with our customers responsible for further transportation. Producers usually pay shipping costs from the mine to the port. In 2011, our Central Appalachia produced coal was transported from the mines and to the customer primarily by rail, with the main rail carriers being CSX Transportation and Norfolk Southern Railway Company. The majority of our sales volume is shipped by rail, but a portion of our production is shipped by barge and truck.

In the Midwest, coal is shipped primarily by train and by truck to our customers. The trucked coal is primarily sold f.o.b delivery point with transportation costs borne by either the customer or us. Coal delivered by train and barge is sold f.o.b. at the point of loading. Our Triad mining complex has rail service provided by Indiana Railroad and Indiana Southern Railroad.

Our mining complexes are supported by personnel primarily located in London and Lexington, Kentucky and Charleston and Gilbert, West Virginia who provide engineering and permitting assistance, project management, land management and lease administration, coal quality control and quality reporting, accounting and purchasing support, and railroad transportation scheduling services.

Customers and Coal Contracts

As is customary in the coal industry, we regularly enter into long-term contracts (which we define as contracts with terms of one year or longer) with many of our customers. These arrangements allow customers to secure a supply for their future needs and provide us with greater predictability of sales volume and sales prices. In 2011, we generated 56% of our total revenues from coal sales to electric utility customers and the remaining 44% from coal sales (including metallurgical coal) to industrial and other customers. For the year ended December 31, 2011, South Carolina Public Service Authority (20%) and Georgia Power Company (11%) were our largest customers by revenues. No other customer accounted for more than 10% of total revenues.

In 2011, we sold approximately 9.3 million tons of coal in the CAPP region at an average selling price of $107.28 per ton. In the CAPP region, we currently have approximately 7.9 million and 1.3 million tons contracted to be sold in 2012 and 2013, respectively, at average selling prices in excess of $90.0 and $80.0, respectively. Current market prices for steam and metallurgical coal in the CAPP region are substantially below our average 2011 sales price for those coals. If the market does not strengthen, our sales price for future tons sold will be adversely impacted as compared to 2011.

In 2011, we sold approximately 2.5 million tons of coal in the Midwest region at an average selling price of $42.49 per ton. In the Midwest region, we currently have approximately 2.7 million and 2.1 million tons contracted to be sold in 2012 and 2013, respectively, at average selling prices in excess of our 2011 average selling price.

The terms of our contracts result from a bidding and negotiation process with our customers. Consequently, the terms of these contracts often vary significantly in many respects. Our long-term supply contracts typically contain one or more of the following pricing mechanisms:

- Fixed price contracts;
- Annually negotiated prices that reflect market conditions at the time; or
- Base-price-plus-escalation methods that allow for periodic price adjustments based on fixed percentages or, in certain limited cases, pass-through of actual cost changes.

A limited number of our contracts have features of several contract types, such as provisions that allow for renegotiation of prices on a limited basis within a base-price-plus-escalation agreement. Such re-opener provisions allow both the customer and us an opportunity to adjust prices to a level close to the current market conditions. Each contract is negotiated separately, and the triggers for re-opener provisions differ from contract to contract. Some of our existing contracts with re-opener provisions adjust the contract price to the market price at the time the re-opener provision is triggered. Re-opener provisions could result in early termination of a contract or a reduction in the volume to be purchased if the parties were to fail to agree on price.

Our long-term supply contracts also typically contain force majeure provisions allowing for the suspension of performance by the customer or us for the duration of specified events beyond the control of the affected party, including labor disputes. Some contracts may terminate upon continuance of an event of force majeure for an extended period, which is generally three to six months. Certain of our contracts are fixed in quantity but are priced on a quarterly basis. Contracts also typically specify minimum and maximum quality specifications regarding the coal to be delivered. Failure to meet these conditions could result in substantial price reductions or termination of the contract, at the election of the customer. Although the volume to be delivered under a long-term contract is stipulated, we, or the customer, may vary the timing of delivery within specified limits.

The terms of our long-term coal supply contracts also vary significantly in other respects, including: coal quantity parameters, flexibility and adjustment mechanisms, permitted sources of supply, treatment of environmental constraints, options to extend, suspension, termination and assignment provisions, and provisions regarding the allocation between the parties of the cost of complying with future government regulations.

Competition

The U.S. coal industry is highly competitive, with numerous producers in all coal producing regions. We compete against various large producers and hundreds of small producers. According to the U.S. Energy Information Administration, the largest producer produced approximately 17.7% (based on tonnage produced) of the total United States production in 2010, the latest year for which government statistics are available. The U.S. Department of Energy also reported 1,285 active coal mines in the United States in 2010. Demand for our coal by our principal customers is affected by:

- the price of competing coal and alternative fuel supplies, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric power;
- government regulations that affect end users' ability to burn coal;
- coal quality;
- transportation costs from the mine to the customer; and
- the reliability of supply.

Continued demand for our coal and the prices that we obtain are affected by demand for electricity, environmental and government regulation, technological developments and the availability and price of competing coal and alternative fuel supplies.

Employees

At December 31, 2011, we had 2,405 employees. None of our employees are currently represented by collective bargaining agreements. Relations with our employees are generally good.

Environmental and other Regulatory Matters

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

- employee health and safety;
- permitting and licensing requirements;
- air quality standards;
- water quality standards;
- plant, wildlife and wetland protection;

- blasting operations;
- the management and disposal of hazardous and non-hazardous materials generated by mining operations;
- the storage of petroleum products and other hazardous substances;
- reclamation and restoration of properties after mining operations are completed;
- discharge of materials into the environment, including air emissions and wastewater discharge;
- surface subsidence from underground mining; and
- the effects of mining operations on groundwater quality and availability.

Complying with these requirements, including the terms of our permits, has had, and will continue to have, a significant effect on our costs of operations. We could incur substantial costs, including clean up costs, fines, civil or criminal sanctions and third party claims for personal injury or property damage as a result of violations of or liabilities under these laws and regulations.

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 our coal. The possibility exists that new legislation or regulations may be adopted which would have a significant impact on our mining operations or our customers' ability to use coal and may require us or our customers to change operations significantly or incur substantial costs.

Numerous governmental permits and approvals are required for mining operations. In connection with obtaining these permits and approvals, we are, or may be, required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed exploration for or production of coal may have upon the environment, the public, historical artifacts and structures, and our employees' health and safety. The requirements imposed by such authorities may be costly and time-consuming and may delay commencement or continuation of exploration or production operations. Future legislation and administrative regulations may emphasize the protection of the environment and health and safety and, as a consequence, our activities may be more closely regulated. Such legislation and regulations, as well as future interpretations of existing laws, may require substantial increases in our equipment and operating costs and delays, interruptions or a termination of operations, the extent of which cannot be predicted.

While it is not possible to quantify the costs of compliance with all applicable federal and state laws, those costs have been and are expected to continue to be significant. We estimate that we will make expenditures of approximately \$3.4 million and \$3.2 million for environmental control facilities and complying with safety regulations in 2012 and 2013, respectively. These costs are in addition to reclamation and mine closing costs and the costs of treating mine water discharge, when necessary. Compliance with these laws has substantially increased the cost of coal mining, but is, in general, a cost common to all domestic coal producers.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") was enacted on July 21, 2010. Section 1503 of the Dodd-Frank Act contains new reporting requirements regarding coal or other mine safety. On December 21, 2011, the Securities and Exchange Commission adopted final rules that implement Section 1503 of the Dodd-Frank Act, and these rules went into effect on January 27, 2012. Our mine safety disclosures required pursuant to the Dodd-Frank Act appear in Exhibit 95 to this Annual Report on Form 10-K.

Mine Safety and Health Laws

Stringent federal health and safety standards were imposed by the Federal Coal Mine Safety and Health Act of 1969 and again with the adoption of the Federal Mine Safety and Health Act of 1977. Mine safety and health standards were further expanded in 2006 with the passage of the Mine Improvement and New Emergency Response Act ("MINER Act"). The combined federal regulations are comprehensive and affect numerous aspects of mining operations, including training of mine personnel, mining procedures, emergency response capabilities, availability of emergency breathable air, communication and tracking systems, blasting, the equipment used in mining operations and other matters.

The Federal Mine Safety and Health Administration ("MSHA"), is the primary regulating agency for safety and health matters and issues rules and regulations addressing mine safety and health. On June 21, 2011, MSHA issued a final rule requiring that the total incombustible content ("TIC") of the combined coal, rock and other dusts in underground coal mines be at least 80%. In addition, the final rule requires that where methane is present in any ventilating current, the TIC of such combined dust shall be increased 0.4% for each 0.1% of methane. The new rule revised the existing standard, which permitted TIC of combined dusts to be 65% in areas of a mine other than return air courses.

On October 19, 2010, MSHA issued a proposed rule ("PR1"), which would lower the current two milligram dust standard to one milligram gradually over a two-year period, mandate the use of continuous personal dust monitors, address extended work shifts, redefine normal production shifts, require additional medical surveillance examinations for miners, and provide for the use of a single, full-shift sample to determine compliance.

The PR1 would phase in the required use of the Continuous Personal Dust Monitor ("CPDM"). The CPDMs would electronically store all respirable dust sampling data collected during a shift and would be sent to MSHA electronically. The CPDMs would be optional for surface coal mines and for non-production areas of underground coal mines (such as outby areas).

Other changes include: requiring sampling of extended work shifts to account for occupational exposures of greater than eight hours per shift; requiring sampling when production is equivalent to or greater than the level of average production level over the last 30 production shifts; requiring spirometry testing, occupational history and symptom assessment to be implemented, in addition to the chest x-ray exam currently required for underground coal miners and medical surveillance; and finally, a single, full-shift sample collected by MSHA or the mine operator would be used to determine compliance rather than averaging multiple dust samples of different miners' exposures per the current requirements.

On February 2, 2011, MSHA published proposed changes to 30 C.F.R. Part 104 regarding the Pattern of Violations ("POV") program ("PR2"). Under the PR2, MSHA will consider all significant and substantial ("S&S") citations and orders issued, including non-final citations and orders, when determining POV status. The existing initial screening criteria found at 30 C.F.R. § 104.2 will be eliminated. Additionally, the PR2 removes the potential POV notice and instead will post the pattern criteria online so that operators can track their status. MSHA will also post compliance data that the agency will use on its website and provide access to mine operators in a searchable form. Finally, mines will be reviewed at least twice annually for POV status under the PR2. The new POV status will utilize similar criteria as to what is currently set forth in 30 C.F.R. § 104.3, including the history of S&S violations, § 104(b) failure to abate orders for S&S violations, § 104(d) citations and orders for an unwarrantable failure to comply, § 107(a) imminent danger orders, § 104(g) orders for untrained miner withdrawal orders, and other information "that demonstrates a serious safety or health management problem at the mine, such as accident, injury and illness records." Mitigating circumstances will also be considered, including changes in ownership, however, it is unclear at what point in the process the mine operator may offer such information to MSHA.

On December 27, 2010, MSHA issued a proposed rule, 75 *Fed. Reg.* 81165 ("PR3"), to revise the requirements for pre-shift, supplemental, on-shift and weekly examinations of underground coal mines. The PR3 would add the requirement that operators identify violations of mandatory health or safety standards and would also require the mine operator to record and correct these violations, note the actions taken to correct the conditions and review with mine examiners (*e.g.*, the mine foreman, assistant mine foreman or other certified persons) on a quarterly basis all citations and orders issued in areas where pre-shift, supplemental, on-shift and weekly examinations are required.

The Federal Mine Safety and Health Administration monitors compliance with these federal laws and regulations and can impose under recently enacted regulations maximum penalties of up to $220,000 for certain violations, as well as closure of the mine.

The states in which we operate have state mine safety and health regulation and enforcement similar to those at the federal level. Collectively, federal and state safety and health regulation in the coal mining industry is, perhaps, the most comprehensive for protection of employee health and safety affecting any segment of industry in the United States. While regulation has a significant effect on our operating costs, our United States competitors are subject to the same regulation.

Black Lung Legislation

Under the federal Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator is required to make black lung benefits or contribution payments to:

- current and former coal miners who are totally disabled from black lung disease;
- certain survivors of a miner who dies from black lung disease or pneumoconiosis; and
- a trust fund for the payment of benefits and medical expenses to any claimant whose last mine employment was before January 1, 1970, or where a miner's last coal employment was on or after January 1, 1970 and no responsible coal mine operator has been identified for claims, or where the responsible coal mine operator has defaulted on the payment of such benefits.

Federal black lung benefits rates are periodically adjusted according to the percentage increase of the federal pay rate.

In addition to the Black Lung Act, we also are liable under various state statutes for black lung claims. To a certain extent, our federal black lung liabilities are reduced by our state liabilities.

In January 2001, the United States Department of Labor amended regulations implementing the federal black lung laws to give greater weight to the opinion of a claimant's treating physician, expand the definition of black lung disease and limit the amount of medical evidence that can be submitted by claimants and respondents. The amendments also alter administrative procedures for the adjudication of claims, which, according to the Department of Labor, results in streamlined procedures that are less formal, less adversarial and easier for participants to understand. These and other changes to the federal black lung regulations could significantly increase our exposure to black lung benefits liabilities.

The Patient Protection and Affordable Care Act of 2010 (the "Act") was enacted into law on March 23, 2010 and included a black-lung provision that creates a rebuttable presumption that a miner with at least 15 years of service, with totally disabling pulmonary or respiratory lung impairment and negative radiographic chest x-ray evidence would be disabled due to pneumoconiosis and be eligible for black lung benefits. The new Act also makes it easier for widows of miners to become eligible for benefits. The enactment of this new legislation could significantly impact the Company's future payments for black lung benefits.

In recent years, legislation on black lung reform has been introduced but not enacted in Congress and in the Kentucky legislature. It is possible that additional legislation will be reintroduced for consideration by Congress. If any of the proposals included in this or similar legislation is passed, the number of claimants who are awarded benefits could significantly increase. Any such changes in black lung legislation, if approved, may adversely affect our business, financial condition and results of operations.

Environmental Laws and Regulations

We are subject to various federal environmental laws and regulatory entities, including:

- the Surface Mining Control and Reclamation Act of 1977;
- the Clean Air Act;
- the Clean Water Act;
- the Toxic Substances Control Act;
- the Comprehensive Environmental Response, Compensation and Liability Act;
- the U.S. Army Corps of Engineers; and
- the Resource Conservation and Recovery Act.

We are also subject to state laws of similar scope in each state in which we operate.

These environmental laws require reporting, permitting and/or approval of many aspects of coal operations. Both federal and state inspectors regularly visit mines and other facilities to ensure compliance. We have ongoing compliance and permitting programs designed to ensure compliance with such environmental laws.

Given the retroactive nature of certain environmental laws, we have incurred and may in the future incur liabilities, including clean-up costs, in connection with properties and facilities currently or previously owned or operated as well as sites to which we or our subsidiaries sent waste materials.

Surface Mining Control and Reclamation Act (SMCRA)

The SMCRA, and its state counterparts, establish operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of underground mining. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and following completion of mining activities. Permits for all mining operations must be obtained from the Federal Office of Surface Mining Reclamation and Enforcement or, where state regulatory agencies have adopted federally approved state programs under SMCRA, the state becomes the regulatory authority with primacy and issues the permits with federal oversight.

SMCRA and similar state statutes, among other things, require that mined property be restored in accordance with specified standards and approved reclamation plans. The mine operator must submit a bond or otherwise secure the performance of these reclamation obligations. The earliest a reclamation bond can be fully released is five years after reclamation has been achieved. All states impose on mine operators the responsibility for repairing or compensating for damage occurring on the surface as a result of mine subsidence, a possible consequence of underground mining. In addition, the Abandoned Mine Reclamation Fund, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore unreclaimed mines closed before 1977. The maximum tax is $0.315 per ton on surface mined coal and $0.135 per ton on coal produced by underground mining.

Our future operating results would be adversely affected if our accruals for reclamation were determined to be insufficient. These obligations are unfunded. The amount that was expensed for the year ended December 31, 2011 was $4.5 million, while the related cash payment for such liability during the same period was $4.9 million.

We also lease some of our coal reserves to third-party operators. Although specific criteria vary from state to state as to what constitutes an "owner" or "controller" relationship, under SMCRA, responsibility for reclamation or remediation, unabated violations, unpaid civil penalties and unpaid reclamation fees of independent contract mine operators can be imputed to other companies which are deemed, according to the regulations, to have "owned" or "controlled" the contract mine operator. Sanctions against the "owner" or "controller" are quite severe and can include being blocked, nationwide, from receiving new permits, or amendments and revisions to existing permits, and revocation, rescission and/or suspension of any permits that have been issued since the time of the violations or, in the case of civil penalties and reclamation fees, since the time such amounts became due.

The Clean Air Act and Related Rules

The federal Clean Air Act and similar state laws and regulations, which regulate emissions into the air, affect coal mining and processing operations primarily through permitting and/or emissions control requirements. In addition, the Environmental Protection Agency (the "EPA") has issued certain, and is considering further, regulations relating to fugitive dust and particulate matter emissions that could restrict our ability to develop new mines or require us to modify our operations. Regulations under the Clean Air Act may restrict our ability to develop new mines or could require us to modify our existing operations, and may have a material adverse effect on our financial condition and results of operations.

The Clean Air Act also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants. Coal contains impurities, such as sulfur, mercury and other constituents, many of which are released into the air when coal is burned. New environmental regulations governing emissions from coal-fired electric generating plants could reduce demand for coal as a fuel source and affect the volume of our sales. For example, the federal Clean Air Act places limits on sulfur dioxide emissions from electric power plants. In order to meet the federal Clean Air Act limits for sulfur dioxide emissions from electric power plants, coal users need to install scrubbers, use sulfur dioxide emission allowances (some of which they may purchase), blend high sulfur coal with low sulfur coal or switch to low sulfur coal or other fuels. The cost of installing scrubbers is significant and emission allowances may become more expensive as their availability declines. Switching to other fuels may require expensive modifications to existing plants.

Cross State Air Pollution Rule

On August 8, 2011, the EPA published the final Cross State Air Pollution Rule (CSAPR) requiring reductions of sulfur dioxide and nitrogen oxide emissions from power plants in 27 states located in the eastern half of the U.S. CSAPR addresses interstate emissions of sulfur dioxide and nitrogen oxides that interfere with downwind states' ability to meet or maintain national ambient air quality standards for ozone and/or particulate matter. CSAPR has been challenged by numerous states, trade associations, and individual companies, and many of those parties have also asked the EPA to reconsider the rule. The first phase of CSAPR compliance was scheduled to take effect on January 1, 2012 but has been delayed by the U.S. Court of Appeals for the D.C. Circuit. CSAPR replaces the 2005 Clean Air Interstate Rule, which in 2008 was struck down by the U.S. Court of Appeals for the D.C. Circuit and remanded to the EPA for further consideration. We sell coal into many of the states covered by CSAPR, and the new rule could significantly reduce the demand for coal for power generation in these states. The ultimate outcome of CSAPR will depend on the outcome of any legal and administrative proceedings and proposed revisions and cannot be determined at this time.

Maximum Achievable Control Technology ("MACT")

On December 21, 2011, the EPA issued its Utility MACT rule, which imposes stringent emission limits on coal- and oil-fired electric utility steam generating units (EGUs). Utility MACT contains numeric emission limits for acid gases, mercury, and total particulate matter. Meeting the limits will likely require utilities to add emission control equipment such as scrubbers, selective catalytic reduction units, baghouses, and other control measures at many coal-fired EGUs.

On March 21, 2011 the EPA issued the Industrial Boiler MACT rule, standards establishing emissions limits for various hazardous air pollutants typically emitted from industrial boilers, including coal-fired boilers. At the same time of issuance of the rule, the EPA issued a notice of intent to reconsider the rule to allow for additional public review and comment. On December 23, 2011, the EPA issued a proposed rule that would modify the Industrial Boiler MACT as a result of the reconsideration. The EPA has announced plans to finalize the rule by April 30, 2012. The effect of the regulatory proceedings will depend on the final form of the revised regulations and the outcome of any legal challenges and cannot be determined at this time.

These new and proposed regulations will make it more costly to operate coal-fired plants and could make coal a less attractive fuel alternative in the planning and building of utility power plants in the future. To the extent that any new and proposed requirements affect our customers, this could adversely affect our operations and results.

Regional Haze Program.

In 1999, the EPA promulgated a regional haze program designed to protect and to improve visibility at and around so-called Class I Areas, which are generally National Parks, National Wilderness Areas and International Parks. This program may restrict the construction of new coal-fired power plants whose operation may impair visibility at and around the Class I Areas. Moreover, the program requires certain existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxide and particulate matter. States were required to submit Regional Haze State Implementation Plans ("SIPs") to the EPA by December 17, 2007. Many states did not meet the December 17, 2007 deadline, and on February 4, 2011, several environmental groups (including the Sierra Club and Environmental Defense Fund) notified the EPA that they intend to sue the EPA under the citizen suit provision of the Clean Air Act for failure to enforce the regional haze rule. In addition, the EPA issued a proposed rule on December 30, 2011 that would allow states subject to the CSAPR rule to rely on the CSAPR trading program to meet some of the requirements in the regional haze program. However, as noted above, the implementation of the CSAPR rule has been delayed by litigation. We are unable to predict the impact on the coal market of either the states' failure to submit Regional Haze SIPs by the deadline or the potential litigation.

Initiatives to Reduce Greenhouse Gas Emissions

Considerable and increasing government attention in the United States and other countries is being paid to reducing greenhouse gas ("GHG") emissions, including carbon dioxide ("CO2") emissions from coal-fired power plants and methane emissions from mining operations. Although the United States has not ratified the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change ("UNFCCC"), which became effective for many countries in 2005 and establishes a binding set of emission targets for greenhouse gases, the United States is actively participating in various international initiatives within and outside of the UNFCCC process to negotiate developed and developing nation commitments for greenhouse gas emission reductions and related financing. Any international greenhouse gas agreement in which the United States participates, if at all, could adversely affect the price and demand for coal.

In addition to possible future U.S. treaty obligations, regulation of greenhouse gases in the United States could occur pursuant to new or amended federal or state legislation, including but not limited to regulatory changes under the Clean Air Act, Public Utility Regulatory Policies Act, state initiatives, or otherwise. At the federal level, Congress actively considered in the past, and may consider in the future, legislation that would establish a nationwide GHG emissions cap-and-trade or other market-based program to reduce greenhouse gas emissions. There are other types of legislative proposals that would promote clean energy that Congress has also considered in the past, and is currently considering. Many of these proposals would tend to favor fuels that have a lower carbon content than coal, but such proposals also incent the construction and development of carbon capture and sequestration plants as well as other advanced coal technologies. We cannot predict the financial impact of future greenhouse gas or clean energy legislation on our operations or our customers at this time.

The EPA also is implementing plans to regulate carbon dioxide emissions. In October 2009, the EPA published its final Mandatory Greenhouse Gas Reporting Rule, which requires power plants and other large sources of greenhouse gases to commence data collection in January 2010 and to file their first annual reports disclosing greenhouse gas emissions in 2011. In July 2010, the EPA issued amendments that would require underground coal mines and certain other source categories to file their first annual reports disclosing greenhouse gas emissions in 2012, covering calendar year 2011.

In December 2009, the EPA issued a *Final Endangerment and Cause or Contribute Findings for Greenhouse Gases* under Section 202(a) of the Clean Air Act, wherein the EPA concluded that GHGs endanger the public health and welfare. In April 2010, the EPA issued, along with the Department of Transportation, a rule to regulate GHG emissions from new cars and trucks. This rule took effect in January 2011, and according to EPA, established GHG emissions as "regulated pollutants" under the Clean Air Act. As a consequence, and in conjunction with an EPA *Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, it requires new and modified emission sources to meet Best Available Control Technology for GHG emissions. The EPA has announced plans to begin issuing GHG performance standards for new and existing power plants and some other source categories. Although the EPA announced a proposed schedule for establishing greenhouse gas emissions limits for fossil fuel fired electric generation facilities calling for proposed regulations by July 2011 and final regulations by May 2012, that schedule has been delayed. Federal legislation that would variously suspend or eliminate EPA's regulatory authority over GHGs has been introduced in both the House and Senate.

In addition to federal GHG regulations, there are several new state programs to limit greenhouse gas emissions and others have been proposed. State and regional climate change initiatives are taking effect before federal action. Beginning January 1, 2009 the Regional Greenhouse Gas Initiative ("RGGI"), a regional GHG cap-and-trade program calling for a ten percent reduction of emissions by 2018, was established by ten Northeastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont). The RGGI program has had several emission allowances auctions and will enter its second three-year control period in 2012. In October 2011, the California Air Resources Board adopted regulations that establish a statewide cap and trade program to control GHG emissions. The program will take effect in 2013.

Predicting the economic effects of greenhouse gas legislation is difficult given the various alternatives proposed and the complexities of the interactions between economic and environmental issues. Coal-fired generators could switch to other fuels that generate less of these emissions, possibly reducing the construction of coal-fired power plants or causing some users of our coal to switch to a lower CO_2 generating fuel, or more generally reducing the demand for coal-fired electricity generation. This could result in an indeterminate decrease in demand for coal nationally, and various mechanisms proposed to limit greenhouse gas emissions could impact the price of coal and the cost of coal-fired generation. The majority of our coal supply agreements contain provisions that allow a purchaser to terminate its contract if legislation is passed that either restricts the use or type of coal permissible at the purchaser's plant or results in specified increases in the cost of coal or its use to comply with applicable ambient air quality standards. In addition, if regulation of greenhouse gas emissions does not exempt the release of coalbed methane, we may have to curtail coal production, pay higher taxes, or incur costs to purchase credits that permit us to continue operations as they now exist at our underground coal mines.

The Clean Water Act and Related Rules

The Clean Water Act of 1972 (the "CWA") and corresponding state laws affect coal mining operations by imposing restrictions on the discharge of certain pollutants into water and on dredging and filling wetlands. The CWA establishes in-stream water quality standards and treatment standards for wastewater discharge through the National Pollutant Discharge Elimination System ("NPDES"). Regular monitoring, as well as compliance with reporting requirements and performance standards, are preconditions for the issuance and renewal of NPDES permits that govern the discharge of pollutants into water. These requirements are complex, lengthy and becoming increasingly stringent as new regulations or amendments to existing regulations are adopted. In addition, legal challenges to regulations may impact their content and the timing of their implementation.

Section 404 Permitting

Permits under Section 404 of the CWA are required for coal companies to conduct dredging or filling activities in jurisdictional waters for the purpose of creating slurry ponds, water impoundments, refuse disposal areas, valley fills or other mining activities. Jurisdictional waters typically include ephemeral, intermittent, and perennial streams and may in certain instances include man-made conveyances that have a hydrologic connection to a stream or wetland. The U.S. Army Corps of Engineers (COE) only has jurisdiction over the "navigable waters" of the United States, and outside these waters there is arguably no need to procure a 404 permit. The United States Supreme Court ruled in *Rapanos v. United States* in 2006 that upper reaches of streams which are intermittent or do not flow might not be jurisdictional waters requiring 404 permits. The case did not involve disposal of mining refuse, but has implications for the mining industry. Subsequently, in June 2007 the COE and EPA issued a joint guidance document to attempt to develop a policy that will apply the jurisdictional standards imposed by the Supreme Court. The guidance requires a case-by-case analysis of whether the area to be filled has a sufficient nexus to downstream navigable waters so as to require 404 permits. Review and implementation of this guidance by the COE field offices remains inconsistent; the extent to which decisions made pursuant to this guidance will be challenged remains an open question.

The COE's issuance of 404 permits is subject to the National Environmental Policy Act ("NEPA"). NEPA defines the procedures by which a federal agency must administer its permitting programs. The law requires that a federal agency must take a "hard look" at any activity that may "significantly affect the quality of the human environment". This "hard look" is accomplished through an Environmental Impact Statement ("EIS"), a very lengthy data collection and review process. After the EIS is complete, only then can the 404 permit application be considered. However, the law also allows an initial Environmental Assessment ("EA") to be completed to determine if a project will have a significant impact on the environment. To date, the COE has typically used the less detailed EA process to determine the impacts from impoundments, fills and other activities associated with coal mining. However, in some cases the full EIS process is being required for mining projects. In general, the preliminary findings show that these types of mining related activities will not have a significant effect on the environment, and as such a full EIS is not required. Should a full EIS be required for every permit, significant permitting delays could affect mining costs or cause operations not to be opened in the first instance, or to be idled or closed.

In March 2007, the U.S. District Court for the Southern District of West Virginia issued a decision concerning 404 permitting for fills. The court held that widely used pre-mining assessments of areas to be impacted required by the COE and conducted by the permit applicants are inadequate and do not accurately assess the nature of the headwater areas being filled. As such, the court found the COE erred in its finding of no significant impact from this activity. Based on this conclusion, the court went on to find that proposed mitigation to offset the adverse impacts of the area to be filled also are not supported by adequate data. Due to this decision, the COE is assessing the protocol for evaluating the pre-mining stream conditions, as well as procedures used in the measurement of the success of mitigation. That effort to revise the protocol and associated findings is ongoing and may be challenged as it is applied to newly issued permits. Until this process is completed, preparing and submitting new permit applications is somewhat hindered. The March 2007 decision was appealed to the Fourth Circuit Court of Appeals. In June 2007, the same federal district court also effectively prohibited mine operators from impounding streams below their valley fills for the purpose of constructing sediment ponds. Mine operators are required to route drainage from valley fills to sediment control structures and to meet NPDES permit limits for discharges from those structures. In the steep sloped areas of Central Appalachia, often the only practicable location for those structures is in the stream channel itself downstream of the valley fills. The COE and EPA had both considered such ponds to be "treatment systems" excluded from the definition of "waters of the United States" to which the Clean Water Act applies. The court's June 2007 opinion, though, held that these ponds remain "waters of the United States" and that mine operators must meet effluent limits for discharges into the ponds as well as from the ponds. Meeting these limits at the point where water first leaves a valley fill or enters the stream or pond would be difficult. This decision was also appealed to the Fourth Circuit Court of Appeals. In February 2009, the Fourth Circuit Court of Appeals overturned these lower court decisions. The United States Supreme Court dismissed the plaintiffs' appeal of the Fourth Circuit's ruling. Legislation also may be introduced at the state or federal level in order to override this decision by the Court of Appeals. An outcome that prevents the placement of mining spoil or refuse into valleys could have a material adverse impact on the ability to maintain current operations and to permit new operations.

The COE is empowered to issue nationwide permits for specific categories of filling activity that are determined to have minimal environmental adverse effects in order to save the cost and time of issuing individual permits under Section 404. Nationwide Permit 21 ("NWP 21") authorizes the disposal of dredge-and-fill material from mining activities into the waters of the United States. Over the last decade several citizens groups have sued the COE in federal court in West Virginia and Kentucky seeking to invalidate nationwide permits utilized by the COE and the coal industry for permitting most in-stream disturbances associated with coal mining, including excess spoil valley fills and refuse impoundments. The plaintiffs sought to enjoin the prospective approval of these nationwide permits and to enjoin some coal operators from additional use of existing nationwide permit approvals until they obtain more detailed individual permits. These litigation challenges have been followed by significant policy changes by the COE. In June 2010, the COE suspended use of the NWP 21 within a six-state region, including Kentucky, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia. In February 2012, the COE reissued the NWP 21 permit with significant new limitations. The reissued NWP 21 permit only authorizes impacts to one-half acre of surface water and no more than 300 linear feet of stream bed. In addition, the construction of valley fills is not authorized in the permit. The new limitations in the NWP 21 permit may require us to undertake the more burdensome approach of obtaining individual Section 404 permits for new projects.

In September 2009, the EPA announced it had identified 79 pending permit applications for Appalachian surface coal mining, under an enhanced coordination process with the COE and the United States Department of the Interior entered into in June 2009, that the EPA believes warrant further review because of its continuing concerns about water quality and/or regulatory compliance issues. These included four of our permit applications, two of which we have abandoned. We continue to wait on the issuance of the remaining two permit applications. While the EPA has stated that its identification of these 79 permit applications does not constitute a determination that the mining involved cannot be permitted under the CWA and does not constitute a final recommendation from the EPA to the COE on these projects, it is uncertain how long the further review will take for our two subject permit applications, what types of conditions or restrictions will be imposed or what the final outcome will be.

Further, the EPA has begun to apply its enhanced permitting coordination process, called the Surface Coal Mining Pending Permit Coordination Procedures issued by EPA and the COE on June 11, 2009 (the "ECP"). Use of this guidance by EPA without going through formal rulemaking procedures has been challenged in court by the National Mining Association and by several states. On October 6, 2011, a federal court vacated the ECP. EPA has also published guidance in a July 21, 2011 Final Memorandum entitled "Improving EPA Review of Appalachian Surface Coal Mining Operations Under the Clean Water Act, National Environmental Policy Act, and the

Environmental Justice Executive Order" ("EPA Mining Guidance"). Application of the EPA Mining Guidance has the potential to delay issuance of permits for the company, or to change the conditions or restrictions imposed in those permits.

National Pollutant Discharge Elimination Permits

The Clean Water Act ("CWA") requires that all of our operations obtain NPDES permits for discharges of water from all of our mining operations. All NPDES permits require regular monitoring and reporting of one or more parameters on all discharges from permitted outfalls. Additional parameters, including selenium, aluminum, total dissolved solids and conductivity, stemming in part from application of the EPA Mining Guidance discussed above and increasingly more restrictive limits are being added to NPDES permits in all states which potentially could create requirements for treatment systems and higher costs to comply with permit conditions. In particular, the EPA Mining Guidance establishes threshold conductivity levels to be used as a basis for evaluating compliance with narrative water quality standards. Conductivity is a measure that reflects levels of various salts present in water. In order to obtain federal Clean Water Act new and renewal permits for coal mining in Appalachia, as defined in the guidance, applicants must perform an evaluation to determine if a reasonable potential exists that the proposed mining would cause a violation of water quality standards, including narrative standards. The EPA Administrator has stated that these water quality standards may be difficult for most mining operations to meet. Additionally, the EPA Mining Guidance contains requirements for avoidance and minimization of environmental impacts, mitigation of mining impacts, consideration of the full range of potential impacts on the environment, human health, and communities, including low-income or minority populations, and provision of meaningful opportunities for public participation in the permit process. In the future, to obtain necessary new permits and renewals, we and other mining companies will be required to meet these requirements. We have begun to incorporate these new requirements into some of our current permitting actions, however there can be no guarantee that we will be able to meet these or any other new standards with respect to our future permit applications or renewals.

When a water discharge occurs and one or more parameters are outside the approved limits permitted in an NPDES permit, these exceedances of permit limits are self-reported to the pertinent agency. The agency may impose penalties for each such release in excess of permitted amounts. If factors such as heavy rains or geologic conditions cause persistent releases in excess of amounts allowed under NPDES permits, costs of compliance can be material, fines may be imposed, or operations may have to be idled until remedial actions are possible. Additionally, the CWA has citizen suit provisions which allow individuals or organized groups to file suit against permit holders or the EPA or state agencies for failure to enforce all aspects of the CWA. Although we are aware of citizen suit actions against a small number of our permits, we do not think these actions are material to our business, and we believe the citizen suit actions lack merit. Similar actions have recently been filed against other companies.

The Clean Water Act has specialized sections that address NPDES permit conditions for discharges to waters in which state-issued water quality standards are violated and where the quality exceeds the levels established by those standards. For those waters where conditions violate state water quality standards, states or the EPA are required to prepare a Total Maximum Daily Load ("TMDL") by which new discharge limits are imposed on existing and future discharges in an effort to restore the water quality of the receiving streams. Likewise, when water quality in a receiving stream is better than required, states are required to adopt an "anti-degradation policy" by which further "degradation" of the existing water quality is reviewed and possibly limited. In the case of both the TMDL and anti-degradation review, the limits in our NPDES discharge permits could become more stringent, thereby potentially increasing our treatment costs and making it more difficult to obtain new surface mining permits. New standards may also require us to install expensive water treatment facilities or otherwise modify mining practices and thereby substantially increase mining costs. These increased costs may render some operations unprofitable.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act (commonly known as Superfund) and similar state laws create liabilities for the investigation and remediation of releases of hazardous substances into the environment and for damages to natural resources. Our current and former coal mining operations incur, and will continue to incur, expenditures associated with the investigation and remediation of facilities and environmental conditions, including underground storage tanks, solid and hazardous waste disposal and other matters under these environmental laws. We also must comply with reporting requirements under the Emergency Planning and Community Right-to-Know Act and the Toxic Substances Control Act.

The magnitude of the liability and the cost of complying with environmental laws with respect to particular sites cannot be predicted with certainty due to the lack of specific information available, the potential for new or changed laws and regulations, the development of new remediation technologies, and the uncertainty regarding the timing of remedial work. As a result, we may incur material liabilities or costs related to environmental matters in the future and such environmental liabilities or costs could adversely affect our results and financial condition. In addition, there can be no assurance that changes in laws or regulations would not result in additional costs and affect the manner in which we are required to conduct our operations.

Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act and corresponding state laws and regulations affect coal mining operations by imposing requirements for the treatment, storage and disposal of hazardous wastes. Facilities at which hazardous wastes have been treated, stored or disposed of are subject to corrective action orders issued by the EPA and other potential obligations, which could adversely affect our results of operations or financial condition.

Item 1A. Risk Factors

Risks Related to the Coal Industry

Because the demand and pricing for coal is greatly influenced by consumption patterns of the domestic electricity generation industry and the worldwide steel industry, a reduction in the demand for coal by these industries would likely cause our revenues and profitability to decline significantly.

We derived 56% of our total revenues in 2011 and 88% of our total revenues in 2010, from our electric utility customers. In connection with the IRP Acquisition, we also began to provide metallurgical coal to the steel industry and as a result 44% of our total revenues in 2011 were from industrial customers, including those in the steel industry.

We compete with coal producers in the United States and overseas for domestic and international sales. Demand for our coal and the prices that we will be able to obtain primarily will depend upon coal consumption patterns of the electric utility industry and the worldwide steel industry. Consumption by the utility industry is affected by the demand for electricity, environmental and other governmental regulations, technological developments and the price of competing coal and alternative fuel supplies including nuclear, natural gas, oil and renewable energy sources, including hydroelectric power. Demand by the electricity industry is impacted by weather patterns, overall economic activity and the associated demand for power by industrial users. Demand by the steel industry is primarily affected by economic growth and the demand for steel used in construction as well as appliances and automobiles.

Due to economic and market conditions, our contracts for steam and metallurgical coal deliveries in 2012 provide lower sales prices than the average sales prices we received for deliveries of similar coal in 2011. While we manage our coal contracts on a composite basis to maximize the returns on our coal sold by moving coal to higher priced markets where possible (for example moving coal between the industrial coal market and the domestic utility market) there can be no assurances that pricing we receive on tons sold in 2012 and beyond will be reflective of the per-ton price of coal that we have received in prior periods.

Portions of our coal reserves possess quality characteristics that enable us to mine, process and market them as either metallurgical coal or high quality steam coal, depending on the prevailing conditions in the markets for metallurgical and steam coal. A decline in the metallurgical market relative to the steam market could cause us to shift coal from the metallurgical market to the steam market, potentially reducing the price we could obtain for this coal and adversely impacting our cash flows, results of operations or financial condition.

Any downward pressure on coal prices would likely cause our profitability to decline.

Electric utility deregulation is expected to provide incentives to generators of electricity to minimize their fuel costs and is believed to have caused electric generators to be more aggressive in negotiating prices with coal suppliers. To the extent utility deregulation causes our customers to be more cost-sensitive, deregulation may have a negative effect on our profitability.

Changes in the export and import markets for coal products could affect the demand for our coal, our pricing and our profitability.

We compete in a worldwide market. The pricing and demand for our products is affected by a number of factors beyond our control. These factors include:

- currency exchange rates;
- growth of economic development;
- price of alternative sources of electricity or steel;
- worldwide demand; and
- ocean freight rates.

Any decrease in the amount of coal exported from the United States, or any increase in the amount of coal imported into the United States, could have a material adverse impact on the demand for our coal, our pricing and our profitability.

Increased consolidation and competition in the U.S. coal industry may adversely affect our revenues and profitability.

During the last several years, the U.S. coal industry has experienced increased consolidation, which has contributed to the industry becoming more competitive. Consequently, many of our competitors in the domestic coal industry are major coal producers who have significantly greater financial resources than us. The intense competition among coal producers may impact our ability to retain or attract customers and may therefore adversely affect our future revenues and profitability.

If the coal industry experiences overcapacity in the future, our profitability could be impaired.

An increase in the demand for coal could attract new investors to the coal industry, which could spur the development of new mines, and result in added production capacity throughout the industry. Higher price levels of coal could also encourage the development of expanded capacity by new or existing coal producers. Any resulting increases in capacity could reduce coal prices and reduce our margins.

Fluctuations in transportation costs and the availability and dependability of transportation could affect the demand for our coal and our ability to deliver coal to our customers.

Increases in transportation costs could have an adverse effect on demand for our coal. Customers choose coal supplies based, primarily, on the total delivered cost of coal. Any increase in transportation costs would cause an increase in the total delivered cost of coal. That could cause some of our customers to seek less expensive sources of coal or alternative fuels to satisfy their energy needs. In addition, significant decreases in transportation costs from other coal-producing regions, both domestic and international, could result in increased competition from coal producers in those regions. For instance, coal mines in the western United States could become more attractive as a source of coal to consumers in the eastern United States, if the costs of transporting coal from the West were significantly reduced.

Our Central Appalachia mines generally ship coal via rail systems, ocean vessels and barges. During 2011, we shipped approximately 90% of our coal from our Central Appalachia mines via rail system, including coal that was transported by rail to export vessels. In the Midwest, we shipped approximately 55% of our produced coal by truck and the remainder via the rail system or by barge. We believe that our 2012 transportation modes will continue to be comparable to those used in 2011. Our dependence upon railroads, third party trucking companies, ocean vessels and barges impacts our ability to deliver coal to our customers. Disruption of service due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks and other events could temporarily impair our ability to supply coal to our customers, resulting in decreased shipments. Decreased performance levels over longer periods of time could cause our customers to look elsewhere for their fuel needs, negatively affecting our revenues and profitability.

In past years, the major eastern railroads (CSX and Norfolk Southern) have experienced periods of increased overall rail traffic due to an expanding economy and shortages of both equipment and personnel. This increase in traffic could impact our ability to obtain the necessary rail cars to deliver coal to our customers and have an adverse impact on our financial results.

Shortages or increased costs of skilled labor in the coal regions that we operate may hamper our ability to achieve high labor productivity and competitive costs.

Coal mining continues to be a labor-intensive industry. In times of increased demand, many producers attempt to increase coal production, which historically has resulted in a competitive market for the limited supply of trained coal miners. In some cases, this market situation has caused compensation levels to increase, particularly for “skilled” positions such as electricians and mine foremen. To maintain current production levels, we may be forced to respond to increases in wages and other forms of compensation, and related recruiting efforts by our competitors. Any future shortage of skilled miners, or increases in our labor costs, could have an adverse impact on our labor productivity and costs and on our ability to expand production.

Government laws, regulations and other requirements relating to the protection of the environment, health and safety and other matters impose significant costs on us, and future requirements could limit our ability to produce coal at a competitive price.

We are subject to extensive federal, state and local regulations with respect to matters such as:

- employee health and safety;
- permitting and licensing requirements;
- air quality standards;
- water quality standards;
- plant, wildlife and wetland protection;
- blasting operations;
- the management and disposal of hazardous and non-hazardous materials generated by mining operations;
- the storage of petroleum products and other hazardous substances;
- reclamation and restoration of properties after mining operations are completed;
- discharge of materials into the environment, including air emissions and wastewater discharge;
- surface subsidence from underground mining; and
- the effects of mining operations on groundwater quality and availability.

Complying with these requirements, including the terms of our permits, has had, and will continue to have, a significant effect on our costs of operations. We could incur substantial costs, including clean up costs, fines, civil or criminal sanctions and third party claims for personal injury or property damage as a result of violations of or liabilities under these laws and regulations.

The coal industry is also affected by significant legislation mandating specified benefits for retired miners. 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 generating activities. Coal contains impurities, including sulfur, mercury, chlorine and other elements or compounds, many of which are released into the air when coal is burned. Stricter environmental regulations of emissions from coal-fired electric generating plants could increase the costs of using coal, thereby reducing demand for coal as a fuel source or the volume and price of our coal sales, or making coal a less attractive fuel alternative in the planning and building of utility power plants in the future.

New legislation, regulations and orders adopted or implemented in the future (or changes in interpretations of existing laws and regulations) may materially adversely affect our mining operations, our cost structure and our customers' operations or ability to use coal.

The majority of our coal supply agreements contain provisions that allow the purchaser to terminate its contract if legislation is passed that either restricts the use or type of coal permissible at the purchaser's plant or results in too great an increase in the cost of coal. These factors and legislation, if enacted, could have a material adverse effect on our financial condition and results of operations.

Climate change initiatives could significantly reduce the demand for coal, increase our costs and reduce the value of our coal assets.

Global climate change continues to attract considerable public and scientific attention with widespread concern about the impacts of human activity, especially the emissions of greenhouse gases ("GHG"), such as carbon dioxide and methane. Combustion of fossil fuels, such as the coal we produce, results in the creation of carbon dioxide that is currently emitted into the atmosphere by coal end users, such as coal-fired electric generation power plants. Our underground mines emit methane, which must be expelled for safety reasons.

Considerable and increasing government attention in the United States and other countries is being paid to reducing greenhouse gas emissions, including CO2 emissions from coal-fired power plants and methane emissions from mining operations. Although the United States has not ratified the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change ("UNFCCC"), which became effective for many countries in 2005 and establishes a binding set of emission targets for greenhouse gases, the United States is actively participating in various international initiatives within and outside of the UNFCCC process to negotiate developed and developing nation commitments for greenhouse gas emission reductions and related financing. For example, in December 2009, approximately 190 countries participated in the UNFCC meetings in Copenhagen. The participants "took note" of a non-binding accord under which participating nations would report their commitments to reduce greenhouse gas emissions. Under this non-binding framework, the U.S. committed to cut greenhouse gas emissions by 17% below 2005 levels by 2020, 42% below 2005 levels by 2030, and 83% below 2005 levels by 2050. Any international greenhouse gas agreement in which the United States participates, if at all, could adversely affect the price and demand for coal.

U.S. legislative and regulatory action also may address greenhouse gas emissions. At the federal level, Congress actively considered in the past, and may consider in the future, legislation that would establish a nationwide GHG emissions cap-and-trade or other market-based program to reduce greenhouse gas emissions. The EPA also has commenced regulatory action that could lead to controls on carbon dioxide from larger emitters such as coal-fired power plants and industrial sources. In advance of federal action, state and regional climate change initiatives, such as the Regional Greenhouse Gas Initiative of eastern states, the Western Regional Climate Action Initiative, and recently enacted legislation in California and other states are taking effect before federal action. In addition, some states and municipalities in the United States have adopted or may adopt in the future regulations on greenhouse gas emissions. Some states and municipal entities have commenced litigation in different jurisdictions seeking to have certain utilities, including some of our customers, reduce their emission of carbon dioxide. Apart from governmental regulation, in February 2008, three of Wall Street's largest investment banks announced that they had adopted climate change guidelines for lenders. The guidelines require the evaluation of carbon risks in the financing of utility power plants which may make it more difficult for utilities to obtain financing for coal-fired plants.

Considerable uncertainty is associated with these climate change initiatives. The content of new treaties, legislation or regulation is not yet determined, and many of the new regulatory initiatives remain subject to review by the agencies or the courts. Predicting the economic effects of climate change legislation is difficult given the various alternatives proposed and the complexities of the interactions between economic and environmental issues. Any regulations on greenhouse gas emissions, however, are likely to impose significant emissions control expenditures on many coal-fired power plants and industrial boilers and could have the effect of making them unprofitable. As a result, these generators may switch to other fuels that generate less of these emissions, possibly reducing future demand for coal and the construction of coal-fired power plants. In this regard, many of our coal supply agreements contain provisions that allow a purchaser to terminate its contract if legislation is passed that either restricts the use or type of coal permissible at the purchaser's plant or results in specified increases in the cost of coal or its use to comply with applicable ambient air quality standards. Any switching of fuel sources away from coal, closure of existing coal-fired plants, or reduced construction of new plants could have a material adverse effect on demand for and prices received for our coal and a material adverse effect on our results of operations, cash flows and financial condition. In addition, if regulation of greenhouse gas emissions does not exempt the release of coalbed methane, we may have to curtail coal production, pay higher taxes, or incur costs to purchase credits that permit us to continue operations as they now exist at our underground coal mines.

We are subject to the federal Clean Water Act and similar state laws which impose treatment, monitoring and reporting obligations.

The federal Clean Water Act and corresponding state laws affect coal mining operations by imposing restrictions on discharges into regulated waters. Permits requiring regular monitoring and compliance with effluent limitations and reporting requirements govern the discharge of pollutants into regulated waters. New requirements under the Clean Water Act and corresponding state laws could cause us to incur significant additional costs that adversely affect our operating results.

Regulations have expanded the definition of black lung disease and generally made it easier for claimants to assert and prosecute claims, which could increase our exposure to black lung benefit liabilities.

In January 2001, the United States Department of Labor amended the regulations implementing the federal black lung laws to give greater weight to the opinion of a claimant's treating physician, expand the definition of black lung disease and limit the amount of medical evidence that can be submitted by claimants and respondents. The amendments also alter administrative procedures for the adjudication of claims, which, according to the Department of Labor, results in streamlined procedures that are less formal, less adversarial and easier for participants to understand. These and other changes to the federal black lung regulations could significantly increase our exposure to black lung benefits liabilities.

The Patient Protection and Affordable Care Act of 2010 (Act) was enacted into law on March 23, 2010 and included a black-lung provision that creates a rebuttable presumption that a miner with at least 15 years of service, with totally disabling pulmonary or respiratory lung impairment and negative radiographic chest x-ray evidence would be disabled due to pneumoconiosis and be eligible for black lung benefits. The new Act also makes it easier for widows of miners to become eligible for benefits. The enactment of this new legislation could significantly impact the Company's future payments for black lung benefits.

In recent years, legislation on black lung reform has been introduced but not enacted in Congress and in the Kentucky legislature. It is possible that additional legislation will be reintroduced for consideration by Congress. If any of the proposals included in this or similar legislation is passed, the number of claimants who are awarded benefits could significantly increase. Any such changes in black lung legislation, if approved, may adversely affect our business, financial condition and results of operations.

Extensive environmental laws and regulations affect the end-users of coal and could reduce the demand for coal as a fuel source and cause the volume of our sales to decline.

The Clean Air Act and similar state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from electric power plants, which are the largest end-users of our coal. Compliance with such laws and regulations, which can take a variety of forms, may reduce demand for coal as a fuel source because they can require significant emissions control expenditures for coal-fired power plants to attain applicable ambient air quality standards, which may lead these generators to switch to other fuels that generate less of these emissions, to retire or reduce production from older coal-fired power plants and/or to decrease the construction of coal-fired power plants.

The EPA has adopted more stringent National Ambient Air Quality Standards for nitrogen dioxide and sulfur dioxide, both of which are emitted from coal-fired combustion units. The EPA is considering whether to adopt a more stringent standard for ground-level ozone, to which emissions from coal combustion units can contribute. The demand for coal could be affected at electric generating facilities located in geographic areas that exceed the modified standards.

The U.S. Department of Justice, on behalf of the EPA, has in the past filed lawsuits against several investor-owned electric utilities for alleged violations of the Clean Air Act. We supply coal to some of the utilities that have been sued in the past, although none of these lawsuits are active, and it is possible that other of our customers will be sued on these grounds in the future. These lawsuits could require the utilities to pay penalties, install pollution control equipment or undertake other emission reduction measures, any of which could adversely impact their demand for our coal.

A regional haze program initiated by the EPA to protect and to improve visibility at and around national parks, national wilderness areas and international parks restricts the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas and may require some existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions.

The Clean Air Act also imposes standards on sources of hazardous air pollutants. The EPA's Utility MACT rule regulates emissions of mercury and other inorganic pollutants from electric power plants. The rule also includes standards for nitrogen oxides, sulfur dioxide, and particulate matter. The EPA's Industrial Boiler MACT rule limits emissions from industrial boilers, including those fueled by coal. These standards and future standards could have the effect of decreasing demand for coal. So-called multi-pollutant bills, which could regulate additional air pollutants, have been proposed by various members of Congress. If such initiatives are enacted into law, power plant operators could choose other fuel sources to meet their requirements, reducing the demand for coal.

The EPA's Cross-State Air Pollution Rule (CSAPR) could cause power plant operators to choose other fuel sources to meet their requirements, reducing the demand for coal, which may cause coal prices and sales of our coal to materially decline. The impact of CSAPR will depend on its final form and the outcome of any legal challenges and cannot be determined at this time.

As a result of the U.S. Supreme Court's decision on April 2, 2007 in Massachusetts, et al. v. EPA, 549 U.S. 497 (2007), finding that greenhouse gases fall within the Clean Air Act definition of "air pollutant," the EPA was required to determine whether emissions of greenhouse gases "endanger" public health or welfare. In December 2009, the EPA published its finding that current and projected concentrations of carbon dioxide and five other greenhouse gases in the atmosphere threaten the public's health and welfare. This finding enables the EPA to proceed with a broad regulatory program for the control of greenhouse gas emissions, including carbon dioxide emissions. The EPA has recently completed several rulemaking actions indicating its intent to do so, including, among others, a final greenhouse gas reporting rule for certain major stationary source permitting programs, final regulations to control greenhouse gas emissions from light duty vehicles, and a final "tailoring" rule explaining how it would implement the Clean Air Act's Title V and prevention of significant deterioration permitting programs with respect to greenhouse gas emissions from major stationary sources. In recent legislative sessions, both houses of Congress have considered, but failed to enact, new legislation that could establish a national cap on, or other regulation of, carbon emissions and other greenhouse gases. Recent proposals include a cap and trade system that would require the purchase of emission permits, which could be traded on the open market. These and other proposals would make it more costly to operate coal-fired plants and could make coal a less attractive fuel for future power plants. Any new or proposed requirements adversely affecting the use of coal could adversely affect our operations and results.

The permitting of new coal-fired power plants has also recently been contested by state regulators and environmental organizations based on concerns relating to greenhouse gas emissions. In several litigation cases, plaintiffs are seeking various remedies, including injunctive relief, against power plant owners. However, the risk of an adverse outcome has been mitigated by the June 20, 2011 decision of the U.S. Supreme Court in Connecticut v. AEP. The Supreme Court reversed the decision of the United States Court of Appeals for the Second Circuit which had allowed plaintiffs' claims that public utilities' greenhouse gas emissions created a "public nuisance" to go to trial. The Supreme Court held that the EPA's authority to regulate greenhouse gas emissions under the Clean Air Act displaces federal common law claims. The effect of these recent cases may also be mitigated in the event Congress adopts greenhouse gas legislation and because the EPA has finalized the adoption of greenhouse gas emission standards. Nevertheless, increased efforts to control greenhouse gas emissions by state, federal, judicial or international authorities could result in reduced demand for coal.

The EPA has issued a proposed rule to regulate the management of coal ash that results from the combustion of coal. The proposed rule would classify coal ash produced at electric power plants as a waste, thereby making it subject to significant restrictions on storage and disposal. In conjunction with the rulemaking, EPA has conducted assessments of the integrity of dams, impoundments, and other structures where coal ash from electric power plants is deposited. Although the rulemaking has been delayed, further scrutiny of coal ash management practices could result in reduced demand for coal.

We must obtain governmental permits and approvals for mining operations, which can be a costly and time consuming process and result in restrictions on our operations.

Numerous governmental permits and approvals are required for mining operations. Our operations are principally regulated under permits issued by state regulatory and enforcement agencies pursuant to the federal Surface Mining Control and Reclamation Act (SMCRA). Additionally, we often require permits under the Clean Water Act and the Clean Air Act. Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. Requirements imposed by these authorities may be costly and time consuming and may result in delays in the commencement or continuation of exploration or production operations. In addition, we often are required to prepare and present to federal, state and local authorities data pertaining to the effect or impact that proposed exploration for or production of coal might have on the environment. Further, the public may comment on and otherwise engage in the permitting process, including through intervention in the courts. Accordingly, the permits we need may not be issued, or, if issued, may not be issued in a timely fashion, or may involve requirements that restrict our ability to conduct our mining operations or to do so profitably.

In particular, permit issuance under Section 404 of the Clean Water Act, which is often required for valley fills, ponds or impoundments, refuse, road building, placement of excess material and other mine development activities, is facing increasingly stringent regulatory and administrative requirements and a series of court challenges that have resulted in increased costs and delays in the permitting process. Previously, a Section 404 permit could be either a simplified Nationwide Permit #21 (NWP 21) or a more complicated individual permit. Litigation respecting the validity of the NWP 21 permit program has been ongoing for several years. In 2010, the Army Corps of Engineers (COE) announced its decision to suspend the use of NWP 21 in a six state Appalachian region, including Kentucky and West Virginia, where we operate. Recently, the COE reissued the NWP 21 permit with significant new limitations on authorized impacts to surface water, including a prohibition against valley fills. Litigation respecting the issuance of certain Section 404 permits has also been ongoing for several years, focusing primarily on whether the COE's decision to issue such permits conformed to the requirements of the Clean Water Act and/or the National Environmental Policy Act. The matters at issue in such litigation are such that a ruling for the plaintiffs could have an adverse impact on our planned surface mining operations.

In 2009, the EPA announced publicly that it will exercise its statutory right to more actively review Section 404 permitting actions by the COE. In the third quarter of 2009, the EPA announced that it would further review 79 surface mining permit applications, including four of our permits. These 79 permits were identified as likely to impact water quality and therefore requiring additional review under the Clean Water Act. EPA oversight could further delay and/or restrict the issuance of such permits, either of which events could have an adverse impact on our planned mining operations.

More recently, the EPA announced acceptable levels for the conductivity of water in streams receiving discharge from permitted coal mining sites in a six-state area of Central Appalachia, including Kentucky and West Virginia. If such levels of conductivity are enforced as numerical limits, they could have a significant impact on our ability to secure Section 404 permits and have a material impact on our operations. The National Mining Association (NMA), on behalf of its member companies including coal producers such as ourselves, filed suit against the EPA and the COE contesting the legality of the enhanced review process and the imposition of such conductivity standard. The U.S. District Court for the District of Columbia granted the NMA's motion for partial summary judgment and vacated the multi-criteria integrated resource assessment and the enhanced coordination process. The court determined that in issuing the guidance, the EPA exceeded its statutory authority under the Clean Water Act. The court also determined those pronouncements to constitute legislative rules, and as such, to have been issued in violation of the Administrative Procedures Act because they were issued without public notice and an opportunity to submit comments. The states of West Virginia and Kentucky, and the coal associations in those states, have also filed suits contesting these actions by the EPA.

Environmental groups have recently filed lawsuits against multiple mining companies, including us, for alleged discharges of selenium in violation of applicable permit levels at coal mining sites. The lawsuits have been filed under the citizen suit provisions of the federal Clean Water Act. In the lawsuits, the environmental groups contend that the mining companies should install treatment facilities to limit the discharge of selenium and pay civil penalties for the alleged violations. Some of the cases have been resolved through settlements between the environmental groups and the mining companies. We currently do not believe any lawsuit brought against us related to these matters will have a material impact on our operations.

Also, see Item 1 "Business — Environmental and Other Regulatory Matters" for discussion related to the Clean Water Act.

We have significant reclamation and mine closure obligations. If the assumptions underlying our accruals are materially inaccurate, we could be required to expend greater amounts than anticipated.

The SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of underground mining. We accrue for the costs of current mine disturbance and of final mine closure, including the cost of treating mine water discharge where necessary. Under U.S. generally accepted accounting principles we are required to account for the costs related to the closure of mines and the reclamation of the land upon exhaustion of coal reserves. The fair value of an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the long-lived asset. The amounts recorded are dependent upon a number of variables, including the estimated future retirement costs, estimated proven reserves, assumptions involving profit margins, inflation rates, and the assumed credit-adjusted interest rates. Furthermore, these obligations are unfunded. If these accruals are insufficient or our liability in a particular year is greater than currently anticipated, our future operating results could be adversely affected. Also, see "Critical Accounting Estimates — Reclamation and Mine Closure Obligation" for additional information regarding our accrued reclamation costs.

Our operations may adversely impact the environment which could result in material liabilities to us.

The processes required to mine coal may cause certain impacts or generate certain materials that might adversely affect the environment from time to time. The mining processes we use could cause us to become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and clean up of soil, surface water, groundwater, and other media. Such claims may arise, for example, out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or even for the entire claim.

Certain coal that we mine needs to be cleaned at preparation plants, which generally require coal refuse areas and/or slurry impoundments. Such areas and impoundments are subject to extensive regulation and monitoring. Slurry impoundments have been known to fail, releasing large volumes of coal slurry into nearby surface waters and property, resulting in damage to the environment and natural resources, as well as injuries to wildlife. We maintain coal refuse areas and slurry impoundments at a number of our mining complexes. If one of our impoundments were to fail, we could be subject to substantial claims for the resulting environmental impact and associated liability, as well as for fines and penalties.

Drainage flowing from or caused by mining activities can be acidic with elevated levels of dissolved metals, a condition referred to as acid mine drainage ("AMD"). We include our estimated exposure for AMD in our accrued reclamation costs. If these accruals are insufficient or our liability in a particular year is greater than currently anticipated, our future operating results could be adversely affected.

These and other similar unforeseen impacts that our operations may have on the environment, as well as exposures to certain substances or wastes associated with our operations, could result in costs and liabilities that could materially and adversely affect us and could have a material adverse impact on our cash flows, results of operations or financial condition.

Foreign currency fluctuations could adversely affect the competitiveness of our coal abroad.

We rely on customers in other countries for a portion of our sales, with shipments to countries in North America, South America, Europe, Asia and Africa. We compete in these international markets against coal produced in other countries. Coal is sold internationally in United States dollars. As a result, mining costs in competing producing countries may be reduced in United States dollar terms based on currency exchange rates, providing an advantage to foreign coal producers. Currency fluctuations among countries purchasing and selling coal could adversely affect the competitiveness of our coal in international markets.

Terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war may negatively affect our business, financial condition and results of operations.

Terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war may negatively affect our business, financial condition and results of operations. Our business is affected by general economic conditions, fluctuations in consumer confidence and spending, and market liquidity, which can decline as a result of numerous factors outside of our control, such as terrorist attacks and acts of war. Future terrorist attacks against U.S. targets, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions affecting our customers could cause delays or losses in transportation and deliveries of coal to our customers, decreased sales of our coal and extension of time for payment of accounts receivable from our customers. Strategic targets such as energy-related assets may be at greater risk of future terrorist attacks than other targets in the United States. In addition, disruption or significant increases in energy prices could result in government-imposed price controls. It is possible that any, or a combination, of these occurrences could have a material adverse effect on our business, financial condition and results of operations.

Risks Related to Our Operations

We have experienced operating losses and net losses in recent years and may experience losses in the future.

We experienced operating losses in 2011, 2008 and 2007. While we were profitable in 2010 and 2009, we must continue to carefully manage our business, including the management of our contracts and our production costs. Although we seek to balance the open portion of our contracts to achieve optimal revenues over the long term, the market price of coal is affected by many factors that are outside of our control. We have experienced an increase in production costs in recent years. Additionally, certain of our long term contracts for sales of coal are priced substantially above current spot prices for coal. Our profitability in the future will be impacted by the price levels that we achieve on future long term contracts. Accordingly, we cannot assure you that we will be able to achieve profitability in the future.

We may fail to realize the growth prospects and cost savings anticipated as a result of the IRP Acquisition.

The success of the recent IRP Acquisition will depend, in part, on our ability to realize the anticipated business opportunities and growth prospects from combining our businesses with those of IRP. We may never realize these business opportunities and growth prospects. Integrating operations will be complex and will require significant efforts and expenditures. Our management might have its attention diverted while trying to integrate operations and corporate and administrative infrastructures. We might experience increased competition that limits our ability to expand our business, and we might not be able to capitalize on expected business opportunities, including retaining current customers. If any of these factors limit our ability to integrate the operations successfully or on a timely basis, the expectations of future results of operations expected to result from the IRP Acquisition might not be met.

It is possible that the integration process could result in the loss of key employees, the disruption of each company's ongoing businesses, tax costs or inefficiencies, or inconsistencies in standards, controls, information technology systems, procedures and policies, any of which could adversely affect our ability to maintain relationships with clients, employees or other third parties or our ability to achieve the anticipated benefits of the IRP Acquisition and could harm our financial performance.

We continue to incur significant transaction and acquisition-related integration costs in connection with the IRP Acquisition.

We are currently implementing our plan to integrate the operations of IRP. In connection with that plan, we anticipate that we will incur certain non-recurring charges, such as system conversion costs, in connection with this integration. We cannot identify the timing, nature and amount of all such charges at this time. The acquisition-related integration costs could materially affect our results of operations in the period in which such charges are recorded. Although we believe that the realization of efficiencies related to the integration of the businesses, will offset acquisition-related costs over time, this net benefit may not be achieved in the near term, or at all.

The new obligations of IRP becoming part of a public company may require significant resources and management attention.

Upon consummation of the IRP Acquisition, we acquired a privately-held company that had not previously been required to prepare or file periodic and other reports with the SEC or to generally comply with the requirements of the federal securities laws applicable to public companies, including rules and regulations implemented by the SEC and the Public Company Accounting Oversight Board and the requirement to document and assess the effectiveness of its internal control over financial reporting in order to satisfy the requirements of Section 404 of

Sarbanes-Oxley. We will need to include an assessment of our internal control over financial reporting that includes the IRP business in our periodic reports by December 31, 2012. Establishing, testing and maintaining an effective system of internal control over financial reporting requires significant resources and time commitments on the part of our management and our finance and accounting staff, may require additional staffing and infrastructure investments, could increase our legal, insurance and financial compliance costs and may divert the attention of management. In addition, our actual operating costs may exceed the operating costs set forth in our pro forma financials. Moreover, if we discover aspects of IRP's internal control over financial reporting that require improvement, we cannot be certain that our remedial measures will be effective. Any failure to implement required new or improved controls, or difficulties encountered in their implementation could adversely affect our financial and operating results, investor's confidence or increase our risk of material weaknesses in internal control over financial reporting.

The loss of, or significant reduction in, purchases by our largest customers could adversely affect our revenues.

In 2011, we generated approximately 20% of our total revenue from South Carolina Public Service Authority and 11% of our total revenue from Georgia Power Company. At December 31, 2011, we had coal supply agreements with these customers that expire in 2012 and 2013, respectively. The execution of a substantial coal supply agreement is frequently the basis on which we undertake the development of coal reserves required to be supplied under the contract. We could be materially adversely affected to the extent that we are unable to replace these expiring coal supply agreements with agreements providing similar profit margins.

Many of our coal supply agreements contain provisions that permit adjustment of the contract price upward or downward at specified times. Failure of the parties to agree on a price under those provisions may allow either party to either terminate the contract or reduce the coal to be delivered under the contract. Coal supply agreements also typically contain force majeure provisions allowing temporary suspension of performance by the customer or us for the duration of specified events beyond the control of the affected party. Most coal supply agreements contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as:

- British thermal units (Btus);
- sulfur content;
- ash content;
- grindability; and
- ash fusion temperature.

In some cases, failure to meet these specifications could result in economic penalties, including price adjustments, the rejection of deliveries or termination of the contracts. In addition, all of our contracts allow our customers to renegotiate or terminate their contracts in the event of changes in regulations or other governmental impositions affecting our industry that increase the cost of coal beyond specified limits. Further, we have been required in the past to purchase sulfur credits or make other pricing adjustments to comply with contractual requirements relating to the sulfur content of coal sold to our customers, and may be required to do so in the future.

The operating profits we realize from coal sold under supply agreements depend on a variety of factors. In addition, price adjustments and other provisions may increase our exposure to short term coal price volatility provided by those contracts.

Certain of our contracts are fixed in quantity but are priced on a quarterly basis. Our operating results are impacted by these quarterly changes in prices. A reduction in prices will result in a decrease to our profit margins.

In addition, our ability to receive payment for coal sold and delivered under these contracts depends on the continued creditworthiness of our customers. The bankruptcy of any of our customers could materially and adversely affect our financial position.

Our financial condition may be adversely affected if we are required by some of our customers to provide performance assurances for certain below-market sales contracts.

Some of our coal supply contracts contain provisions that could require us to provide performance assurances if we experience a material adverse change or, under certain other contracts, if the customer believes our creditworthiness has become unsatisfactory. Generally, under such contracts, performance assurances are only required if the contract price per ton of coal is below the current market price of the coal. The performance assurances are generally provided by the posting of a letter of credit, cash collateral, other security, or a guaranty from a creditworthy guarantor. As of December 31, 2011, we have not received any requests from any of our customers to provide performance assurances. If we are required to post performance assurances on some or all of our contracts with performance assurances provisions, there could be a material adverse impact on our cash flows, results of operations or financial condition.

Our operating results will be negatively impacted if we are unable to balance our mix of contract and spot sales.

We have implemented a sales plan that includes long term contracts (one year or greater) and spot sales/ short term contracts (less than one year). We have structured our sales plan based on the assumptions that demand will remain adequate to maintain current shipping levels and that any disruptions in the market will be relatively short-lived. If we are unable to maintain our planned balance of contract sales with spot sales, or our markets become depressed for an extended period of time, our volumes and margins could decrease, negatively affecting our operating results.

Our ability to operate our company effectively could be impaired if we lose senior executives or fail to employ needed additional personnel.

The loss of senior executives could have a material adverse effect on our business. There may be a limited number of persons with the requisite experience and skills to serve in our senior management positions. We may not be able to locate or employ qualified executives on acceptable terms. In addition, as our business develops and expands, we believe that our future success will depend greatly on our continued ability to attract and retain highly skilled and qualified personnel. We might not continue to be able to employ key personnel, or to attract and retain qualified personnel in the future. Failure to retain senior executives or attract key personnel could have a material adverse effect on our operations and financial results.

Underground mining is subject to increased regulation, and may require us to incur additional cost.

Underground coal mining is subject to ever increasing federal and state regulatory control relating to mine safety and health and to ever increasing enforcement activities intended to compel compliance with such laws and regulations. Within the last few years the industry has seen enactment of the federal MINER Act and subsequent additional legislation and regulation imposing significant new safety initiatives and the Dodd-Frank Act imposing new mine safety information reporting requirements. Various states also have enacted their own new laws and regulations imposing additional requirements related to mine safety. These new laws and regulations have and will continue to cause us to incur substantial additional costs, which will adversely impact our operating performance.

The U.S. Department of Labor, Mine Safety and Health Administration (MSHA), periodically notifies certain coal mines that a potential pattern of violations may exist based upon an initial statistical screening of violation history and pattern criteria review by MSHA. In the past, certain of our mines have received notices that a potential pattern of violations might exist. Upon receipt of such a notification, we conduct a comprehensive review of the operation that received the notification and prepare and submit to MSHA a plan designed to enhance employee safety at the mine through better education, training, mining practices, and safety management. Following implementation of the plan, MSHA conducts a complete inspection of the mine and further evaluates the situation and then advises the operator whether a Pattern of Violation (POV) exists and whether further action will be taken. The failure to remediate the situation resulting in a finding that a POV does exist at a mine could have a significant impact on our operations, including the permanent or temporary closure of our mines.

On April 12, 2011, MSHA notified our subsidiary Bledsoe Coal Corporation that a POV exists at its Abner Branch Rider Mine. As a result, if MSHA finds any violation of a mandatory health or safety standard that could significantly and substantially contribute to the cause and effect of a coal or other mine safety or health hazard, MSHA shall require all persons in the areas affected by such violation, except those persons referred to in Section 104(c) of the Mine Act, to be withdrawn from, and to be prohibited from entering such area until MSHA determines the violation has been abated. A POV can be terminated when 1) an inspection of the entire mine is completed and no significant and substantial health or safety violations are found, or 2) no withdrawal order is issued by MSHA in accordance with Section 104(e)(1) of the Mine Act within 90 days of the issuance of the pattern notice. The Abner Branch Rider Mine produced approximately 293,000 tons in 2011, of which approximately 206,000 tons were produced after being placed on POV. The POV could have a significant impact on the operations of that mine.

In 2010, a U.S. House of Representatives committee approved a mine safety bill which would give MSHA additional powers to temporarily close mines, mandate additional safety training and impose larger penalties on companies and their executives. A comparable bill introduced in the US Senate failed to receive the necessary votes for passage. If reintroduced and subsequently enacted, this or a similar bill could further increase our costs and impact operating performance.

Unexpected decreases in availability of raw materials or increases in raw material costs could significantly impair our operating results.

Our operations are dependent on reliable supplies of mining equipment, replacement parts, explosives, diesel fuel, tires, magnetite and steel-related products (including roof bolts). If the cost of any mining equipment or key supplies increases significantly, or if they should become unavailable due to higher industry-wide demand or less production by suppliers, there could be an adverse impact on our cash flows, results of operations or financial condition.

Coal mining is subject to conditions or events beyond our control, which could cause our quarterly or annual results to deteriorate.

Our coal mining operations are conducted in underground and surface mines. These mines are subject to conditions or events beyond our control that could disrupt operations, affect production and the cost of mining at particular mines for varying lengths of time and have a significant impact on our operating results. These conditions or events have included:

- variations in thickness of the layer, or seam, of coal;
- variations in geological conditions;
- amounts of rock and other natural materials intruding into the coal seam;
- equipment failures and unexpected major repairs;
- unexpected maintenance problems;
- unexpected departures of one or more of our contract miners;
- fires and explosions from methane and other sources;
- accidental mine water discharges or other environmental accidents;
- other accidents or natural disasters; and
- weather conditions.

Mining in Central Appalachia is complex due to geological characteristics of the region.

The geological characteristics of coal reserves in Central Appalachia, such as depth of overburden and coal seam thickness, make them complex and costly to mine. As mines become depleted, replacement reserves may not be available when required or, if available, may not be capable of being mined at costs comparable to those characteristic of the depleting mines. In addition, as compared to mines in other regions permitting, licensing and other environmental and regulatory requirements are more costly and time consuming to satisfy. These factors could materially adversely affect the mining operations and cost structures of, and customers' ability to use coal produced by, operators in Central Appalachia, including us.

Our future success depends upon our ability to acquire or develop additional coal reserves that are economically recoverable.

Our recoverable reserves decline as we produce coal. Since we attempt, where practical, to mine our lowest-cost reserves first, we may not be able to mine all of our reserves at a similar cost as we do at our current operations. Our planned development and exploration projects might not result in significant additional reserves, and we might not have continuing success developing additional mines. For example, our construction of additional mining facilities necessary to exploit our reserves could be delayed or terminated due to various factors, including unforeseen geological conditions, weather delays or unanticipated development costs. Our ability to acquire additional coal reserves in the future also could be limited by restrictions under our existing or future debt facilities, competition from other coal companies for attractive properties or the lack of suitable acquisition candidates.

In order to develop our reserves, we must receive various governmental permits. We have not yet applied for the permits required or developed the mines necessary to mine all of our reserves. In addition, we might not continue to receive the permits necessary for us to operate profitably in the future. We may not be able to negotiate new leases from the government or from private parties or obtain mining contracts for properties containing additional reserves or maintain our leasehold interests in properties on which mining operations are not commenced during the term of the lease.

We face significant uncertainty in estimating our recoverable coal reserves, and variations from those estimates could lead to decreased revenues and profitability.

Forecasts of our future performance are based on estimates of our recoverable coal reserves. Estimates of those reserves were initially based on studies conducted by Marshall Miller & Associates, Inc. in 2004 for our CAPP reserves and 2005 and 2006 for our Midwest reserves in accordance with industry-accepted standards which we have updated for current activity using similar methodologies. A number of sources of information were used to determine recoverable reserves estimates, including:

- currently available geological, mining and property control data and maps;
- our own operational experience and that of our consultants;
- historical production from similar areas with similar conditions;
- previously completed geological and reserve studies;
- the assumed effects of regulations and taxes by governmental agencies; and
- assumptions governing future prices and future operating costs.

Reserve estimates will change from time to time to reflect, among other factors:

- mining activities;
- new engineering and geological data;
- acquisition or divestiture of reserve holdings; and
- modification of mining plans or mining methods.

Therefore, actual coal tonnage recovered from identified reserve areas or properties, and costs associated with our mining operations, may vary from estimates. These variations could be material, and therefore could result in decreased profitability.

Defects in title or loss of any leasehold interests in our properties could limit our ability to mine these properties or result in significant unanticipated costs.

We conduct substantially all of our mining operations on properties that we lease. The loss of any lease could adversely affect our ability to mine the associated reserves. Because we generally do not obtain title insurance or otherwise verify title to our leased properties, our right to mine some of our reserves has been in the past, and may again in the future be, adversely affected if defects in title or boundaries exist. In order to obtain leases or rights to conduct our mining operations on property where these defects exist, we have had to, and may in the future have to, incur unanticipated costs. In addition, we may not be able to successfully negotiate new leases for properties containing additional reserves. Some leases have minimum production requirements. Failure to meet those requirements could result in losses of prepaid royalties and, in some rare cases, could result in a loss of the lease itself.

Factors beyond our control could impact the amount and pricing of coal supplied by our independent contractors and other third parties.

In addition to coal we produce from our Company-operated mines, we have mines that typically are operated by independent contract mine operators, and we purchase coal from third parties for resale. For 2012, we anticipate approximately 7% of our total production will come from mines operated by independent contract mine operators and from third party purchased coal sources. Operational difficulties, changes in demand for contract mine operators from our competitors and other factors beyond our control could affect the availability, pricing and quality of coal produced for us by independent contract mine operators. Disruptions in supply, increases in prices paid for coal produced by independent contract mine operators or purchased from third parties, or the availability of more lucrative direct sales opportunities for our purchased coal sources could increase our costs or lower our volumes, either of which could negatively affect our profitability.

Our operations could be adversely affected if we are unable to obtain required surety bonds.

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, to pay federal and state workers' compensation and to satisfy other miscellaneous obligations. Certain insurance companies have informed us, along with other participants in the coal industry, that they no longer will provide surety bonds for workers' compensation and other post-employment benefits without collateral. We have satisfied our obligations under these statutes and regulations by providing letters of credit, cash collateral or other assurances of payment. However, letters of credit can be significantly more costly to us than surety bonds. The issuance of letters of credit under our Revolver also reduces amounts that we can borrow under our Revolver. If we are unable to secure surety bonds for these obligations in the future, and are forced to secure letters of credit indefinitely, our profitability may be negatively affected.

Our work force could become unionized in the future, which could adversely affect the stability of our production and reduce our profitability.

Our company owned mines are currently operated by union-free employees. However, our subsidiaries' employees have the right at any time under the National Labor Relations Act to form or affiliate with a union. Any unionization of our subsidiaries' employees, or the employees of third-party contractors who mine coal for us, could adversely affect the stability of our production and reduce our profitability. The current administration has indicated that it will support legislation that may make it easier for employees to unionize.

We have significant unfunded obligations for long-term employee benefits for which we accrue based upon assumptions, which, if incorrect, could result in us being required to expend greater amounts than anticipated.

We are required by law to provide various long term employee benefits. We accrue amounts for these obligations based on the present value of expected future costs. We employed an independent actuary to complete estimates for our workers' compensation and black lung (both state and federal) obligations.

We use a valuation method under which the total present and future liabilities are booked based on actuarial studies. Our independent actuary updates these liability estimates annually. However, if our assumptions are incorrect, we could be required to expend greater amounts than anticipated. All of these obligations are unfunded. In addition, the federal government and the governments of the states in which we operate consider changes in workers' compensation laws from time to time. Such changes, if enacted, could increase our benefit expenses and payments.

See "Critical Accounting Estimates — Workers' Compensation and Coal Miners' Pneumoconiosis" for additional information regarding our workers' compensation and black lung obligations.

We may be unable to adequately provide funding for our pension plan obligations based on our current estimates of those obligations.

We provide benefits under a defined benefit pension plan that was frozen in 2007. If future payments are insufficient to fund the pension plan adequately to cover our future pension obligations, we could incur cash expenditures and costs materially higher than anticipated. The pension obligation is calculated annually and is based on several assumptions, including then prevailing conditions, which may change from year to year. In any year, if our assumptions are inaccurate, we could be required to expend greater amounts than anticipated.

See "Critical Accounting Estimates — Defined Benefit Pension" for additional information regarding our pension plan obligations.

Substantially all of our assets are subject to security interests.

Substantially all of our cash, receivables, inventory and other assets are subject to various liens and security interests under our debt instruments. If one of these security interest holders becomes entitled to exercise its rights as a secured party, it would have the right to foreclose upon and sell, or otherwise transfer, the collateral subject to its security interest, and the collateral accordingly would be unavailable to us and our other creditors, except to the extent, if any, that other creditors have a superior or equal security interest in the affected collateral or the value of the affected collateral exceeds the amount of indebtedness in respect of which these foreclosure rights are exercised.

The level of our indebtedness could adversely affect our financial condition and results of operations.

Our total consolidated long-term debt as of December 31, 2011 was $582.2 million (net of discounts on our convertible notes of $95.3 million). Our level of indebtedness could result in the following:

- it could affect our ability to satisfy our outstanding obligations;
- a substantial portion of our cash flows from operations will have to be dedicated to interest and principal payments and may not be available for operations, working capital, capital expenditures, expansion, acquisitions or general corporate or other purposes;
- it may impair our ability to obtain additional financing in the future;
- it may limit our flexibility in planning for, or reacting to, changes in our business and industry; and
- it may make us more vulnerable to downturns in our business, our industry or the economy in general.

Our operations may not generate sufficient cash to enable us to service our debt. If we fail to make a payment on our debt, this could cause us to be in default on our outstanding indebtedness. In addition, we may incur additional indebtedness in the future, and, as a result, the related risks that we now face, including those described above, could intensify.

We may be unable to comply with restrictions imposed by the terms of our indebtedness, which could result in a default under these instruments.

Our debt instruments impose a number of restrictions on us. A failure to comply with these restrictions could adversely affect our ability to borrow under our Revolver or result in an event of default under our other debt instruments. Our Revolver contains financial covenants that require us to maintain a minimum Consolidated Fixed Charge Coverage Ratio and limits on our capital expenditure. The Consolidated Fixed Charge Coverage Ratio covenant under our Revolver is only applicable if the sum of our unrestricted cash plus our availability under our Revolver falls below $35 million and would remain in effect until the sum of our unrestricted cash and availability under our Revolver exceeds $35 million for 90 consecutive days. Our Revolver limits the capital expenditures that we may make or agree to make in any fiscal year, but such limitation only will apply if the sum of our unrestricted cash plus our availability under our Revolver falls below $50 million for a period of 5 consecutive days and would remain in effect until the sum of our unrestricted cash and availability under our Revolver exceeds $50 million for 90 consecutive days. As of December 31, 2011, our unrestricted cash was $199.7 million and the unused availability under our Revolver was $37.2 million.

Additional detail regarding the terms of our Revolver, including these covenants and the related definitions, can be found in our debt agreements, as amended, that have been filed as exhibits to our SEC filings.

In the event of a default, our lenders could terminate their commitments to us and declare all amounts borrowed, together with accrued interest and fees, immediately due and payable. If this were to occur, we might not be able to pay these amounts or we might be forced to seek amendments to our debt agreements which could make the terms of these agreements more onerous for us and require the payment of amendment or waiver fees. Failure to comply with these restrictions, even if waived by our lenders, also could adversely affect our credit ratings, which could increase our costs of debt financings and impair our ability to obtain additional debt financing. While the lenders have, to date, waived any covenant violations and amended the covenants, there is no guarantee they will continue to do so if future violations occur.

Changes in our credit ratings could adversely affect our costs and expenses.

Any downgrade in our credit ratings could adversely affect our ability to borrow and result in more restrictive borrowing terms, including increased borrowing costs, more restrictive covenants and the extension of less open credit. This, in turn, could affect our internal cost of capital estimates and therefore impact operational decisions.

Inability to satisfy contractual obligations may adversely affect our profitability.

From time to time, we have disputes with our customers over the provisions of long term contracts relating to, among other things, coal quality, pricing, quantity and delays in delivery. In addition, we may not be able to produce sufficient amounts of coal to meet our commitments to our customers. Our inability to satisfy our contractual obligations could result in our need to purchase coal from third party sources to satisfy those obligations or may result in customers initiating claims against us. We may not be able to resolve all of these disputes in a satisfactory manner, which could result in substantial damages or otherwise harm our relationships with customers.

We may be unable to exploit opportunities to diversify our operations.

Our future business plan may consider opportunities other than underground and surface mining in eastern Kentucky, southern West Virginia and southern Indiana. We may consider opportunities to expand both surface and underground mining activities in areas that are outside of eastern Kentucky, southern West Virginia and southern Indiana. We may also consider opportunities in other energy-related areas that are not prohibited by our debt instruments. If we undertake these diversification strategies and fail to execute them successfully, our financial condition and results of operations may be adversely affected.

There are risks associated with our acquisition strategy, including our inability to successfully complete acquisitions, our assumption of liabilities, dilution of your investment, significant costs and additional financing required.

We may explore opportunities to expand our operations through strategic acquisitions of other coal mining companies. Risks associated with our current and potential acquisitions, including the recent acquisition of IRP, include the disruption of our ongoing business, problems retaining the employees of the acquired business, assets acquired proving to be less valuable than expected, the potential assumption of unknown or unexpected liabilities, costs and problems, the inability of management to maintain uniform standards, controls, procedures and policies, the difficulty of managing a larger company, the risk of becoming involved in labor, commercial or regulatory disputes or litigation related to the new enterprises and the difficulty of integrating the acquired operations and personnel into our existing business.

We may choose to use shares of our common stock or other securities to finance a portion of the consideration for future acquisitions, either by issuing them to pay a portion of the purchase price or selling additional shares to investors to raise cash to pay a portion of the purchase price. If shares of our common stock do not maintain sufficient market value or potential acquisition candidates are unwilling to accept shares of our common stock as part of the consideration for the sale of their businesses, we will be required to raise capital through additional sales of debt or equity securities, which might not be possible, or forego the acquisition opportunity, and our growth could be limited. In addition, securities issued in such acquisitions may dilute the holdings of our current or future shareholders.

Our currently available cash may not be sufficient to finance any additional acquisitions.

We believe that our cash on hand, the availability under our Revolver and cash generated from our operations will provide us with adequate liquidity through 2012. However, such funds may not provide sufficient cash to fund any future acquisitions. Accordingly, we may need to conduct additional debt or equity financings in order to fund any such additional acquisitions, unless we issue shares of our common stock as consideration for those acquisitions. If we are unable to obtain any such financings, we may be required to forego future acquisition opportunities.

Surface mining is subject to increased regulation, and may require us to incur additional costs.

Surface mining is subject to numerous regulations related, among others, to blasting activities that can result in additional costs. For example, when blasting in close proximity to structures, additional costs are incurred in designing and implementing more complex blast delay regimens, conducting pre-blast surveys and blast monitoring, and the risk of potential blast-related damages increases. Since the nature of surface mining requires ongoing disturbance to the surface, environmental compliance costs can be significantly greater than with underground operations. In addition, the COE imposes stream mitigation requirements on surface mining operations. These regulations require that footage of stream loss be replaced through various mitigation processes, if any ephemeral, intermittent, or perennial streams are filled due to mining operations. In 2008, the U.S. Department of Interior's Office of Surface Mining imposed regulatory requirements applicable to excess spoil placement, including the requirement that operators return as much spoil as possible to the excavation created by the mine. These regulations may cause us to incur significant additional costs, which could adversely impact our operating performance.

We are subject to various legal proceedings, which may have an adverse effect on our business.

We are party to a number of legal proceedings incidental to our normal business activities, including a large number of workers' compensation claims. While we cannot predict the outcome of the proceedings, there is always the potential that the costs of defending litigation in an individual matter or the aggregation of many matters could have an adverse effect on our cash flows, results of operations or financial position.

Our ability to use net operating loss carryforwards may be subject to limitation

Section 382 of the U.S. Internal Revenue Code of 1986, as amended, imposes an annual limit on the amount of net operating loss carryforwards that may be used to offset taxable income when a corporation has undergone significant changes in its stock ownership or equity structure. Our ability to use net operating losses is limited by prior changes in our ownership, and may be further limited by issuances of common stock, in connection with the conversion of the existing convertible senior notes or by the consummation of other transactions. As a result, as we earn net taxable income, our ability to use net operating loss carryforwards to offset U.S. federal taxable income may become subject to limitations, which could potentially result in increased future tax liabilities for us.

Changes in federal or state income tax laws, particularly in the area of percentage depletion, could cause our financial position and profitability to deteriorate.

The federal government has been reviewing the income tax laws relating to the coal industry regarding percentage depletion benefits. If the percentage depletion tax benefit was reduced or eliminated, our cash flows, results of operations or financial condition could be materially impacted.

Risks Relating to our Common Stock

The market price of our common stock has been volatile and difficult to predict, and may continue to be volatile and difficult to predict in the future, and the value of your investment may decline.

The market price of our common stock has been volatile in the past and may continue to be volatile in the future. The market price of our common stock will be affected by, among other things:

- variations in our quarterly operating results;
- changes in financial estimates by securities analysts;

- sales of shares of our common stock by our officers and directors or by our shareholders;
- changes in general conditions in the economy or the financial markets;
- changes in accounting standards, policies or interpretations;
- other developments affecting us, our industry, clients or competitors; and
- the operating and stock price performance of companies that investors deem comparable to us.

Any of these factors could have a negative effect on the price of our common stock on the Nasdaq Global Select Market, make it difficult to predict the market price for our common stock in the future and cause the value of your investment to decline.

We do not intend to pay cash dividends on our common stock in the foreseeable future.

We do not anticipate paying cash dividends on our common stock in the foreseeable future. In addition, covenants in our Revolver and our 2019 Senior Notes restrict our ability to pay cash dividends and may prohibit the payment of dividends and certain other payments.

Provisions of our articles of incorporation, bylaws and shareholder rights agreement could discourage potential acquisition proposals and could deter or prevent a change in control.

Some provisions of our articles of incorporation and bylaws, as well as Virginia statutes, may have the effect of delaying, deferring or preventing a change in control. These provisions may make it more difficult for other persons, without the approval of our Board of Directors, to make a tender offer or otherwise acquire substantial amounts of our common stock or to launch other takeover attempts that a shareholder might consider to be in such shareholder's best interest. These provisions could limit the price that some investors might be willing to pay in the future for shares of our common stock.

We have a shareholder rights agreement which, in certain circumstances, including a person or group acquiring, or the commencement of a tender or exchange offer that would result in a person or group acquiring, beneficial ownership of more than 20% of the outstanding shares of our common stock, would entitle each right holder, other than the person or group triggering the plan, to receive, upon exercise of the right, shares of our common stock having a then-current fair value equal to twice the exercise price of a right.

This shareholder rights agreement provides us with a defensive mechanism that decreases the risk that a hostile acquirer will attempt to take control of us without negotiating directly with our Board of Directors. The shareholder rights agreement may discourage acquirers from attempting to purchase us, which may adversely affect the price of our common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2011, we owned approximately 13,800 acres of land. Our mineral rights are primarily controlled through leases. In a mining context, control of a property is typically divided into three categories:

- mineral rights, which allows the controlling party to remove the minerals on the property;
- surface rights, which allows the controlling party to use and disturb the surface of the property; and
- fee control, which includes both mineral and surface rights.

Our rights with respect to properties that we lease vary from lease to lease, but encompass mineral rights, surface rights, or both.

The coal properties that we control in Central Appalachia are located primarily in eastern Kentucky and southern West Virginia. The coal properties that we control in the Midwest are part of the Illinois Coal basin and are located in southwest Indiana.

The terms of our leases can vary significantly, including the following provisions:

- length of term;
- renewal requirements;
- minimum royalties;
- recoupment provisions;
- tonnage royalty rates;
- minimum tonnage royalty rates;
- wheelage rates;
- usage fees; and
- other factors.

Our leases typically provide for periodic royalty payments, subject to specified annual minimums. The annual minimums are typically based on the forecasted tonnage of coal to be produced on the leased property over the term of the lease. Payments made pursuant to these minimums for years in which periodic royalty payments do not meet the minimums are typically recoupable against future periodic production royalties paid within a fixed period of time. We typically are responsible for the payment of property taxes due on the properties we have under lease.

For a discussion of our coal reserves see Item 1 Business "Reserves."

Our corporate headquarters is located at 901 E. Byrd Street; Richmond, Virginia and is occupied pursuant to a lease that expires in 2014.

Item 3. Legal Proceedings

We are parties to a number of legal proceedings incidental to our normal business activities, including a large number of workers' compensation claims. While we cannot predict the outcome of these proceedings, in our opinion, any liability arising from these matters individually and in the aggregate should not have a material adverse effect on our consolidated financial position, cash flows or results of operations.

On January 9, 2012, Triad Mining Inc., a subsidiary of the Company, agreed to settle an enforcement action by the EPA. The EPA alleged that Triad conducted unpermitted excavation and filling of streams that flow into the White River in Indiana. Under the proposed settlement, Triad must enhance streams to address and mitigate the impact of its mining activities, create and maintain forested buffer areas and wetland to protect the restored streams, and pay an $810,171 civil penalty. The proposed settlement is part of a consent decree that is subject to public comment and court approval. The Company has accrued for this settlement as of December 31, 2011.

Item 4. Mine Safety Disclosures

Information concerning mine safety and health violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95 to this report.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock trades on the Nasdaq Global Select Market under the ticker symbol "JRCC". The table below sets forth the high and low closing sales prices for our common stock for the periods indicated, as reported by Nasdaq.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Fiscal year ended December 31, 2011				
High	$26.84	25.14	21.85	11.44
Low	$19.89	18.68	6.37	5.55
Fiscal year ended December 31, 2010				
High	$22.18	19.39	19.83	25.33
Low	$15.17	14.67	15.28	16.00

Recent Sales or Purchases of Unregistered Securities

We did not sell or purchase any unregistered securities during 2011.

Holders

As of December 31, 2011, there were 146 record holders of our common stock.

Dividends

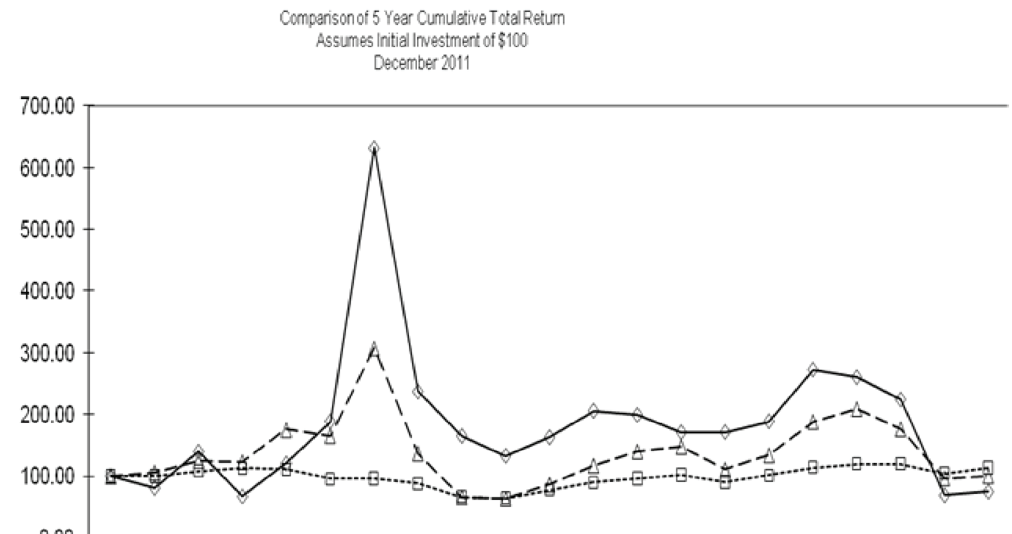
We did not pay any cash dividends on our common stock during the years ended December 31, 2011, 2010 or 2009. We do not anticipate paying cash dividends in the foreseeable future. Any future determination as to the payment of cash dividends will depend upon such factors as earnings, capital requirements, our financial condition, restrictions in financing agreements and other factors deemed relevant by the Board of Directors. In addition, covenants in our Revolver and our 2019 Senior Notes restrict our ability to pay cash dividends and may prohibit the payment of dividends and certain other payments.

Securities Authorized for Issuance under Equity Compensation Plans

Please refer to note 7 of our December 31, 2011 consolidated financial statements for securities authorized to be issued under our 2004 Equity Incentive Plan.

Stock Performance Graph

Set forth below is a line graph comparing the percentage change in the cumulative total shareholder return of James River Coal Company's Common Stock against the cumulative total return of the NASDAQ Composite Index and the Dow Jones U.S. Coal Index on a quarterly basis for the period commencing on December 31, 2006 and ending on December 31, 2011. You are cautioned against drawing any conclusions from the data contained in this graph, as past results are not necessarily indicative of future performance. The indices used are included for comparative purposes only and do not indicate an opinion of management that such indices are necessarily an appropriate measure of the relative performance of our stock.



	12/31/2006	3/31/2007	6/30/2007	9/30/2007	12/31/2007	3/31/2008	6/30/2008	9/30/2008	12/31/2008	3/31/2009	6/30/2009	9/30/2009	12/31/2009	3/31/2010	6/30/2010	9/30/2010	12/31/2010	3/31/2011	6/30/2011	9/30/2011	12/31/2011
James River Coal Company	100.00	80.49	139.63	66.80	120.45	188.74	632.25	236.91	165.14	132.92	162.97	205.84	199.14	171.25	171.47	188.82	272.83	260.36	224.27	68.62	74.55
NASDAQ Composite-Total Returns	100.00	100.44	108.17	112.48	110.65	95.30	96.07	87.82	66.42	64.57	77.70	90.05	96.54	102.24	90.16	101.54	114.07	119.83	119.78	104.58	113.17
Dow Jones US Coal Index	100.00	106.28	125.69	123.33	175.54	165.93	307.47	137.11	66.31	63.72	86.65	117.30	140.54	147.87	110.84	134.41	188.67	209.17	176.87	96.75	100.58

James River Coal Company — NASDAQ Composite-Total Returns — Dow Jones US Coal Index

Item 6. Selected Financial Data

The following table presents our selected consolidated financial and operating data as of and for each of the periods indicated. The selected consolidated financial data is derived from our audited consolidated financial statements. The selected consolidated financial and operating data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes.

On April 18, 2011, we acquired International Resource Partners LP and its subsidiary companies (collectively IRP). Our financial position and supplemental operating data prior to 2011 and our results of operations for the years ended December 31, 2010, 2009, 2008 and 2007 do not include the financial results for IRP.

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(in thousands, except for per share information)				
Consolidated Statement of Operations:					
Revenues					
Coal sales revenue	$1,105,370	698,949	678,562	566,310	511,739
Freight and handling revenue	72,285	2,167	2,996	2,197	1,967
Other Revenues	—	—	—	—	6,854
Total Revenues	1,177,655	701,116	681,558	568,507	520,560
Cost of coal sold	905,482	512,348	505,892	525,691	471,380
Freight and handling Costs	72,285	2,167	2,996	2,197	1,967
Gain on curtailment of pension plan	—	—	—	—	(6,091)
Depreciation, depletion, and amortization	108,914	64,368	62,078	70,277	71,856
Gross profit (loss)	90,974	122,233	110,592	(29,658)	(18,552)
Selling, general, and administrative expenses	57,078	38,347	39,720	34,992	32,191
Acquisition costs	8,504	—	—	—	—
Operating income (loss)	25,392	83,886	70,872	(64,650)	(50,743)
Interest expense	50,096	29,943	17,057	17,746	19,764
Interest income	(494)	(683)	(60)	(469)	(471)
Charges associated with repayment and amendment of debt	740	—	1,643	15,618	2,421
Miscellaneous (income) expense, net	(812)	27	(281)	(1,279)	(598)
Income tax expense (benefit)	14,951	(23,566)	1,559	(273)	(17,844)
Net income (loss)	$ (39,089)	78,165	50,954	(95,993)	(54,015)

	December 31,				
	2011	2010	2009	2008	2007
	(in thousands)				
Consolidated Balance Sheet Data:					
Working capital (deficit) (a)	$ 227,022	191,625	109,998	(54,961)	(8,471)
Property, plant, and equipment, net	909,294	385,652	354,088	344,848	319,204
Total assets	1,404,582	784,569	669,312	463,546	439,287
Long term debt, including current portion	582,193	284,022	278,268	168,000	188,800
Total shareholders' equity	396,662	247,383	170,342	65,238	69,774

	Year Ended December 31				
	2011	2010	2009	2008	2007
	(in thousands)				
Consolidated Statement of Cash Flow Data:					
Net cash provided by (used in) operating activities	$ 163,772	169,062	27,559	(1,576)	4,022
Net cash used in investing activities	(654,314)	(95,344)	(72,010)	(73,589)	(49,201)
Net cash provided by (used in) financing activities	509,877	(1,273)	149,058	73,076	48,785

	Year Ended December 31				
	2011	2010	2009	2008	2007
	(in thousands, except tons, per ton and number of employees)				
Supplemental Operating Data:					
Tons sold	11,801	8,919	9,623	11,383	12,049
Tons produced (includes purchased tons)	11,859	8,910	9,877	11,355	12,051
Coal sales revenue per ton sold	$ 93.67	78.37	70.51	49.75	42.47
Number of employees	2,405	1,746	1,736	1,751	1,681
Capital expenditures	$138,455	95,426	72,159	74,697	49,343

(a) Working capital is current assets less current liabilities

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and the accompanying notes and "Selected Financial Data" included elsewhere in this filing. This discussion contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in the forward-looking statements as a result of numerous factors, including the risks discussed in "Risk Factors" in this filing. For more on forward looking statements, see the section entitled "Forward Looking Statements" at the beginning of this report.

Overview

We mine, process and sell thermal and metallurgical coal through eight active mining complexes located throughout eastern Kentucky, southern West Virginia and southern Indiana. The majority of our metallurgical coal was obtained in the April 18, 2011 acquisition (the IRP Acquisition) of International Resource Partners LP and its subsidiary companies (collectively IRP). We have two reportable business segments based on the coal basins in which we operate (Central Appalachia (CAPP) and the Midwest (Midwest)). IRP is included in our CAPP segment. We derived 56% of our total revenues in 2011 from coal sales to electric utility customers and the remaining 44% from coal sales (including metallurgical coal) to industrial and other customers. In 2011, our mines produced 10.3 million tons of coal (including 0.7 million tons of contract coal) and we purchased another 1.6 million tons for resale. Of the 10.3 million tons produced from Company mines, approximately 63% came from underground mines, while the remaining 37% came from surface mines. In 2011, we generated total revenues of $1.2 billion and a net loss of $39.1 million.

The IRP Acquisition has been treated as a purchase of assets for tax purposes. The IRP Acquisition was completed on April 18, 2011 for $516.0 million in an all-cash transaction. The base purchase price of $475.0 million was increased by the cash acquired and any working capital (as defined in the agreement) that exceeded $18.5 million. IRP did not have any debt at the time of the closing. The IRP Acquisition increases our offerings of metallurgical coal, provides us with greater access to the international seaborne coal market and expands our brokering and trading operations. IRP is a fully integrated coal company focused on producing and marketing high quality metallurgical and steam coal in Central Appalachia. IRP produces and sells various grades of metallurgical and steam coal from underground and surface mining operations in southern West Virginia and eastern Kentucky. IRP's customer base consists of domestic steel and coke producers, international steel producers and domestic electric utilities. At the time of the IRP Acquisition, IRP operated nine mines, including five underground mines and four surface mines.

For the year ended December 31, 2010, IRP produced approximately 1.9 million tons of coal, including 1.2 million tons of metallurgical coal and 0.7 million tons of steam coal. Total 2010 shipments, including coal purchased for blending purposes, were 3.7 million tons. These tons included 2.6 million tons of metallurgical coal and 1.1 million tons of steam coal. IRP generated revenues of $490.3 million and income before taxes at the partnership level of $51.3 million in 2010. IRP's coal reserves and resources are located in West Virginia and Kentucky. As of December 31, 2010, IRP controlled approximately 136 million tons of coal reserves and resources, consisting of approximately 61 million tons of metallurgical coal and an estimated 75 million tons of steam coal. The coal reserves and resources acquired from IRP include 85.5 million of proven and probable reserves. IRP leases a substantial portion of its coal reserves and resources from various third-party landowners.

CAPP Segment

In Central Appalachia, our thermal coal sales are primarily to customers in the southern portion of the South Atlantic region of the United States. The South Atlantic Region includes the states of Florida, Georgia, South Carolina, North Carolina, West Virginia, Virginia, Maryland and Delaware. Our metallurgical coal is sold primarily to steel companies in North America, South America, Europe, Asia and Africa. Approximately 35% of our total CAPP segment revenues in 2011 were derived from sales made outside the United States, including Brazil, Canada, Egypt, France, Germany, India and United Kingdom. In 2011, our CAPP mines produced 7.8 million tons of coal (including 0.7 million tons of contract coal) and we purchased another 1.6 million tons for resale. Of the 7.8 million tons produced from CAPP company mines, 75% came from Company operated underground mines. In 2011, we shipped 9.3 million tons of coal and generated coal sale revenues of $1.0 billion from our CAPP segment. In 2011, South Carolina Public Service Authority and Georgia Power Company were our largest customers, representing approximately 20% and 11% of our total revenues, respectively. No other CAPP customer accounted for more than 10% of our total revenues.

As of December 31, 2011, we estimate that we controlled approximately 322.4 million tons of proven and probable coal reserves in our CAPP segment. Based on our most recent analysis prepared by Marshall Miller & Associates, Inc. ("MM&A") as of March 31, 2004 and December 31, 2010, we estimate that th ese reserves have an average heat content of 13,200 Btu per pound and an average sulfur content of 1.2%. At current production levels, we believe these reserves would support more than 30 years of production.

Midwest Segment

In the Midwest, the majority of our coal is sold in the East North Central Region, which includes the states of Illinois, Indiana, Ohio, Michigan and Wisconsin. In 2011, our Midwest mines produced approximately 2.4 million tons of coal. Of the Midwest tons produced, 77% came from Company operated surface mines. In 2011, we shipped 2.5 million tons of coal and generated coal sale revenues of $105.4 million from our Midwest segment. No Midwest customer accounted for more than 10% of our total revenues.

As of December 31, 2011, we estimate that we controlled approximately 40.4 million tons of proven and probable coal reserves in our Midwest segment. Based on our most recent analyses prepared by MM&A as of February 1, 2005 and April 11, 2006, we estimate that these reserves have an average heat content of 12,000 Btu per pound and average sulfur content of 3.2%. At current production levels, we believe these reserves would support more than 15 years of production.

Reserves

MM&A prepared a detailed study of our CAPP reserves as of March 31, 2004 based on all of our geologic information, including our updated drilling and mining data. MM&A completed their report on our CAPP reserves in June 2004. MM&A also prepared a detailed study of the reserves as of December 31, 2010 for the reserves obtained in the IRP Acquisition (which was based in part on previous evaluations of the properties). For our Midwest reserves, MM&A prepared a detailed study of reserves as of February 1, 2005 for the reserves obtained in the acquisition of Triad and as of April 11, 2006 for certain additional reserves acquired in the second quarter of 2006 in the Midwest. The MM&A studies were planned and performed to obtain reasonable assurance of the subject demonstrated reserves. In connection with the studies, MM&A prepared reserve maps and had certified professional geologists develop estimates based on data supplied by us, Triad and IRP using standards accepted by government and industry. We have used MM&A's March 31, 2004 study of the CAPP reserves and the December 31, 2010 study of the reserves acquired from IRP as the basis for our current internal estimate of our CAPP reserves and MM&A's February 1, 2005 and April 11, 2006 studies as the basis for our current internal estimate of our Midwest reserves.

Reserves for these purposes are defined by SEC Industry Guide 7 as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. The reserve estimates were prepared using industry-standard methodology to provide reasonable assurance that the reserves are recoverable, considering technical, economic and legal limitations. Although MM&A has reviewed our reserves and found them to be reasonable (notwithstanding unforeseen geological, market, labor or regulatory issues that may affect the operations), MM&A's engagement did not include performing an economic feasibility study for our reserves. In accordance with standard industry practice, we have performed our own economic feasibility analysis for our reserves. It is not generally considered to be practical, however, nor is it standard industry practice, to perform a feasibility study for a company's entire reserve portfolio. In addition, MM&A did not independently verify our control of our properties, and has relied solely on property information supplied by us. Reserve acreage, average seam thickness, average seam density and average mine and wash recovery percentages were verified by MM&A to prepare a reserve tonnage estimate for each reserve. There are numerous uncertainties inherent in estimating quantities and values of economically recoverable coal reserves as discussed in "Critical Accounting Estimates — Coal Reserves".

Based on the MM&A reserve studies and the foregoing assumptions and qualifications, and after giving effect to our operations from the respective dates of the studies through December 31, 2011, we estimate that, as of December 31, 2011, we controlled approximately 322.4 million tons of proven and probable coal reserves in the CAPP region and 40.4 million tons in the Midwest region. The following table provides additional information regarding changes to our reserves for the year ended December 31, 2011 (in millions of tons):

	CAPP	Midwest	Total
Proven and Probable Reserves, as of December 31, 2010 (1)	230.4	40.9	271.3
Coal Extracted	(7.9)	(2.4)	(10.3)
IRP Acquisition (2)	85.5	—	85.5
Acquisitions (3)	3.1	—	3.1
Adjustments (4)	11.5	1.9	13.4
Divesture (5)	(0.2)	—	(0.2)
Proven and Probable Reserves, as of December 31, 2011 (1)	322.4	40.4	362.8

(1) Calculated in the same manner, and based on the same assumptions and qualifications, as used in the MM&A studies described above, but these estimates have not been reviewed by MM&A. Proven reserves have the highest degree of geologic assurance and are reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings, or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspections, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established. Probable reserves have a moderate degree of geologic assurance and are reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation. This reserve information reflects recoverable tonnage on an as-received basis with 5.5% moisture.

(2) Based on a detailed study by MMA of the reserves as of December 31, 2010 obtained in the IRP Acquisition.

(3) Represents estimated reserves on leases entered into or properties acquired during the relevant period. We calculated the reserves in the same manner, and based on the same assumptions and qualifications, as used in the MM&A studies described above, but these estimates have not been reviewed by MM&A.

(4) Represents changes in reserves due to additional information obtained from exploration activities, production activities or discovery of new geologic information. We calculated the adjustments to the reserves in the same

manner, and based on the same assumptions and qualifications, as used in the MM&A studies described above, but these estimates have not been reviewed by MM&A.

(5) Represents changes in reserves due to expired or transferred leases.

Key Performance Indicators

We manage our business through several key performance metrics that provide a summary of information in the areas of sales, operations, and general and administrative costs.

In the sales area, our long-term metrics are the volume-weighted average remaining term of our contracts and our open contract position for the next several years. During periods of high prices, we may seek to lengthen the average remaining term of our contracts and reduce the open tonnage for future periods. In the short-term, we closely monitor the Average Selling Price per Ton (ASP), and the mix between our spot sales and contract sales.

In the operations area, we monitor the volume of coal that is produced by each of our principal sources, including company mines, contract mines, and purchased coal sources. For our company mines, we focus on both operating costs and operating productivity. We closely monitor the cost per ton of our mines against our budgeted costs and against our other mines.

EBITDA and Adjusted EBITDA are also measures used by management to measure operating performance. We define EBITDA as net income (loss) plus interest expense (net), income tax expense (benefit) and depreciation, depletion and amortization. We regularly use EBITDA to evaluate our performance as compared to other companies in our industry that have different financing and capital structures and/or tax rates. In addition, we use EBITDA in evaluating acquisition targets. EBITDA is not a recognized term under U.S generally accepted accounting principles (US GAAP) and is not an alternative to net income, operating income or any other performance measures derived in accordance with US GAAP or an alternative to cash flow from operating activities as a measure of operating liquidity. Adjusted EBITDA is used in calculating compliance with our debt covenants and adjusts EBITDA for certain items as defined in our debt agreements, including stock compensation, acquisition costs and certain bank fees.

Trends and Uncertainties In Our Business

Near-term, the global economic slowdown has lowered demand for steam coal which has resulted in a general decline in coal prices. Looking forward, several factors are exerting downward pressure on steam coal prices, including lower demand for coal to generate electricity, lower natural gas prices, and concerns about the effects of recent and proposed U.S. Environmental Protection Agency (EPA) rules such at the Cross-State Air Pollution Rule and the Mercury and Air Toxics Standards rule. See Item 1. Business — Environmental and other Regulatory Matters — Environmental Laws and Regulations — The Clean Air Act for information on the Cross-State Air Pollution Rule and the Mercury and Air Toxics Standards rule.

The U.S. Energy Information Administration (EIA) forecasts that in 2012 coal will fuel 42.2% of total U.S. electricity generation and 41.5% in 2013, down from 43% of generation in 2011. The decline in coal fired electrical generation is due in part to natural gas. Production of natural gas from non-traditional sources such as shale has resulted in growing natural gas inventories and lower prices. At the end of December 2011, the EIA estimates that U.S. natural gas working inventories were at 3.5 trillion cubic feet, a record high. Due to record inventories, the EIA estimates that the 2012 average natural gas spot price will decline by almost $0.50 per MMBtu from the 2011 average spot price of $4.00 per MMBtu. The EIA forecasts that by 2013 natural gas prices will be above $4.00 per MMBtu.

Although natural gas is relatively inexpensive when compared to coal, electrical utilities continue to build and bring online coal fired generation. The National Energy Technology Laboratory's July 2011 report on new coal-fired power plants estimates that there are 7,384 megawatts of new coal-fired electrical generation under construction in the United States. An additional 13,844 megawatts of coal-fired electrical generation have been announced and are in the early stages of development.

The weakness in the U.S. domestic coal market has been partially offset by strong U.S. coal exports. According to the EIA, in 2011, the U.S. exported 107 million short tons of coal, the highest since 1991, and is forecasted to export 98 million short tons in 2012 and 2013. The Central Appalachia region, which accounts for all of our shipments to international markets, was the primary beneficiary of the export market, largely due to Central Appalachia's production of metallurgical coal. Steel production has continued to recover since the 2009 lows, which accounts for the increased demand for metallurgical coal. In addition, 2011 saw severe flooding in the Australian coal fields, which led to record high prices for U.S. exports of metallurgical coal. While we anticipate that the demand for metallurgical coal will continue to be strong, we are seeing indications that 2012 pricing will be lower than prices realized in 2011.

Long-term, we believe that the demand for coal worldwide will continue to be strong. The EIA's 2011 International Energy Outlook (the "2011 International Outlook") forecasts that world net electricity generation will increase by 84% from 2008 to 2035. Much of that electricity demand will be driven by rising living standards in the undeveloped world, where 1.4 billion people still do not have access to electricity. Coal provides the largest share of world electricity generation and will continue to do so through 2035 according to the 2011 International Outlook. Although coal's share of electricity generation is expected to decline, in absolute terms coal demand will increase. The 2011 International Outlook states that coal consumption worldwide is expected to increase by an average of 1.5% year-over-year through 2035. Coal consumption in countries outside the Organization for Economic Cooperation and Development is expected to grow on average 2.3% year-over-year. Much of the growth is expected to come from India and China. The 2011 International Outlook estimates that installed coal-fired generating capacity in China will nearly double from 2008 to 2035, and coal use in China's industrial sector will grow by 67 percent. Between 2008 and 2035, India's coal fired generating capacity is forecasted to rise by 72% while its industrial sector coal use increases by 94%. Our ability to capitalize on worldwide coal demand will depend on many factors beyond our control, such as transportation costs, supplies of competing coals and world economic conditions, among others.

While the prospects for coal demand worldwide are favorable, any global treaties that restrict carbon dioxide emissions or favor renewable energy sources over coal will reduce demand for coal. See Item 1 "Business — Environmental and Other Regulatory Matters" for discussion related to the global initiatives to reduce carbon dioxide emissions.

In addition to coal prices and demand, our profitability is affected by our production costs, which have increased in recent years. We expect the higher costs to continue for the next several years, due to a number of factors, including increased governmental regulations, high prices in worldwide commodity markets, and a highly competitive market for a limited supply of skilled mining personnel. See Item 1A "Risk Factors" for additional information on factors beyond our control that could affect our production costs.

Results of Operations

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010

The following table shows selected operating results for 2011 and 2010 (in thousands, except per ton amounts):

	Year Ended December 31,				
	2011		2010		Change
	Total	Per Ton	Total	Per Ton	Total
Volume Shipped (tons)	11,801		8,919		32%
Coal sales revenue	$1,105,370	$93.67	$698,949	$78.37	58%
Freight and handling revenue	72,285	6.13	2,167	0.24	3236%
Cost of coal sold	905,482	76.73	512,348	57.44	77%
Freight and handling costs	72,285	6.13	2,167	0.24	3236%
Depreciation, depletion and amortization	108,914	9.23	64,368	7.22	69%
Gross profit	90,974	7.71	122,233	13.70	–26%
Selling, general and administrative	57,078	4.84	38,347	4.30	49%

Volume and Revenues by Segment

The following tables show volume and revenue information by segment (in thousands, except per ton amounts).

	Year ended December 31, 2011	2010	Change
Volume shipped (tons)			
CAPP tons			
Steam	7,166	6,109	17%
Metallurgical	2,155	—	NA
Total CAPP tons	9,321	6,109	53%
Midwest steam tons	2,480	2,810	–12%
Total volume shipped	11,801	8,919	32%

	Year ended December 31, 2011		2010		Change
	Total	Per Ton	Total	Per Ton	Total
Revenues					
Coal sales revenue					
CAPP steam	$ 651,016	90.85	$585,064	95.77	11%
CAPP metallurgical	348,972	161.94	—	—	—
Total CAPP coal sales revenue	999,988	107.28	585,064	95.77	71%
Midwest steam	105,382	42.49	113,885	40.53	–7%
Total coal sales revenue	1,105,370	93.67	698,949	78.37	58%
Freight and handling revenue					
CAPP	69,778		—		—
Midwest	2,507		2,167		16%
Total freight and handling revenue	72,285		2,167		3236%
Total revenue	1,177,655		701,116		68%

Total tons shipped increased by 32% in 2011 as compared to 2010. Coal sales revenue increased 58% in 2011 as compared to 2010. The increase in tons shipped and coal sales revenue (including the change in mix to include metallurgical coal) was primarily related to contracts acquired in the IRP Acquisition and additional tons produced from the properties acquired in the IRP Acquisition. The overall increase in tons was partially offset by a decrease in tons shipped in our Midwest Region in 2011 as compared to 2010.

Freight and handling revenue consists of shipping and handling costs invoiced to coal customers and paid to third-party carriers. These revenues are directly offset by freight and handling costs.

Operating and Other Costs

The following tables show selected costs in total and by segment (in thousands, except per ton amounts).

	2011		2010		Change
	Total	Per Ton	Total	Per Ton	Total
Volume shipped (tons)	11,801		8,919		
Cost of coal sold	$905,482	$76.73	$512,348	$57.44	77%
Freight and handling costs	72,285	6.13	2,167	0.24	3236%
Depreciation, depletion and amortization	108,914	9.23	64,368	7.22	69%
Selling, general and administrative	57,078	4.84	38,347	4.30	49%
Acquisition costs	8,504	0.72	—	—	NA
Interest expense	50,096	4.25	29,943	3.36	67%

	2011			2010		
	CAPP	Midwest	Corporate	CAPP	Midwest	Corporate
Cost of coal sold	$811,573	$93,909	$—	$419,564	$92,784	$—
Per ton	87.07	37.87	—	68.68	33.02	—
Freight and handling costs	69,778	2,507	—	—	2,167	—
Per ton	7.49	1.01	—	—	0.77	—
Depreciation, depletion and amortization	96,455	12,407	52	53,467	10,840	61
Per ton	10.35	5.00	—	8.75	3.86	—

The cost of coal sold, excluding depreciation, depletion and amortization, increased from $512.3 million in 2010 to $905.5 million in 2011. Our cost per ton of coal sold in the CAPP region increased from $68.68 per ton in 2010 to $87.07 per ton in the 2011. Our costs in the CAPP region are impacted by increased costs as a result of the IRP Acquisition. Generally, the mines acquired from IRP have more metallurgical coal than our legacy operations. These metallurgical coal mines produce higher coal sales revenue but are more costly to mine. Our costs were also impacted by an increase in metallurgical coal purchased that is used to blend with our metallurgical coal production to meet quality requirements under our sales contracts. The impact of the change in our mix to additional metallurgical coal production is approximately $9.92 per ton. The remaining increase of $8.47 over the prior year is primarily due to an increase in our labor and benefit costs of $1.79 per ton, variable costs of $3.88 per ton and preparation plants and raw trucking costs of $1.59 at our mines that do not produce metallurgical coal. Our costs continue to be impacted by lower productivity due to increased federal and state regulatory scrutiny, a decrease in tons produced in response to market conditions and an increase in commodity prices. For more detail regarding the increased regulatory activity see “Part II — Item 1A — Risk Factors — Underground mining is subject to increased regulation, and may require us to incur additional cost.”

Our cost per ton of coal sold in the Midwest increased $4.85 per ton to $37.87 per ton in the 2011 period as compared to the 2010 period. The major components of this increase include an increase in the trucking and preparation costs of $1.75 per ton, variable costs of $1.23 per ton and labor and benefit costs of $1.06 per ton.

Freight and handling costs

In 2011, freight and handling costs increased due an increase in export shipments of metallurgical coal primarily from operations acquired from IRP.

Depreciation, depletion and amortization

Depreciation, depletion and amortization increased from $64.4 million in the 2010 to $108.9 million in the 2011 period. In the CAPP region, depreciation, depletion and amortization increased $43.0 million to $96.5 million, which is due to the increase in the asset base as a result of the IRP Acquisition and $5.9 million of amortization on contracts acquired from IRP. In the Midwest, depreciation, depletion and amortization increased $1.6 million to $12.4 million.

Selling, general and administrative

Selling, general and administrative expenses increased from $38.3 million in the 2010 period to $57.1 million in the 2011 period, which is primarily due to increased selling, general and administrative expenses as a result of the IRP Acquisition.

Acquisition costs

In 2011, costs of $8.5 million were incurred related to the IRP Acquisition.

Interest Expense

Interest expense increased from $29.9 million in 2010 to $50.1 million in 2011. The increase in our interest expense was the result of the issuance of our 2018 Convertible Senior Notes and 2019 Senior Notes in March 2011, offset by the redemption in full of our 2012 Senior Notes in June 2011. These debt transactions are described below in Liquidity and Capital Resources. Interest expense for 2011 and 2010 includes $14.7 million and $8.1 million, respectively, related to the amortization of debt discounts and debt issuance costs.

Income Taxes

Our effective tax rate in 2011 was an expense of 61.9% and our effective tax rate in 2010 was a benefit of 43.2%. For 2011, our effective income tax rate was impacted primarily by a valuation allowance and the effects of percentage depletion. In 2011, in connection with the completion of our forecasts which considered the decline in coal prices and market demand that occurred towards the end of 2011, and after weighing all positive and negative evidence, we concluded that it was not more likely than not to realize a portion of our gross deferred tax assets and as a result a valuation allowance of $37.3 million was recorded. For 2010, our effective tax rate was reduced from the statutory federal rate of 35% primarily as the result of the reversal of our income tax valuation allowance (60.9%) and by percentage depletion (20.4%).

The criteria for recording a valuation allowance are described in "Critical Accounting Estimates — Income Taxes." As of December 31, 2011, we had a recorded a $37.3 million valuation allowance against our gross deferred tax assets. Percentage depletion is an income tax deduction that is limited to a percentage of taxable income from each of our mining properties. Because percentage depletion can be deducted in excess of cost basis in the properties, it creates a permanent difference and directly impacts the effective tax rate. Fluctuations in the effective tax rate may occur due to the varying levels of profitability (and thus, taxable income and percentage depletion) at each of our mine locations.

Results of Operations

Year Ended December 31, 2010 Compared with the Year Ended December 31, 2009

The following table shows selected operating results for 2010 and 2009 (in thousands, except per ton amounts):

	Year Ended December 31,				
	2010		2009		Change
	Total	Per Ton	Total	Per Ton	Total
Volume Shipped (tons)	8,919		9,623		–7%
Coal sales revenue	$698,949	$78.37	$678,562	$70.51	3%
Freight and handling revenue	2,167	0.24	2,996	0.31	–28%
Cost of coal sold	512,348	57.44	505,892	52.57	1%
Freight and handling costs	2,167	0.24	2,996	0.31	–28%
Depreciation, depletion and amortization	64,368	7.22	62,078	6.45	4%
Gross profit	122,233	13.70	110,592	11.49	11%
Selling, general and administrative	38,347	4.30	39,720	4.13	–3%

Volume and Revenues by Segment

The following tables show volume and revenue information by segment (in thousands, except per ton amounts).

	Year ended December 31,		
	2010	2009	Change
Volume shipped (tons)			
CAPP tons			
Steam	6,109	6,525	–6%
Metallurgical	—	—	NA
Total CAPP tons	6,109	6,525	–6%
Midwest steam tons	2,810	3,098	–9%
Total volume shipped	8,919	9,623	–7%

	Year ended December 31, 2010 Total	2010 Per Ton	2009 Total	2009 Per Ton	Change Total
Revenues					
Coal sales revenue					
CAPP steam	$585,064	$95.77	$579,108	$88.75	1%
CAPP metallurgical	—	—	—	—	—
Total CAPP coal sales revenue	585,064	95.77	579,108	88.75	1%
Midwest steam	113,885	40.53	99,454	32.10	15%
Total coal sales revenue	698,949	78.37	678,562	70.51	3%
Freight and handling revenue					
CAPP	—		—		—
Midwest	2,167		2,996		–28%
Total freight and handling revenue	2,167		2,996		–28%
Total revenue	701,116		681,558		3%

Coal sales revenue increased 3% in 2010 as compared to 2009. The increase in coal sales revenue was the result of an increase in the average sales price in the CAPP region of $7.02 to $95.77 and in the Midwest region of $8.43 to $40.53. The impact of the increase in the average sales price was offset by a decrease in volume shipped in both regions.

Operating and Other Costs

The following tables show selected costs in total and by segment (in thousands, except per ton amounts).

	2010 Total	2010 Per Ton	2009 Total	2009 Per Ton	Change Total
Volume shipped (tons)	8,919		9,623		
Cost of coal sold	$512,348	$57.44	$505,892	$52.57	1%
Freight and handling costs	2,167	0.24	2,996	0.31	–28%
Depreciation, depletion and amortization	64,368	7.22	62,078	6.45	4%
Selling, general and administrative	38,347	4.30	39,720	4.13	–3%
Interest expense	29,943	3.36	17,057	1.77	76%

	2010 CAPP	2010 Midwest	2010 Corporate	2009 CAPP	2009 Midwest	2009 Corporate
Cost of coal sold	$419,564	$92,784	$—	$416,721	$89,171	$—
Per ton	68.68	33.02	—	63.87	28.78	—
Freight and handling costs	—	2,167	—	—	2,996	—
Per ton	—	0.77	—	—	0.97	—
Depreciation, depletion and amortization	53,467	10,840	61	49,380	12,646	52
Per ton	8.75	3.86	—	7.57	4.08	—

The cost of coal sold, excluding depreciation, depletion and amortization, increased from $505.9 million in 2009 to $512.3 million in 2010. Our cost per ton of coal sold in the CAPP region increased from $63.87 per ton in 2009 to $68.68 per ton in 2010. Our costs continue to be impacted by lower productivity due to increased federal and state regulatory scrutiny and a decrease in tons produced in response to market conditions. The major components of the $4.81 per ton increase in the cost per ton of coal sold from 2009 to 2010 include an increase in our labor and benefit costs of $1.71 per ton, sales related costs of $1.48 per ton and variable costs of $0.74 per ton. For more detail regarding the increased regulatory activity see "Part II — Item 1A — Risk Factors — Underground mining is subject to increased regulation, and may require us to incur additional cost."

Our cost per ton of coal sold in the Midwest increased $4.24 per ton from $28.78 in the 2009 period to $33.02 per ton in the 2010 period. The major components of this increase include an increase in the variable costs of $1.63 per ton, labor and benefit costs of $0.82 per ton, and sales related costs of $0.83 per ton. The increase in the variable costs was primarily due to an increase in diesel and explosives costs.

Depreciation, depletion and amortization

Depreciation, depletion and amortization increased from $62.1 million in 2009 to $64.4 million in 2010. In the CAPP region, depreciation, depletion and amortization increased $4.1 million to $53.5 million or $8.75 per ton. In the Midwest, depreciation, depletion and amortization decreased $1.8 million to $10.8 million or $3.86 per ton.

Selling, general and administrative

Selling, general and administrative expenses decreased from $39.7 million in 2009 to $38.3 million in 2010. This decrease was primarily due to a decrease in bank fees associated with the issuance of letters of credit.

Interest Expense

Interest expense increased from $17.1 million in 2009 to $29.9 million in 2010. This increase was the result of additional interest expense associated with our convertible senior notes that were issued in the fourth quarter of 2009. Interest expense for 2010 and 2009 includes $8.1 million and $1.8 million, respectively, related to the amortization of debt discounts and debt issuance costs.

Income Taxes

Our effective tax (benefit) rates for 2010 and 2009 were (43.2%) and 3.0%, respectively. Our effective income tax rate, as compared to the statutory federal rate, is impacted primarily by the amount of the valuation allowance recorded against our deferred tax assets, including our net operating loss carryforwards, and percentage depletion. For 2010, our effective tax rate was reduced from the statutory federal rate of 35% primarily as the result of the reversal of our income tax valuation allowance (60.9%) and by percentage depletion (20.4%). As described further in "Critical Accounting Estimates — Income Taxes," the reversal of our income tax valuation allowance, during 2010, was the result of the conclusion that our deferred tax assets that were previously reduced by a valuation allowance were more likely than not to ultimately be realizable. In making this conclusion we considered our forecasts of future taxable income and other relevant factors, including a history of recent positive operating results. For 2009 our effective tax rate was reduced from the statutory federal tax rate primarily by percentage depletion (25.8%) and a change in the valuation allowance (6.2%).

Liquidity and Capital Resources

The following chart reflects the components of our debt as of December 31, 2011 and 2010 (in thousands):

	2011	2010
2019 Senior Notes	$275,000	$ —
2012 Senior Notes	—	150,000
2018 Convertible Senior Notes, net of discount	166,821	—
2015 Convertible Senior Notes, net of discount	140,372	134,022
Revolver	—	—
Total long-term debt	$582,193	$284,022

2019 Senior Notes

In the first quarter of 2011, we issued $275 million of 2019 Senior Notes due on April 1, 2019. The 2019 Senior Notes are unsecured and accrue interest at 7.875% per annum. Interest payments on the 2019 Senior Notes are required semi-annually. We may redeem the 2019 Senior Notes, in whole or in part, at any time on or after April 1, 2015 at redemption prices ranging from 103.938% beginning April 1, 2015 to 100% beginning on April 1, 2017. In addition, at any time prior to April 1, 2014, we may redeem up to 35% of the principal amount of the

2019 Senior Notes with the net cash proceeds of a public equity offering at a redemption price of 107.875%, plus accrued and unpaid interest to the redemption date.

The 2019 Senior Notes limit our ability, among other things, to pay cash dividends. In addition, if a change of control occurs (as defined in the Indenture), each holder of the 2019 Senior Notes will have the right to require us to repurchase all or a part of the 2019 Senior Notes at a price equal to 101% of their principal amount, plus any accrued interest to the date of repurchase.

We incurred approximately $6.7 million of costs during 2011 in connection with the issuance of the 2019 Senior Notes.

2012 Senior Notes and Redemption of 2012 Senior Notes

In the second quarter of 2011, we redeemed all $150.0 million our senior notes that were due on June 1, 2012 (the 2012 Senior Notes) at a redemption price of 100% of their face value. The 2012 Senior Notes accrued interest at 9.375% per annum. In connection with the redemption of the 2012 Senior Notes, we expensed $0.7 million of unamortized financing costs.

2015 Convertible Senior Notes

There have been no changes to the terms of our outstanding 4.5% convertible senior notes due on December 1, 2015 (the 2015 Convertible Senior Notes) during 2011. The 2015 Convertible Senior Notes are shown net of a $32.1 million discount as of December 31, 2011. See Item 1 of Part I, "Financial Statements — Note 4 — Long Term Debt and Interest Expense" for a description of our 2015 Convertible Senior Notes.

2018 Convertible Senior Notes

In the first quarter of 2011, we issued $230.0 million of 3.125% convertible senior notes due on March 15, 2018 (the 2018 Convertible Senior Notes). The 2018 Convertible Senior Notes are shown net of a $63.2 million discount as of December 31, 2011. The discount on the 2018 Convertible Senior Notes relates to the $68.7 million of the proceeds that were allocated to the equity component of the 2018 Convertible Senior Notes at issuance, resulting in an effective interest rate of 8.9%. The 2018 Convertible Senior Notes are unsecured and are convertible under certain circumstances and during certain periods at an initial conversion rate of 32.7332 shares of our common stock per $1,000 principal amount of 2018 Convertible Senior Notes, representing an initial conversion price of approximately $30.55 per share of the Company's stock. Interest payments on the 2018 Convertible Senior Notes are required semi-annually.

None of the 2018 Convertible Senior Notes are currently eligible for conversion. The 2018 Convertible Senior Notes are convertible at the option of the holders (with the length of time the 2018 Convertible Senior Notes are convertible being dependent upon the conversion trigger) upon the occurrence of any of the following events:

- At any time from December 15, 2017 until March 15, 2018;
- If the closing sale price of our common stock for each of 20 or more trading days in a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter exceeds 130% of the conversion price of the 2018 Convertible Senior Notes in effect on the last trading day of the immediately preceding calendar quarter;
- If the trading price of the 2018 Convertible Senior Notes for each trading day during any five consecutive business day period, as determined following a request of a holder of 2018 Convertible Senior Notes, was equal to or less than 97% of the "Conversion Value" of the Notes on such trading day; or
- If we elect to make certain distributions to the holders of our common stock or engage in certain corporate transactions.

Revolving Credit Agreement

In 2011, we entered into two agreements each of which amended and restated our existing Revolving Credit Agreement and resulted in an increase to the maximum availability under the Revolver to $100.0 million (as amended and restated the Revolving Credit Agreement is referred to as the Revolver). The following is a summary of the significant terms of the Revolver.

Maturity	June 30, 2015
Interest Rate	Our option of Base Rate (a) plus 2.25% or LIBOR plus 3.25% per annum.
Maximum Availability	Lesser of $100.0 million or the borrowing base (b)
Periodic Principal Payments	None

(a) Base rate is the higher of (1) the Federal Fund Rate plus 0.5%, (2) the prime rate and (3) a three month LIBOR rate plus a percentage as defined in the agreement.

(b) The Revolver's borrowing base is based on the sum of 90% of our eligible accounts receivable plus 65% of the eligible inventory (not to exceed $40.0 million) less reserves from time to time set by the administrative agent. The eligible accounts receivable and inventories are further adjusted as specified in the Revolver and the eligible inventory currently excludes certain inventories of our subsidiaries in West Virginia. Our borrowing base can also be increased by 95% of any cash collateral that we maintain in a cash collateral account.

The Revolver provides that we can use the Revolver availability to issue letters of credit. The Revolver provides for a 3.5% fee on any outstanding letters of credit issued under the Revolver and a 0.5% fee on the unused portion of the Revolver. The Revolver requires certain mandatory prepayments from certain asset sales, incurrence of indebtedness and excess cash flow. The Revolver includes financial covenants that require us to maintain a minimum Fixed Charge Coverage Ratio and limit capital expenditures, each as defined by the agreement. The minimum Fixed Charge Coverage Ratio is only applicable if the sum of our unrestricted cash plus the availability under the Revolver falls below $35.0 million and would remain in effect until the sum of our unrestricted cash plus the availability under the Revolver exceeds $35.0 million for 90 consecutive days. The limit on capital expenditures is only applicable if our unrestricted cash plus the availability under the Revolver falls below $50.0 million for a period of 5 consecutive days and would remain in effect until our unrestricted cash plus the availability under the Revolver exceeds $50.0 million for 90 consecutive days.

As of December 31, 2011, we had used $62.8 million of the $100.0 million then available under the Revolver to secure outstanding letters of credit.

We incurred approximately $1.9 million of costs in connection with the amendments and restatements to the Revolver in 2011. The costs, net of amortization, are included in other assets on our balance sheets.

We were in compliance with all of the financial covenants under our outstanding debt instruments as of December 31, 2011. We cannot assure you that we will remain in compliance in subsequent periods. If necessary, we will consider seeking a waiver or other alternatives to remain in compliance with the covenants. For more detail regarding the covenants under our indebtedness, see Part I — Item 1A — Risk Factors—"We may be unable to comply with restrictions imposed by the terms of our indebtedness, which could result in a default under these instruments."

Liquidity

As of December 31, 2011, we had total liquidity of approximately $236.9 million, consisting of $37.2 million of unused borrowing capacity under the Revolver and $199.7 million of cash and cash equivalents (excluding restricted cash and short term investments). As of December 31, 2011, we had used $62.8 million of the availability under the Revolver to secure outstanding letters of credit.

Our primary source of cash is expected to be sales of coal to our utility, industrial and steel customers. The price of coal received can change dramatically based on market factors and will directly affect this source of cash. Our primary uses of cash include the payment of ordinary mining expenses to mine coal, capital expenditures, scheduled debt and interest payments and benefit payments. Ordinary mining expenses are driven by the cost of supplies, including steel prices and diesel fuel. Benefit payments include payments for workers' compensation and black lung benefits paid over the lives of our employees as the claims are submitted. We are required to pay these when due, and are not required to set aside cash for these payments. We have posted surety bonds secured by letters of credit or issued letters of credit with state regulatory departments to guarantee these payments. We believe that our Revolver provides us with the ability to meet the necessary bonding requirements.

We believe that currently available cash, cash generated from operations, borrowings under our Revolver and future debt and equity offerings, if any, will be sufficient to meet working capital requirements, anticipated capital expenditures and scheduled debt payments throughout 2012 and for the next several years. Nevertheless, our ability to satisfy our working capital requirements and debt service obligations, or fund planned capital expenditures, will substantially depend upon our future operating performance (which will be affected by prevailing economic conditions in the coal industry), debt covenants, and financial, business and other factors, some of which are beyond our control.

In the event that the sources of cash described above are not sufficient to meet our future cash requirements, we will need to reduce certain planned expenditures, seek additional financing, or both. We may seek to raise funds through additional debt financing or the issuance of additional equity securities. If such actions are not sufficient, we may need to limit our growth, sell assets or reduce or curtail some of our operations to levels consistent with the constraints imposed by our available cash flow, or any combination of these options. Our ability to seek additional debt or equity financing may be limited by our existing and any future financing arrangements, economic and financial conditions, or all three. In particular, our existing 2019 Senior Notes, 2015 Convertible Senior Notes, 2018 Convertible Senior Notes and Revolver restrict our ability to incur additional indebtedness. We cannot provide assurance that any reductions in our planned expenditures or in our expansion would be sufficient to cover shortfalls in available cash or that additional debt or equity financing would be available on terms acceptable to us, if at all.

We currently project that our capital expenditures for 2012 will be approximately $125 million. These projected capital expenditures primarily consist of capital expenditure for normal mining activities including new and replacement mine equipment. Our projected capital expenditures for 2012 also include approximately $20 million for safety mandates and new mine and infrastructure development. We expect that such expenditures will be funded through cash on hand and cash generated by operations.

Net cash from operating activities reflects net income (loss) adjusted for non-cash charges and changes in net working capital (including non-current operating assets and liabilities). Net cash provided by operating activities was $163.8 million and $169.1 million in 2011 and 2010, respectively. During 2011, our net loss, as adjusted for non cash charges was increased by a $54.7 million increase in cash from changes in our operating assets and liabilities. The $54.7 million change in our operating assets and liabilities for 2011, includes a $69.0 million decrease in receivables and a $14.0 million increase in inventory. The change in our accounts receivable is primarily due to the timing of shipments. We had a net loss of $39.1 million in 2011 as compared to net income of $78.2 million in 2010. During 2010, our net income, as adjusted for non cash charges was decreased by a $31.7 million decrease in cash from our operating assets and liabilities. The $31.7 million change in our operating assets and liabilities for 2010, includes a $38.5 million decrease in restricted cash and short term investments, a $16.7 million increase in accounts receivables and a $10.9 million increase in accounts payable.

Net cash used in investing activities increased by $559.0 million to $654.3 million for in 2011 as compared to 2010, which includes a payment for the IRP Acquisition net of cash acquired, of $516.0 million. Capital expenditures for property, plant and equipment increased $43.0 million to $138.5 million in 2011 as compared to 2010. Capital expenditures primarily consisted of new and replacement mine equipment and various projects to improve the production and efficiency of our mining operations. Additionally, during 2011 and 2010, our capital expenditures included approximately $37.5 million and $30 million, respectively, for safety mandates and new mine and infrastructure development.

Net cash provided by financing activities was $509.9 million in 2011 and consists of $491.2 million of net proceeds from the issuance of the 2019 Senior Notes and the 2018 Convertible Senior Notes, net of debt issuance costs; $170.5 million of net proceeds from the issuance of common stock, which were offset by $150.0 million used to repay the 2012 Senior Notes; and $1.9 million of costs in connection with the amendments and restatements to the Revolver. Net cash used by financing activities was $1.3 million in 2010 and consisted primarily of debt issuance costs on the amendment to the Revolver.

Contractual Obligations

The following is a summary of our contractual obligations and commitments as of December 31, 2011:

Contractual Obligations	Payment Due by Period (in thousands) Total	2012	2013–2014	2015–2016	Thereafter
Long term debt (1)	$ 677,500	—	—	172,500	505,000
Cash interest on long term debt and fees under our Revolver for letters of credit (2)	254,190	40,606	81,212	67,450	64,922
Operating lease obligations (3)	4,919	2,634	2,285	—	—
Royalty obligations (4)	211,611	26,539	46,792	42,062	96,218
Purchase obligations (5)	—	—	—	—	—
	$1,148,220	69,779	130,289	282,012	666,140

(1) Consists of our 2019 Senior Notes and our 2015 and 2018 Convertible Senior Notes.

(2) Consists of interest payments on our 2019 Senior Notes and our 2015 and 2018 Convertible Senior Notes. Also includes a charge associated with outstanding letters of credit fees under the Revolver through the Revolver's maturity (assumes the full amount of the Revolver capacity is used for letters of credit). No replacement facilities are shown to replace the 2019 Senior Notes, 2015 and 2018 Convertible Senior Notes or Revolver upon expiration of those facilities.

(3) See Note 11 in the notes to the consolidated financial statements for additional information on leases.

(4) Royalty obligations include minimum royalties payable on leased coal rights. Certain coal leases do not have set expiration dates but extend until completion of mining of all merchantable and mineable coal reserves. For purposes of this table, we have generally assumed that minimum royalties on such leases will be paid for a period of ten years. Certain coal leases require payment based on minimum tonnage, for these contracts an average sales price of $85.00 per ton was used to project the future commitment. See Note 12 in the notes to the consolidated financial statements for additional information on royalty obligations.

(5) Purchase obligations do not include agreements to purchase coal with vendors that are less than 3 months in length, do not include quantities or minimum tonnages, or monthly purchase orders.

Additionally, we have liabilities relating to pension, workers' compensation, black lung, and mine reclamation and closure. As of December 31, 2011, the undiscounted payments related to these items are estimated to be:

Payments Due by Years (In Thousands) Within 1 Year	2–3 Years	4–5 Years
$21,196	48,525	42,552

Our determination of these noncurrent liabilities is calculated annually and is based on several assumptions, including then prevailing conditions, which may change from year to year. In any year, if our assumptions are inaccurate, we could be required to expend greater amounts than anticipated. Moreover, in particular for periods after 2012, our estimates may change from the amounts included in the table, and may change significantly, if our assumptions change to reflect changing conditions. These assumptions are discussed in the Notes to the Consolidated Financial Statements and in the Critical Accounting Estimates in Management's Discussion and Analysis.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements, including guarantees, operating leases, indemnifications, and financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. Liabilities related to these arrangements are not reflected in our consolidated balance sheets, and, except for the operating leases, we do not expect any material impact on our cash flow, results of operations or financial condition from these off-balance sheet arrangements.

We use surety bonds to secure reclamation, workers' compensation and other miscellaneous obligations. At December 31, 2011, we had $139.1 million of outstanding surety bonds with third parties. These bonds were in place to secure obligations as follows: post-mining reclamation bonds of $94.7 million, workers' compensation bonds of $40.3 million, wage payment, collection bonds, and other miscellaneous obligation bonds of $4.1 million. Surety bond costs have increased over time and the market terms of surety bonds have generally become less favorable. To the extent that surety bonds become unavailable, we would seek to secure obligations with letters of credit, cash deposits, or other suitable forms of collateral.

We also use cash collateral accounts and bank letters of credit to secure our obligations for post-mining reclamation, workers' compensation programs, various insurance contracts and other obligations. As of December 31, 2011, we had $62.8 million of letters of credit outstanding. The letters of credit are issued under our Revolver.

Critical Accounting Estimates

Overview

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources are based upon our consolidated financial statements, which have been prepared in accordance with U.S generally accepted accounting principles (US GAAP). US GAAP require estimates and judgments that affect reported amounts for assets, liabilities, revenues and expenses. The estimates and judgments we make in connection with our consolidated financial statements are based on historical experience and various other factors we believe are reasonable under the circumstances. Note 1 of the notes to the consolidated financial statements lists and describes our significant accounting policies. The following critical accounting policies have a material effect on amounts reported in our consolidated financial statements.

Business Combinations

We account for our business combinations under the acquisition method of accounting. The total cost of acquisitions is allocated to the underlying identifiable net tangible and intangible assets based on their respective estimated fair values. Determining the fair value of assets acquired and liabilities assumed requires management's judgment, with assistance of third party valuation services, and often involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items.

Workers' Compensation

We are liable under various state statutes for providing workers' compensation benefits. Except as indicated, we are self insured for workers' compensation at our Kentucky operations, with specific excess insurance purchased from independent insurance carriers to cover individual traumatic claims in excess of the self-insured limits. For the period June 2002 to June 2005, workers compensation coverage was insured through a third party insurance company using a large risk rating plan. Our operations in Indiana are insured through a third party insurance company using a large risk rating plan. Our operations in West Virginia are fully insured with a guaranteed cost policy through a third party insurance company for both Workers' Compensation and Employers Liability coverage.

We accrue for the present value of certain workers' compensation obligations as calculated annually by an independent actuary based upon assumptions for work-related injury and illness rates, discount rates and future trends for medical care costs. The discount rate is based on interest rates on bonds with maturities similar to the estimated future cash flows. The discount rate used to calculate the present value of these future obligations was 3.8% at December 31, 2011. Significant changes to interest rates result in substantial volatility to our consolidated financial statements. If we were to decrease our estimate of the discount rate from 3.8% to 3.3%, all other things being equal, the present value of our workers' compensation obligation would increase by approximately $2.6 million. A change in the law, through either legislation or judicial action, could cause these assumptions to change. If the estimates do not materialize as anticipated, our actual costs and cash expenditures could differ materially from that currently estimated. Our estimated workers' compensation liability as of December 31, 2011 was $69.9 million.

Coal Miners' Pneumoconiosis

We are required under the Federal Mine Safety and Health Act of 1977, as amended, as well as various state statutes, to provide pneumoconiosis (black lung) benefits to eligible current and former employees and their dependents. We provide for federal and state black lung claims through a self-insurance program for our operations in Kentucky. For the period between June 2002 and June 2005, all black lung liabilities were insured through a third party insurance company using a large risk rating plan. Our operations in Indiana are insured through a third party insurance company using a large risk rating plan. Our operations in West Virginia are fully insured with a guaranteed cost policy through a third party insurance company.

An independent actuary calculates the estimated pneumoconiosis liability annually based on assumptions regarding disability incidence, medical costs, mortality, death benefits, dependents and interest rates. The discount rate is based on interest rates on high quality corporate bonds with maturities similar to the estimated future cash flows. The discount rate used to calculate the present value of these future obligations was 4.3% at December 31, 2011. Significant changes to interest rates result in substantial volatility to our consolidated financial statements. If we were to decrease our estimate of the discount rate by 0.5% to 3.8%, all other things being equal, the present value of our black lung obligation would increase by approximately $4.6 million. A change in the law, through either legislation or judicial action, could cause these assumptions to change. If these estimates prove inaccurate, the actual costs and cash expenditures could vary materially from the amount currently estimated. Our estimated pneumoconiosis liability as of December 31, 2011 was $58.7 million.

Defined Benefit Pension

We have in place a non-contributory defined benefit pension plan under which all benefits were frozen in 2007. The estimated cost and benefits of our non-contributory defined benefit pension plans are determined annually by independent actuaries, who, with our review and approval, use various actuarial assumptions, including discount rate and expected long-term rate of return on pension plan assets. In estimating the discount rate, we look to rates of return on high-quality, fixed-income investments with comparable maturities. At December 31, 2011, the discount rate used to determine the obligation was 4.2%. Significant changes to interest rates result in substantial volatility to our consolidated financial statements. If we were to decrease our estimate of the discount rate from 4.2% to 3.7%, all other things being equal, the present value of our projected benefit obligation would increase by approximately $6.3 million. The expected long-term rate of return on pension plan assets is based on long-term historical return information and future estimates of long-term investment returns for the target asset allocation of investments that comprise plan assets. The expected long-term rate of return on plan assets used to determine expense was 7.5% for the period ended December 31, 2011. Significant changes to these rates would introduce volatility to our pension expense. Our accrued pension obligation as of December 31, 2011 was $29.1 million.

Reclamation and Mine Closure Obligation

The Surface Mining Control Reclamation Act of 1977 establishes operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of underground mining. Our asset retirement obligation liabilities consist of spending estimates related to reclaiming surface land and support facilities at both surface and underground mines in accordance with federal and state reclamation laws. Our total reclamation and mine-closing liabilities are based upon permit requirements and our engineering estimates related to these requirements. US GAAP requires that asset retirement obligations be initially recorded as a liability based on fair value, which is calculated as the present value of the estimated future cash flows. Our management and engineers periodically review the estimate of ultimate reclamation liability and the expected period in which reclamation work will be performed. In estimating future cash flows, we considered the estimated current cost of reclamation and applied inflation rates and a third party profit. The third party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. The discount rate is our estimate of our credit adjusted risk free rate. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly. The actual costs could be different due to several reasons, including the possibility that our estimates could be incorrect, in which case our liabilities would differ. If we perform the reclamation work using our personnel rather than hiring a third party, as assumed under US GAAP, then the costs should be lower. If governmental regulations change, then the costs of reclamation will be impacted.

US GAAP recognizes that the recorded liability could be different than the final cost of the reclamation and addresses the settlement of the liability. When the obligation is settled, and there is a difference between the recorded liability and the amount paid to settle the obligation, a gain or loss upon settlement is included in earnings. Our asset retirement obligation as of December 31, 2011 was $101.5 million, which includes an additional $50.9 million increase in the asset retirement obligation as a result of the IRP Acquisition.

Contingencies

We are the subject of, or a party to, various suits and pending or threatened litigation involving governmental agencies or private interests. We have accrued the probable and reasonably estimable costs for the resolution of these claims based upon management's best estimate of potential results, assuming a combination of litigation and settlement strategies. Management does not believe that the outcome or timing of current legal or environmental matters will have a material impact on our financial condition, results of operations, or cash flows. See the notes to the consolidated financial statements for further discussion on our contingencies.

Income Taxes

Deferred tax assets and liabilities are required to be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. Deferred tax assets are also required to be reduced by a valuation allowance if it is more likely than not that some portion of the deferred tax asset will not be realized. In evaluating the need for a valuation allowance, we take into account various factors, including the expected level of future taxable income. We have also considered tax planning strategies in determining the deferred tax asset that will ultimately be realized. If actual results differ from the assumptions made in the evaluation of the amount of our valuation allowance, we record a change in valuation allowance through income tax expense in the period such determination is made.

We have a valuation allowance of $37.3 million against our gross deferred tax assets as of December 31, 2011.

Coal Reserves

There are numerous uncertainties inherent in estimating quantities and values of economically recoverable coal reserves. Many of these uncertainties are beyond our control. As a result, estimates of economically recoverable coal reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data initially assembled by our staff and analyzed by Marshall Miller & Associates, Inc. (MM&A). The reserve information has subsequently been updated by our staff. The updates to the reserves have been calculated in the same manner, and based on similar assumptions and qualifications, as used in the MM&A studies described above, but these updates to the reserve estimates have not been reviewed by MM&A. A number of sources of information were used to determine accurate recoverable reserves estimates, including:

- all currently available data;
- our own operational experience and that of our consultants;
- historical production from similar areas with similar conditions;
- previously completed geological and reserve studies;
- the assumed effects of regulations and taxes by governmental agencies; and
- assumptions governing future prices and future operating costs.

Reserve estimates will change from time to time to reflect, among other factors:

- mining activities;
- new engineering and geological data;
- acquisition or divestiture of reserve holdings; and
- modification of mining plans or mining methods.

Each of these factors may in fact vary considerably from the assumptions used in estimating reserves. For these reasons, estimates of the economically recoverable quantities of coal attributable to a particular group of properties, and classifications of these reserves based on risk of recovery and estimates of future net cash flows may vary substantially. Actual production, revenue and expenditures with respect to reserves will likely vary from estimates, and these variances could be material. In particular, a variance in reserve estimates could have a material adverse impact on our annual expense for depreciation, depletion and amortization and on our annual calculation for potential impairment. For a further discussion of our coal reserves, see "Reserves."

Evaluation of Goodwill and Long-Lived Assets for Impairment

Goodwill is not amortized, but is subject to periodic assessments of impairment. Impairment testing is performed at the reporting unit level. We test goodwill for impairment annually during the fourth quarter, or when changes in circumstances indicate that the carrying value may not be recoverable. Long-lived asset groups are tested for recoverability when changes in circumstances indicate the carrying value may not be recoverable. Events that trigger a test for recoverability include material adverse changes in projected revenues and expenses, significant underperformance relative to historical or projected future operating results and significant negative industry or economic trends.

The estimates used to determine whether impairment has occurred to goodwill and long-lived assets are subject to a number of management assumptions. We estimate the fair value of a reporting unit or asset group based on market prices (i.e., the amount for which the asset could be bought by or sold to a third party), when available. When market prices are not available, we estimate the fair value of the reporting unit or asset group using the income approach and/or the market approach, which are subject to a number of management assumptions. The income approach uses cash flow projections. Inherent in our development of cash flow projections are assumptions and estimates derived from a review of our operating results, approved operating budgets, expected growth rates and cost of capital. We also make certain assumptions about future economic conditions, interest rates, and other market data. Many of the factors used in assessing fair value are outside the control of management, and these assumptions and estimates can change in future periods.

Changes in assumptions or estimates could materially affect the determination of fair value of an asset group, and therefore could affect the amount of potential impairment of the asset. The following assumptions are key to our income approach:

- We make assumptions about coal production, sales price for unpriced coal, cost to mine the coal and estimated residual value of property, plant and equipment. These assumptions are key inputs for developing our cash flow projections. These projections are derived using our internal operating budget and are developed on a mine by mine basis. These projections are updated annually and reviewed by the Board of Directors. Historically, the Company's primary variances between its projections and actual results have been with regard to assumptions for future coal production, sales prices of coal and costs to mine the coal. These factors are based on our best knowledge at the time we prepare our budgets but can vary significantly due to regulatory issues, unforeseen mining conditions, change in commodity prices, availability and costs of labor and changes in supply and demand. While we make our best estimates at the time we prepare our budgets it is reasonably likely that these estimates will change in future budgets, due to the changing nature of the coal environment;

- *Economic Projections* — Assumptions regarding general economic conditions are included in and affect the assumptions used in our impairment tests. These assumptions include, but are not limited to, supply and demand for coal, inflation, interest rates, and prices of raw materials (commodities); and

- *Discount Rates* — When measuring a possible impairment, future cash flows are discounted at a rate that we believe represents our cost of capital.

Recent Accounting Pronouncements

See Item 15 of Part IV, "Financial Statements — Note 1 — Summary of Significant Accounting Policies and Other Information — Recent Accounting Pronouncements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

At December 31, 2011, all $582.2 million of our outstanding debt has a fixed interest rate and is not sensitive to changes in the general level of interest rates. Our Revolver has floating interest rates based on our option of either the base rate or LIBOR rate. As of December 31, 2011, we had no borrowings outstanding under the Revolver. We currently do not use interest rate swaps to manage this risk. A 100 basis point (1.0%) increase in the average interest rate for our floating rate borrowings would increase our annual interest expense by approximately $0.1 million for each $10 million of borrowings under the Revolver.

We manage our commodity price risk through the use of long-term coal supply agreements, which we define as contracts with a term of one year or more, rather than through the use of derivative instruments. The percentage of our total revenues pursuant to long-term contracts was approximately 69% for the year ended December 31, 2011.

All of our transactions are denominated in U.S. dollars, and, as a result, we do not have material exposure to currency exchange-rate risks.

We are not engaged in any foreign currency exchange rate or commodity price-hedging transactions and we have no trading market risk.

Item 8. Financial Statements and Supplementary Data

See Financial Statements beginning on page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures

None.

Item 9A. Controls and Procedures

Pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934 ("Exchange Act"), the Company carried out an evaluation, with the participation of the Company's management, including the Company's Chief Executive Officer ("CEO") and Chief Accounting Officer ("CAO") (the Company's principal financial and accounting officer), of the effectiveness of the Company's disclosure controls and procedures (as defined under Rule 13a-15(e) under the Exchange Act) as of the end of the period covered by this report. Based upon that evaluation, the Company's CEO and CAO concluded that the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in the reports that the Company files or submits under the Exchange Act, is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to the Company's management, including the Company's CEO and CAO, as appropriate, to allow timely decisions regarding required disclosure.

The Company acquired International Resource Partners LP ("IRP") on April 18, 2011. Subsequent to the acquisition, IRP's Kentucky operations were integrated into our existing operations, and are subject to the Company's internal controls and procedures as covered by this report. However, in reliance on the guidance set forth in Question 3 of a "Frequently Asked Questions" interpretative release issued by the Staff of the SEC's Office of the Chief Accountant and the Division of Corporation Finance in September 2004, as revised on September 24, 2007, regarding Securities Exchange Act Release No. 34-47986, Management's Report on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports, our management determined that it would exclude IRP's West Virginia operations from the scope of its assessment of the effectiveness of internal control over financial reporting for the year ended December 31, 2011. IRP's West Virginia operations represent approximately 44% and 39% of our total assets and total revenues, respectively, as of and for the year ended December 31, 2011.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate control over financial reporting. Internal control over financial reporting is a process to provide reasonable assurance regarding the reliability of consolidated financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

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

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

There has been no change in the Company's internal control over financial reporting during the fourth quarter of the fiscal year covered by this Annual Report on Form 10-K that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management's assessment of internal control over financial reporting as of December 31, 2011, excludes IRP's West Virginia operations which represent approximately 44% and 39% of our total assets and total revenues, respectively, as of and for the year ended December 31, 2011. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report set forth in the Report of Independent Registered Public Accounting Firm in Part II, Item 9A of this Annual Report on Form 10-K.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
James River Coal Company:

We have audited James River Coal Company and subsidiaries' (the Company's) internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, James River Coal Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

The Company acquired International Resource Partners LP ("IRP") on April 18, 2011. Management's assessment of internal control over financial reporting as of December 31, 2011, excludes IRP's West Virginia operations which represent approximately 44% and 39% of the Company's consolidated total assets and total revenues, respectively, as of and for the year ended December 31, 2011. Our audit of internal control over financial reporting of James River Coal Company also excluded an evaluation of the internal control over financial reporting of IRP's West Virginia operations.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of James River Coal Company and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, changes in stockholders' equity and comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2011, and our report dated March 1, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG, LLP

Richmond, VA

March 1, 2012

Item 9B. Other Information

None.

PART III

Item 10. Director, Executive Officers and Corporate Governance

The information contained under the headings “Election of Directors”, “Section 16(a) Beneficial Ownership Reporting Compliance” “Board Matters” and “Management” in the definitive Proxy Statement used in connection with the solicitation of proxies for the Company’s 2012 Annual Meeting of Shareholders, to be filed with the Commission, is hereby incorporated herein by reference.

Item 11. Executive Compensation

The information contained under the headings “Compensation Committee Report,” “Executive Compensation,” “Equity Compensation Plans,” and “Compensation Committee Interlocks and Insider Participation” in the definitive Proxy Statement used in connection with the solicitation of proxies for the Company’s 2012 Annual Meeting of Shareholders, to be filed with the Commission, is hereby incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information contained under the headings “Principal Shareholders and Securities Ownership of Management,” and “Equity Compensation Plans” in the definitive Proxy Statement used in connection with the solicitation of proxies for the Company’s 2012 Annual Meeting of Shareholders, to be filed with the Commission, is hereby incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions and Director Independence

The information contained under the heading “Compensation Committee Interlocks and Insider Participation” in the definitive Proxy Statement used in connection with the solicitation of proxies for the Company’s 2012 Annual Meeting of Shareholders, to be filed with the Commission, is hereby incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information contained under the heading “Independent Registered Public Accountants” in the definitive Proxy Statement used in connection with the solicitation of proxies for the Company’s 2012 Annual Meeting of Shareholders, to be filed with the Commission, is hereby incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this Report:

1. Financial Statements

The following financial statements and related report of Independent Registered Public Accounting Firm are incorporated in Item 8 of this report:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of December 31, 2011 and 2010

Consolidated Statements of Operations for the years ended December 31, 2011, 2010 and 2009

Consolidated Statements of Changes in Shareholders' Equity and Comprehensive Income (Loss) for the years ended December 31, 2011, 2010 and 2009

Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009

Notes to Consolidated Financial Statements

2. Financial Statement Schedules

None.

3. Exhibits

The following exhibits are required to be filed with this Report by Item 601 of Regulation S-K:

Exhibit Number	Description
2.1	Second Amended Joint Plan of Reorganization Under Chapter 11 of the Bankruptcy Code of the Registrant and its Subsidiaries, dated as of April 20, 2004, incorporated herein by reference to Exhibit 2 to the Registrant's Registration Statement on Form S-1 filed August 13, 2004
2.2	Stock Purchase Agreement by and among James River Coal Company, Triad Mining, Inc. and the Stockholders of Triad Mining, Inc. dated as of March 30, 2005, incorporated herein by reference to Exhibit 2.2 to the Registrant's Registration Statement on Form S-1 filed April 19, 2005
3.1	Amended and Restated Articles of Incorporation of the Registrant, incorporated herein by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form S-3 filed August 6, 2010
3.2	Amended and Restated Bylaws of the Registrant, incorporated herein by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed January 27, 2012
4.1	Specimen common stock certificate, incorporated herein by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form S-1 filed August 13, 2004
4.2	Rights Agreement between the Registrant and SunTrust Bank as Rights Agent, dated as of May 25, 2004, incorporated herein by reference to Exhibit 4.2 to the Registrant's Registration Statement on Form S-1 filed August 13, 2004
4.3	Amendment No. 1 to Rights Agreement between the Registrant and Computershare Trust Company, N.A., successor to SunTrust Bank, as Rights Agent, dated as of November 3, 2006, incorporated herein by reference to Exhibit 4.2 to the Registrant's Quarterly Report on Form 10-Q filed November 9, 2006
4.4	Amendment No. 2 to Rights Agreement between the Registrant and Computershare Trust Company, N.A., successor to SunTrust Bank, as Rights Agent, dated as of August 2, 2007, incorporated herein by reference to Exhibit 4.2 to the Registrant's Quarterly Report on Form 10-Q filed August 9, 2007
4.5	Amendment No. 3 to Rights Agreement between Registrant and Computershare Trust Company, N.A., successor to SunTrust Bank, as Rights Agent, dated as of November 3, 2009, incorporated herein by reference to Exhibit 4.1 to the Registrant's Amendment No. 1 to Form 8-A filed November 3, 2009

Exhibit Number	Description
4.6	Form of rights certificate, incorporated herein by reference to Exhibit 4.3 to the Registrant's Registration Statement on Form 8-A filed January 24, 2005
4.10	Indenture related to the 4.50% Convertible Senior Notes due 2015, dated as of November 20, 2009, between James River Coal Company and U.S. Bank National Association, as trustee (including the form of 4.50% Convertible Senior Notes due 2015), incorporated herein by reference to Exhibit 4.1 to the Registrant's Form 8-K filed November 25, 2009
4.11	Indenture relating to the 3.125% Convertible Senior Notes, dated as of March 29, 2011, between the Registrant and U.S. Bank National Association, as trustee (including the form of 3.125% Convertible Senior Notes), incorporated herein by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K dated March 29, 2011
4.12	Indenture relating to the 7.785% Senior Notes, dated as of March 29, 2011, between James River Escrow Inc. and U.S. Bank National Association, as trustee (including the form of 7.785% Senior Notes), incorporated herein by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed March 29, 2011
4.13	Registration Rights Agreement, dated as of March 29, 2011, between James River Escrow Inc., and Deutsche Bank Securities Inc. and UBS Securities LLC, as Representatives of the Initial Purchasers, incorporated herein by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed March 29, 2011
10.1	Registration Rights Agreement by and among the Registrant and the Shareholders identified therein, dated May 6, 2004, incorporated herein by reference to Exhibit 10.1 to the Registrant's Registration Statement on Form S-1 filed August 13, 2004
10.4*	Employment Agreement between the Registrant and Peter T. Socha, dated as of May 7, 2004, incorporated herein by reference to Exhibit 10.4 to the Registrant's Registration Statement on Form S-1 filed August 13, 2004
10.4a*	Amendment to Employment Agreement between the Registrant and Peter T. Socha, dated as of December 31, 2008, incorporated herein by reference to Exhibit 10.4a to the Registrant's Annual Report on Form 10-K filed February 27, 2009
10.5*	2004 Equity Incentive Plan of the Registrant, incorporated herein by reference to Exhibit 10.5 to the Registrant's Registration Statement on Form S-1 filed August 13, 2004
10.5a*	Amendment to the James River Coal Company 2004 Equity Incentive Plan, incorporated herein by reference to Appendix B to the Registrant's Definitive Proxy Statement on Form DEF 14A filed April 30, 2009
10.6	Form of Indemnification Agreement between the Registrant and its officers and directors, incorporated herein by reference to Exhibit 10.6 to the Registrant's Registration Statement on Form S-1 filed August 13, 2004
10.8**	Agreement No. 2 for Purchase and Sale of Coal among Georgia Power Company, the Registrant and James River Coal Sales, Inc., dated as of May 15, 2008
10.8a**	First Amendment to Agreement No. 2 for Purchase and Sale of Coal among Georgia Power Company, the Registrant and James River Coal Sales, Inc., dated as of July 21, 2008
10.9**	Fuel Supply Agreement #141944 between South Carolina Public Service Authority and the Registrant, dated as of March 1, 2004, incorporated herein by reference to Exhibit 10.8 to the Registrant's Registration Statement on Form S-1 filed August 13, 2004
10.9a**	Amendment to Fuel Supply #141944 between South Carolina Public Service Authority, the Registrant and James River Coal Sales, Inc., dated April 7, 2009
10.15	Registration Rights Agreement between the Registrant and the Shareholders named therein, dated as of May 31, 2005, incorporated herein by reference to Exhibit 10.9 to the Registrant's Annual report on Form 10-K filed March 16, 2006

Exhibit Number	Description
10.16*	Severance and Retention Plan, effective as of March 13, 2006, incorporated herein by reference to Exhibit 10.12 to the Registrant's Quarterly Report on Form 10-Q filed August 9, 2006
10.16a*	Amendment to Severance and Retention Plan dated as of December 31, 2008
10.22	Amended and Restated Revolving Credit Agreement by and among the Registrant, James River Coal Service Company, Leeco, Inc., Triad Mining, Inc., Triad Underground Mining, LLC, Bledsoe Coal Corporation, Johns Creek Elkhorn Coal Corporation, Bell County Coal Corporation, James River Coal Sales, Inc., Bledsoe Coal Leasing Company, Blue Diamond Coal Company, and McCoy Elkhorn Coal Corporation, as Borrowers, the other Credit Parties thereto from time to time, as Guarantors, the Lenders party thereto from time to time, and General Electric Capital Corporation, as Administrative Agent and Collateral Agent, GE Capital Markets, Inc., and UBS Securities LLC, as Joint Lead Arrangers and Joint Bookrunners, and UBS Securities LLC, as Documentation Agent, dated as of January 28, 2010, incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K, dated February 3, 2010
10.22a	First Amendment to Amended and Restated Revolving Credit Agreement by and among James River Coal Company and certain of its Subsidiaries identified on the signature pages thereto, as Borrowers, and the other credit parties thereto identified on the signature pages as Guarantors, the Lenders party thereto, and General Electric Capital Corporation, as Administrative Agent and Collateral Agent, dated as of August 16, 2010, incorporated herein by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed August 20, 2010
10.22b	Second Amendment to Amended and Restated Revolving Credit Agreement by and among James River Coal Company, certain of its subsidiaries, the Lenders thereto, and General Electric Capital Corporation as Administrative and Collateral Agent, dated as of October 29, 2010, incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed November 3, 2010
10.22c	Consent and Third Amendment to Amended and Restated Revolving Credit Agreement, dated as of March 6, 2011, by and among James River Coal Company and certain of its subsidiaries identified on the signature pages thereto, as Borrowers, and the other credit parties thereto, indentified on the signature pages thereto as Guarantors, the Lenders party thereto, and General Electrical Capital Corporation, as Administrative Agent and as Collateral Agent, incorporated herein by reference to Exhibit 10.2 of the Registrant's Current Report on Form 8-K filed March 7, 2011
10.22d	Fourth Amendment to Amended and Restated Revolving Credit Agreement, dated as of April 15, 2011, by and among the Registrant and certain of its Subsidiaries identified on the signature pages thereto, as Borrowers, and the other credit parties thereto, identified on the signature pages thereto as Guarantors, the Lenders party thereto, and General Electrical Capital Corporation, as Administrative Agent and as Collateral Agent, incorporated herein by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed April 21, 2011
10.23	Second Amended and Restated Revolving Credit Agreement by and among James River Coal Company, James River Coal Service Company, Leeco, Inc., Triad Mining, Inc., Triad Underground Mining, LLC, Bledsoe Coal Corporation, Johns Creek Elkhorn Coal Corporation, Bell County Coal Corporation, James River Coal Sales, Inc., Bledsoe Coal Leasing Company, Blue Diamond Coal Company, McCoy Elkhorn Coal Corporation, Chafin Branch Coal Company, LLC, Hampden Coal Company, LLC, Laurel Mountain Resources, LLC, Logan & Kanawha Coal Co., LLC, Rockhouse Creek Development, LLC, and Snap Creek Mining, LLC, as Borrowers, the other Credit Parties thereto from time to time, as Guarantors, the Lenders party thereto from time to time, and General Electric Capital Corporation, as Administrative Agent and Collateral Agent, GE Capital Markets, Inc., and UBS Securities LLC, as Joint Lead Arrangers and Joint Bookrunners, and UBS Securities LLC, as Documentation Agent, dated as of June 30, 2011, incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed July 7, 2011.
10.25*	James River Coal Company Amended and Restated Annual Incentive Compensation Plan (Revised Incentive Plan), incorporated herein by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed November 8, 2011

Exhibit Number	Description
12.1	Computation of Ratio of Earnings to Fixed Charges
21	Subsidiaries of the Registrant
23.1	Consent of Marshall Miller & Associates, Inc. (filed herewith)
23.2	Consent of KPMG LLP (filed herewith)
24	Power of Attorney (see signature page)
31.1	Certification of Peter T. Socha, President and Chief Executive Officer of James River Coal Company, pursuant to rule 13a-14(a) or 15d-14(a) of the Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith)
31.2	Certification of Samuel M. Hopkins, II, Vice President and Chief Accounting Officer of James River Coal Company, pursuant to rule 13a-14(a) or 15d-14(a) of the Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith)
32.1	Certification of Peter T. Socha, President and Chief Executive Officer of James River Coal Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith)
32.2	Certification of Samuel M. Hopkins, II, Vice President and Chief Accounting Officer of James River Coal Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith)
95	Mine Safety Disclosures (filed herewith)
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

* Management contract or compensatory plan or arrangement.

** Portions of these documents have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment of the omitted portions.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Audited Financial Statements

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
James River Coal Company:

We have audited the accompanying consolidated balance sheets of James River Coal Company and subsidiaries (the Company) as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2011. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of James River Coal Company and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), James River Coal Company's internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 1, 2012 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Richmond, VA
March 1, 2012

JAMES RIVER COAL COMPANY
AND SUBSIDIARIES

Consolidated Balance Sheets
(in thousands, except share data)

	December 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 199,711	180,376
Trade receivables	107,557	59,970
Inventories:		
Coal	52,717	23,305
Materials and supplies	17,800	13,690
Total inventories	70,517	36,995
Prepaid royalties	8,465	6,039
Other current assets	11,461	5,991
Total current assets	397,711	289,371
Property, plant, and equipment, net	909,294	385,652
Goodwill	26,492	26,492
Restricted cash and short term investments (note 1)	29,510	23,500
Other assets	41,575	59,554
Total assets	$1,404,582	784,569
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 110,557	57,300
Accrued salaries, wages, and employee benefits	12,996	7,744
Workers' compensation benefits	9,200	9,000
Black lung benefits	2,512	2,282
Accrued taxes	7,563	4,924
Other current liabilities	27,861	16,496
Total current liabilities	170,689	97,746
Long-term debt, less current maturities	582,193	284,022
Other liabilities:		
Noncurrent portion of workers' compensation benefits	60,721	55,944
Noncurrent portion of black lung benefits	56,152	43,443
Pension obligations	29,121	11,968
Asset retirement obligations	94,654	43,398
Other	14,390	665
Total other liabilities	255,038	155,418
Total liabilities	1,007,920	537,186
Commitments and contingencies (note 12)		
Shareholders' equity:		
Preferred stock, $1.00 par value. Authorized 10,000,000 shares	—	—
Common stock, $.01 par value. Authorized 100,000,000 shares; issued and outstanding 35,671,953 and 27,779,351 shares as of December 31, 2011 and December 31, 2010	357	278
Paid-in-capital	541,362	324,705
Accumulated deficit	(97,682)	(58,593)
Accumulated other comprehensive loss	(47,375)	(19,007)
Total shareholders' equity	396,662	247,383
Total liabilities and shareholders' equity	$1,404,582	784,569

See accompanying notes to consolidated financial statements.

JAMES RIVER COAL COMPANY
AND SUBSIDIARIES

Consolidated Statements of Operations
(in thousands, except per share data)

	Year Ended December 31, 2011	2010	2009
Revenues			
Coal sales revenue	$1,105,370	698,949	678,562
Freight and handling revenue	72,285	2,167	2,996
Total revenue	1,177,655	701,116	681,558
Cost of sales:			
Cost of coal sold	905,482	512,348	505,892
Freight and handling costs	72,285	2,167	2,996
Depreciation, depletion and amortization	108,914	64,368	62,078
Total cost of sales	1,086,681	578,883	570,966
Gross profit	90,974	122,233	110,592
Selling, general and administrative expenses	57,078	38,347	39,720
Acquisition costs (note 2)	8,504	—	—
Total operating income	25,392	83,886	70,872
Interest expense	50,096	29,943	17,057
Interest income	(494)	(683)	(60)
Charges associated with repayment of debt (note 4)	740	—	1,643
Miscellaneous (income) expense, net	(812)	27	(281)
Total other expense, net	49,530	29,287	18,359
Income (loss) before income taxes	(24,138)	54,599	52,513
Income tax expense (benefit)	14,951	(23,566)	1,559
Net income (loss)	$ (39,089)	78,165	50,954
Earnings (loss) per common share (note 13)			
Basic earnings (loss) per common share	$ (1.19)	2.82	1.85
Diluted earnings (loss) per common share	$ (1.19)	2.82	1.85

See accompanying notes to consolidated financial statements.

JAMES RIVER COAL COMPANY
AND SUBSIDIARIES

Consolidated Statements of Changes in Shareholders' Equity and Comprehensive Income (Loss)
(in thousands)

	Common stock shares	Common stock par value	Paid-in-capital	Retained earnings (accumulated deficit)	Accumulated other comprehensive income (loss)	Total
Balances, December 31, 2008	27,393	$274	272,366	(187,712)	(19,690)	65,238
Net Income	—	—	—	50,954	—	50,954
Amortization of pension actuarial amount	—	—	—	—	1,606	1,606
Black lung obligation adjustment	—	—	—	—	(574)	(574)
Pension liability adjustment	—	—	—	—	5,404	5,404
Comprehensive income						57,390
Equity component of convertible debt offering, net of offering costs of $1,433			43,385	—	—	43,385
Issuance of restricted stock awards, net of forfeitures	234	2	(2)	—	—	—
Repurchase of shares for tax withholding	(87)	(1)	(1,712)	—	—	(1,713)
Exercise of stock options	5	—	75	—	—	75
Stock based compensation	—	—	5,967	—	—	5,967
Balances, December 31, 2009	27,545	275	320,079	(136,758)	(13,254)	170,342
Net Income	—	—	—	78,165	—	78,165
Amortization of pension actuarial amount	—	—	—	—	783	783
Amortization of black lung actuarial amount					412	412
Black lung obligation adjustment	—	—	—	—	(10,320)	(10,320)
Pension liability adjustment					(168)	(168)
Tax impact of adjustments to accumulated other comprehensive loss	—	—	—	—	3,540	3,540
Comprehensive income						72,412
Issuance of restricted stock awards, net of forfeitures	284	3	(3)	—	—	—
Repurchase of shares for tax withholding	(55)	—	(844)	—	—	(844)
Exercise of stock options	5	—	73	—	—	73
Stock based compensation	—	—	5,400	—	—	5,400
Balances, December 31, 2010	27,779	278	324,705	(58,593)	(19,007)	247,383
Net loss	—	—	—	(39,089)	—	(39,089)
Amortization of pension actuarial amount	—	—	—	—	791	791
Amortization of black lung actuarial amount	—	—	—	—	568	568
Black lung obligation adjustment	—	—	—	—	(10,087)	(10,087)
Pension liability adjustment					(19,640)	(19,640)
Comprehensive loss						(67,457)
Issuance of common stock, net of offering costs of $9,171	7,648	76	170,469	—	—	170,545
Equity component of convertible debt offering, net of offering costs of $2,117 and deferred taxes of $24,427	—	—	42,174	—	—	42,174
Issuance of restricted stock awards, net of forfeitures	307	3	(3)	—	—	—
Repurchase of shares for tax withholding	(62)	—	(1,266)	—	—	(1,266)
Stock based compensation	—	—	5,283	—	—	5,283
Balances, December 31, 2011	35,672	$357	541,362	(97,682)	(47,375)	396,662

See accompanying notes to consolidated financial statements.

JAMES RIVER COAL COMPANY
AND SUBSIDIARIES

Consolidated Statements of Cash Flows
(in thousands)

	Year Ended December 31, 2011	Year Ended December 31, 2010	Year Ended December 31, 2009
Cash flows from operating activities:			
Net income (loss)	$ (39,089)	78,165	50,954
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion, and amortization	108,914	64,368	62,078
Accretion of asset retirement obligations	4,477	3,334	3,212
Amortization of debt discount and issue costs	14,684	8,066	1,813
Stock-based compensation	5,283	5,400	5,967
Deferred income tax expense (benefit)	14,139	(22,236)	180
Loss (gain) on sale or disposal of property, plant, and equipment	(59)	307	(61)
Write-off of deferred financing costs	740	—	—
Changes in operating assets and liabilities:			
Receivables	69,043	(16,681)	(9,988)
Inventories	(13,967)	(3,680)	(15,025)
Prepaid royalties and other current assets	(104)	(2,433)	(1,440)
Restricted cash and short term investments	(6,010)	38,542	(56,820)
Other assets	566	(2,060)	(4,233)
Accounts payable	(3,145)	10,828	(10,596)
Accrued salaries, wages, and employee benefits	892	762	340
Accrued taxes	(889)	(303)	(1,787)
Other current liabilities	7,497	1,066	(3,626)
Workers' compensation benefits	4,977	5,609	3,558
Black lung benefits	3,420	3,018	1,657
Pension obligations	(1,696)	(2,244)	2,144
Asset retirement obligations	(5,204)	(809)	(861)
Other liabilities	(697)	43	93
Net cash provided by operating activities	163,772	169,062	27,559
Cash flows from investing activities:			
Additions to property, plant, and equipment	(138,455)	(95,426)	(72,159)
Payment for acquisition, net of cash acquired	(515,962)	—	—
Proceeds from sale of property, plant and equipment	103	82	149
Net cash used in investing activities	(654,314)	(95,344)	(72,010)
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	505,000	—	172,500
Repayment of long-term debt	(150,000)	—	—
Proceeds from Revolver	—	—	12,500
Repayments of Revolver	—	—	(30,500)
Net proceeds from issuance of common stock	170,545	—	—
Debt issuance costs	(15,668)	(1,346)	(5,517)
Proceeds from exercise of stock options	—	73	75
Net cash provided by (used in) financing activities	509,877	(1,273)	149,058
Increase in cash and cash equivalents	19,335	72,445	104,607
Cash and cash equivalents at beginning of period	180,376	107,931	3,324
Cash and cash equivalents at end of period	$ 199,711	180,376	107,931

See accompanying notes to consolidated financial statements.

(1) Summary of Significant Accounting Policies and Other Information

Description of Business and Principles of Consolidation

James River Coal Company and its wholly owned subsidiaries (collectively, the Company) mine, process and sell thermal and metallurgical coal through eight active mining complexes located throughout eastern Kentucky, southern West Virginia and southern Indiana. Substantially all coal sales and account receivables relate to the utility industry, steel industry and industrial markets.

The consolidated financial statements include the accounts of James River Coal Company and its wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

Cash and Cash Equivalents and Restricted Cash and Short Term Investments

Cash and cash equivalents are stated at cost. Cash equivalents consist of highly-liquid investments with an original maturity of three months or less when purchased.

Restricted cash is stated at cost. Restricted cash and short term investments consists of cash, cash equivalents and investments in bonds and certificate of deposits. The Company intends to hold all investments held as restricted cash until maturity. The restricted cash and short term investments are maintained in collateral accounts which provide the Company additional capacity under the Revolver to support it outstanding letters of credit (note 4) and to support the issuance of surety bonds.

Trade Receivables

Trade receivables are recorded at the invoiced amount and do not bear interest. The Company evaluates the need for an allowance for doubtful accounts based on review of historical write off experience. The Company has determined that no allowance is necessary for trade receivables as of December 31, 2011 and 2010. The Company does not have any off-balance sheet credit exposure related to its customers.

Inventories

Inventories of coal and materials and supplies are stated at the lower of cost or market. Cost is determined using the average cost for coal inventories and the first-in, first-out method for materials and supplies. Coal inventory costs include labor, supplies, equipment cost, depletion, royalties, black lung tax, reclamation tax and preparation plant cost.

Asset Retirement Obligations

The Company's asset retirement obligation liabilities primarily consist of spending estimates related to reclaiming surface land and support facilities at both surface and underground mines in accordance with federal and state reclamation laws. Asset retirement obligations are initially recorded as a liability based on fair value, which is calculated as the present value of the estimated future cash flows, in the period in which it is incurred. The estimate of ultimate reclamation liability and the expected period in which reclamation work will be performed is reviewed periodically by the Company's management and engineers. In estimating future cash flows, the Company considers the estimated current cost of reclamation and applies inflation rates and a third party profit. The third party profit is an estimate of the approximate markup that would be charged by contractors for work performed on behalf of the Company. When the liability is initially recorded, the offset is capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Accretion expense is included in cost of produced coal. To the extent there is a difference between the liability recorded and the cost incurred, a gain or loss upon settlement

(1) Summary of Significant Accounting Policies and Other Information (Continued)

is recognized. The following table sets forth the changes in the Company's asset retirement obligations at December 31, 2011 and 2010 (in thousands):

	2011	2010
Asset retirement obligations at beginning of year	$ 48,389	$44,843
Liabilities assumed in acquisition	50,858	—
Liabilities incurred	2,937	1,166
Liabilities disposed	(426)	(154)
Revisions in estimated cash flows	127	50
Accretion expense	4,477	3,334
Liabilities settled	(4,846)	(850)
Asset retirement obligations at end of year	101,516	48,389
Less amount included in other current liabilities	(6,862)	(4,991)
Total non-current liability	$ 94,654	$43,398

Property, Plant, and Equipment

Property, plant and equipment as of December 31, 2011 and 2010 are as follows (in thousands):

	2011	2010
Property, plant, and equipment, at cost:		
Land	$ 9,930	7,751
Mineral rights	618,605	231,681
Buildings, machinery and equipment	635,055	423,617
Mine development costs	56,555	48,301
Total property, plant, and equipment	1,320,145	711,350
Less accumulated depreciation, depletion, and amortization	410,851	325,698
Property, plant and equipment, net	$ 909,294	385,652

Expenditures for maintenance and repairs are charged to expense, and the costs of mining equipment rebuilds and betterments that extend the useful life are capitalized. Depreciation is provided principally using the straight-line method based upon estimated useful lives, generally ten to twenty years for buildings and one to seven years for machinery and equipment. Mine development costs are capitalized and amortized by the units of production method over estimated total recoverable proven and probable reserves. Amortization of mineral rights is provided by the units of production method over estimated total recoverable proven and probable reserves.

Impairment of Long-Lived Assets

Long-lived assets, such as property, plant, and equipment are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or asset group may not be recoverable. Events that trigger a test for recoverability include material adverse changes in projected revenues and expenses, significant underperformance relative to historical or projected future operating results, and significant negative industry or economic trends. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized for the amount by which the carrying amount of the asset exceeds the fair value of the asset. The Company did not recognize any impairment charges during the periods presented.

(1) Summary of Significant Accounting Policies and Other Information (Continued)

Goodwill

Goodwill represents the excess of purchase price and related costs over the value assigned to the net tangible and identifiable intangible assets of businesses acquired. Goodwill is not amortized but is tested for impairment annually, or if certain circumstances indicate a possible impairment may exist. Impairment testing is performed at a reporting unit level. An impairment loss generally would be recognized when the carrying amount of the reporting unit exceeds the fair value of the reporting unit, with the fair value of the reporting unit determined using a discounted cash flow analysis.

Prepaid Royalties

Lease rights to coal lands are often acquired in exchange for royalty payments. Prepaid royalties represent prepayments made to lessors under terms of mineral lease agreements that are recoupable against future production. Prepaid amounts expected to be recouped within one year are classified as a current asset. As mining occurs on these leases, the prepayment is offset against earned royalties and is included in the cost of coal sold. The Company regularly reviews recoverability of prepaid royalties and establishes or adjusts the allowance for prepaid royalties as necessary using the specific identification method. In instances where prepaid royalty payments are not expected to be offset against future production royalties, the Company establishes a provision for losses on the advance payments. Prepaid royalty balances are charged off against the provision when the lease rights are either terminated or expire.

The following table sets forth the changes in the Company's allowance for prepaid royalties (in thousands):

Allowance for prepaid royalties at December 31, 2008	$ (6,993)
Provision for non-recoupable prepaid royalties	(1,235)
Write-offs of prepaid royalties	503
Allowance for prepaid royalties at December 31, 2009	(7,725)
Provision for non-recoupable prepaid royalties	(41)
Write-offs of prepaid royalties	262
Allowance for prepaid royalties at December 31, 2010	(7,504)
Provision on acquired leases	(888)
Provision for non-recoupable prepaid royalties	(4,510)
Write-offs of prepaid royalties	729
Allowance for prepaid royalties at December 31, 2011	(12,173)

Other Assets

Other assets at December 31, 2011 and 2010 are as follows (in thousands):

	2011	2010
Deferred tax asset, net	$ —	30,847
Prepaid royalties, net of current portion	19,757	17,064
Deferred financing costs	15,858	5,842
Other	5,960	5,801
	$41,575	59,554

Deferred financing costs are the costs to obtain new debt financing or amend existing financing agreements and are deferred and amortized to interest expense over the life of the related indebtedness or credit facility using either the effective interest method or the straight-line method if it approximates the effective interest method.

(1) Summary of Significant Accounting Policies and Other Information (Continued)

Revenue Recognition

Revenues include sales to customers of Company-produced coal and coal purchased from third parties. The Company recognizes revenue from the sale of Company-produced coal and coal purchased from third parties at the time delivery occurs and risk of loss passes to the customer, which is either upon shipment or upon customer receipt of coal based on contractual terms. Also, the sales price must be determinable and collection reasonably assured.

Freight and handling revenue consists of shipping and handling costs invoiced to coal customers and paid to third-party carriers. These revenues are directly offset by freight and handling costs.

Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled.

The Company evaluates its deferred tax assets to determine the necessity of a valuation allowance. A valuation allowance is required if it is more likely than not that some portion of the deferred tax asset will not be realized. In evaluating the need for a valuation allowance, the Company takes into account various factors, including the expected level of future taxable income. The Company also considers tax planning strategies in determining the deferred tax asset that will ultimately be realized.

Our effective income tax rate is impacted by the amount of the valuation allowance recorded and percentage depletion. Percentage depletion is an income tax deduction that is limited to a percentage of taxable income from each of our mining properties. Because percentage depletion can be deducted in excess of the cost bases of the properties, it creates a permanent difference and directly impacts the effective tax rate. Fluctuations in the effective tax rate may occur between fiscal periods due to the varying levels of profitability (and thus, taxable income and percentage depletion) at each of our mine locations.

The Company records interest and penalties, if any, associated with income taxes as a component of income tax expense.

Accumulated Other Comprehensive Income (Loss)

The accumulated other comprehensive income (loss) at December 31, 2011, includes a $31.1 million actuarial loss on the Company's pension plan, a $19.8 million actuarial loss on its black lung obligation and a $3.5 million tax benefit associated with the items included in accumulated comprehensive income (loss). The accumulated other comprehensive income (loss) at December 31, 2010, includes a $12.2 million actuarial loss on the Company's pension plan, a $10.3 million actuarial loss on its black lung obligation and a $3.5 million tax benefit associated with the items included in accumulated comprehensive income (loss).

Workers' Compensation

The Company is liable under various state statutes for providing workers' compensation benefits. Except as indicated, the Company is self insured for workers' compensation for its Kentucky operations, with specific excess insurance purchased from independent insurance carriers to cover individual traumatic claims in excess of the self-insured limits. For the period June 2002 to June 2005, workers compensation coverage was insured through a third party insurance company using a large risk rating plan. The Company's operations in Indiana are insured through a third party insurance company using a large risk rating plan. The Company's West Virginia operations are fully

(1) Summary of Significant Accounting Policies and Other Information (Continued)

insured with a guaranteed cost policy through a third party insurance company for both workers' compensation and employers' liability coverage.

The Company accrues for workers' compensation benefits by recognizing a liability when it is probable that the liability has been incurred and the cost can be reasonably estimated. The Company provides information to independent actuaries, who after review and consultation with the Company with regards to actuarial assumptions, including the discount rate, prepare an estimate of the liabilities for workers' compensation benefits.

Black Lung Benefits

The Company is responsible under the Federal Coal Mine Health and Safety Act of 1969, as amended, and various states' statutes for the payment of medical and disability benefits to employees and their dependents resulting from occurrences of coal worker's pneumoconiosis disease (black lung). The Company provides coverage for federal and state black lung claims through its self-insurance programs for its operations in Kentucky. For the period between June 2002 and June 2005, all black lung liabilities were insured through a third party insurance company using a large risk rating plan. The Company's operations in Indiana are insured through a third party insurance company using a large risk rating plan. The Company's operations in West Virginia are fully insured with a guaranteed cost policy through a third party insurance company.

The Company uses the service cost method to account for its self-insured black lung obligation. The liability measured under the service cost method represents the discounted future estimated cost for former employees either receiving or projected to receive benefits, and the portion of the projected liability relative to prior service for active employees projected to receive benefits. The periodic expense for black lung claims under the service cost method represents the service cost, which is the portion of the present value of benefits allocated to the current year, interest on the accumulated benefit obligation, and amortization of unrecognized actuarial gains and losses. Actuarial gains and losses are included as a component of accumulated other comprehensive income (loss) and are amortized over the average remaining work life of the workforce.

Annual actuarial studies are prepared by independent actuaries using certain assumptions to determine the liability. The calculation is based on assumptions regarding disability incidence, medical costs, mortality, death benefits, dependents, and interest rates. These assumptions are derived from actual Company experience and industry sources.

Health Claims

The Company is self-insured for certain health care coverage. The cost of this self-insurance program is accrued based upon estimates of the costs for known and anticipated claims. The Company recorded an estimated amount to cover known claims and claims incurred but not reported of $2.3 million and $1.7 million as of December 31, 2011 and 2010, respectively, which is included in accrued salaries, wages, and employee benefits.

Equity-Based Compensation Plan

The Company's stock compensation expense is based on estimated grant-date fair values. Compensation expense is adjusted for estimated forfeitures and is recognized on a straight-line basis over the requisite service period of the award. The Company's estimated future forfeiture rates are based on its historical experience.

Use of Estimates

Management of the Company has made a number of estimates and assumptions relating to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities in order to prepare these consolidated financial statements in conformity with U.S. generally accepted accounting principles (U.S.

(1) Summary of Significant Accounting Policies and Other Information (Continued)

GAAP). Significant estimates made by management include the allocation of the purchase price in the IRP Acquisition (note 2) to acquired assets and liabilities, allowance for non-recoupable prepaid royalties, the valuation allowance for deferred tax assets, asset retirement obligations and amounts accrued related to the Company's workers' compensation, black lung, pension and health claim obligations. Actual results could differ from these estimates.

Recent Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board ("FASB") issued ASU No. 2011-05, "Presentation of Comprehensive Income." ASU 2011-05 eliminates the option to report other comprehensive income and its components in the consolidated statement of shareholder's equity and comprehensive income and requires an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. This pronouncement is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. The adoption of ASU 2011-05 concerns presentation and disclosure only and will not have an impact on its consolidated financial position or results of operations.

(2) International Resource Partners Acquisition

On April 18, 2011, the Company completed the acquisition of a 100 percent interest in International Resource Partners LP and its subsidiary companies (collectively IRP) for $516.0 million in an all-cash transaction (the IRP Acquisition). The base purchase price of $475.0 million was increased by the cash acquired and any working capital (as defined in the agreement) that exceeded $18.5 million. IRP did not have any debt at the time of the closing of the IRP Acquisition. The IRP Acquisition will be treated as a purchase of assets for tax purposes.

Prior to the acquisition, IRP was a privately held fully integrated coal company focused on producing and marketing high quality metallurgical and steam coal in Central Appalachia. IRP produced and sold various grades of metallurgical and steam coal from underground and surface mining operations in southern West Virginia and eastern Kentucky. IRP's customer base consisted of domestic steel and coke producers, international steel producers and domestic electric utilities. At the acquisition date, IRP operated nine mines, including five underground mines and four surface mines.

For the year ended December 31, 2010, IRP had revenues of $490.3 million and income before taxes at the partnership level of $51.3 million. IRP's coal reserves and resources are located in West Virginia and Kentucky. As of the date of the IRP Acquisition, IRP controlled approximately 136 million tons of coal reserves and resources, consisting of approximately 61 million tons of metallurgical coal and an estimated 75 million tons of steam coal. The coal reserves and resources acquired from IRP include 85.5 million of proven and probable reserves. IRP leases a substantial portion of its coal reserves and resources from various third-party landowners.

(2) International Resource Partners Acquisition (Continued)

The purchase price was allocated to the assets acquired and liabilities assumed based on estimated fair values of the assets acquired and liabilities assumed. The purchase price allocation (net of cash acquired) was as follows (in thousands):

Trade and other accounts receivable	$116,630
Inventories	17,373
Other current assets	2,830
Property, plant and equipment	487,359
Other noncurrent assets	14,352
Total assets	638,544
Accounts payable, principally trade	56,402
Other current liabilities	8,619
Asset retirement obligations	50,858
Other noncurrent liabilities	6,703
Total liabilities	122,582
Net assets acquired, excluding cash	$515,962

The following unaudited pro forma information has been prepared for illustrative purposes only. The pro forma information assumes the IRP Acquisition and the financing transactions that were completed to affect the IRP Acquisition occurred on January 1, 2010. The financing transactions include the issuance of the 2019 Senior Notes, the redemption of the 2012 Senior Notes, the issuance of the 2018 Convertible Notes and the amendments to the Revolving Credit Agreement (all as described in note 4), as well as the equity issuance described in note 7. The unaudited pro forma results have been prepared based on estimates and assumptions that we believe are reasonable; however, they are not necessarily indicative of the consolidated results of operations had the IRP Acquisition and the related financing transaction occurred at the beginning of each of the periods presented or of future results of operations.

	Year Ended December 31,	
	2011	2010
	(in thousands)	
Total revenues		
As reported	$1,177,655	701,116
Pro forma	1,401,835	1,191,452
Net income (loss)		
As reported	(39,089)	78,165
Pro forma	(9,216)	96,222

For the year ended December 31, 2011, costs of $8.5 million were incurred related to the IRP Acquisition. The acquisition costs include $3.8 million of commitment fees associated with $375.0 million of committed bridge financing (Bridge Commitment) that the Company secured to provide adequate liquidity to complete the IRP Acquisition in the event alternative financing could not be raised. The Bridge Commitment expired, without any amounts being drawn.

The amount of revenues and earnings attributable to IRP in the statements of operations for the year ended December 31, 2011 are not readily determinable, due to the consolidation of a portion of IRP's operations into the Company's existing operations, fulfillment of historical sales contracts between operations and various intercompany transactions.

(3) Other Current Liabilities

Other current liabilities at December 31, 2011 and 2010 are as follows (in thousands):

	2011	2010
Accrued royalties	$10,655	$ 7,284
Accrued interest	8,396	2,098
Current portion of asset retirement obligation	6,862	4,991
Other	1,948	2,123
	$27,861	$16,496

(4) Long Term Debt and Interest Expense

Long-term debt is as follows at December 31, 2011 and 2010 (in thousands):

	2011	2010
2019 Senior Notes	$275,000	$ —
2012 Senior Notes	—	150,000
2018 Convertible Senior Notes, net of discount	166,821	—
2015 Convertible Senior Notes, net of discount	140,372	134,022
Revolver	—	—
Total long-term debt	$582,193	$284,022

Scheduled maturities of long-term debt are as follows (in thousands):

Year ended December 31:	
2012 to 2014	$ —
2015	172,500
2016	—
Thereafter	505,000
	$677,500

2019 Senior Notes

In the first quarter of 2011, the Company issued $275.0 million of senior notes due on April 1, 2019 (the 2019 Senior Notes). The 2019 Senior Notes are unsecured and accrue interest at 7.875% per annum. Interest payments on the 2019 Senior Notes are required semi-annually. The Company may redeem the 2019 Senior Notes, in whole or in part, at any time on or after April 1, 2015 at redemption prices ranging from 103.938% beginning April 1, 2015 to 100% beginning on April 1, 2017. In addition, at any time prior to April 1, 2014, the Company may redeem up to 35% of the principal amount of the 2019 Senior Notes with the net cash proceeds of a public equity offering at a redemption price of 107.875%, plus accrued and unpaid interest to the redemption date.

The 2019 Senior Notes limit the Company's ability, among other things, to pay cash dividends. In addition, if a change of control occurs (as defined in the Indenture), each holder of the 2019 Senior Notes will have the right to require the Company to repurchase all or a part of the 2019 Senior Notes at a price equal to 101% of their principal amount, plus any accrued interest to the date of repurchase.

The Company incurred approximately $6.7 million of costs in connection with the issuance of the 2019 Senior Notes. The costs, net of amortization, are included in other assets on the accompanying balance sheets.

(4) Long Term Debt and Interest Expense (Continued)

2015 Convertible Senior Notes

In 2009, the Company issued $172.5 million of 4.5% convertible senior notes due on December 1, 2015 (the 2015 Convertible Senior Notes). The 2015 Convertible Senior Notes are shown net of a $32.1 million and a $38.5 million discount as of December 31, 2011 and 2010, respectively. The discount on the 2015 Convertible Senior Notes relates to the $44.8 million of the proceeds that were allocated to the equity component of the 2015 Convertible Senior Notes at issuance, resulting in an effective interest rate of 10.2%. The 2015 Convertible Senior Notes are unsecured and are convertible under certain circumstances and during certain periods at an initial conversion rate of 38.7913 shares of the Company's common stock per $1,000 principal amount of the 2015 Convertible Senior Notes, representing an initial conversion price of approximately $25.78 per share of the Company's stock. Interest on the 2015 Convertible Senior Notes is paid semi-annually.

None of the 2015 Convertible Senior Notes are currently eligible for conversion. The 2015 Convertible Senior Notes are convertible at the option of the holders (with the length of time the 2015 Convertible Senior Notes are convertible being dependent upon the conversion trigger) upon the occurrence of any of the following events:

- At any time from September 1, 2015 until December 1, 2015;
- If the closing sale price of the Company's common stock for each of 20 or more trading days in a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter exceeds 130% of the conversion price of the 2015 Convertible Senior Notes in effect on the last trading day of the immediately preceding calendar quarter;
- If the trading price of the 2015 Convertible Senior Notes for each trading day during any five consecutive business day period, as determined following a request of a holder of Notes, was equal to or less than 97% of the "Conversion Value" of the 2015 Convertible Senior Notes on such trading day; or
- If the Company elects to make certain distributions to the holders of its common stock or engage in certain corporate transactions.

2018 Convertible Senior Notes

In the first quarter of 2011, the Company issued $230.0 million of 3.125% convertible senior notes due on March 15, 2018 (the 2018 Convertible Senior Notes). The 2018 Convertible Senior Notes are shown net of a $63.2 million discount as of December 31, 2011. The discount on the 2018 Convertible Senior Notes relates to the $68.7 million of the proceeds that were allocated to the equity component of the 2018 Convertible Senior Notes at issuance, resulting in an effective interest rate of 8.9%. The equity component was recorded as an increase to shareholders' equity, net of allocated issuance costs and deferred income taxes of $2.1 million and $24.4 million, respectively. The 2018 Convertible Senior Notes are unsecured and are convertible under certain circumstances and during certain periods at an initial conversion rate of 32.7332 shares of the Company's common stock per $1,000 principal amount of 2018 Convertible Senior Notes, representing an initial conversion price of approximately $30.55 per share of the Company's stock. Interest payments on the 2018 Convertible Senior Notes are required semi-annually.

None of the 2018 Convertible Senior Notes are currently eligible for conversion. The 2018 Convertible Senior Notes are convertible at the option of the holders (with the length of time the 2018 Convertible Senior Notes are convertible being dependent upon the conversion trigger) upon the occurrence of any of the following events:

- At any time from December 15, 2017 until March 15, 2018;
- If the closing sale price of the Company's common stock for each of 20 or more trading days in a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter

(4) Long Term Debt and Interest Expense (Continued)

exceeds 130% of the conversion price of the 2018 Convertible Senior Notes in effect on the last trading day of the immediately preceding calendar quarter;

- If the trading price of the 2018 Convertible Senior Notes for each trading day during any five consecutive business day period, as determined following a request of a holder of 2018 Convertible Senior Notes, was equal to or less than 97% of the "Conversion Value" of the Notes on such trading day; or
- If the Company elects to make certain distributions to the holders of its common stock or engage in certain corporate transactions.

The Company incurred approximately $7.1 million of costs in connection with the issuance of the 2018 Convertible Senior Notes issuance, including $2.1 million which was allocated to the equity portion of the transaction. The costs allocated to the debt portion of the transaction, net of amortization, are included in other assets on the accompanying balance sheets.

Revolving Credit Agreement

In the second quarter of 2011, the Company entered into two agreements which amended and restated its existing Revolving Credit Agreement and resulted in an increase to the maximum availability under the Revolver to $100.0 million (as amended and restated the Revolving Credit Agreement is referred to as the Revolver). The following is a summary of the significant terms of the Revolver.

Maturity	June 30, 2015
Interest Rate	Company's option of Base Rate (a) plus 2.25% or LIBOR plus 3.25% per annum.
Maximum Availability	Lesser of $100.0 million or the borrowing base (b)
Periodic Principal Payments	None

(a) Base rate is the higher of (1) the Federal Fund Rate plus 0.5%, (2) the prime rate and (3) a three month LIBOR rate plus a percentage as defined in the agreement.

(b) The Revolver's borrowing base is based on the sum of 90% of the Company's eligible accounts receivable plus 65% of the eligible inventory (not to exceed $40.0 million) less reserves from time to time set by the administrative agent. The eligible accounts receivable and inventories are further adjusted as specified in the Revolver and the eligible inventory currently excludes certain inventories of our subsidiaries in West Virginia. The Company's borrowing base can also be increased by 95% of any cash collateral that the Company maintains in a cash collateral account.

The Revolver provides that the Company can use the Revolver availability to issue letters of credit. The Revolver provides for a 3.5% fee on any outstanding letters of credit issued under the Revolver and a 0.5% fee on the unused portion of the Revolver. The Revolver requires certain mandatory prepayments from certain asset sales, incurrence of indebtedness and excess cash flow. The Revolver includes financial covenants that require the Company to maintain a minimum Fixed Charge Coverage Ratio and limit capital expenditures, each as defined by the agreement. The minimum Fixed Charge Coverage Ratio is only applicable if the sum of the Company's unrestricted cash plus the availability under the Revolver falls below $35.0 million and would remain in effect until the sum of the Company's unrestricted cash plus the availability under the Revolver exceeds $35.0 million for 90 consecutive days. The limit on capital expenditures is only applicable if the Company's unrestricted cash plus the availability under the Revolver falls below $50.0 million for a period of 5 consecutive days and would remain in effect until the Company's unrestricted cash plus the availability under the Revolver exceeds $50.0 million for 90 consecutive days.

As of December 31, 2011, the Company had used $62.8 million of the $100.0 million then available under the Revolver to secure outstanding letters of credit. As of December 31, 2011, the Company had $21.0 million of

(4) Long Term Debt and Interest Expense (Continued)

cash in a restricted cash collateral account to ensure that the Company has adequate capacity under the Revolver to support its outstanding letters of credit.

The Company incurred approximately $1.9 million of costs in connection with the amendments and restatements to the Revolver in 2011. The costs, net of amortization, are included in other assets on the accompanying balance sheets.

Prior Debt Agreements

In the second quarter of 2011, the Company redeemed all $150.0 million of its senior notes that were due on June 1, 2012 (the 2012 Senior Notes) at a redemption price of 100% of their face value. The 2012 Senior Notes accrued interest at 9.375% per annum. In connection with the redemption of the 2012 Senior Notes, the Company expensed $0.7 million of unamortized financing costs and these costs are included in charges associated with repayment of debt on the accompanying statement of operations.

The Company expensed $1.6 million in 2009 in connection with a fee to terminate a Prior Letter of Credit Facility and included the fee in charges associated with the repayment and amendment of debt in the consolidated financials statements for the year ended December 31, 2009.

Interest Expense and Other

During the years ended December 31, 2011, 2010 and 2009, the Company paid $29.1 million, $22.1 million, and $14.4 million in interest, respectively.

The Company was in compliance with all of the financial covenants under its outstanding debt instruments as of December 31, 2011.

The proceeds from the equity offering (note 7), the issuance of the 2019 Senior Notes and the issuance of the 2018 Convertible Senior Notes were used to fund the IRP Acquisition (note 2) and repay the outstanding 2012 Senior Notes, with the remainder available for general working capital purposes.

Principal and interest payments on the 2019 Senior Notes, which have been registered under the Securities Act of 1933, are guaranteed by each of James River Coal Company's subsidiaries. James River Coal Company has no independent assets or operations (as defined in Rule 3-10(h)(5) of Regulation S-X) aside from those of its subsidiaries. The guarantees are full and unconditional and joint and several obligations (as such terms are defined in Rule 3-10(h)(5) of Regulation S-X) issued by all of the James River Coal Company's subsidiaries. Accordingly, pursuant to Rule 3-10(f) of Regulation S-X, separate financial information with respect to the subsidiaries of James River Coal Company have not been provided.

The 2015 and 2018 Convertible Senior Notes (collectively the Convertible Senior Notes) rank equally with all of the Company's existing and future senior unsecured indebtedness, including the Company's 2019 Senior Notes. The Convertible Senior Notes are not guaranteed by any of James River Coal Company's subsidiaries. The Convertible Senior Notes are effectively subordinated to all of the Company's existing and future secured indebtedness (to the extent of the assets securing such indebtedness) and structurally subordinated to all existing and future liabilities of James River Coal Company's subsidiaries, including their trade payables.

The Revolver is secured by substantially all of the Company's assets.

(5) Workers' Compensation Benefits

As of December 31, 2011 and 2010, the workers' compensation benefit obligation consisted of the following (in thousands):

	2011	2010
Workers' compensation benefits	$69,921	64,944
Less current portion	9,200	9,000
Noncurrent portion of workers' compensation benefits	$60,721	55,944

Actuarial assumptions used in the determination of the liability for the self-insured portion of workers' compensation benefits included a discount rate of 3.8% and 4.5% at December 31, 2011 and 2010, respectively.

(6) Pneumoconiosis (Black Lung) Benefits

As of December 31, 2011 and 2010, the black lung benefit obligation consisted of the following (in thousands):

	2011	2010
Black lung benefits	$58,664	45,725
Less current portion	2,512	2,282
Noncurrent portion of black lung benefits	$56,152	43,443

A reconciliation of the changes in the black lung benefit obligation is as follows (in thousands):

	2011	2010
Beginning of the year black lung obligation	$45,725	32,799
Black lung actuarial liability adjustment	10,087	10,320
Service cost	1,824	1,757
Interest cost	2,389	2,235
Benefit payments	(1,361)	(1,386)
End of year accumulated black lung obligation	$58,664	45,725

The actuarial assumptions used in the determination of accumulated black lung obligations as of December 31, 2011 and 2010 included a discount rate of 4.3% and 5.4%, respectively. A 1.0% decrease in the discount rate used at December 31, 2011, would increase the black lung obligation by approximately $9.8 million. For purposes of determining net periodic expense related to such obligations, the Company used a discount rate of 5.4%, 5.8%, and 5.8% for the years ended December 31, 2011, 2010 and 2009.

The components of net periodic benefit cost are as follows (in thousands):

	2011	2010	2009
Service cost	$1,824	1,757	1,225
Interest cost	2,389	2,235	1,712
Amortization of actuarial losses (gains)	568	412	—
Net periodic benefit cost	$4,781	4,404	2,937

As of December 31, 2011, the Company has a $19.8 million gross actuarial loss recorded in accumulated other comprehensive income (loss) on its black lung obligation. The Company expects that it will amortize $1.5 million of this actuarial loss during the year ended December 31, 2012.

(7) Equity

Preferred Stock and Shareholder Rights Agreement

The Company has authorized 10,000,000 shares of preferred stock, $1.00 par value per share, the rights and preferences of which are established by the Board of the Directors. The Company has reserved 500,000 of these shares as Series A Participating Cumulative Preferred Stock for issuance under a shareholder rights agreement (the Rights Agreement).

In 2004, the Company's shareholders approved the Rights Agreement and declared a dividend of one preferred share purchase right (Right) for each two shares of common stock outstanding. Each Right entitles the registered holder to purchase from the Company one one-hundredth (1/100) of a share of our Series A Participating Cumulative Preferred Stock, par value $1.00 per share, at a price of $200 per one one-hundredth of a Series A preferred share. The Rights are not exercisable until a person or group of affiliated or associated persons (an Acquiring Person) has acquired or announced the intention to acquire 20% or more of the Company's outstanding common stock.

In the event that the Company is acquired in a merger or other business combination transaction or 50% or more of the Company's consolidated assets or earning power is sold after a person or group has become an Acquiring Person, each holder of a Right, other than the Rights beneficially owned by the Acquiring Person (which will thereafter be void), will receive, upon the exercise of the Right, that number of shares of common stock of the acquiring company which at the time of such transaction will have a market value of two times the exercise price of the Right. In the event that any person becomes an Acquiring Person, each Right holder, other than the Acquiring Person (whose Rights will become void), will have the right to receive upon exercise that number of shares of common stock having a market value of two times the exercise price of the Right.

The rights will expire May 25, 2014, unless that expiration date is extended. The Board of Directors may redeem the Rights at a price of $0.001 per Right at any time prior to the time that a person or group becomes an Acquiring Person.

Equity Issuance

In the first quarter of 2011, the Company received proceeds of approximately $170.5 million, net of offering costs, through the issuance of approximately 7.6 million shares of common stock.

Equity Based Compensation

Under the 2004 Equity Incentive Plan (the Plan), participants may be granted stock options (qualified and nonqualified), stock appreciation rights (SARs), restricted stock, restricted stock units, and performance shares. The total number of shares that may be awarded under the Plan is 2,400,000, and no more than 1,000,000 of the shares reserved under the Plan may be granted in the form of incentive stock options. The Company currently has the following types of equity awards outstanding under the Plan.

Restricted Stock Awards

Pursuant to the Plan certain directors and employees have been awarded restricted common stock with such shares vesting over two to five years. The related expense is amortized over the vesting period.

Stock Option Awards

Pursuant to the Plan certain directors and employees have been awarded options to purchase common stock with such options vesting ratably over three to five years. The Company's stock options have been issued at exercise prices equal to or greater than the fair value of the Company's stock at the date of grant.

Shares awarded or subject to purchase under the Plan that are not delivered or purchased, or revert to the Company as a result of forfeiture or termination, expiration or cancellation of an award or that are used to exercise

(7) Equity (Continued)

an award or for tax withholding, will be again available for issuance under the Plan. At December 31, 2011, there were 329,241 shares available under the Plan for future awards.

The following table highlights the expense related to share-based payment for the periods ended December 31 (in thousands):

	2011	2010	2009
Restricted stock	$4,991	$5,095	5,655
Stock options	292	305	312
Stock based compensation	$5,283	$5,400	5,967

The fair value of the restricted stock issued and outstanding is equal to the value of shares at the grant date. At this time, the Company does not expect any of its restricted shares or options to be forfeited before vesting. The fair value of stock options was estimated using the Black-Scholes option pricing model. The Company used the following assumptions to value the stock options issued during the periods indicated below:

	2011	2010	2009
Dividend yield	0.0%	0.0%	0.0%
Expected volatility factor (1)	90.0%	90.0%	90.0%
Weighted average expected volatility	90.0%	90.0%	90.0%
Risk-free interest rate (2)	3.4%	3.9%	2.6%
Expected term (in years)	6.5	6.5	6.5

(1) The Company used historical experience to estimate its volatility.

(2) The risk-free interest rate for periods is based on U.S. Treasury yields in effect at the time of grant.

The following is a summary of restricted stock and stock option awards:

	Restricted Stock		Stock Options	
	Number of Shares Outstanding	Weighted Average Fair Value at Issue	Number of Shares Outstanding	Weighted Average Exercise Price
January 1, 2009	702,049	$22.78	261,000	$16.51
Granted	234,311	13.87	20,000	13.87
Exercised/Vested	(218,708)	16.27	(5,000)	15.00
Canceled	—	—	—	—
December 31, 2009	717,652	21.86	276,000	16.34
Granted	287,622	17.01	20,000	17.01
Exercised/Vested	(158,788)	26.69	(5,000)	14.60
Canceled	(3,600)	19.36	—	—
December 31, 2010	842,886	19.30	291,000	16.42
Granted	306,363	20.92	20,000	22.31
Exercised/Vested	(183,896)	24.44	—	—
Canceled	—	—	—	—
December 31, 2011	965,353	$18.84	311,000	$16.80

(7) Equity (Continued)

The following table summarizes additional information about the stock options outstanding at December 31, 2011.

	Range of Exercise Price	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (1) (in 000's)
Outstanding at December 31, 2011	$10.80–$36.30	311,000	$16.80	4.1	$—
Exercisable at December 31, 2011	$10.80–$36.30	271,000	$16.45	3.4	$—
Vested and expected to vest at December 31, 2011		311,000	$16.80	4.1	$—

(1) The difference between a stock award's exercise price and the underlying stock's market price at December 31, 2011.

No value is assigned to stock awards whose option price exceeds the stock's market price at December 31, 2011.

The following table summarizes the Company's total unrecognized compensation cost related to stock based compensation as of December 31, 2011.

	Unearned Compensation (in 000's)	Weighted Average Remaining Period Of Expense Recognition (in years)
Stock Options	$ 427	1.8
Restricted Stock	11,001	2.3
Total	$11,428	

(8) Income Taxes

Income tax expense (benefit) consists of the following (in thousands):

	2011	2010	2009
Current:			
Federal	$ —	(1,354)	1,354
State	812	24	25
	812	(1,330)	1,379
Deferred:			
Federal	11,716	(20,720)	165
State	2,423	(1,516)	15
	14,139	(22,236)	180
	$14,951	(23,566)	1,559

(8) Income Taxes (Continued)

A reconciliation of income taxes computed at the statutory federal income tax rate to the effective tax rate for income taxes included in the consolidated statements of operations is presented below:

	2011	2010	2009
Federal income taxes at statutory rates	(35.0)%	35.0%	34.0%
Percentage depletion	(15.4)	(20.4)	(25.8)
Effect of state and federal tax rate change, net	—	1.7	(0.2)
Change in valuation allowance	111.1	(60.9)	(6.2)
State income taxes, net of federal	(3.1)	(1.8)	0.4
Other, net	4.3	3.2	0.8
	61.9%	(43.2)%	3.0%

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2011 and 2010 are presented below (in thousands):

	2011	2010
Deferred tax assets:		
Accruals for financial reporting purposes, principally workers' compensation and black lung obligations	$ 87,032	60,520
Net operating loss carryforwards	98,443	75,182
Accumulated comprehensive income, principally pension	18,815	8,258
Other	104	104
Total gross deferred tax assets	204,394	144,064
Less valuation allowance	37,270	—
Gross deferred tax assets net of valuation	167,124	144,064
Deferred tax liabilities:		
Discount on Convertible Senior Notes	35,410	14,120
Tangible fixed assets and mineral rights due to differences in depreciation, depletion and amortization	119,227	—
Other	20,206	99,097
Total gross deferred tax liability	174,843	113,217
Net deferred tax asset (liability)	$ (7,719)	30,847

In 2011, the net deferred tax liability is included in other liabilities. In 2010, the net deferred tax asset is included in other assets. In 2011, in connection with the completion of our forecasts which considered the decline in coal prices and market demand that occurred towards the end of 2011, and after weighing all positive and negative evidence, the Company concluded that it was not more likely than not to realize a portion of its gross deferred tax assets and as a result a valuation allowance of $37.3 million was recorded. In 2010, in connection with the completion of our forecasts for future taxable income at that time and considering other relevant factors, including a history of positive operating results, the Company concluded that the deferred tax assets that were previously being reduced by a valuation allowance were more likely than not to be realizable. As a result, the 2010 income taxes include a $33.2 million income tax benefit related to the reversal of the income tax valuation allowance. This $33.2 million income tax benefit consists of the year end reversal of $22.1 million of the valuation allowance in connection with the conclusion that the deferred tax assets would be more likely than not to be realized and the reversal of $11.1 million of the valuation allowance during the year in connection with the utilization of net operating losses.

(8) Income Taxes (Continued)

At December 31, 2011, the Company has consolidated NOLs for federal income tax purposes of approximately $268 million that expire beginning in 2023, consolidated Kentucky net operating loss carryforwards of approximately $95 million which expire beginning in 2023 and consolidated West Virginia net operating loss carryforwards of approximately $16 million that expire beginning in 2026. These net operating loss carryforwards generate a combined federal and state deferred tax asset of approximately $98 million.

The Company has analyzed filing positions in all of the federal and state jurisdictions where it is required to file income tax returns, as well as all open tax years in these jurisdictions. The Company has identified its federal tax return and its state tax returns in Virginia, Kentucky, West Virginia and Indiana as “major” tax jurisdictions. The only periods subject to examination for the Company’s federal return are the 2008 through 2011 tax years. The periods subject to examination for the Company’s state returns in Virginia are years 2008 through 2011; Kentucky are years 2007 through 2011; West Virginia are years 2008 through 2011; and Indiana are years 2008 through 2011. The Company believes that its income tax filing positions and deductions will be sustained on audit and does not anticipate any adjustments that will result in a material change to its consolidated financial position. Therefore, no reserves for uncertain income tax positions have been recorded.

During the year ended December 31, 2011, the Company paid income taxes of $0.7 million. During the year ended December 31, 2010, the Company paid no income taxes. During the year ended December 31, 2009, the Company paid income taxes of $1.6 million. The income tax benefit (expense) includes no interest and penalties for the years ended December 31, 2011, 2010 and 2009.

(9) Employee Benefit Plans

Defined Benefit Pension Plan

In 2007, the Company froze pension plan benefit accruals for all employees covered under its qualified non-contributory defined benefit pension plan. The Company’s funding policy is to contribute annually an amount at least equal to the minimum funding requirements actuarially determined in accordance with the Employee Retirement Income Security Act of 1974.

The plan assets for the qualified defined benefit pension plan are held by an independent trustee. The plan’s assets include investments in cash and cash equivalents and mutual funds holding corporate and government bonds and preferred and common stocks. The Company has an internal investment committee that sets investment policy, selects and monitors investment managers and monitors asset allocation.

The investment policy for the pension plan assets includes the objectives of providing growth of capital and income while achieving a target annual rate of return of 7.5% over a full market cycle, approximately 5 to 7 years. Diversification of assets is employed to reduce risk. The current target asset allocation is 70% for equity securities (including 45% Large Cap, 15% Small Cap, 10% International) and 30% for cash and interest bearing securities. The investment policy is based on the assumption that the overall portfolio volatility will be similar to that of the target allocation. Given the volatility of the capital markets, strategic adjustments in various asset classes may be required to rebalance asset allocation back to its target policy. Investment fund managers are not permitted to invest in certain securities and transactions as outlined by the investment policy statements specific to each investment category without prior investment committee approval.

To develop the expected long-term rate of return on assets assumption, the Company performs a periodic analysis which considers the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension portfolio. This evaluation resulted in the selection of the 7.5% long-term rate of return on assets assumption for the year ended December 31, 2011.

The Company utilizes a fair value hierarchy, which maximizes the use of observable inputs and minimizes the use of unobservable inputs when measuring fair value. The plan assets are valued using unadjusted quoted prices

(9) Employee Benefit Plans (Continued)

in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The fair value of the major categories of qualified defined benefit pension plan assets includes the following (in thousands):

	2011		2010	
	Amount	Percentage	Amount	Percentage
Mutual funds — equity	$34,771	61.8%	$35,547	61.9%
Mutual funds — international equity	4,569	8.1%	5,113	8.9%
Mutual funds — fixed income/taxable	16,712	29.7%	16,507	28.7%
Money market funds and cash	238	0.4%	309	0.5%
	$56,290	100.0%	$57,476	100.0%

The following table sets forth changes in the plan's benefit obligations, changes in the fair value of plan assets, and funded status at December 31, 2011 and 2010 (in thousands):

	2011	2010
Change in benefit obligation:		
Projected benefit obligation at beginning of year	$ 69,444	65,161
Interest cost	3,642	3,760
Actuarial loss	14,892	3,103
Benefits paid	(2,567)	(2,580)
Projected benefit obligation at end of year	$ 85,411	69,444
Change in plan assets:		
Fair value of plan assets at beginning of year	$ 57,476	50,334
Actual return on plan assets	(470)	6,624
Employer contributions	1,851	3,098
Benefits paid	(2,567)	(2,580)
Fair value of plan assets at end of year	$ 56,290	57,476
Reconciliation of funded status:		
Funded status	$(29,121)	(11,968)
Net amount recognized	$(29,121)	(11,968)
Amounts recognized in the consolidated balance sheets consist of:		
Accrued benefit liability	$(29,121)	(11,968)

The accumulated benefit obligation of the plan was $85.4 million and $69.4 million as of December 31, 2011 and 2010, respectively. Company contributions in 2012 are expected to be approximately $2.7 million.

The components of net periodic benefit cost and benefits paid by period are as follows (in thousands):

	2011	2010	2009
Interest cost	$ 3,642	3,760	3,660
Expected return on plan assets	(4,279)	(3,689)	(3,099)
Recognized net actuarial loss	791	783	1,606
Net periodic benefit cost	$ 154	854	2,167
Benefits paid	$ 2,567	2,580	2,323

(9) Employee Benefit Plans (Continued)

As of December 31, 2011 and 2010 the Company had a $31.1 million and a $12.2 million gross actuarial loss recorded in accumulated other comprehensive loss on its defined benefit plan. The Company expects to recognize $3.3 million of the gross actuarial loss in the year ended December 31, 2012.

The weighted-average assumptions used to determine the pension benefit obligations are as follows:

	2011	2010
Discount rate	4.2%	5.4%
Expected return on plan assets	7.5%	7.5%

The weighted-average assumptions used to determine the net periodic benefit cost are as follows:

	2011	2010	2009
Discount rate	5.4%	5.9%	6.0%
Expected return on plan assets	7.5%	7.5%	7.5%

The following benefit payments are expected to be paid (based on the assumptions described above (in thousands)).

Year ended December 31:	
2012	$ 3,427
2013	3,395
2014	3,680
2015	3,825
2016	3,995
2017–2021	22,590

Savings and Profit Sharing Plan

The Company sponsors defined contribution pension plans and profit sharing plans. All U.S. employees are eligible for at least one of the Company's plans. The Company's contributions vary depending on the plan and cannot exceed the maximum allowable for tax purposes. The Company recognized approximately $5.2 million, $2.8 million and $3.3 million of expense relating to these plans for the years ended December 31, 2011, 2010 and 2009, respectively.

(10) Major Customers

During 2011, approximately 31% of total revenues were from two customers in the CAPP segment, the largest of which represented 20% of total revenues. During 2010, approximately 71% of total revenues were from two customers in the CAPP segment, the largest of which represented 39% of total revenues, and an additional 11% of our total revenues were from one customer in the Midwest segment. During 2009, approximately 76% of total revenues were from two customers in the CAPP segment, the largest of which represented 39% of revenues. No other customers were over 10% of total revenues for 2011, 2010 and 2009. The segment revenues are included in note 15.

The Company ships coal to customers in the United States and in international markets, including Canada and various European and Asian countries. During 2011, approximately 31.4% of total revenues were from shipments to international markets. During 2010 and 2009, there were no revenues from shipments to international markets.

(11) Leases

The Company leases equipment and various other properties under non-cancelable long-term leases, expiring at various dates. Certain leases contain options that would allow the Company to extend the lease or purchase the

(11) Leases (Continued)

leased asset at the end of the base lease term. Future minimum lease payments under noncancelable operating leases (with initial or remaining lease terms in excess of one year) as of December 31, 2011 were as follows (in thousands):

	Operating leases
Year ended December 31:	
2012	$2,634
2013	1,464
2014	821
Thereafter	—
	$4,919

The Company incurred rent expense on equipment and office space of approximately $12.1 million, $11.2 million and $10.8 million for the years ended December 31, 2011, 2010 and 2009, respectively.

(12) Commitments and Contingencies

Future minimum royalty commitments under coal lease agreements at December 31, 2011 were as follows (in thousands):

	Royalty commitments
Year ended December 31:	
2012	$ 26,539
2013	24,399
2014	22,393
2015	21,537
2016	20,525
2017 and thereafter	96,218
	$211,611

(a) Certain coal leases do not have set expiration dates but extend until completion of mining of all merchantable and mineable coal reserves. For purposes of this table, we have generally assumed that minimum royalties on such leases will be paid for a period of ten years.

(b) Certain coal leases require payment based on minimum tonnage, for these contracts an average sales price of $85.00 per ton was used to project the future commitment.

The Company has established irrevocable letters of credit totaling $62.8 million as of December 31, 2011 to guarantee performance under certain contractual arrangements. The letters of credit have been issued under the Revolver (note 4).

The Company is involved in various claims and legal actions arising in the ordinary course of business. In the opinion of management, the ultimate disposition of these matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or liquidity.

(13) Earnings (Loss) Per Share

Basic earnings (loss) per share is computed by dividing net income (loss) available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per share is calculated based on the weighted average number of common shares outstanding during the period and, when

(13) Earnings (Loss) Per Share (Continued)

dilutive, potential common shares from the exercise of stock options and restricted common stock subject to continuing vesting requirements, pursuant to the treasury stock method.

The following table provides a reconciliation of the number of shares used to calculate basic and diluted earnings (loss) per share (in thousands):

	2011	2010	2009
Basic earnings per common share:			
Net income (loss)	$(39,089)	78,165	50,954
Income allocated to participating securities	—	(2,336)	(1,395)
Net income (loss) available to common shareholders	$(39,089)	75,829	49,559
Weighted average number of common and common equivalent shares outstanding:			
Basic number of common shares outstanding	32,832	26,883	26,765
Dilutive effect of unvested restricted stock (participating securities)	—	830	754
Dilutive effect of stock options	—	54	49
Diluted number of common shares and common equivalent shares outstanding	32,832	27,767	27,568
Basic earnings (loss) per common share	$ (1.19)	2.82	1.85
Diluted net income per common share:			
Net income (loss)	$(39,089)	78,165	50,954
Income allocated to participating securities	—	—	—
Net income (loss) available to potential common shareholders	$(39,089)	78,165	50,954
Diluted net earnings (loss) per share	$ (1.19)	2.82	1.85

For periods in which there was a loss, the Company excludes from its diluted loss per share calculation options to purchase shares and the unvested portion of time vested restricted shares, as inclusion of these securities would have reduced the net loss per share. The excluded instruments would have increased the diluted weighted average number of common and common equivalent shares outstanding by approximately 1.0 million for the year ended December 31, 2011. In addition, in periods of net losses, the Company has not allocated any portion of such losses to participating securities holders for its basic loss per share calculation as such participating securities holders are not contractually obligated to fund such losses.

The Company's 2015 and 2018 Convertible Senior Notes are convertible at the option of the holders upon the occurrence of certain events (note 4). As of December 31, 2011, none of the convertible senior notes had reached the specified thresholds for conversion.

(14) Fair Value of Financial Instruments

The estimated fair value of financial instruments has been determined by the Company using available market information. As of December 31, 2011 and 2010, except for long-term debt obligations, the carrying amounts of all financial instruments approximate their fair values due to their short maturities.

(14) Fair Value of Financial Instruments (Continued)

The carrying values and fair values of our long-term debt are as follows (in thousands)

	2011		2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
2019 Senior Notes	$275,000	$207,625	—	—
2012 Senior Notes	—	—	$150,000	$153,000
2015 Convertible Senior Notes (excludes discount)	172,500	137,569	172,500	210,880
2018 Convertible Senior Notes (excludes discount)	230,000	135,976	—	—

The fair value of our senior notes and convertible senior notes are based on available market data at the date presented. The carrying value of the convertible senior notes reflected in long-term debt in the table above reflects the full face amount and have been adjusted in the Consolidated Balance Sheets for a discount related to the convertible feature (note 4).

(15) Segment Information

The Company has two segments based on the coal basins in which the Company operates. These basins are located in Central Appalachia (CAPP) and in the Midwest (Midwest). The Company's CAPP operations, which include the assets acquired in the IRP Acquisition, are located in eastern Kentucky and southern West Virginia. The Company's Midwest operations are located in southern Indiana. The Company manages its coal sales by coal basin, not by individual mine complex. Mine operations are evaluated based on their per-ton operating costs. Operating segment results are shown below (in thousands).

	Years Ended December 31,		
	2011	2010	2009
Revenues			
CAPP	$1,069,766	585,064	579,108
Midwest	107,889	116,052	102,450
Corporate	—	—	—
Total	$1,177,655	701,116	681,558
Depreciation, depletion and amortization			
CAPP	$ 96,455	53,467	49,380
Midwest	12,407	10,840	12,646
Corporate	52	61	52
Total	$ 108,914	64,368	62,078
Total operating income (loss)			
CAPP	$ 58,574	96,237	98,485
Midwest	(3,882)	7,537	(4,909)
Corporate	(29,300)	(19,888)	(22,704)
Total	$ 25,392	83,886	70,872
Interest Income (1)			
Corporate	$ (494)	(683)	(60)
Total	$ (494)	(683)	(60)
Interest Expense (1)			
Corporate	$ 50,096	29,943	17,057
Total	$ 50,096	29,943	17,057
Income tax (benefit) expense (1)			
Corporate	$ 14,951	(23,566)	1,559
Total	$ 14,951	(23,566)	1,559
Net earnings (loss) (1)			
CAPP	$ 58,574	96,237	98,485
Midwest	(3,882)	7,537	(4,909)
Corporate	(93,781)	(25,609)	(42,622)
Total	$ (39,089)	78,165	50,954

(1) The Company does not allocate interest income, interest expense or income taxes to its segments.

(15) Segment Information (Continued)

	December 31, 2011	December 31, 2010
Total Assets		
CAPP	$1,232,029	551,762
Midwest	122,290	114,939
Corporate	50,263	117,868
Total	$1,404,582	784,569
Goodwill		
CAPP	$ —	—
Midwest	26,492	26,492
Corporate	—	—
Total	$ 26,492	26,492

	Years Ended December 31, 2011	2010	2009
Capital Expenditures			
CAPP	$110,592	75,795	58,147
Midwest	27,863	19,631	13,840
Corporate	—	—	172
Total	$138,455	95,426	72,159

(16) Quarterly Information (Unaudited)

Set forth below is the Company's quarterly financial information for the previous two fiscal years (in thousands, except per share amounts):

	Three Months Ended			
	March 31, 2011	June 30, 2011	September 30, 2011	December 31, 2011
Total revenue	$164,582	352,037	303,858	357,178
Gross profit	15,001	35,864	15,101	25,008
Income (loss) from operations	986	17,194	(1,243)	8,455
Income (loss) before taxes	(6,689)	1,156	(14,014)	(4,591)
Net income (loss)	(7,604)	789	(3,732)	(28,542)
Basic Earnings (loss) per share	$ (0.28)	0.02	(0.11)	(0.82)
Diluted Earning (loss) per share	(0.28)	0.02	(0.11)	(0.82)

(16) Quarterly Information (Unaudited) (Continued)

	Three Months Ended			
	March 31, 2010	June 30, 2010	September 30, 2010	December 31, 2010
Total revenue	$184,601	183,045	171,420	162,050
Gross profit	38,926	38,098	25,500	19,709
Income from operations	29,607	28,275	15,695	10,309
Income before taxes	22,272	20,594	8,755	2,978
Net income	23,245	19,850	9,200	25,870
Basic Earnings per share	0.84	0.72	0.33	0.93
Diluted Earning per share	0.84	0.71	0.33	0.93

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 1st day of March, 2012.

JAMES RIVER COAL COMPANY

By: /s/ Peter T. Socha

Peter T. Socha
Chairman of the Board,
President and Chief Executive Officer
(principal executive officer)

Know all men by these presents, that each person whose signature appears below constitutes and appoints Peter T. Socha and Samuel M. Hopkins, II, or either of them, as attorneys-in-fact, with power of substitution, for him in any and all capacities, to sign any amendments to this annual report on Form 10-K, and to file the same, with exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that said attorneys-in-fact may do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the Registrant in the capacities indicated on the 1 st day of March, 2012.

Signature	Title
/s/ Peter T. Socha Peter T. Socha	Chairman of the Board, President and Chief Executive Officer (principal executive officer)
/s/ Samuel M. Hopkins, II Samuel M. Hopkins, II	Vice President and Chief Accounting Officer (principal financial officer and principal accounting officer)
/s/ Alan F. Crown Alan F. Crown	Director
/s/ Ronald J. FlorJancic Ronald J. FlorJancic	Director
/s/ Leonard J. Kujawa Leonard J. Kujawa	Director
/s/ Joseph H. Vipperman Joseph H. Vipperman	Director