International Coal Group, Inc.
Form 10-K
January 29, 2010

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2009

OR

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

Commission file number: 001-32679

International Coal Group, Inc.
(Exact Name of Registrant as Specified in Its Charter)

| | |
|---|---|
| Delaware<br>(State or Other Jurisdiction of Incorporation or Organization) | 20-2641185<br>(I.R.S. Employer Identification No.) |

300 Corporate Centre Drive
Scott Depot, WV 25560
(Address of Principal Executive Offices—Zip Code)

(304) 760-2400
(Registrant's Telephone Number, Including Area Code)

| Securities registered pursuant to Section 12(b) of the Act: | Name on each exchange on which registered: |
|---|---|
| Common Stock, par value $0.01 per share | The New York Stock Exchange |

Securities registered pursuant to Section 12(g) of the Act:
None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Exchange Act. Yes ¨ No x

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 x 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. Yes x No ¨

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

Large accelerated filer ¨ Accelerated filer x 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 Act). Yes ¨ No x

Aggregate market value of common stock held by non-affiliates of the registrant as of June 30, 2009, the last business day of the registrant's most recently completed second fiscal quarter, at a closing price of $2.86 per share as reported by the New York Stock Exchange, was $262,328,609. Shares of common stock beneficially held by each executive officer and director and their respective spouses have been excluded since such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

Number of shares of common stock outstanding as of January 20, 2010 was 179,014,632.

DOCUMENTS INCORPORATED BY REFERENCE

Part III incorporates certain information by reference from the registrant's definitive proxy statement for the 2010 annual meeting of stockholders, which proxy statement will be filed on or about April 1, 2010.

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ON FORM 10-K

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* The information required by Items 10, 11, 12, 13 and 14, to the extent not included in this document, is incorporated herein by reference to the information included under the captions “Election of Directors,” “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters,” “Certain Relationships and Related Party Transactions,” “Audit Matters” and “ Executive Officers” in the registrant’s definitive proxy statement which is expected to be filed on or about April 1, 2010.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Statements in this Annual Report on Form 10-K that are not historical facts are forward-looking statements within the "safe harbor" provision of the Private Securities Litigation Reform Act of 1995 and may involve a number of risks and uncertainties. We have used the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "plan," "predict and similar terms and phrases, including references to assumptions, in this report to identify forward-looking statements. These forward-looking statements are made based on expectations and beliefs concerning future events affecting us and are subject to various risks, uncertainties and factors relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control, that could cause our actual results to differ materially from those matters expressed in or implied by these forward-looking statements. The following factors are among those that may cause actual results to differ materially from our forward-looking statements:

- market demand for coal, electricity and steel;
- availability of qualified workers;
- future economic or capital market conditions;
- weather conditions or catastrophic weather-related damage;
- our production capabilities;
- consummation of financing, acquisition or disposition transactions and the effect thereof on our business;
- a significant number of conversions of our Convertible Senior Notes prior to maturity;
- our plans and objectives for future operations and expansion or consolidation;
- our relationships with, and other conditions affecting, our customers;
- availability and costs of key supplies or commodities such as diesel fuel, steel, explosives and tires;
- availability and costs of capital equipment;
- prices of fuels which compete with or impact coal usage, such as oil and natural gas;
- timing of reductions or increases in customer coal inventories;
- long-term coal supply arrangements;
- reductions and/or deferrals of purchases by major customers;
- risks in or related to coal mining operations, including risks relating to third-party suppliers and carriers operating at our mines or complexes;
- unexpected maintenance and equipment failure;

- environmental, safety and other laws and regulations, including those directly affecting our coal mining and production, and those affecting our customers' coal usage;
- ability to obtain and maintain all necessary governmental permits and authorizations;
- competition among coal and other energy producers in the United States and internationally;
- railroad, barge, trucking and other transportation availability, performance and costs;
- employee benefits costs and labor relations issues;
- replacement of our reserves;
- our assumptions concerning economically recoverable coal reserve estimates;
- availability and costs of credit, surety bonds and letters of credit;

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- title defects or loss of leasehold interests in our properties which could result in unanticipated costs or inability to mine these properties;
- future legislation and changes in regulations or governmental policies or changes in interpretations or enforcement thereof, including with respect to safety enhancements and environmental initiatives relating to global warming and climate change;
- impairment of the value of our long-lived and deferred tax assets;
- our liquidity, including our ability to adhere to financial covenants related to our borrowing arrangements;
- adequacy and sufficiency of our internal controls; and
- legal and administrative proceedings, settlements, investigations and claims and the availability of related insurance coverage.

You should keep in mind that any forward-looking statements made by us in this Annual Report on Form 10-K or elsewhere speaks only as of the date on which the statements were made. New risks and uncertainties arise from time to time, and it is impossible for us to predict these events or how they may affect us or anticipated results. We have no duty to, and do not intend to, update or revise the forward-looking statements in this report after the date of this report, except as may be required by law. In light of these risks and uncertainties, you should keep in mind that any forward-looking statement made in this report might not occur.

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# PART I

## Introduction

This report is both our 2009 annual report to stockholders and our 2009 Annual Report on Form 10-K required under the federal securities laws.

Unless the context otherwise indicates, as used in this annual report, the terms “ICG,” “we,” “our,” “us” and similar terms refer to International Coal Group, Inc. and its consolidated subsidiaries.

The term “coal reserves” as used in this report means proven and probable reserves that are the part of a mineral deposit that can be economically and legally extracted or produced at the time of the reserve determination and the term “non-reserve coal deposits” in this report means a coal bearing body that has been sufficiently sampled and analyzed to assume continuity between sample points, but does not qualify as a commercially viable coal reserve as prescribed by SEC rules until a final comprehensive SEC-prescribed evaluation is performed.

Because certain terms used in the coal industry may be unfamiliar to many investors, we have provided a “Glossary of Selected Terms” at the end of Item 1.

## ITEM 1. BUSINESS

### Overview

We are a leading producer of coal in Northern and Central Appalachia with a broad range of mid- to high-Btu, low- to medium-sulfur steam and metallurgical coal. Our 12 Appalachian mining complexes are located in West Virginia, Kentucky, Virginia and Maryland. We also have a complementary mining complex of mid- to high-sulfur steam coal strategically located in the Illinois Basin. We market our coal to a diverse customer base of largely investment grade electric utilities, as well as domestic and international industrial customers. The high quality of our coal and the availability of multiple transportation options, including rail, truck and barge, throughout the Appalachian region enable us to participate in both the domestic and international coal markets. Coal markets, particularly Appalachian coal markets, have exhibited significant price volatility in 2008 and 2009 and may continue to do so due to a number of factors, including regulatory and other actions delaying the issuance of necessary permits, general economic conditions and customer usage of coal.

As of December 31, 2009, management estimates that we owned or controlled approximately 325 million tons of metallurgical quality coal reserves and approximately 765 million tons of steam coal reserves. Management’s estimates were developed considering an initial evaluation, as well as subsequent acquisitions, dispositions, depleted reserves, changes in available geological or mining data and other factors. Further, we own or control approximately 431 million tons of non-reserve coal deposits. Our assets are high quality reserves strategically located in Appalachia and the Illinois Basin and are operated union free.

For the year ended December 31, 2009, we sold 16.8 million tons of coal, of which approximately 16.0 million tons were produced from our mining activities and approximately 0.8 million tons were purchased through brokered coal contracts (coal purchased from third parties for resale), at an average sale price of $60.16 and $52.62, respectively. Of the tons sold, 15.8 million tons were steam coal and 1.0 million tons were metallurgical coal. Our steam coal sales volume in 2009 consisted of mid- to high-quality, high-Btu (greater than 12,000 Btu/lb.), low- to medium-sulfur (1.5% or less) coal, which typically sells at a premium to lower quality, lower Btu, higher sulfur steam coal. Our three largest customers for the year ended December 31, 2009 were Progress Energy, Georgia Power and Santee Cooper and we derived approximately 36% of our revenues from sales to our five largest customers. We did not derive more than 10% of our revenues from any single customer in 2009.

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We have three reportable business segments, which are based on the coal regions in which we operate: (i) Central Appalachian, comprised of both surface and underground mines, (ii) Northern Appalachian, comprised of both surface and underground mines and (iii) Illinois Basin, representing one underground mine. Financial information concerning industry segments, as defined by accounting principles generally accepted in the United States of America, as of and for the years ended December 31, 2009, 2008 and 2007 is included in Note 20 to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

## The Coal Industry

A major contributor to the world energy supply, coal represents over 27% of the world's primary energy consumption according to the World Coal Institute. The primary use for coal is to fuel electric power generation. In 2008, coal-fired plants generated approximately 49% of the electricity produced in the United States, according to the Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy.

## Coal Markets

Coal produced in the United States is used primarily by utilities to generate electricity, by steel companies to produce coke for use in blast furnaces and by a variety of industrial users to heat and power foundries, cement plants, paper mills, chemical plants and other manufacturing and processing facilities. Significant quantities of coal are also exported from both east and west coast terminals. Coal used as fuel to generate electricity is commonly referred to as "steam coal."

Coal has long been favored as an electricity generating fuel by regulated utilities because of its basic economic advantage. The largest cost component in electricity generation is fuel. According to the National Mining Association, coal is the most affordable source of power fuel per million Btu, averaging less than one-quarter the price of both petroleum and natural gas.

The other major market for coal is the steel industry. The type of coal used in steel making is referred to as "metallurgical coal" and is distinguished by special quality characteristics that include high carbon content, favorable coking characteristics and various other chemical attributes. Metallurgical coal is also generally higher in heat content (as measured in Btus), and therefore is also desirable to utilities as fuel for electricity generation. Consequently, metallurgical coal producers have the ongoing opportunity to select the market that provides maximum revenue and margins. The premium price offered by steel makers for the metallurgical quality attributes is typically higher than the price offered by utility coal buyers that value only the heat content.

## Coal Mining Methods

We produce coal using two mining methods: underground room-and-pillar mining using continuous mining equipment and surface mining, which are explained as follows:

### Underground Mining

Underground mines in the United States are typically operated using one of two different mining methods: room-and-pillar or longwall. In 2009, approximately 47% of our produced and processed coal volume came from underground mining operations using the room-and-pillar method with continuous mining equipment.

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### Room-and-Pillar Mining

In room-and-pillar mining, rooms are cut into the coal seam leaving a series of pillars, or columns of coal, to help support the mine roof and control the flow of air. Continuous mining equipment is used to cut the coal from the mining face. Generally, openings are driven 20 feet wide and the pillars are rectangular in shape measuring 35-50 feet wide by 35-80 feet long. As mining advances, a grid-like pattern of entries and pillars is formed. Shuttle cars are used to transport coal to the conveyor belt for transport to the surface. When mining advances to the end of a panel, 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. When retreat mining is completed to the mouth of the panel, the mined panel is abandoned. The room-and-pillar method is often used to mine smaller coal blocks or thinner seams. It is also employed whenever subsidence is prohibited. Seam recovery ranges from 35% to 70%, with higher seam recovery rates applicable where retreat mining is combined with room-and-pillar mining.

### Longwall Mining

The other underground mining method commonly used in the United States is longwall mining. We do not currently have any longwall mining operations, but we expect to use this mining method in the development of our Tygart property in Taylor County, West Virginia. In longwall mining, a rotating drum is trammed mechanically across the face of coal and a hydraulic system supports the roof of the mine while it advances through the coal. Chain conveyors then move the loosened coal to an underground mine conveyor system for delivery to the surface.

### Surface Mining

Surface mining is used when coal is found close to the surface. In 2009, approximately 53% of our produced and processed coal volume came from surface mines. This method involves the removal of overburden (earth and rock covering the coal) with heavy earth moving equipment and explosives, extraction of the coal, replacing the overburden and topsoil after the coal has been excavated, reestablishing vegetation and plant life and frequently making other improvements that have local community and environmental benefit. Overburden is typically removed at our mines using large, rubber-tired diesel loaders. Seam recovery for surface mining is typically between 80% and 90%. Productivity depends on equipment, geological composition and mining ratios.

We use the following two types of surface mining methods.

### Truck-and-Shovel/Loader Mining

Truck-and-shovel/loader mining is a surface mining method that uses large shovels or loaders to remove overburden which is used to backfill pits after coal removal. Shovels or loaders load coal into haul trucks for transportation to a preparation plant or unit train loadout facility. Seam recovery using the truck-and-shovel/loader mining method is typically 85% or more.

### Highwall Mining

Highwall mining is a surface mining method generally utilized in conjunction with truck-and-shovel/loader surface mining. At the highwall exposed by the truck-and-shovel/loader operation, a modified continuous miner with an attached beltline system cuts horizontal passages from the highwall into a seam. These passages can penetrate to a depth of up to 1,600 feet. This method typically can recover up to 65% of the reserve block penetrated.

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## Coal Preparation and Blending

Depending on coal quality and customer requirements, raw coal may in some cases be shipped directly from the mine to the customer. Generally, raw coal from surface mines can be shipped in this manner. However, the quality of most underground raw coal does not allow it to be shipped directly to the customer without processing in a preparation plant. Preparation plants separate impurities from coal. This processing upgrades the quality and heating value of the coal by removing or reducing sulfur and ash-producing materials, but entails additional expense and results in some loss of coal. Coals of various sulfur and ash contents can be mixed, or “blended,” at a preparation plant or loading facility to meet the specific combustion and environmental needs of customers. Coal blending helps increase profitability by meeting the quality requirements of specific customer contracts, while maximizing revenue through optimal use of coal inventories.

## Coal Characteristics

In general, coal of all geological composition is characterized by end use as either steam coal or metallurgical coal. Heat value and sulfur content are the most important variables in the profitable marketing and transportation of steam coal, while ash, sulfur and various coking characteristics are important variables in the profitable marketing and transportation of metallurgical coal. We mine, process, market and transport bituminous steam and metallurgical coal, characteristics of which are described below.

### Heat Value

The heat value of coal is commonly measured in Btus per pound of coal. A Btu is the amount of heat needed to raise one pound of water one degree Fahrenheit. Coal found in the eastern and Midwestern regions of the United States tends to have a heat content ranging from 10,000 to 14,000 Btus per pound, as received. As received Btus per pound includes the weight of moisture in the coal on an as sold basis. Most coal found in the Western United States ranges from 8,000 to 10,000 Btus per pound, as received.

### Bituminous Coal

Bituminous coal is a relatively soft black coal with a heat content that ranges from 10,000 to 14,000 Btus per pound. This coal is located primarily in Appalachia, Arizona, Colorado, the Midwest and Utah, and is the type most commonly used for electricity generation in the United States. Bituminous coal is also used for industrial steam purposes by utility and industrial customers, and as metallurgical coal in steel production.

### Sulfur Content

Sulfur content can vary from coal seam to coal seam and sometimes within each seam. When coal is burned, it produces sulfur dioxide, the amount of which varies depending on the chemical composition and the concentration of sulfur in the coal. Compliance coal is coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million Btus and complies with the requirements of the Clean Air Act Acid Rain Program. Low sulfur coal is coal which, when burned, emits approximately 1.6 pounds or less of sulfur dioxide per million Btus. Mid-sulfur coal is characterized as coal which, when burned, emits greater than 1.6 pounds of sulfur dioxide per million Btus, but less than 2.5 pounds of sulfur dioxide per million Btus. High sulfur coal is generally characterized as coal which, when burned, emits greater than 2.5 pounds per million Btus.

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High sulfur coal can be burned in electric utility plants equipped with sulfur-reduction technology, such as scrubbers, which can reduce sulfur dioxide emissions by up to 99%. Plants without scrubbers can burn high sulfur coal by blending it with lower sulfur coal or by purchasing emission allowances on the open market. Each emission allowance permits the user to emit a ton of sulfur dioxide. By 2000, 90,000 megawatts of electric generation capacity utilized scrubbing technologies. According to the EIA, by 2030, more than 114 gigawatts of existing coal-fired capacity will have installed scrubbers. Additional scrubbing will provide new market opportunities for our medium to high sulfur coal. All new coal-fired electric utility generation plants built in the United States will use clean coal-burning technology.

Other Characteristics

Ash is the inorganic residue remaining after the combustion of coal. As with sulfur content, ash content varies from coal seam to coal seam. Ash content is an important characteristic of coal because it increases transportation costs and electric generating plants must handle and dispose of ash following combustion.

Moisture content of coal varies by the type of coal, the region where it is mined and the location of coal within a seam. In general, high moisture content decreases the heat value per pound of coal, thereby increasing the delivered cost per Btu. Moisture content in coal, as sold, can range from approximately 5% to 30% of the coal’s weight.

Operations

As of December 31, 2009, we operated a total of 11 surface and 11 underground coal mines located in Kentucky, Maryland, Virginia, West Virginia and Illinois. Approximately 53% of our 2009 production came from surface mines, and the remaining 47% of our production came from our underground mines. These mining facilities include 10 preparation plants, each of which receive, blend, process and ship coal that is produced from one or more of our 22 active mines. Our underground mines generally consist of one or more single or dual continuous miner sections which are made up of the continuous miner, shuttle cars, roof bolters and various ancillary equipment. Our surface mines are a combination of mountain top removal, highwall, contour and cross ridge operations using truck/loader equipment fleets along with large production tractors. Most of our preparation plants are modern heavy media plants that generally have both coarse and fine coal cleaning circuits. We currently own most of the equipment utilized in our mining operations. We employ preventive maintenance and rebuild programs to ensure that our equipment is modern and well maintained. The mobile equipment utilized at our mining operations is replaced on an on-going basis with new, more efficient units based on equipment age and mechanical condition. Each year we endeavor to replace the oldest units, thereby maintaining productivity while minimizing capital expenditures.

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The following table provides summary information regarding our principal active operations as of December 31, 2009:

| Mining Complexes | Location | Preparation Plants | Type and Number of Mines Under-ground | Surface | Total | Mining Method (1) | Transportation | Tons Produced in 2009 (in thousands) |
|---|---|---|---|---|---|---|---|---|
| Eastern | Cowen, WV | 1 | — | 1 | 1 | MTR, TSL | Rail | 2,500.7 |
| Hazard | Hazard, KY | — | — | 4 | 4 | CTR, MTR, TSL | Rail, Truck | 3,669.6 |
| Flint Ridge | Hazard, KY | 1 | 1 | — | 1 | R&P | Rail, Truck | 800.8 |
| Knott County | Kite, KY | 1 | 2 | — | 2 | R&P | Rail | 518.1 |
| Raven | Raven, KY | 1 | 2 | — | 2 | R&P | Rail | 728.5 |
| East Kentucky | Pike Co., KY | — | — | 2 | 2 | CTR, MTR, TSL | Rail | 933.0 |
| Beckley | Eccles, WV | 1 | 1 | — | 1 | R&P | Rail | 750.5 |
| Vindex Energy Corporation | Garrett Co., MD | 1 | — | 3 | 3 | CRM, TSL | Truck, Rail | 740.1 |
| Patriot Mining Company | Monongalia Co., WV | — | — | 1 | 1 | CTR, TSL | Barge, Rail, Truck | 744.9 |
| Wolf Run Mining Buckhannon Division | Upshur Co., WV | 1 | 2 | — | 2 | R&P | Rail, Truck | 1,042.4 |
| Powell Mountain | St. Charles, VA | 1 | 1 | — | 1 | R&P | Rail | 203.1 |
| Sentinel | Barbour Co., WV | 1 | 1 | — | 1 | R&P | Rail, Truck | 1,367.5 |
| Illinois | Williamsville, IL | 1 | 1 | — | 1 | R&P | Truck | 2,252.0 |

(1) CRM = Cross Ridge Mining; CTR = Contour Mining; R&P = Room-and-pillar; MTR = Mountain Top Removal; HW = Highwall; TSL = Truck and Shovel/Loader.

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The following table provides the last three years annual production and the average prices received for our coal for each of our mining complexes:

| | 2009 | | 2008 | | 2007 | |
|---|---|---|---|---|---|---|
| Mining Complexes | Tons Produced | Sales Realizations (1) | Tons Produced | Sales Realizations (1) | Tons Produced | Sales Realizations (1) |
| Eastern | 2,500,707 | $ 66.92 | 3,234,517 | $ 55.36 | 3,268,000 | $ 42.15 |
| Hazard | 3,669,581 | $ 65.72 | 4,055,874 | $ 54.56 | 3,868,959 | $ 45.04 |
| Flint Ridge | 800,792 | $ 66.25 | 1,055,996 | $ 55.05 | 1,306,428 | $ 45.49 |
| Knott County | 518,095 | $ 64.84 | 948,445 | $ 52.57 | 1,039,714 | $ 46.41 |
| Raven | 728,487 | $ 66.81 | 664,265 | $ 54.45 | 608,068 | $ 48.30 |
| East Kentucky | 933,030 | $ 55.49 | 1,058,092 | $ 58.39 | 1,001,911 | $ 51.42 |
| Beckley(2) | 750,478 | $ 91.89 | 531,842 | $ 106.66 | 39,748 | $ 72.82 |
| Vindex Energy Corporation | 740,084 | $ 48.02 | 939,141 | $ 54.43 | 853,695 | $ 36.83 |
| Patriot Mining Company | 744,908 | $ 51.14 | 929,645 | $ 40.56 | 885,108 | $ 25.12 |
| Wolf Run Mining Buckhannon Division | 1,042,384 | $ 57.59 | 993,807 | $ 56.48 | 636,002 | $ 41.94 |
| Powell Mountain(3) | 203,110 | $ 106.45 | 100,322 | $ 132.17 | — | $ — |
| Sentinel | 1,367,597 | $ 57.42 | 1,007,425 | $ 60.73 | 681,814 | $ 47.22 |
| Illinois | 2,251,951 | $ 33.63 | 2,261,028 | $ 29.94 | 2,085,495 | $ 29.84 |
| Sycamore Group | — (4) | $ — | — (4) | $ — | 82,904 | $ 30.14 |
| | 16,251,204 | | 17,780,399 | | 16,357,846 | |

(1) Excludes freight and handling revenue.
(2) Beckley was in development until the fall of 2008.
(3) Powell Mountain was acquired in 2008.
(4) The Sycamore No. 1 mine was depleted and reclaimed in 2007.

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Northern and Central Appalachian Mining Operations

Below is a map showing the location and access to our coal properties in Northern and Central Appalachia as of December 31, 2009:

Our Northern and Central Appalachian mining facilities and reserves are strategically located across West Virginia, Kentucky, Maryland, Virginia and Ohio and are used to produce and ship coal to our customers located primarily in the eastern half of the United States. All of our Northern and Central Appalachian mining operations are union free.

Our mines in Central Appalachia produced 10.1 million tons of coal in 2009 and our mines in Northern Appalachia produced 3.9 million tons of coal in 2009. The coal produced in 2009 from our Northern and Central Appalachian mining operations was, on average, 12,229 Btu/lb., 1.33% sulfur and 12.35% ash by content. Shipments bound for electric utilities accounted for approximately 92% of the coal shipped by these mines in 2009 compared to 91% of shipments in 2008. Within each mining complex, mines have been developed at strategic locations in proximity to our preparation plants and rail shipping facilities. The mines located in Central Appalachia ship the majority of their coal via the CSX rail road and, to a lesser extent, via the Norfolk Southern rail system. Some shipments may also be delivered by truck or barge, depending on the customer. Northern Appalachia shipments are primarily via CSX rail with some barge and truck to customer shipments.

As of December 31, 2009, these mines had 2,006 employees.

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Eastern

Eastern operates the Birch River surface mine, located 60 miles east of Charleston, near Cowen in Webster County, West Virginia. Birch River is extracting coal from the Freeport, Upper Kittanning, Middle Kittanning, Upper Clarion and Lower Clarion coal seams. Birch River controls an estimated 9.7 million tons of coal reserves. Additional potential reserves, mineable by both surface and deep mining methods, have been identified in the immediate vicinity of the Birch River mine and exploration activities are currently being conducted in order to add those potential reserves to the reserve base.

The coal reserves are predominantly leased. The leases are retained by annual minimum payments and by tonnage-based royalty payments. Most of the leased reserves are held by four lessors. Most of the leases can be renewed until all mineable and merchantable coal has been exhausted.

Overburden is removed by an excavator, front-end loaders, end dumps and bulldozers. Approximately one-third of the total coal sales are run-of-mine, while the other two-thirds are washed at Birch River’s preparation plant. Coal is transported by conveyor belt from the preparation plant to Birch River’s rail loadout, which is served by CSX via the A&O Railroad, a short-line carrier that is partially owned by CSX.

Hazard

Hazard currently operates four surface mines, a unit train loadout (Kentucky River Loading) and other support facilities in eastern Kentucky, near Hazard. Hazard’s four surface mines include East Mac & Nellie, Rowdy Gap, Sam Campbell and Thunder Ridge. The coal from these mines is being extracted from the Hazard 10, Hazard 9, Hazard 8, Hazard 7 and Hazard 5A seams. Nearly all of the coal is marketed as a blend of run-of-mine product with the remainder being washed. Overburden is removed by front-end loaders, end dumps, bulldozers and cast blasting. East Mac & Nellie also utilizes a large capacity hydraulic shovel. Coal is transported by on-highway trucks from the mines to the Kentucky River Loading rail loadout, which is served by CSX. Some coal is direct shipped to the customer by truck from the mine pits.

We estimate that Hazard controls 64.5 million tons of coal reserves, plus 8.0 million tons of coal that is classified as non-reserve coal deposits. Most of the property has been adequately explored, but additional core drilling will be conducted within specified locations to better define the reserves.

Approximately 63% of Hazard’s reserves are leased. Most of the leased reserves are held by seven lessors. In several cases, Hazard has multiple leases with each lessor. The leases are retained by annual minimum payments and by tonnage-based royalty payments. Most of the leases can be renewed until all mineable and merchantable coal has been exhausted.

Flint Ridge

As of year-end, Flint Ridge, located near Breathitt County, Kentucky, was currently operating one underground mine and one preparation plant. The underground mine operates in the Hazard 8 seam.

Flint Ridge’s underground mine is a room-and-pillar operation, utilizing continuous miners and shuttle cars. All of the run-of-mine coal is processed at the Flint Ridge preparation plant, which was extensively upgraded in early 2005. Since July 2005, it has been processing coal from the Hazard and Flint Ridge mining complexes.

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The majority of the processed coal is trucked to the Kentucky River Loading rail loadout. Some processed coal is trucked directly to the customer from the preparation facility.

We estimate that Flint Ridge controls 23.4 million tons of coal reserves, plus 0.9 million tons of non-reserve coal deposits. Approximately 98% of Flint Ridge's reserves are leased, while 2% are owned in fee. The leases are retained by annual minimum payments and by tonnage-based royalty payments. Most of the leases can be renewed until all mineable and merchantable coal has been exhausted.

Knott County

Knott County operates two underground mines, the Supreme Energy preparation plant and rail loadout and other facilities necessary to support the mining operations in eastern Kentucky, near Kite. Knott County owns certain reserves in fee with the remaining reserves being leased from a number of lessors.

Knott County is producing coal from the Hazard 4 and Elkhorn 3 coal seams. The Calvary mine is operating in the Hazard 4 coal seam, while the Classic mine is operating in the Elkhorn 3 coal seam. Two additional properties are in the process of being permitted for underground mine development. We estimate Knott County controls 18.1 million tons of coal reserves. A significant portion of the property has been explored, but additional core drilling will be conducted within specified locations to better define the reserves.

Approximately 28% of Knott County's reserves are owned in fee, while approximately 72% are leased. The leases are retained by annual minimum payments and by tonnage-based royalty payments. The leases typically can be renewed until all mineable and merchantable coal has been exhausted.

Knott County's two underground mines are room-and-pillar operations, utilizing continuous miners and shuttle cars. Nearly all of the run-of-mine coal is processed at the Supreme Energy preparation plant; some of the Hazard 4 run-of-mine coal is blended with the washed coal. All of Knott County's coal is transported by rail from loadouts served by CSX.

Raven

Raven, located in Knott County, Kentucky, operates two underground mines and the Raven preparation plant. Raven's two underground mines are producing coal from the Elkhorn 2 coal seam. Two additional properties are in the process of being permitted for underground mine development. We estimate Raven controls 10.2 million tons of coal reserves. Most of the property has been extensively explored, but additional core drilling will be conducted within specified locations to better define the reserves.

Raven's reserves are all leased from one lessor, Penn Virginia Resource Partners, L.P. The leases are retained by annual minimum payments and by tonnage-based royalty payments. The leases can be renewed until all mineable and merchantable coal has been exhausted.

Raven's two underground mines are room-and-pillar operations, utilizing continuous miners and battery powered ram cars. The coal is processed at the Raven preparation plant, which began operations in 2006. Nearly all of Raven's coal is transported by rail via CSX.

East Kentucky

East Kentucky is a surface mining operation located in Martin and Pike Counties, Kentucky, near the Tug Fork River. East Kentucky currently operates the Mt. Sterling and Peelpoplar surface mines and the Sandlick loadout. The loadout is serviced by Norfolk Southern railroad.

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Mt. Sterling is an area surface mine that produces coal from the Taylor, Coalburg, Winifrede, Buffalo and Stockton coal seams. All of the coal is sold run-of-mine. We estimate that the Mt. Sterling mine controls 1.5 million tons of coal reserves, of which 88% are owned. No additional exploration is required. Overburden at the Mt. Sterling mine is removed by front-end loaders, end dumps, bulldozers and cast blasting. Coal from the pits is transported by truck to the Sandlick loadout.

Peelpoplar is a surface mine that produces coal using contour mining from the Little Fireclay and Whitesburg Middle coal seams that we estimate to control 0.1 million tons of coal reserves, none of which are owned. Mining is performed using a front-end loader/truck spread and bulldozers. Coal produced is transported by on-highway trucks to the Sandlick loadout. We plan to operate the Peelpoplar mine through early second quarter 2010.

Although Mt. Sterling and Peelpoplar are mined by East Kentucky, the properties are held by our ICG Natural Resources subsidiary. The leases are retained by annual minimum payments and by tonnage-based royalty payments. Most of the leases can be renewed until all mineable and merchantable coal has been exhausted.

Beckley

The Beckley Pocahontas Mine, located near Beckley in Raleigh County, West Virginia, was placed into production in the fall of 2008 and accesses a 31.3 million-ton deep reserve of high quality low-volatile metallurgical coal in the Pocahontas No. 3 seam. Most of the 16,800 acre Beckley reserve is leased from three land companies: Western Pocahontas Properties, Crab Orchard Coal Company and Beaver Coal Company.

Construction of the slope portal and a new preparation plant was completed in late 2007 with remaining development completed in 2008. Underground production is by means of the room-and-pillar method with continuous miners, shuttle cars and battery haulers. Coal produced from the Beckley operation is marketed to domestic steel producers and for export. Additionally, we have the ability to produce metallurgical coal by reprocessing a nearby coal refuse pile located at Eccles, West Virginia.

Powell Mountain

Acquired in 2008, Powell Mountain, located in Lee County, Virginia and Harlan County, Kentucky, currently operates the Darby mine, a room-and-pillar mine operating two sections with continuous miners and shuttle cars. The mine is operating in the Darby seam with all coal being trucked to the Mayflower preparation plant for processing. Coal is shipped by rail through the dual service rail loadout facility with rail service provided by both the Norfolk Southern and CSX railroads. Some purchased coal is brought into the facility for processing and blending. We plan to begin operation of the new Middle Splint mine in 2011.

Vindex Energy Corporation

Vindex Energy Corporation operates three surface mines, the Carlos mine, the Island mine and the Jackson Mountain mine, all located in Garrett and Allegany Counties, Maryland. The reserves at Vindex are leased from multiple landowners. All surface mines operated by Vindex Energy are truck-and-shovel/loader mining operations which extract coal from the Upper Freeport, Bakerstown, Middle Kittanning, Upper Kittanning, Pittsburgh and Redstone seams. In 2007, Vindex added the Cabin Run property and the Buffalo properties to its reserve base. The total surface mineable reserves at Vindex amount to approximately 11.0 million tons.

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Vindex also controls approximately 54.0 million tons of deep mineable reserves in the Bakerstown and Upper Freeport seams. These reserves are low-volatile metallurgical coals suitable for steel making. Permits are in place to allow the prompt development of the reserves.

Most of the surface mine production is shipped directly to the customer as run-of-mine product; however, approximately 15,000 tons per month are targeted toward the export low-volatile metallurgical market. Any coal that must be washed is processed at our preparation plant located near Mount Storm, West Virginia, where the product is shipped to the customer by either truck or rail. A second preparation plant with rail access remains idle, although it is currently used for loading rail shipments to metallurgical customers.

Patriot Mining Company

Patriot Mining Company currently consists of the Guston Run surface mine, located near Morgantown in Monongalia County, West Virginia. The majority of the coal and surface is leased under renewable contracts with small annual minimum holding costs. Coal is extracted from the Waynesburg seam using contour mining methods with dozers, loaders and trucks. As mining progresses, reserves are being acquired and permitted for future operations. The coal is shipped to the customer by rail, truck or barge using a loading facility which is located near Morgantown, West Virginia. Patriot Mining Company currently controls approximately 9.4 million tons of coal reserves, of which 100% are leased.

Buckhannon Division

Wolf Run Mining Company's Buckhannon Division currently consists of two active underground mines: the Imperial mine located in Upshur County, West Virginia, near the town of Buckhannon, and the Sycamore No. 2 mine located in Harrison County, West Virginia, approximately ten miles west of Clarksburg. Nearly all of the reserves in Upshur County are owned, while those in Harrison County are leased. The Buckhannon Division currently controls approximately 58.0 million tons of reserves, all of which are suited for underground mining.

The Imperial mine extracts coal from the Middle Kittanning seam. The coal produced at the Imperial mine is processed through the nearby Sawmill Run preparation plant and shipped by CSX rail with origination by the A&O Railroad, although some coal is trucked to local industrial customers. The reserves at the Buckhannon Division have characteristics that make it marketable to both steam and export metallurgical coal customers.

The Sycamore No. 2 mine began producing coal from the Pittsburgh seam by the room-and-pillar mining method with continuous miners and shuttle cars in the fourth quarter of 2005. The reserve is primarily leased from one landowner with an annual minimum holding costs and an automatic renewal based on an annual minimum production of 250,000 tons. An independent contractor has operated the mine since September 2007. The coal produced from the Sycamore No. 2 mine is sold on a raw basis and shipped to Allegheny Power Service Corporation's Harrison Power Station by truck.

Sentinel

Sentinel consists of one underground mine that extracts coal from the Clarion seam using the room-and-pillar mining method. Clarion seam reserves at the Sentinel mine amount to approximately 13.4 million tons, of which approximately 12% is owned and 88% is leased. Additionally, 19.4 million tons of underground reserves in the Lower Kittanning seam are accessible from the Sentinel mine.

Coal is fed directly from the mine to a preparation plant and loadout facility served by the CSX railroad with origination by the A&O Railroad. The product can be shipped to steam or metallurgical markets, by either rail or truck.

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New Appalachian Mine Developments

Tygart Property

The Tygart property (formerly known as the Hillman property), located in Taylor County, West Virginia, near Grafton, includes approximately 186.1 million tons of deep coal reserves of both steam and metallurgical quality coal in the Lower Kittanning seam, covering approximately 65,000 acres. The reserve extends into parts of Barbour, Marion and Harrison Counties as well. ICG owns the Tygart coal reserve, in addition to nearly 4,000 acres of surface property to accommodate the development of two projected mining operations. In addition to the Lower Kittanning reserves, significant non-reserve coal deposits in the Kittanning, Freeport, Clarion and Mercer seams exist on the Tygart property.

The West Virginia Department of Environmental Protection (the "WVDEP") issued a surface mine permit on June 5, 2007 for the Tygart No. 1 underground longwall mine and preparation plant complex located on the Tygart property. Following an appeal filed by anti-mining activists, the WV Surface Mine Board remanded the permit for additional modifications. The modified permit application was approved in April 2008 and mine site development commenced. A subsequent appeal by the same activists to the WV Surface Mine Board resulted in the suspension of the permit in October 2008 and cessation of construction activity. A modified permit was reissued on May 27, 2009 by the WVDEP, and is again under appeal by the same activists.

Construction of our Tygart No. 1 mining complex is not expected to resume until permit appeals have been exhausted and market conditions justify the additional production. Resumption of work is not currently expected before 2011. At full production, Tygart No. 1 is expected to produce 3.5 million tons annually of high quality coal that is well suited to both the utility market and the high volatile metallurgical market.

Upshur Property

The Upshur Property, located in Northern Appalachia, contains approximately 93.0 million tons of non-reserve coal deposits in the Middle and Lower Kittanning seams. Due to unique geologic characteristics and coal quality constraints, Upshur is a potential location for an on-site power plant. Some preliminary research, including air quality monitoring, has been completed as part of conceptual planning for the future construction of a circulating fluidized bed power plant at Upshur.

Big Creek Property

Our Big Creek reserve, located in Central Appalachia, covers 10,000 acres of leased coal lands located north of the town of Richlands in Tazewell County, Virginia. Total recoverable reserves are 25.9 million tons in the Jawbone and War Creek seams. The Big Creek reserve is all leased from Southern Regional Industrial Realty. The War Creek mine, which is permitted as a room-and-pillar mining operation, is expected to be developed in the future as market conditions warrant. We receive an overriding royalty on coalbed methane production from this property.

Jennie Creek Property

The Jennie Creek reserve, located in Mingo County, West Virginia, is a 44.9 million ton reserve of surface and deep mineable steam coal. This property contains 14.7 million tons of surface mineable, low sulfur coal reserves and 30.2 million tons of high-Btu, mid-sulfur underground reserves in the Alma seam. Efforts are underway to secure an Army Corps of Engineers Section 404 authorization to complete permitting for surface mining on this property. Our Section 404 permit application is currently under enhanced review by the Environmental Protection Agency and the Army Corps of Engineers. We intend to produce the coal by mountaintop, contour and highwall mining. Also, permitting is now in progress for an Alma seam underground mine on this Central Appalachian property.

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Illinois Basin Mining Operations

Below is a map showing the location and access to our coal properties in the Illinois Basin as of December 31, 2009:

Illinois operates one large underground coal mine, the Viper mine, in central Illinois. Viper commenced mining operations in 1982 and produces coal from the Illinois No. 5 Seam, also referred to as the Springfield Seam. Viper controls approximately 46.1 million tons of coal reserves. Approximately 82% of the coal reserves are leased, while 18% are owned in fee. The leases are retained by annual minimum payments and by tonnage-based royalty payments.

The Viper mine is a room-and-pillar operation, utilizing continuous miners and battery coal haulers. All of the raw coal is processed at Viper's preparation plant and shipped by truck to utility and industrial customers located in North Central Illinois. A major rail line is located a short distance from the plant, giving Viper the option of constructing a rail loadout. Shipments to electric utilities account for approximately 68% of coal sales.

Illinois has begun the development of a new portal facility that will allow it to eliminate the operation and maintenance of over five miles of underground beltlines and to seal and close the previously mined area.

As of December 31, 2009, this mine had 287 employees.

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Other Operations

Brokered coal sales

In addition to the coal we mine, we purchase and resell coal produced by third parties to fulfill certain sales obligations.

ADDCAR Systems

In our highwall mining business, we have four systems in operation using our patented ADDCAR highwall mining system and intend to build additional ADDCAR systems as required. ADDCAR(TM) is the registered trademark of ICG. The ADDCAR highwall mining system is an innovative and efficient mining system often deployed at reserves that cannot be economically mined by other methods.

A typical ADDCAR highwall mining system consists of a launch vehicle, continuous miner, conveyor cars, a stacker conveyor, electric generator, water tanker for cooling and dust suppression and a wheel loader with forklift attachment.

A five person crew operates the entire ADDCAR highwall mining system with control of the continuous miner being performed remotely by one person from the climate-controlled cab. Our system utilizes a navigational package to provide horizontal guidance, which helps to control rib width, and thus roof stability. In addition, the system provides vertical guidance for avoiding or limiting out of seam dilutions. The ADDCAR highwall mining system is equipped with high-quality video monitors to provide the operator with visual displays of the mining process from inside each entry being mined.

The mining cycle begins by aligning the ADDCAR highwall mining system onto the desired heading and starting the entry. As the remotely controlled continuous miner penetrates the coal seam, ADDCAR conveyor cars are added behind it, forming a continuous cascading conveyor train. This continues until the entry is at the planned full depth of up to 1,200 to 1,500 feet. After retraction, the launch vehicle is moved to the next entry, leaving a support pillar of coal between entries. This process recovers as much as 65% of the reserves while keeping all personnel outside the coal seam in a safe working environment. A wide range of seam heights can be mined with high production in seams as low as 3.5 feet and as high as 15 feet in a single pass. If the seam height is greater than 15 feet, then multi-lifts can be mined to create an unlimited entry height. The navigational features on the ADDCAR highwall mining system allow for multi-lift mining while ensuring that the designed pillar width is maintained.

During the mining cycle, in addition to the tramming effort provided by the crawler drive of the continuous miner, the ADDCAR highwall mining system increases the cutting capability of the machine through additional forces provided by hydraulic cylinders which transmit thrust to the back of the miner through blocks mounted on the side of the conveyor cars. This additional energy allows the continuous miner to achieve maximum cutting and loading rates as it moves forward into the seam.

In addition to its standard highwall mining system, ADDCAR has also developed a narrow bench highwall mining system and a steep-dip highwall mining system. The narrow bench highwall mining system has a smaller operational footprint that allows operation on narrower mine benches that are often found in Appalachia. The first ADDCAR narrow bench highwall mining system was placed in operation in 2007. The steep-dip highwall mining system allows for mining in steeply dipping coal seams often found in the western U.S. and Canada. The first ADDCAR steep-dip highwall mining system was delivered to a Canadian customer in 2009.

We currently have the exclusive North American distribution rights, as well as certain international patent rights acquired in the third quarter of 2009, for the ADDCAR highwall mining system.

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Coalbed methane

Our subsidiary, CoalQuest, has entered into a lease and joint operating agreement pursuant to which it leases coalbed methane, which is pipeline quality gas that resides in coal seams, and participates in certain coalbed methane wells, from its properties in Barbour, Harrison and Taylor counties in West Virginia. The first production well owned in part by CoalQuest began commercial operations in June 2006 and ten additional wells partially owned by CoalQuest were brought online by the end of 2007. Our coalbed methane lessee developed other wells in which CoalQuest is not a partial owner. In the eastern United States, conventional natural gas fields are typically located in various sedimentary formations at depths ranging from 2,000 to 15,000 feet. Exploration companies often put capital at risk by searching for gas in commercially exploitable quantities at these depths. By contrast, the coal seams from which we recover coalbed methane are typically less than 1,000 feet deep and are usually better defined than deeper formations. We believe that this contributes to lower exploration costs than those incurred by producers that operate in deeper, less defined formations. We believe this project is part of the first application of proprietary horizontal drilling technology for coalbed methane in northern West Virginia coalfields. We have not filed reserve estimates with any federal agency.

We receive an overriding royalty on coalbed methane production from the Crab Orchard Coal Company and Beaver Coal Company coal reserves leased by ICG Beckley in Raleigh County, West Virginia and from the leased Big Creek coal reserves in Tazewell County, Virginia. We also lease coalbed methane from certain of our properties in Kentucky and will receive rents and royalties on future production.

Customers and Coal Contracts

Customers

Our primary customers are investment grade electric utility companies primarily in the eastern half of the United States. The majority of our customers purchase coal for terms of one year or longer, but we also supply coal on a short-term spot basis for some of our customers. Our three largest customers for the year ended December 31, 2009 were Progress Energy, Georgia Power and Santee Cooper and we derived approximately 36% of our revenues from sales to our five largest customers. We did not derive more than 10% of our revenues from any single customer in 2009.

Long-term coal supply agreements

As is customary in the coal industry, we enter into long-term supply contracts (exceeding one year in duration) with many of our customers when market conditions are appropriate. These contracts allow customers to secure a supply for their future needs and provide us with greater predictability of sales volumes and prices. For the year ended December 31, 2009, approximately 89% of our coal sales revenues were derived from long-term supply contracts. We sell the remainder of our coal through short-term contracts and on the spot market. We have also entered into certain brokered transactions to purchase certain amounts of coal to meet our sales commitments. These purchase coal contracts expire in 2010 and are expected to provide us a minimum of approximately 0.5 million tons of coal through the remaining lives of the contracts.

We have certain contracts which are below current market rates because they were entered into during periods of suppressed coal prices. As the net costs associated with producing coal have increased due to higher energy, transportation and steel prices, the price adjustment mechanisms within several of our long-term contracts do not reflect current market prices. This has resulted in certain counterparties to these contracts benefiting from below-market prices for our coal.

The terms of our coal supply agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these contracts vary significantly by customer, including price adjustment features, price reopener terms, coal quality requirements, quantity adjustment mechanisms, permitted sources of supply, future regulatory changes, extension options, force majeure provisions and termination and assignment provisions.

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Some of our long-term contracts provide for a pre-determined adjustment to the stipulated base price at times specified in the agreement or at other periodic intervals to account for changes due to inflation or deflation in prevailing market prices.

In addition, most of our contracts contain provisions to adjust the base price due to new statutes, ordinances or regulations that impact our costs related to performance of the agreement. Also, some of our contracts contain provisions that allow for the recovery of costs impacted by modifications or changes in the interpretations or application of any applicable government statutes.

Price reopener provisions are present in several of our long-term contracts. These price reopener provisions may automatically set a new price based on prevailing market price or, in some instances, require the parties to agree on a new price, sometimes within a specified range of prices. In a limited number of agreements, failure of the parties to agree on a price under a price reopener provision can lead to termination of the contract. Under some of our contracts, we have the right to match lower prices offered to our customers by other suppliers.

Quality and volumes for the coal are stipulated in coal supply agreements and, in some instances, buyers have the option to vary annual or monthly volumes. Most of our coal supply agreements contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics such as heat content, sulfur, ash, hardness and ash fusion temperature. Failure to meet these specifications can result in economic penalties, suspension or cancellation of shipments or termination of the contracts.

Transportation/Logistics

We ship coal to our customers by rail, truck or barge. We typically pay the transportation costs for our coal to be delivered to the barge or rail loadout facility, where the coal is then loaded for final delivery. Once the coal is loaded in the barge or railcar, our customer is typically responsible for the freight costs to the ultimate destination. Transportation costs vary greatly based on the customer’s proximity to the mine and our proximity to the loadout facilities. We use a variety of independent companies for our transportation needs and typically enter into multiple agreements with transportation companies throughout the year.

In 2009, approximately 99% of our coal (both produced and purchased) from our Central Appalachian operations was delivered to our customers by rail generally on either the Norfolk Southern or CSX rail lines, with the remaining 1% delivered by truck. For our Illinois Basin operations, all of our coal was delivered by truck to customers, generally within an 80 mile radius of our Illinois mine.

We believe we enjoy good relationships with rail carriers and barge companies due, in part, to our modern coal-loading facilities and the experience of our transportation and distribution employees.

Suppliers

In 2009, we spent more than $324.6 million to procure goods and services in support of our business activities, excluding capital expenditures. Principal commodities include maintenance and repair parts and services, fuel, roof control and support items, explosives, tires, conveyance structure, ventilation supplies and lubricants. Our outside suppliers perform a significant portion of our equipment rebuilds and repairs both on- and off-site, as well as construction and reclamation activities.

Each of our regional mining operations has developed its own supplier base consistent with local needs. We have a centralized sourcing group for major supplier contract negotiation and administration, for the negotiation and purchase of major capital goods and to support the business units. The supplier base has been relatively stable for many years, but there has been some consolidation. We are not dependent on any one supplier in any region. We promote competition between suppliers and seek to develop relationships with those suppliers whose focus is on lowering our costs. We seek suppliers who identify and concentrate on implementing continuous improvement opportunities within their area of expertise.

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## Competition

The coal industry is intensely competitive. Our main competitors are Massey Energy Company, Arch Coal, Consol Energy, Alpha Natural Resources, James River Coal Company, Patriot Coal Corporation and various other smaller, independent producers. The most important factors on which we compete are coal price at the mine, coal quality and characteristics, transportation costs and the reliability of supply. Demand for coal and the prices that we are able to obtain for our coal are closely linked to coal consumption patterns of the domestic electric generation industry, which accounted for approximately 93% of domestic coal consumption in 2008. These coal consumption patterns are influenced by factors beyond our control, including the demand for electricity which is significantly dependent upon economic activity, weather patterns in the United States, government regulation, technological developments and the location, availability, quality and price of competing sources of coal, changes in international supply and demand, alternative fuels such as natural gas, oil and nuclear and alternative energy sources, such as hydroelectric power.

## Employees

As of December 31, 2009, we had 2,562 employees of which 24% were salaried and 76% were hourly. We believe our relationship with our employees is positive. Our entire workforce is union free.

## Reclamation

Reclamation expenses are a significant part of any coal mining operation. Prior to commencing mining operations, a company is required to apply for numerous permits in the state where the mining is to occur. Before a state will approve and issue these permits, it typically requires the mine operator to present a reclamation plan which meets regulatory criteria and to secure a surety bond to guarantee performance of reclamation in an amount determined under state law. Bonding companies also require posting of collateral, typically in the form of letters of credit, to secure the surety bonds. As of December 31, 2009, we had $61.1 million in letters of credit supporting our reclamation surety bonds. While bonds are issued against reclamation liability for a particular permit at a particular site, collateral posted in support of the bond is not allocated to a specific bond, but instead is part of a collateral pool supporting all bonds issued by that particular insurer. Bonds are released in phases as reclamation is completed in a particular area.

## Environmental, Safety and Other Regulatory Matters

Federal, state and local authorities regulate the U.S. coal mining industry with respect to matters such as permitting and licensing requirements, employee health and safety, air quality standards, water pollution, plant and wildlife protection, the reclamation and restoration of mining properties after mining has been completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects of mining on groundwater quality and availability. These laws and regulations have had, and will continue to have, a significant effect on our costs of production and competitive position. Future legislation, regulations or orders may be adopted or become effective which may adversely affect our mining operations, cost structure or the ability of our customers to use coal. For instance, new legislation, regulations or orders, as well as future interpretations and more rigorous enforcement of existing laws, may require substantial increases in equipment and operating costs to us and delays, interruptions or a termination of operations, the extent of which we cannot predict. Future legislation, regulations or orders or negative perceptions due to environmental issues may also cause coal to become a less attractive fuel source, resulting in a reduction in coal's share of the market for fuels used to generate electricity.

We endeavor to conduct our mining operations in compliance with all applicable federal, state and local laws and regulations. However, due in part to the extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time in the industry and at our operations.

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Mining Permits and Approvals

Numerous governmental permits or approvals are required for mining operations. In connection with obtaining these permits and approvals, we may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production or processing of coal may have upon the environment. The requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations and could have a material adverse effect on our business. Applications for permits are subject to public comment and may be subject to litigation from third parties seeking to deny issuance of a permit, which may also delay commencement or continuation of mining operations and could have a material adverse effect on our business. Regulations also provide that a mining permit or modification can be delayed, refused or revoked if an officer, director or a stockholder with a 10% or greater interest in the entity is affiliated with or is in a position to control another entity that has outstanding permit violations. Thus, past or ongoing violations of federal and state mining laws could provide a basis to revoke existing permits and to deny the issuance of additional permits.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators must also submit a comprehensive plan for mining and restoring, upon the completion of mining operations, the mined property to its prior condition, productive use or other permitted condition. Typically, we submit our necessary mining permit applications for our planned mines promptly upon securing the necessary property rights and required geologic and environmental data. In our experience, mining permit approvals generally require 12 to 18 months after initial submission; however, in the current regulatory environment, with enhanced scrutiny by regulators, increased opposition by environmental groups and others and potential resultant delays and permit application denials, we now anticipate that mining permit approvals will take even longer than previously experienced, and some permits may not be issued at all. Significant delays in obtaining, or denial of, permits could have a material adverse effect on our business.

Surface Mining Control and Reclamation Act

The Surface Mining Control and Reclamation Act of 1977 ("SMCRA"), which is administered by the Department of Interior's Office of Surface Mining Reclamation and Enforcement ("OSM"), establishes mining, environmental protection and reclamation standards for all aspects of surface mining, as well as for the surface effects of deep mining. Mine operators must obtain SMCRA permits and permit renewals from the OSM, or the appropriate state regulatory agency, for authorization of certain mining operations that result in a disturbance of the surface. If a state adopts a regulatory program as comprehensive as the federal mining program under SMCRA, the state becomes the regulatory authority. States in which we have active mining operations have achieved primary control of enforcement through federal approval of the state program.

SMCRA permit provisions include requirements for coal prospecting, mine plan development, topsoil removal, storage and replacement, selective handling of overburden materials, mine pit backfilling and grading, protection of the hydrologic balance, subsidence control for underground mines, surface drainage control, mine drainage and mine discharge control and treatment and revegetation. These requirements seek to limit the adverse impacts of coal mining and more restrictive requirements may be adopted from time to time.

The mining permit application process is initiated by collecting baseline data to adequately characterize the pre-mine environmental condition of the permit area. This work includes surveys of cultural resources, soils, vegetation, wildlife, assessment of surface and ground water hydrology, climatology and wetlands. In conducting this work, we collect geologic data to define and model the soil and rock structures and coal that we will mine. We develop mine and reclamation plans by utilizing this geologic data and incorporating elements of the environmental data. The mine and reclamation plan incorporates the provisions of SMCRA, the state programs and the complementary environmental programs that impact coal mining.

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Also included in the permit application are documents defining ownership and agreements pertaining to coal, minerals, oil and gas, water rights, rights of way and surface land, and documents required by the OSM's Applicant Violator System, including the mining and compliance history of officers, directors and principal owners of the entity.

Once a permit application is prepared and submitted to the regulatory agency, it goes through a completeness review and technical review. Public notice and opportunity for public comment on a proposed permit is required before a permit can be issued. Some SMCRA mine permits take over a year to prepare, depending on the size and complexity of the mine and typically take 12 to 18 months, or even longer, to be issued. Regulatory authorities have considerable discretion in the timing of the permit issuance and the public has rights to comment on, and otherwise engage in, the permitting process, including through intervention in the courts. From time to time, litigation is brought to modify, revoke or enjoin the issuance of SMCRA and other permits. For example, our Hazard Thunder Ridge permit was previously the subject of litigation seeking to enjoin the construction of certain valley fills, and our Tygart Valley surface mine permit is currently being administratively appealed by an anti-mining activist group.

Before a SMCRA permit is issued, a mine operator must submit a bond or otherwise secure the performance of reclamation obligations. The Abandoned Mine Land Fund, which is part of SMCRA, requires a fee on all coal produced. The proceeds are used to reclaim mine lands closed or abandoned prior to 1977. On December 7, 2006, the Abandoned Mine Land Program was extended for 15 years.

SMCRA stipulates compliance with many other major environmental statutes, including: the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act ("RCRA"), and the Comprehensive Environmental Response, Compensation and Liability Act ("Superfund").

Surety Bonds

Federal and state laws require us to obtain surety bonds to secure payment of certain long-term obligations, including mine closure or reclamation costs, coal leases and other miscellaneous obligations. Many of these bonds are renewable on a yearly basis.

Surety bond costs have increased in recent years while the market terms of such bonds have generally become more unfavorable. In addition, the number of companies willing to issue surety bonds has decreased. Bonding companies also require posting of collateral, typically in the form of letters of credit, to secure the surety bonds. As of December 31, 2009, we had $61.1 million in letters of credit supporting our reclamation surety bonds.

Clean Air Act

The federal Clean Air Act, and comparable state laws that regulate air emissions, directly affect coal mining operations, but have a far greater indirect effect. Direct impacts on coal mining and processing operations may occur through permitting requirements and/or emission control requirements relating to particulate matter, such as fugitive dust, or fine particulate matter measuring 2.5 micrometers in diameter or smaller. The Clean Air Act indirectly affects coal mining operations by extensively regulating the air emissions of sulfur dioxide, nitrogen oxides, mercury and other compounds emitted by coal-fired electricity generating plants and coke ovens. Proposed regulations would also subject greenhouse gas emissions to regulation under the Clean Air Act. The general effect of such extensive regulation of emissions from coal-fired power plants could be to reduce demand for coal.

Clean Air Act requirements that may directly or indirectly affect our operations include the following:

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Acid Rain

Title IV of the Clean Air Act required a two-phase reduction of sulfur dioxide emissions by electric utilities. Phase II became effective in 2000 and extended the Title IV requirements to all coal-fired power plants with generating capacity greater than 25 megawatts. The affected electricity generators have sought to meet these requirements by, among other compliance methods, switching to lower sulfur fuels, installing pollution control devices, reducing electricity generating levels or purchasing sulfur dioxide emission allowances. We cannot accurately predict the effect of these provisions of the Clean Air Act on us in future years. At this time, we believe that implementation of Phase II has resulted in an upward pressure on the price of lower sulfur coals as coal-fired power plants continue to comply with the more stringent restrictions of Title IV.

Criteria Pollutants

The Clean Air Act authorizes the U.S. Environmental Protection Agency (the "EPA") to set standards, referred to as National Ambient Air Quality Standards ("NAAQS") for pollutants. Among the pollutants for which standards have been adopted (criteria pollutants) are sulfur dioxide, nitrogen oxides, ozone, particulate matter and fine particulates. Areas that are not in compliance with these standards (non-attainment areas) must take steps to reduce emissions levels. The EPA is required to regularly review these standards and may revise them following such reviews. Revisions to the standards typically make them more stringent and increase compliance costs as they are implemented.

Following identification of non-attainment areas, each individual state will identify the sources of emissions and develop emission reduction plans. These plans may be state-specific or regional in scope. Future regulation and enforcement of the most recent ozone and PM2.5 standards will affect many power plants, especially coal-fired plants and all plants in non-attainment areas.

Significant additional emissions control expenditures will be required at coal-fired power plants to meet the current NAAQS for ozone. Nitrogen oxides, which are a by-product of coal combustion, can lead to the creation of ozone. Accordingly, emissions control requirements for new and expanded coal-fired power plants and industrial boilers will continue to become more demanding in the years ahead.

New source review requirements, which are imposed on major sources of pollutants, such as coal-fired power plants, and new source performance standards also impose control and emission requirements.

Installation of additional control measures, such as selective catalytic reduction devices, will make it more costly to operate coal-fired electricity generating plants and industrial boilers, thereby making coal a less attractive fuel and reducing demand for our products.

Mercury

The EPA has announced that it intends to initiate a rulemaking to adopt technology-based standards for mercury emissions from coal-fired power plants in response to a court order which vacated and remanded its 2005 Clean Air Mercury Rule, which would have reduced mercury emissions from such plants by a nationwide average of nearly 70%. The parties that overturned this rule seek even greater reductions in mercury emissions uniformly applied to all power plants. Some parties contend that during the pendency of this rulemaking, these plants are subject to mercury emission limitations determined on a case-by-case basis applying maximum achievable control technology.

Other proposals for controlling mercury emissions from coal-fired power plants have been made, such as establishing state or regional emission standards. If these proposals were enacted, the mercury content and variability of our coal would become a factor in future sales and could reduce demand for our products. In addition, seven Northeastern states have prepared and submitted to the EPA a Northeast Regional Mercury Total Maximum Daily Load to reduce mercury in natural water courses by reducing air deposition of mercury primarily from coal-fired power plants in the Midwest.

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Regional Haze

The EPA has initiated a regional haze program designed to protect and improve visibility at and around national parks, national wilderness areas and international parks. This program restricts the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas. Moreover, this program may require certain existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxides, volatile organic chemicals and particulate matter. These limitations could affect the future market for coal.

Climate Change

Global climate change concerns have a potentially far-reaching impact upon our business, including our reputation and results of operations. Concerns over measurements, estimates and projections of global climate change, particularly global warming, have resulted in widespread calls for the reduction, by regulation and voluntary measures, of the emission of greenhouse gases, which include carbon dioxide and methane. These measures could impact the market for our coal and coalbed methane, increase our own energy costs and affect the value of our coal reserves. The United States has not ratified the Framework Convention on Global Climate Change, commonly known as the Kyoto Protocol, which would require our nation to reduce greenhouse gas emissions to 93% of 1990 levels by 2012. The United States is participating in international discussions to develop a treaty or other agreement to require reductions in greenhouse gas emissions after 2012 and has signed the Copenhagen Accord, which includes a non-binding commitment to reduce greenhouse gas emissions.

The U.S. Congress is considering a variety of legislative proposals which would restrict and/or tax the emission of greenhouse gases from the combustion of coal and other fuels and which would mandate or encourage the generation of electricity by new facilities that do not use coal.

A step toward potential federal restriction on greenhouse gas emissions was taken on December 7, 2009 when the EPA issued its so-called Endangerment Finding in response to a decision of the Supreme Court of the United States. The EPA found that the emission of six greenhouse gases, including carbon dioxide (which is emitted from coal combustion) and methane (which is emitted from coal beds) may reasonably be anticipated to endanger public health and welfare. Based on this finding, EPA defined the mix of these six greenhouse gases to be “air pollution” subject to regulation under the Clean Air Act. Although EPA has stated a preference that greenhouse gas regulation be based on new federal legislation rather than the existing Clean Air Act, many sources of greenhouse gas emissions may be regulated without the need for further legislation. The EPA has already proposed regulations that would impact major stationary sources of greenhouse gas emissions, including coal-fired power plants, that could come into effect as early as March 2010.

In addition to materially adversely impacting our markets and the demand for our products, regulations enacted due to climate change concerns could affect our operations by increasing our costs. Our energy costs could increase and we may have to incur higher costs to control emissions of carbon dioxide, methane or other pollutants from our operations.

While advocating for comprehensive federal legislation, many states have adopted measures, sometimes as part of a regional collaboration, to reduce greenhouse gases generated within their own jurisdiction. These measures include emission regulations, including regional cap and trade programs, mandates for utilities to generate a portion of their electricity without using coal and incentives or goals for generating electricity using renewable resources. Some municipalities have also adopted similar measures. Even in the absence of mandatory requirements, some entities are electing to purchase electricity generated by renewable resources for a variety of reasons, including participation in programs calling for voluntary reductions in greenhouse gas emissions.

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Passage of additional state or federal laws or regulations regarding greenhouse gas emissions or other actions to limit greenhouse gas emissions could result in fuel switching, from coal to other fuel sources, by electric generators. Such laws and regulations could, for example, include mandating decreases in greenhouse gas emissions from coal-fired power plants, imposing taxes on greenhouse gas emissions, requiring certain technology to capture and sequester greenhouse gases from new coal-fired power plants and encouraging the production of non-coal-fired power plants. Political and regulatory uncertainty over future emissions controls have been cited as major factors in decisions by power companies to postpone new coal-fired power plants. If measures such as these or other similar measures, like controls on methane emissions from coal mines, are ultimately imposed on the coal industry by federal or state governments or pursuant to international treaty, our operating costs may be materially and adversely affected. Similarly, alternative fuels (non-fossil fuels) could become more attractive than coal in order to reduce greenhouse gas emissions, which could result in a reduction in the demand for coal and, therefore, our revenues.

Clean Water Act

The federal Clean Water Act ("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 and jurisdictional waters. The CWA establishes instream water quality standards, including anti-degradation 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.

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 conducting any instream activities, including installing culverts, creating water impoundments, constructing refuse areas, creating slurry ponds, placing valley fills or performing other mining activities. Jurisdictional waters typically include intermittent and perennial streams and may, in certain instances, include man-made conveyances that have a hydrologic connection to a stream or wetland. The Army Corps of Engineers ("ACOE") authorizes instream activities under either a general "nationwide" permit or under an individual permit, based on the expected environmental impact. A nationwide permit may be issued for specific categories of filling activity that are determined to have minimal environmental adverse effects; however, the effective term of such permits is limited to no longer than five years. Nationwide Permit 21 authorizes the disposal of dredge-and-fill material from mining activities into the waters of the United States. An individual permit typically requires a more comprehensive application process than a nationwide permit, including public notice and comment, but an individual permit can be issued for the project life. We have secured nationwide permits and individual permits, depending on the expected duration and timing of the proposed instream activity. We do not expect to seek further Nationwide Permit 21 authorizations for our relevant operations, but will apply for individual permits.

The coal mining industry, and on occasion our operations, have been subject to litigation to prevent, restrict or delay the issuance of permits under the Clean Water Act. This litigation has resulted in more voluminous and costly permit applications and requirements and delays in obtaining permits.

On July 15, 2009 the ACOE proposed to modify NWP 21 to preclude its use in a six-state Appalachian region, including Kentucky and West Virginia. This action was taken pursuant to a June 11, 2009 memorandum of understanding ("MOU") entered into by OSM, the EPA and ACOE to implement an interagency plan to significantly reduce the harmful environmental consequences of Appalachian surface coal mining.

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In accordance with the MOU, on November 30, 2009, the OSM published an Advance Notice of Proposed Rulemaking announcing its intent to revise the stream buffer zone rule. Certain of the proposed alternatives would effectively prohibit the placement of materials generated by coal mining into intermittent or perennial streams, which practice is essential to surface mining in central Appalachia. A prohibition against excess spoil placement in such streams would essentially eliminate surface mining in steep terrain, thus rendering much of our coal reserves unmineable. Restrictions on the placement of coal refuse material in such streams could limit the life of existing coal processing operations, potentially block new coal preparation plants and at minimum significantly increase our operating costs.

Also subsequent to the MOU, in September 2009, the EPA announced that 79 pending permit applications for Appalachian coal mining warranted further review because of continuing concerns about water quality and/or regulatory compliance issues. These include four of our permit applications: Eastern Jennie Creek Surface Mine, Hazard Rowdy Gap Surface Mine and Bearville North Surface Mine, and Knott County. While the EPA has stated that its identification of these 79 permits does not constitute a determination that the mining involved cannot be permitted under the Clean Water Act and does not constitute a final recommendation from the EPA to the ACOE on these projects, it is unclear how long the further review will take for our four permits or what the final outcome will be. It is also unclear what impact this process may have on our future applications for surface coal mining permits. Excessive delays in permitting may require adjustment of our production budget and mining plans.

Judge Robert C. Chambers of the U.S. District Court for the Southern District of West Virginia ruled in March 2007 in a lawsuit filed by several citizen groups against the ACOE that the ACOE failed to adequately assess the impacts of surface mining on headwaters and approved mitigation that did not appropriately compensate for stream losses. Judge Chambers in June 2007 found that sediment ponds situated within a stream channel violated the prohibition against using the waters of the U.S. for waste treatment and further decided that using the reach of stream between a valley fill and the sediment pond to transport sediment-laden runoff is prohibited by the Clean Water Act. In February 2009, the Fourth Circuit Court of Appeals overturned these decisions and remanded the case for further proceedings. On August 26, 2009 the citizen groups petitioned the Supreme Court for a writ of certiorari. Replies to the writ of certiorari from the ACOE and the intervenors are due March 9, 2010. Additionally, in November 2009, Judge Chambers invalidated two additional permits in a parallel case based on a finding that the public notices of the applications did not provide sufficient information on the proposed mitigation plan to allow meaningful public comment.

On December 6, 2007, the Sierra Club and Kentucky Waterways Alliance sued the ACOE in the U.S. District Court for the Western District of Kentucky alleging that the ACOE Louisville District wrongfully issued a Section 404 authorization to Hazard's Thunder Ridge surface mine in Perry County, Kentucky. The plaintiffs, who were represented by the same counsel as the plaintiffs in the Chambers lawsuit, made essentially the same claims but added the charge that the ACOE violated the National Environmental Policy Act requirement that stream impacts first must be avoided or in the alternative minimized. On December 26, 2007, the ACOE suspended the Section 404 permit to allow it to review and supplement as needed the administrative record on which the permit decision is based. Hazard prepared and submitted supplemental information, including a watershed scale cumulative impact assessment and a site-specific fill minimization plan, for the ACOE's consideration in 2008. The ACOE reissued the Section 404 authorization in March 2009. An agreement was executed on November 13, 2009 between the plaintiffs and Hazard that allowed Hazard to proceed with development of the remaining valley fills in exchange for certain changes to the mine reclamation plan along with a $50,000 contribution to a local watershed restoration project. The court accepted the settlement and entered an order on November 20, 2009 dismissing the litigation.

On October 23, 2003, several citizens groups sued the ACOE in the U.S. District Court for the Southern District of West Virginia seeking to invalidate nationwide permits utilized by the ACOE and the coal industry for permitting most instream disturbances associated with coal mining, including excess spoil valley fills and refuse impoundments. Although the lower court enjoined the issuance of authorizations under Nationwide Permit 21, that decision was overturned by the Fourth Circuit Court of Appeals, which concluded that the ACOE complied with the Clean Water Act in promulgating Nationwide Permit 21. While this case remained dormant since the appeals court decision, the judge asked the parties to brief the court regarding the effects of the Chambers' decision on the Nationwide Permit 21 program. The requested briefs were filed in 2008 and the case is pending decision or further directive by the court.



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A lawsuit making similar claims regarding the Nationwide Permit 21 filed in the United States Court for the Eastern District of Kentucky by a number of environmental groups is still pending. This suit also seeks, among other things, an injunction preventing the ACOE from authorizing pursuant to Nationwide Permit 21 "further discharges of mining rock, dirt or coal refuse into valley fills or surface impoundments" associated with certain specific mining permits, including permits issued to some of our mines in Kentucky. Granting of such relief would interfere with the further operation of these mines. The judge ordered a briefing schedule for the parties in this litigation.

In September 2008 the Sixth Circuit Court of Appeals partly affirmed and partly rejected a federal district court's decision that had upheld EPA's approval of Kentucky's new anti-degradation regulations. Anti-degradation regulations prohibit diminution of water quality in streams. The circuit court upheld Kentucky's methodology for designating high quality waters, even though environmental groups claimed the methodology resulted in too few high quality designations. The circuit court also affirmed Kentucky's designation method on a water body-by-water body approach and rejected environmentalist claims that such designations must be conducted on a parameter by parameter basis. The court also upheld Kentucky's exclusion of "impaired" waters from anti-degradation review. However, the circuit court struck down the district court's approval of Kentucky's alternative anti-degradation implementation procedures for coal mining. See "Legal Proceedings" contained in Item 3 of this Annual Report on Form 10-K. In addition, legislation has been introduced in the U.S. Congress that would restrict or prevent mountaintop mining.

Mine Safety and Health

Stringent health and safety standards have been in effect since Congress enacted the Coal Mine Health and Safety Act of 1969. The Federal Mine Safety and Health Act of 1977 significantly expanded the enforcement of safety and health standards and imposed safety and health standards on all aspects of mining operations. All of the states in which we operate have state programs for mine safety and health regulation and enforcement. Collectively, federal and state safety and health regulation in the coal mining industry is perhaps the most comprehensive and pervasive system for protection of employee health and safety affecting any segment of U.S. industry. The federal Mine Improvement and New Emergency Response Act of 2006 (the "MINER Act") was signed into law on June 15, 2006 and implementation of the specific requirements of the MINER Act is currently underway. The Mine Safety and Health Administration ("MSHA") issued an emergency temporary standard addressing sealing of abandoned areas in underground mines on May 22, 2007 and, on September 6, 2007, MSHA published a proposed rule that would implement Section 4 of the MINER Act by addressing composition and certification of mine rescue teams and improving their availability and training. While mine safety and health regulation has a significant effect on our operating costs, our U.S. competitors are subject to the same degree of regulation. However, pending legislation in various states could result in differing operating costs in different states and, therefore, our competitors operating in states with less stringent new legislation may not be subject to the same degree of regulation.

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator must secure payment of federal black lung benefits to claimants who are current and former employees and to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to July 1, 1973. The trust fund is funded by an excise tax on production of up to $1.10 per ton for underground coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price. The excise tax does not apply to coal shipped outside the United States. In 2009, we recognized $11.6 million of expense related to this excise tax.

Resource Conservation and Recovery Act

The RCRA affects coal mining operations by establishing requirements for the treatment, storage and disposal of hazardous wastes. Certain coal mine wastes, such as overburden and coal cleaning wastes, are exempted from hazardous waste management.

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Subtitle C of the RCRA exempted fossil fuel combustion byproducts from hazardous waste regulation until the EPA completed a report to Congress and, in 1993, made a determination on whether the combustion byproducts should be regulated as hazardous. In the 1993 regulatory determination, the EPA addressed some high volume-low toxicity coal combustion byproducts ("CCBs") generated at electric utility and independent power producing facilities, such as coal ash.

In May 2000, the EPA concluded that CCBs do not warrant regulation as hazardous waste under the RCRA and that the hazardous waste exemption applied to these CCBs. However, the EPA has determined that national non-hazardous waste regulations under the RCRA Subtitle D are needed for CCBs disposed in surface impoundments and landfills and used as mine-fill. The agency also concluded beneficial uses of these CCBs, other than for mine-filling, pose no significant risk and no additional national regulations are needed. However, the EPA has announced that it will issue a proposed rule to regulate the disposal of CCBs under the RCRA. As long as the exemption remains in effect, it is not anticipated that regulation of CCBs will have any material effect on the amount of coal used by electricity generators. Most state hazardous waste laws also exempt CCBs and instead treat them as either a solid waste or a special waste.

Due to the hazardous waste exemption for CCBs such as ash, some of the CCBs are currently put to beneficial use. For example, at certain mines, we sometimes use ash deposits from the combustion of coal as a beneficial use under our reclamation plan. The alkaline ash used for this purpose serves to help alleviate the potential for acid mine drainage. Also, we are paid to dispose of CCBs at our Illinois mine by our customers. Efforts continue by environmental groups and others for the adoption of more stringent disposal requirements for CCBs. Any increased costs associated with handling or disposal of CCBs would increase our customers' operating costs and potentially reduce their coal purchases. Increased regulation may cause us increased costs due to substitute reclamation materials or decreased revenue due to discontinuing disposal on behalf of our customers. In addition, contamination caused by the past disposal of ash can lead to material liability.

Federal and State Superfund Statutes

Superfund and similar state laws affect coal mining and hard rock operations by creating liability for investigation and remediation in response to releases of hazardous substances into the environment and for damages to natural resources caused by such releases. Under Superfund, joint and several liability may be imposed on waste generators, site owners or operators and others regardless of fault. In addition, mining operations may have reporting obligations under these laws.

Coal Industry Retiree Health Benefit Act of 1992

Unlike many companies in the coal business, we do not have significant liabilities under the Coal Industry Retiree Health Benefit Act of 1992 (the "Coal Act"), which requires the payment of substantial sums to provide lifetime health benefits to union-represented miners (and their dependents) who retired before 1992, because liabilities under the Coal Act that had been imposed on our predecessor or acquired companies were retained by the sellers and, if applicable, their parent companies in the applicable acquisition agreements, except for Anker Coal Group, Inc. ("Anker'). We should not be liable for these liabilities retained by the sellers unless they and, if applicable, their parent companies fail to satisfy their obligations with respect to Coal Act claims and retained liabilities covered by the acquisition agreements. Upon the consummation of the business combination with Anker, we assumed Anker's Coal Act liabilities, which were estimated to be $1.4 million at December 31, 2009.

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Endangered Species Act

The federal Endangered Species Act and counterpart state legislation protect species threatened with possible extinction. Protection of threatened and endangered species may have the effect of prohibiting or delaying us from obtaining mining permits and may include restrictions on timber harvesting, road building and other mining or agricultural activities in areas containing the affected species or their habitats. A number of species indigenous to our properties are protected under the Endangered Species Act. However, based on the species that have been identified to date and the current application of applicable laws and regulations, we do not believe there are any species protected under the Endangered Species Act that would materially and adversely affect our ability to mine coal from our properties in accordance with current mining plans.

Emergency Planning and Community Right to Know Act

Some of our subsidiary operations utilize materials and/or store substances that require certain reporting to local and state authorities under the federal Emergency Planning and Community Right to Know Act. If required reporting is missed, it can result in the assessment of fines and penalties. We do not believe that any potential fines or penalties that could potentially arise under the federal Emergency Planning and Community Right to Know Act would materially or adversely affect our ability to mine coal.

Other Regulated Substances

Some of our subsidiary operations utilize certain substances, such as ammonia or caustic soda, for managing water quality in discharges from their mine sites. These materials are considered hazardous and require safeguards in handling and use and, if present in sufficient quantities, create emergency planning and response requirements. The storage of petroleum products in certain quantities can also trigger reporting, planning and response requirements. Our subsidiaries are required to maintain careful control over the storage and use of these substances. The subsidiaries attempt to minimize the amount of materials stored at their operations that give rise to such concerns and to maximize the use of less hazardous materials whenever feasible. If quantities are sufficient, utilization of CCBs for reclamation can trigger certain reporting requirements for constituent trace elements contained in CCBs.

Additional Information

We file annual, quarterly and current reports, as well as amendments to those reports, proxy statements and other information with the Securities and Exchange Commission (“SEC”). You may access and read our SEC filings without charge through our website, www.intlcoal.com, or the SEC’s website, www.sec.gov. You may also read and copy any document we file at the SEC’s public reference room located at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at (800) SEC–0330 for further information on the public reference room. You may also request copies of our filings, at no cost, by telephone at (304) 760-2400 or by mail at: International Coal Group, Inc., 300 Corporate Centre Drive, Scott Depot, West Virginia 25560, Attention: Secretary.

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GLOSSARY OF SELECTED TERMS

Ash. Impurities consisting of silica, alumina, calcium, iron and other incombustible matter that are contained in coal. Since ash increases the weight of coal, it adds to the cost of handling and can affect the burning characteristics of coal.

Base load. The lowest level of power production needs during a season or year.

Bituminous coal. A middle rank coal (between sub-bituminous and anthracite) formed by additional pressure and heat on lignite. It is the most common type of coal with moisture content less than 20% by weight and heating value of 10,000 to 14,000 Btus per pound. It is dense and black and often has well-defined bands of bright and dull material. It may be referred to as soft coal.

British thermal unit or Btu. A measure of the thermal energy required to raise the temperature of one pound of pure liquid water one degree Fahrenheit at the temperature at which water has its greatest density (39 degrees Fahrenheit). On average, coal contains about 22 million Btu per ton.

By-product. Useful substances made from the gases and liquids left over when coal is changed into coke.

Central Appalachia. Coal producing area in eastern Kentucky, Virginia and southern West Virginia.

Clean coal burning technologies. A number of innovative, new technologies designed to use coal in a more efficient and cost-effective manner while enhancing environmental protection. Several promising technologies include fluidized-bed combustion, integrated gasification combined cycle, limestone injection multi-stage burner, enhanced flue gas desulfurization (or scrubbing), coal liquefaction and coal gasification.

Coal seam. A bed or stratum of coal. Usually applies to a large deposit.

Coke. A hard, dry carbon substance produced by heating coal to a very high temperature in the absence of air. Coke is used in the manufacture of iron and steel. Its production results in a number of useful byproducts.

Compliance coal. Coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million Btu, as required by Phase II of the Clean Air Act Acid Rain program.

Continuous miner. A machine that simultaneously extracts and loads coal. This is distinguished from a conventional, or cyclic, unit, which must stop the extraction process for loading to commence.

Deep mine. See Underground mine below.

Fluidized bed combustion. A process with a high success rate in removing sulfur from coal during combustion. Crushed coal and limestone are suspended in the bottom of a boiler by an upward stream of hot air. The coal is burned in this bubbling, liquid-like (or fluidized) mixture. Rather than released as emissions, sulfur from combustion gases combines with the limestone to form a solid compound recovered with the ash.

Fossil fuel. Fuel such as coal, crude oil or natural gas formed from the fossil remains of organic material.

High-Btu coal. Coal which has an average heat content of 12,500 Btus per pound or greater.

High sulfur coal. Coal which, when burned, emits 2.5 pounds or more of sulfur dioxide per million Btu.

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Highwall. The unexcavated face of exposed overburden and coal in a surface mine or in a face or bank on the uphill side of a contour mine excavation.

Illinois Basin. Coal producing area in Illinois, Indiana and western Kentucky.

Longwall mining. The most productive underground mining method in the United States. One of three main underground coal mining methods currently in use. Employs a rotating drum, or less commonly a steel plow, which is pulled mechanically back and forth across a face of coal that is usually about a thousand feet long. The loosened coal falls onto a conveyor for removal from the mine.

Low sulfur coal. Coal which, when burned, emits 1.6 pounds or less of sulfur dioxide per million Btu.

Medium sulfur coal. Coal which, when burned, emits between 1.6 and 2.5 pounds of sulfur dioxide per million Btu.

Metallurgical coal. The various grades of coal suitable for carbonization to make coke for steel manufacture. Also known as "met" coal, its quality depends on four important criteria: volatile matter, which affects coke yield; the level of impurities including sulfur and ash, which affects coke quality; composition, which affects coke strength; and basic characteristics, which affect coke oven safety. Met coal typically has a particularly high-Btu level, but low ash and sulfur content.

Nitrogen oxide (NOx). A gas formed in high temperature environments such as coal combustion. It is a harmful pollutant that contributes to acid rain.

Non-reserve coal deposits. Non-reserve coal deposits are coal bearing bodies that have been sufficiently sampled and analyzed, but do not qualify as a commercially viable coal reserve as prescribed by SEC rules until a final comprehensive SEC-prescribed evaluation is performed.

Northern Appalachia. Coal producing area in Maryland, Ohio, Pennsylvania and northern West Virginia.

Overburden. Layers of earth and rock covering a coal seam. In surface mining operations, overburden is removed prior to coal extraction.

Pillar. An area of coal left to support the overlying strata in a mine; sometimes left permanently to support surface structures.

Powder River Basin. Coal producing area in northeastern Wyoming and southeastern Montana. This is the largest known source of coal reserves and the largest producing region in the United States.

Preparation plant. Usually located on a mine site, although one plant may serve several mines. A preparation plant is a facility for crushing, sizing and washing coal to prepare it for use by a particular customer. The washing process has the added benefit of removing some of the coal's sulfur content.

Probable reserves. 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.

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Reclamation. The process of restoring land and environmental values to a mining site after the coal is extracted. Reclamation operations are usually underway where the resources have already been taken from a mine, even as production operations are taking place elsewhere at the site. This process commonly includes recontouring or reshaping the land to its approximate original appearance, restoring topsoil and planting native grasses, trees and ground covers. Mining reclamation is closely regulated by both state and federal law.

Recoverable reserve. The amount of coal that can be recovered from the Reserves. The recovery factor for underground mines is approximately 60% and for surface mines approximately 80% to 90%. Using these percentages, there are about 275 billion tons of recoverable reserves in the United States.

Reserve. That part of a mineral deposit that could be economically and legally extracted or produced at the time of the reserve determination.

Roof. The stratum of rock or other mineral above a coal seam; the overhead surface of a coal working place.

Room-and-pillar mining. A method of underground mining in which about half of the coal is left in place to support the roof of the active mining area. Large "pillars" are left at regular intervals while "rooms" of coal are extracted.

Scrubber (flue gas desulfurization system). Any of several forms of chemical/physical devices which operate to neutralize sulfur compounds formed during coal combustion. These devices combine the sulfur in gaseous emissions with other chemicals to form inert compounds, such as gypsum, that must then be removed for disposal. Although effective in substantially reducing sulfur from combustion gases, scrubbers require approximately 6% to 7% of a power plant's electrical output and thousands of gallons of water to operate.

Steam coal. Coal used by electric power plants and industrial steam boilers to produce electricity, steam or both. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal.

Sub-bituminous coal. Dull coal that ranks between lignite and bituminous coal. Its moisture content is between 20% and 30% by weight, and its heat content ranges from 7,800 to 9,500 Btus per pound of coal.

Sulfur. One of the elements present in varying quantities in coal that contributes to environmental degradation when coal is burned. Sulfur dioxide is produced as a gaseous by-product of coal combustion.

Tons. A "short," or net, ton is equal to 2,000 pounds. A "long," or British, ton is equal to 2,240 pounds. A "metric" ton is approximately 2,205 pounds. The short ton is the unit of measure referred to in this report.

Truck-and-shovel/loader mining. Similar forms of mining where large shovels or front-end loaders are used to remove overburden, which is used to backfill pits after the coal is removed. Smaller shovels load coal in haul trucks for transportation to the preparation plant or rail loadout.

Underground mine. Also known as a deep mine. Usually located several hundred feet below the earth's surface, an underground mine's resource is removed mechanically and transferred by conveyor to the surface. Most common in the coal industry, underground mines primarily are located east of the Mississippi River and account for approximately one-third of total annual U.S. coal production.

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ITEM 1A. RISK FACTORS

Risks Relating to Our Business

A decline in coal prices could reduce our revenues and the value of our coal reserves.

Our results of operations are dependent upon the prices we receive for our coal, as well as our ability to improve productivity and control costs. Any decreased demand would cause spot prices to decline and require us to increase productivity and decrease costs in order to maintain our margins. A decrease in the price we receive for our coal could adversely affect our operating results and our ability to generate the cash flows we require to meet our bank loan requirements, improve our productivity and invest in our operations. The prices we receive for coal depend upon factors beyond our control, including:

- supply of and demand for domestic and foreign coal;
- demand for electricity;
- domestic and foreign demand for steel and the continued financial viability of the domestic and/or foreign steel industry;
- proximity to, capacity of and cost of transportation facilities;
- domestic and foreign governmental legislation, regulations and taxes;
- air emission standards for coal-fired power plants;
- regulatory, administrative and judicial decisions;
- price and availability of alternative fuels, including the effects of technological developments; and
- effect of worldwide energy conservation measures.

Our coal mining operations are subject to operating risks that could result in decreased coal production, which could reduce our revenues.

Our revenues depend on our level of coal mining production. The level of our production is subject to operating conditions and events beyond our control that could disrupt operations and affect production at particular mines for varying lengths of time. These conditions and events include:

- unavailability of qualified labor;
- our inability to acquire, maintain or renew necessary permits or mining or surface rights in a timely manner, if at all;
- unfavorable geologic conditions, such as the thickness of the coal deposits and the amount of rock embedded in or overlying the coal deposits;
- failure of reserve estimates to prove correct;

- changes in governmental regulation of the coal industry, including the imposition of additional taxes, fees or actions to suspend or revoke our permits or changes in the manner of enforcement of existing regulations;

- mining and processing equipment failures and unexpected maintenance problems;

- adverse weather and natural disasters, such as heavy rains and flooding;

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- increased water entering mining areas and increased or accidental mine water discharges;
- increased or unexpected reclamation costs;
- interruptions due to transportation delays;
- unavailability of required equipment of the type and size needed to meet production expectations; and
- unexpected mine safety accidents, including fires and explosions.

These conditions and events may increase our cost of mining and delay or halt production at particular mines either permanently or for varying lengths of time.

Reduced coal consumption by North American electric power generators could result in lower prices for our coal, which could reduce our revenues and adversely impact our earnings and the value of our coal reserves.

Restrictions on the emission of greenhouse gases, including carbon dioxide, continue to be proposed and adopted by various legislative and regulatory bodies at federal, state and local levels of government and at the international level. The intended effect of these restrictions is to discourage the combustion of fossil fuels in general and the generation of electricity by coal in particular in favor of "alternative sources" of energy which do not involve the combustion of fossil fuels. For example, on June 26, 2009 the U.S. House of Representatives passed The American Clean Energy and Security Act of 2009 (House Bill 2454). If enacted, this bill would create or expand myriad federal programs designed to reduce energy produced by burning fossil fuels and increase alternative energy sources. In particular, the bill would reduce greenhouse gas emissions via a cap and trade system for larger emitters, including coal-fired power plants. A cap would be placed on overall U.S. greenhouse gas emissions beginning in 2012 and, compared to 2005 levels, would increasingly reduce emissions by 83 percent in 2050. The economic impact of the cost of this cap on coal users would be mitigated by allocating to electric utilities and certain other industries "free allowances" which would progressively decrease over time. A similar bill has been introduced in the U.S. Senate. The imposition of such a program, or the effect of negative public perceptions of coal due to climate change issues, may result in more electric power generators shifting from coal to natural gas-fired plants or alternative energy sources. Any reduction in the amount of coal consumed by North American electric power generators could reduce the price of steam coal that we mine and sell, thereby reducing our revenues and adversely impacting our earnings and the value of our coal reserves. The United States is participating in international discussions to develop a treaty or other agreement to require reductions in greenhouse gas emissions after 2012 and has signed the Copenhagen Accord, which includes a non-binding commitment to reduce greenhouse gas emissions.

A step toward potential restriction on greenhouse gas emissions under the Clean Air Act was taken on December 7, 2009 when the EPA issued its so-called Endangerment Finding. The EPA found that the emission of six greenhouse gases, including carbon dioxide (which is emitted from coal combustion) and methane (which is emitted from coal beds) may reasonably be anticipated to endanger public health and welfare. Based on this finding, the EPA defined the mix of these six greenhouse gases to be “air pollution” subject to regulation under the Clean Air Act. Although the EPA has stated a preference that greenhouse gas regulation be based on new federal legislation rather than the existing Clean Air Act, many sources of greenhouse gas emissions may be regulated without the need for further legislation. The EPA has already proposed regulations that would impact major stationary sources of greenhouse gas emissions, including coal-fired power plants, that could come into effect as early as March 2010.

Weather patterns also can greatly affect electricity generation. Extreme temperatures, both hot and cold, cause increased power usage and, therefore, increased generating requirements from all sources. Mild temperatures, on the other hand, result in lower electrical demand, which allows generators to choose the lowest-cost sources of power generation when deciding which generation sources to dispatch. Accordingly, significant changes in weather patterns could reduce the demand for our coal.

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Overall economic activity and the associated demands for power by industrial users can have significant effects on overall electricity demand. Robust economic activity can cause much heavier demands for power, particularly if such activity results in increased utilization of industrial assets during evening and nighttime periods. An economic slowdown can significantly slow the growth of electrical demand and, in some locations, result in contraction of demand. The economy suffered a significant slowdown in the fourth quarter of 2008 that resulted in lower demand. Any downward pressure on coal prices, whether due to increased use of alternative energy sources, changes in weather patterns, decreases in overall demand or otherwise, would likely cause our profitability to decline.

The capability and profitability of our operations may be adversely affected by the status of our long-term coal supply agreements and changes in purchasing patterns in the coal industry.

We sell a significant portion of our coal under long-term coal supply agreements, which we define as contracts with a term greater than 12 months. For the year ended December 31, 2009, approximately 89% of our coal sales revenues were derived from coal sales that were made under long-term coal supply agreements. As of that date, we had 40 long-term sales agreements with a volume-weighted average term of approximately 3.7 years. The prices for coal shipped under these agreements are typically fixed for at least the initial year of the contract, subject to certain adjustments in later years and thus may be below the current market price for similar type coal at any given time, depending on the timeframe of contract execution or initiation. As a consequence of the substantial volume of our sales that are subject to these long-term agreements, we have less coal available with which to capitalize on higher coal prices, if and when they arise. In addition, in some cases, our ability to realize the higher prices that may be available in the spot market may be restricted when customers elect to purchase higher volumes allowable under some contracts. When our current contracts with customers expire or are otherwise renegotiated, our customers may decide not to extend or enter into new long-term contracts or, in the absence of long-term contracts, our customers may decide to purchase fewer tons of coal than in the past or on different terms, including under different pricing terms.

Furthermore, as electric utilities seek to adjust to requirements of the Clean Air Act, and the potential for more stringent requirements, they could become increasingly less willing to enter into long-term coal supply agreements and instead may purchase higher percentages of coal under short-term supply agreements. To the extent the electric utility industry shifts away from long-term supply agreements, it could adversely affect us and the level of our revenues. For example, fewer electric utilities will have a contractual obligation to purchase coal from us, thereby increasing the risk that we will not have a market for our production. Furthermore, spot market prices tend to be more volatile than contractual prices, which could result in decreased revenues.

Certain provisions in our long-term supply agreements may provide limited protection during periods of adverse economic conditions. For example, the customer may be forced to reduce electricity output due to weak demand. If the low demand were to persist for an extended period, the customer might be forced to delay our contract shipments thereby reducing our revenue.

Price adjustment, price reopener and other similar provisions in long-term supply agreements may reduce the protection from short-term coal price volatility traditionally provided by such contracts. Most of our coal supply agreements contain provisions that allow for the purchase price to be renegotiated at periodic intervals. These price reopener provisions may automatically set a new price based on the prevailing market price or, in some instances, require the parties to agree on a new price, sometimes between a specified range of prices. In some circumstances, failure of the parties to agree on a price under a price reopener provision can lead to termination of the contract. Any adjustment or renegotiations leading to a significantly lower contract price would result in decreased revenues. Accordingly, supply contracts with terms of one year or more may provide only limited protection during adverse market conditions.

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Coal supply agreements also typically contain force majeure provisions allowing temporary suspension of performance by us or our customers during the duration of specified events beyond the control of the affected party. Additionally, most of our coal supply agreements contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as heat value (measured in Btus), sulfur content, ash content, hardness and ash fusion temperature. Failure to meet these specifications could result in economic penalties, including price adjustments, the rejection of deliveries or, in the extreme, termination of the contracts.

As the ongoing global economic recession has caused the price of, and demand for, coal to decline, certain of our coal customers have delayed shipments, or requested deferrals, pursuant to our existing long-term coal supply agreements. Other customers similarly may seek to delay shipments or request deferrals under existing agreements. In the current economic environment, the spot market for coal may not provide an acceptable alternative to sell our uncommitted tons. We currently are evaluating customer deferrals and are in negotiations with a number of the customers that have made such requests. There is no assurance that we will be able to resolve existing and potential deferrals on favorable terms, or at all.

Consequently, due to the risks mentioned above, we may not achieve the revenue or profit we expect to achieve from our long-term supply agreements.

A decline in demand for metallurgical coal would limit our ability to sell our high quality steam coal as higher-priced metallurgical coal.

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 metallurgical and steam coal markets. 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, thereby reducing our revenues and profitability. However, some of our mines operate profitably only if all or a portion of their production is sold as metallurgical coal to the steel market. If demand for metallurgical coal declined to the point where we could earn a more attractive return marketing the coal as steam coal, these mines may not be economically viable and may be subject to closure. Such closures would lead to accelerated reclamation costs, as well as reduced revenue and profitability.

Additionally, while we have committed and priced the vast majority of our planned shipments of coal production for next year, 61%, or approximately 900,000 tons, of our uncommitted tonnage for 2010 is metallurgical coal.

Inaccuracies in our estimates of economically recoverable coal reserves could result in lower than expected revenues, higher than expected costs or decreased profitability.

We base our reserves information on engineering, economic and geological data assembled and analyzed by our staff, which includes various engineers and geologists, and which is periodically reviewed by outside firms. The reserves estimates as to both quantity and quality are annually updated to reflect production of coal from the reserves, acquisitions, dispositions, depleted reserves and new drilling or other data received. There are numerous uncertainties inherent in estimating quantities and qualities of and costs to mine recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves and net cash flows necessarily depend upon a number of variable factors and assumptions, all of which may vary considerably from actual results such as:

- geological and mining conditions which may not be fully identified by available exploration data or which may differ from experience in current operations;

- historical production from the area compared with production from other similar producing areas; and

- assumed effects of regulation and taxes by governmental agencies and assumptions concerning coal prices, operating costs, mining technology improvements, severance and excise taxes, development costs and reclamation costs.

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For these reasons, estimates of the economically recoverable quantities and qualities attributable to any particular group of properties, classifications of reserves based on risk of recovery and estimates of net cash flows expected from particular reserves prepared by different engineers or by the same engineers at different times may vary substantially. Actual coal tonnage recovered from identified reserve areas or properties, and revenues and expenditures with respect to our reserves, may vary materially from estimates. These estimates, thus, may not accurately reflect our actual reserves. Any inaccuracy in our estimates related to our reserves could result in lower than expected revenues, higher than expected costs or decreased profitability.

Disruptions in transportation services could limit our ability to deliver coal to our customers, which could cause revenues to decline.

We depend primarily upon railroads, trucks and barges to deliver coal to our customers. Disruption of railroad service due to weather-related problems, strikes, lockouts and other events could temporarily impair our ability to supply coal to our customers, resulting in decreased shipments and related sales revenues. 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.

Several of our mines depend on a single transportation carrier or a single mode of transportation. Disruption of any of these transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks and other events could temporarily impair our ability to supply coal to our customers. Our transportation providers may face difficulties in the future that may impair our ability to supply coal to our customers, resulting in decreased revenues.

If there are disruptions of the transportation services provided by our primary rail carriers that transport our produced coal and we are unable to find alternative transportation providers to ship our coal, our business could be adversely affected.

Fluctuations in transportation costs could impair our ability to supply coal to our customers.

Transportation costs represent a significant portion of the total cost of coal for our customers and, as a result, the cost of transportation is a critical factor in a customer’s purchasing decision. Increases in transportation costs could make coal a less competitive source of energy or could make our coal production less competitive than coal produced from other sources.

Conversely, significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country. For instance, coordination of the many eastern loading facilities, the large number of small shipments, the steeper average grades of the terrain and a more unionized workforce are all issues that combine to make shipments originating in the eastern United States inherently more expensive on a per-mile basis than shipments originating in the western United States. The increased competition could have a material adverse effect on our business, financial condition and results of operations.

Disruption in supplies of coal produced by third parties could temporarily impair our ability to fill our customers’ orders or increase our costs.

In addition to marketing coal that is produced from our controlled reserves, we purchase and resell coal produced by third parties from their controlled reserves to meet customer specifications. Disruption in our supply of third-party coal could temporarily impair our ability to fill our customers’ orders or require us to pay higher prices in order to obtain the required coal from other sources. Any increase in the prices we pay for third-party coal could increase our costs and, therefore, lower our earnings.

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The unavailability of an adequate supply of coal reserves that can be mined at competitive costs could cause our profitability to decline.

Our profitability depends substantially on our ability to mine coal reserves that have the geological characteristics that enable them to be mined at competitive costs and to meet the quality needed by our customers. Because our reserves decline as we mine our coal, our future success and growth depend, in part, upon our ability to acquire additional coal reserves that are economically recoverable. 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. We may not be able to accurately assess the geological characteristics of any reserves that we acquire, which may adversely affect our profitability and financial condition. Exhaustion of reserves at particular mines also may have an adverse effect on our operating results that is disproportionate to the percentage of overall production represented by such mines. Our ability to obtain other reserves in the future could be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties, the lack of suitable acquisition candidates or the inability to acquire coal properties on commercially reasonable terms.

Unexpected increases in raw material costs or decreases in availability could significantly impair our operating profitability.

Our coal mining operations use significant amounts of steel, rubber, petroleum products and other raw materials in various pieces of mining equipment, supplies and materials. Scrap steel prices have risen significantly and, historically, the prices of scrap steel and petroleum have fluctuated. There may be other acts of nature, terrorist attacks or threats or other conditions that could also increase the costs of raw materials. If the price of steel, rubber, petroleum products or other of these materials increase, our operational expenses will increase, which could have a significant negative impact on our profitability. Additionally, shortages in raw materials used in the manufacturing of supplies and mining equipment could limit our ability to obtain such items which could have an adverse effect on our ability to carry out our business plan.

The accident at the Sago mine could negatively impact our business.

On January 2, 2006, an explosion occurred at our Sago mine in West Virginia, which was sealed and permanently closed in 2009. The explosion tragically resulted in the deaths of twelve miners and the critical injury of another miner. As a result of the accident, civil litigation by various claimants has been initiated arising out of the accident. Our business may be negatively impacted by various factors including the diversion of management's attention from our day-to-day business, further negative media attention, the impact of litigation commenced against us and any claims that may be asserted against us that are not covered, in whole or in part, by our insurance policies.

A shortage of skilled labor in the mining industry could pose a risk to achieving optimal labor productivity and competitive costs, which could adversely affect our profitability.

Efficient coal mining using modern techniques and equipment requires skilled laborers, preferably with at least a year of experience and proficiency in multiple mining tasks. In order to support our planned expansion opportunities, we intend to continue sponsoring both in-house and vocational coal mining programs at the local level in order to train additional skilled laborers. A tight labor market in 2008 led to the need to offer more competitive compensation packages. As a result, $15.48 of our cost of coal sales per ton in 2009 was attributable to labor and benefits, compared to $12.68 for 2008. In the event that a shortage of experienced labor were to arise or we are unable to train the necessary amount of skilled laborers, there could be an adverse impact on our labor productivity and costs and our ability to expand production, which could have a material adverse effect on our earnings.

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Our ability to operate our company effectively could be impaired if we fail to attract and retain key personnel.

Our senior management team averages 25 years of experience in the coal industry, which includes developing innovative, low-cost mining operations, maintaining strong customer relationships and making strategic, opportunistic acquisitions. The loss of any of our 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 personnel with coal industry experience. Competition for these persons in the coal industry is intense and we may not be able to successfully recruit, train or retain qualified personnel. We may not be able to continue to employ key personnel or attract and retain qualified personnel in the future. Our failure to retain or attract key personnel could have a material adverse effect on our ability to effectively operate our business.

Acquisitions that we may undertake involve a number of inherent risks, any of which could cause us not to realize the anticipated benefits.

We continually seek to expand our operations and coal reserves through selective acquisitions. If we are unable to successfully integrate the companies, businesses or properties we acquire, our profitability may decline and we could experience a material adverse effect on our business, financial condition or results of operations. Acquisition transactions involve various inherent risks, including:

- uncertainties in assessing the value, strengths and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental or mine safety liabilities) of, acquisition candidates;

- potential loss of key customers, management and employees of an acquired business;

- ability to achieve identified operating and financial synergies anticipated to result from an acquisition;

- discrepancies between the estimated and actual reserves of the acquired business;

- problems that could arise from the integration of the acquired business; and

- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying our rationale for pursuing the acquisition.

Any one or more of these factors could cause us not to realize the benefits anticipated to result from an acquisition. Any acquisition opportunities we pursue could materially affect our liquidity and capital resources and may require us to incur indebtedness, seek equity capital or both. In addition, future acquisitions could result in our assuming more long-term liabilities relative to the value of the acquired assets than we have assumed in our previous acquisitions.

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Risks inherent to mining could increase the cost of operating our business.

Our mining operations are subject to conditions that can impact the safety of our workforce or delay coal deliveries or increase the cost of mining at particular mines for varying lengths of time. These conditions include:

- fires and explosions from methane gas or coal dust;
- accidental minewater discharges;
- weather, flooding and natural disasters;
- unexpected maintenance problems;
- key equipment failures;
- variations in coal seam thickness;
- variations in the amount of rock and soil overlying the coal deposit; and
- variations in rock and other natural materials and variations in geologic conditions.

We maintain insurance policies that provide limited coverage for some of these risks, although there can be no assurance that these risks would be fully covered by our insurance policies. Despite our efforts, significant mine accidents could occur and have a substantial impact. See "– The accident at the Sago mine could negatively impact our business."

Inability of contract miner or brokerage sources to fulfill the delivery terms of their contracts with us could reduce our profitability.

In conducting our mining operations, we utilize third-party sources of coal production, including contract miners and brokerage sources, to fulfill deliveries under our coal supply agreements. Our profitability or exposure to loss on transactions or relationships such as these is dependent upon the reliability (including financial viability) and price of the third-party supply, our obligation to supply coal to customers in the event that adverse geologic mining conditions restrict deliveries from our suppliers, our willingness to participate in temporary cost increases experienced by our third-party coal suppliers, our ability to pass on temporary cost increases to our customers, the ability to substitute, when economical, third-party coal sources with internal production or coal purchased in the market and other factors. Brokerage sources and contract miners may experience adverse geologic mining and/or financial difficulties that make their delivery of coal to us at the contractual price difficult or uncertain. If we have difficulty with our third-party sources of coal, our profitability could decrease.

We may be unable to generate sufficient taxable income from future operations to fully utilize our significant tax net operating loss carryforwards or maintain our deferred tax assets.

As a result of our acquisition of Anker and of historical financial results, we have recorded deferred tax assets. If we fail to generate profits in the foreseeable future, our deferred tax assets may not be fully utilized. We evaluate our ability to utilize our net operating loss ("NOL") and tax credit carryforwards each period and, in compliance with FASB Accounting Standards Codification ("ASC") Topic 740, Income Taxes ("ASC 740"), record any resulting adjustments that may be required to deferred income tax expense. In addition, we will reduce the deferred income tax asset for the benefits of NOL and tax credit carryforwards used in future periods and will recognize and record federal and state income tax expense at statutory rates in future periods. If, in the future, we determine that it is more likely than not that we will not realize all or a portion of the deferred tax assets, we will record a valuation allowance against deferred tax assets which would result in a charge to income tax expense.

Failure to obtain or renew surety bonds in a timely manner and on acceptable terms could affect our ability to secure reclamation and coal lease obligations, which could adversely affect our ability to mine or lease coal.

Federal and state laws require us to obtain surety bonds to secure payment of certain long-term obligations, such as mine closure or reclamation costs and federal and state workers' compensation costs. Certain business transactions, such as coal leases and other obligations, may also require bonding. These bonds are typically renewable annually. Surety bond issuers and holders may not continue to renew the bonds or may demand additional collateral or other less favorable terms upon those renewals. The ability of surety bond issuers and holders to demand additional collateral or other less favorable terms has increased as the number of companies willing to issue these bonds has decreased over time. Our failure to maintain, or our inability to acquire, surety bonds that are required by state and federal law would affect our ability to secure reclamation and coal lease obligations, which could adversely affect our ability to mine or lease coal. That failure could result from a variety of factors including, without limitation:

- lack of availability, higher expense or unfavorable market terms of new bonds;
- restrictions on availability of collateral for current and future third-party surety bond issuers under the terms of our amended and restated credit facility; and
- exercise by third-party surety bond issuers of their right to refuse to renew the surety.

Failure to maintain capacity for required letters of credit could limit our ability to obtain or renew surety bonds.

At December 31, 2009, we had $73.6 million of letters of credit in place, of which $61.1 million serve as collateral for reclamation surety bonds and $12.5 million secured miscellaneous obligations. Our amended and restated credit facility provides for a revolving credit facility of $100.0 million, of which up to $80.0 million may be used for letters of credit. If we do not maintain sufficient borrowing capacity under our amended and restated credit facility for additional letters of credit, we may be unable to obtain or renew surety bonds required for our mining operations.

Our business requires continued capital investment, which we may be unable to provide.

Our business strategy requires continued capital investment for, among other purposes, managing acquired assets, acquiring new equipment, maintaining the condition of our existing equipment and maintaining compliance with environmental laws and regulations. To the extent that cash generated internally and cash available under our credit facilities are not sufficient to fund capital requirements, we will require additional debt and/or equity financing. However, this type of financing may not be available, particularly in current market conditions, or if available, may not be on satisfactory terms. Future debt financings, if available, may result in increased interest and amortization expense, increased leverage and decreased income available to fund further acquisitions and expansion. In addition, future debt financings may limit our ability to withstand competitive pressures and render us more vulnerable to economic downturns. If we fail to generate sufficient earnings or to obtain sufficient additional capital in the future or fail to manage our capital investments effectively, we could be forced to reduce or delay capital expenditures, sell assets or restructure or refinance our indebtedness.

In addition, the credit agreement governing our amended and restated credit facility contains customary affirmative and negative covenants for credit facilities of this type, including, but not limited to, limitations on the incurrence of indebtedness, asset dispositions, acquisitions, investments, dividends and other restricted payments, liens and transactions with affiliates. The credit agreement requires us to meet certain financial tests, including a maximum leverage ratio, a minimum interest coverage ratio, and a limit on capital expenditures. If we fail to comply with any affirmative or negative covenant, or to meet any financial test, in our credit agreement, we may be unable to obtain or renew surety bonds required for our mining operations.

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The credit agreement also contains customary events of default, including, but not limited to, failure to pay principal or interest, breach of covenants or representations and warranties, cross-default to other indebtedness, judgment default and insolvency. If an event of default occurs under the credit agreement, the lenders under the credit agreement will be entitled to take various actions, including demanding payment for all amounts outstanding thereunder and foreclosing on any collateral. If the lenders were to do so, our other debt obligations including the senior notes and the convertible notes, would also have the right to accelerate those obligations which we would be unable to satisfy. See "– Our ability and the ability of some of our subsidiaries to engage in some business transactions or to pursue our business strategy may be limited by the terms of our existing debt."

Increased consolidation and competition in the U.S. coal industry may adversely affect our ability to retain or attract customers and may reduce domestic coal prices.

During the last several years, the U.S. coal industry has experienced increased consolidation, which has contributed to the industry becoming more competitive. According to the EIA, in 1995, the top ten coal producers accounted for approximately 50% of total domestic coal production. By 2008, however, the top ten coal producers' share had increased to approximately 66% of total domestic coal production. 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.

The demand for U.S. coal exports is dependent upon a number of factors outside of our control, including the overall demand for electricity in foreign markets, currency exchange rates, ocean freight rates, the demand for foreign-produced steel both in foreign markets and in the U.S. market (which is dependent in part on tariff rates on steel), general economic conditions in foreign countries, technological developments and environmental and other governmental regulations and any other pressures placed on companies that are connected to the emission of greenhouse gases. If foreign demand for U.S. coal were to decline, this decline could cause competition among coal producers in the United States to intensify, potentially resulting in additional downward pressure on domestic coal prices.

Our ability to collect payments from our customers could be impaired if their creditworthiness deteriorates.

Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. Our customer base is changing with an increasing focus on metallurgical sales to domestic and export steel customers. Despite the recent improvement in steel output, the steel industry experienced a dramatic downturn in late 2008 that continued for most of 2009. Most of the industry experienced steep losses during the period, thus if the current recovery does not continue our ability to collect from some of our customers could be impaired.

Continued deregulation by our utility customers that sell their power plants to their non-regulated affiliates or third parties that may be less creditworthy, thereby increasing the risk we bear on payment default. These new power plant owners may have credit ratings that are below investment grade. Further, competition with other coal suppliers could force us to extend credit to customers and on terms that could increase the risk we bear on payment default.

We sometimes have contracts to supply coal to energy trading and brokering companies under which those companies sell coal to end users. In recent years, the creditworthiness of the energy trading and brokering companies with which we do business declined, increasing the risk that we may not be able to collect payment for all coal sold and delivered to or on behalf of these energy trading and brokering companies.

In the current economic climate certain of our customers and their customers may be affected by cash flow problems, which can increase the time it takes to collect accounts receivable.

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

We conduct a significant part of our mining operations on properties that we lease. A title defect or the loss of any lease upon expiration of its term, upon a default or otherwise, could adversely affect our ability to mine the associated reserves and/or process the coal that we mine. Title to most of our owned or leased properties and mineral rights is not usually verified until we make a commitment to develop a property, which may not occur until after we have obtained necessary permits and completed exploration of the property. In some cases, we rely on title information or representations and warranties provided by our lessors or grantors. Our right to mine some of our reserves has in the past been, and may again in the future be, adversely affected if defects in title or boundaries exist or if a lease expires. Any challenge to our title or leasehold interests could delay the exploration and development of the property and could ultimately result in the loss of some or all of our interest in the property. Mining operations from time to time may rely on an expired lease that we are unable to renew. From time to time we also may be in default with respect to leases for properties on which we have mining operations. In such events, we may have to close down or significantly alter the sequence of such mining operations which may adversely affect our future coal production and future revenues. If we mine on property that we do not own or lease, we could incur liability for such mining. Also, in any such case, the investigation and resolution of title issues would divert management’s time from our business and our results of operations could be adversely affected. Additionally, if we lose any leasehold interests relating to any of our preparation plants, we may need to find an alternative location to process our coal and load it for delivery to customers, which could result in significant unanticipated costs.

In order to obtain leases or mining contracts to conduct our mining operations on property where these defects exist, we may in the future have to incur unanticipated costs. In addition, we may not be able to successfully negotiate new leases or mining contracts for properties containing additional reserves, or maintain our leasehold interests in properties where we have not commenced mining operations during the term of the lease. 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.

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

All of our coal production is from mines 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. If the terms of a union collective bargaining agreement are significantly different from our current compensation arrangements with our employees, any unionization of our subsidiaries’ employees could adversely affect the stability of our production and reduce our profitability.

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

During the mid-1970s and early 1980s, a growing coal market and increased demand for coal attracted new investors to the coal industry, spurred the development of new mines and resulted in production capacity in excess of market demand throughout the industry. Similarly, increases in future coal prices could encourage the development of expanded capacity by new or existing coal producers.

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

We are parties to a number of legal proceedings incidental to normal business activities, including several complaints related to the accident at our Sago mine, a breach of contract complaint by one of our customers related to the idling of our Sycamore No. 2 mine and a class action lawsuit that alleges that the registration statements filed in connection with our initial public offering contained false and misleading statements, and that investors relied upon those securities filings and suffered damages as a result. Some actions brought against us from time to time may have merit. There is always the potential that an individual matter or the aggregation of many matters could have an adverse effect on our financial condition, results of operations or cash flows. See "Legal Proceedings" contained in Item 3 of this Annual Report on Form 10-K.

Risks Relating to Government Regulation

Extensive government regulations impose significant costs on our mining operations, and future regulations could increase those costs or limit our ability to produce and sell coal.

The coal mining industry is subject to increasingly strict regulation by federal, state and local authorities with respect to matters such as:

- limitations on land use;
- employee health and safety;
- mandated benefits for retired coal miners;
- mine permitting and licensing requirements;
- reclamation and restoration of mining properties after mining is completed;
- air quality standards;
- water pollution;
- construction and permitting of facilities required for mining operations, including valley fills and other structures, including those constructed in natural water courses and wetlands;
- protection of human health, plantlife and wildlife;
- discharge of materials into the environment;
- surface subsidence from underground mining; and
- effects of mining on groundwater quality and availability.

In particular, federal and state statutes require us to restore mine property in accordance with specific standards and an approved reclamation plan, and require that we obtain and periodically renew permits for mining operations. If we do not make adequate provisions for all expected reclamation and other costs associated with mine closures, it could harm our future operating results.

Federal and state safety and health regulation in the coal mining industry may be the most comprehensive and pervasive system for protection of employee safety and health affecting any segment of the U.S. industry. It is costly and time-consuming to comply with these requirements and new regulations or orders may materially adversely affect our mining operations or cost structure, any of which could harm our future results.

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Under federal law, each coal mine operator must secure payment of federal black lung benefits to claimants who are current and former employees and contribute to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry before July 1973. The trust fund is funded by an excise tax on coal production. If this tax increases, or if we could no longer pass it on to the purchaser of our coal under many of our long-term sales contracts, it could increase our operating costs and harm our results. Recently, there has been a renewed focus on rates of black lung disease among coal workers. As a result, there may be greater federal scrutiny of the industry that could lead to new and more costly regulation which may increase our cost of contributions to the trust fund.

The costs, liabilities and requirements associated with existing and future regulations may be costly and time-consuming and may delay commencement or continuation of exploration or production operations. Failure to comply with these regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our operations. We may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from our operations. We must compensate employees for work-related injuries. If we do not make adequate provisions for our workers' compensation liabilities, it could harm our future operating results. If we are pursued for these sanctions, costs and liabilities, our mining operations and, as a result, our profitability could be adversely affected. See "Environmental, Safety and Other Regulatory Matters."

The possibility exists that new legislation and/or regulations and orders may be adopted that may materially adversely affect our mining operations, our cost structure and/or our customers' ability to use coal. New legislation or administrative regulations (or new judicial interpretations or administrative enforcement of existing laws and regulations), including proposals related to the protection of the environment that would further regulate and tax the coal industry, may also require us or our customers to change operations significantly or incur increased costs. These regulations, if proposed and enacted in the future, could have a material adverse effect on our financial condition and results of operations.

Judicial rulings that restrict disposal of mining spoil material could significantly increase our operating costs, discourage customers from purchasing our coal and materially harm our financial condition and operating results.

Mining in the mountainous terrain of Appalachia typically requires the use of valley fills for the disposal of excess spoil (rock and soil material) generated by construction and mining activities. In our surface mining operations, we use mountaintop removal mining wherever feasible because it allows us to recover more tons of coal per acre and facilitates the permitting of larger projects, which allows mining to continue over a longer period of time than would be the case using other mining methods. Mountaintop removal mining, along with other methods of surface mining, depends on valley fills to dispose of mining spoil material. Construction of roads, underground mine portal sites, coal processing and handling facilities and coal refuse embankments or impoundments related to both surface and underground mining also require the development of valley fills. We obtain permits to construct and operate valley fills and surface impoundments from the Army Corps of Engineers (the "ACOE") under the auspices of Section 404 of the federal Clean Water Act. Lawsuits challenging the ACOE's authority to authorize surface mining activities under Nationwide Permit 21 ("NWP21") or under more comprehensive individual permits have been instituted by environmental groups, which also advocate for changes in federal and state laws that would prevent or further restrict the issuance of such permits.

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In a March 2007 decision pertaining originally to certain Section 404 permits issued to Massey Energy Company, Judge Robert C. Chambers of the U.S. District Court for the Southern District of West Virginia ruled that the ACOE failed to adequately assess the impacts of surface mining on headwaters and approved mitigation that did not appropriately compensate for stream losses. In June 2007, Judge Chambers found that sediment ponds situated within a stream channel violated the prohibition against using the waters of the U.S. for waste treatment and further decided that using the reach of stream between a valley fill and the sediment pond to transport sediment-laden runoff is prohibited by the Clean Water Act. A three-judge panel of the Fourth Circuit on February 13, 2009 reversed, vacated and remanded Judge Chambers' March 2007 and June 2007 decisions in their entirety, ruling that the ACOE properly exercised its discretion in the permit review and approval process. On August 26, 2009, the environmental groups petitioned the Supreme Court for a writ of certiorari. Additionally, in November 2009, Judge Chambers invalidated two additional permits in a parallel case based on a finding that the public notices of the applications did not provide sufficient information on the proposed mitigation plan to allow meaningful public comment.

A similar challenge to the ACOE Section 404 permit process was launched by environmental groups in Kentucky in December 2007, when a lawsuit was filed in federal court against the ACOE alleging that it wrongfully issued a Section 404 authorization for the expansion of Hazard's Thunder Ridge surface mine. Hazard intervened in the suit to protect our interests. A settlement was negotiated between Hazard and the plaintiffs that allows Hazard the use of the remaining valley fill in exchange for revisions to certain portions of the revegetation plan and a donation of $50,000 to a local watershed improvement project. The federal court on November 20, 2009 entered a "Stipulation of Voluntary Dismissal" that ended the litigation. See "Legal Proceedings" contained in Item 3 of this Annual Report on Form 10-K.

Litigation of this type, which is designed to prevent or delay the issuance of permits needed for mining or to make permit or regulatory standards more stringent, whether brought directly against us or against governmental agencies that establish environmental standards and issue permits, could greatly lengthen the time needed to permit the mining of reserves, significantly increase our operating costs, make it more difficult to economically recover a significant portion of our reserves and lead to a material adverse effect on our financial condition and results of operation. We may not be able to increase the price of our coal to cover higher production costs without reducing customer demand for our coal.

New government regulations as a result of recent mining accidents are increasing our costs.

Both the federal and state governments impose stringent health and safety standards on the mining industry. Regulations are comprehensive and affect nearly every aspect of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations and other matters. As a result of past mining accidents, additional federal and state health and safety regulations have been adopted that have increased operating costs and affect our mining operations. State and federal legislation has been adopted that, among other things, requires additional oxygen supplies, communication and tracking devices, refuge chambers, stronger seal construction and monitoring standards and mine rescue teams. The legislation also raised the maximum civil penalty for certain violations of federal mine safety regulations to $220,000 from $60,000. We expect that new regulations or stricter enforcement of existing regulations will increase our costs related to worker health and safety. Additionally, we could be subject to civil penalties and other penalties if we violate mining regulations.

Mining in Northern and Central Appalachia is more complex and involves more regulatory constraints than mining in the other areas, which could affect productivity and cost structures of these areas.

The geological characteristics of Northern and Central Appalachian coal reserves, 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 the Powder River Basin in northeastern Wyoming and southeastern Montana, permitting, licensing and other environmental and regulatory requirements are more dynamic and thus 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, our mines in Northern and Central Appalachia.

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MSHA or other federal or state regulatory agencies may order certain of our mines to be temporarily or permanently closed, which could adversely affect our ability to meet our customers' demands.

MSHA or other federal or state regulatory agencies may order certain of our mines to be temporarily or permanently closed. Our customers may challenge our issuance of force majeure notices in connection with such closures. If these challenges are successful, we may have to purchase coal from third-party sources to satisfy those challenges, incur capital expenditures to re-open the mines and negotiate settlements with the customers, which may include price reductions, the reduction of commitments or the extension of time for delivery, terminate customers' contracts or face claims initiated by our customers against us. The resolution of these challenges could have an adverse impact on our financial position, results of operations or cash flows.

Federal or state legislation that restricts disposal of mining spoil material or coal refuse material could eliminate certain mining methods, significantly increase our operating costs and materially harm our financial condition and operating results.

The U.S. Congress and state legislatures have in the past and are currently considering proposals that would effectively prohibit the placement of materials generated by coal mining into waters of the United States, which practice is essential to surface mining in central Appalachia. A prohibition against excess spoil placement in streams would essentially eliminate surface mining in steep terrain, thus rendering much of our coal reserves unmineable. Restrictions on the placement of coal refuse material in streams or in abandoned underground coal mines could limit the life of existing coal processing operations, potentially block new coal preparation plants and at minimum significantly increase our operating costs. Public concerns regarding the environmental, health and aesthetic impacts of surface mining could, independent of regulation, affect our reputation and reduce demand for our coal.

Revision of the federal stream buffer zone regulation to restrict disposal of mining spoil material or coal refuse material could eliminate certain mining methods, significantly increase our operating costs and materially harm our financial condition and operating results.

On November 30, 2009, the Office of Surface Mining published an Advance Notice of Proposed Rulemaking announcing its intent to revise the stream buffer zone rule. Certain of the proposed alternatives would effectively prohibit the placement of materials generated by coal mining into intermittent or perennial streams, which practice is essential to surface mining in central Appalachia. A prohibition against excess spoil placement in such streams would essentially eliminate surface mining in steep terrain, thus rendering much of our coal reserves unmineable. Restrictions on the placement of coal refuse material in such streams could limit the life of existing coal processing operations, potentially block new coal preparation plants and at minimum significantly increase our operating costs.

We must obtain governmental permits and approvals for mining operations, which can be a costly and time-consuming process, can result in restrictions on our operations and is subject to litigation that may delay or prevent us from obtaining necessary permits.

Our operations are principally regulated under surface mining permits issued pursuant to the Surface Mining Control and Reclamation Act and state counterpart laws. Such permits are issued for terms of five years with the right of successive renewal. Separately, the Clean Water Act requires permits for operations that discharge into waters of the United States. Valley fills and refuse impoundments are authorized under permits issued by the ACOE. The EPA has the authority, which it has rarely exercised until recently, to object to permits issued by the ACOE. While the ACOE is authorized to issue permits even when the EPA has objections, the EPA does have the ability to override the ACOE decision and veto the permits.

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Under the provisions of a Memorandum of Understanding executed on June 11, 2009 between the EPA, the ACOE and the Department of the Interior, the ACOE intends to suspend the use of NWP21 for surface mining activities in Appalachia while NWP21 is modified to prohibit its use to authorize discharges of dredged or fill material into waters of the United States for surface coal mining activities in the Appalachian region of the following states: Kentucky, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia. In September 2009, the EPA announced 79 pending Clean Water Act 404 permit applications for Appalachian coal mining warranted further review because of continuing concerns about water quality and/or regulatory compliance issues. These include four of our permit applications. One of the permit applications is for our Jennie Creek surface mine. The failure to issue a Section 404 permit would prevent the planned commencement of the Jennie Creek surface mine. Operating alternatives to the other three applications under further review exist, although the alternatives are less economical than the proposed projects. While the EPA has stated that its identification of these 79 permits does not constitute a determination that the mining involved cannot be permitted under the Clean Water Act and does not constitute a final recommendation from the EPA to the ACOE on these projects, it is unclear how long the further review will take for our four permits or what the final outcome will be. It is also unclear what impact this process may have on our future applications for surface coal mining permits. Permitting under the Clean Water Act has been a frequent subject of litigation by environmental advocacy groups that has resulted in periodic delays in such permits issued by the ACOE. Excessive delays in permitting may require adjustments of our production budget and mining plans.

Additionally, certain operations (particularly preparation plants) have permits issued pursuant to the Clean Air Act and state counterpart laws allowing and controlling the discharge of air pollutants. Regulatory authorities exercise considerable discretion in the timing of permit issuance. Requirements imposed by these authorities may be costly and time-consuming and may result in delays in, or in some instances preclude, the commencement or continuation of development or production operations. Adverse outcomes in lawsuits challenging permits or failure to comply with applicable regulations could result in the suspension, denial or revocation of required permits, which could have a material adverse impact on our financial condition, results of operations or cash flows.

We may be unable to obtain and renew permits necessary for our operations, which would reduce our production, cash flow and profitability.

Mining companies must obtain numerous permits that impose strict regulations on various environmental and safety matters in connection with coal mining. These include permits issued by various federal and state agencies and regulatory bodies. The permitting rules are complex and may change over time, making our ability to comply with the applicable requirements more difficult or even impossible, thereby precluding continuing or future mining operations. The public has certain rights to comment upon and otherwise engage in the permitting process, including through court intervention. Furthermore, in the current regulatory environment, with enhanced scrutiny by regulators, increased opposition by environmental groups and others and potential resultant delays and permit application denials, we now anticipate that mining permit approvals will take even longer than previously experienced, and some permits may not be issued at all. Accordingly, the permits we need may not be issued, maintained or renewed, or may not be issued or renewed in a timely fashion or may involve requirements that restrict our ability to conduct our mining operations. An inability to conduct our mining operations pursuant to applicable permits would reduce our production, cash flows and profitability.

If the assumptions underlying our reclamation and mine closure obligations 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 the surface effects of deep mining. Estimates of our total reclamation and mine closure liabilities are based upon permit requirements, engineering studies and our engineering expertise related to these requirements. The estimate of ultimate reclamation liability is reviewed periodically by our management and engineers. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly. Asset retirement obligations are recorded as a liability based on fair value, which is calculated as the present value of the estimated future cash flows. In estimating future cash flows, we considered the estimated current cost of reclamation and applied inflation rates and a third-party profit, as necessary. The third-party profit is an estimate of the approximate markup that would be charged by contractors for work performed on behalf of us. The resulting estimated reclamation and mine closure obligations could change significantly if actual amounts change significantly from our assumptions.

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Our operations may substantially impact the environment or cause exposure to hazardous materials, and our properties may have significant environmental contamination, any of which could result in material liabilities to us.

We use, and in the past have used, hazardous materials and generate, and in the past have generated, hazardous wastes. In addition, many of the locations that we own or operate were used for coal mining and/or involved hazardous materials usage either before or after we were involved with those locations. We may be subject to claims under federal and state statutes and/or common law doctrines for personal injury, property damages, natural resource damages and other damages, as well as the investigation and clean up of soil, surface water, groundwater and other media. Such claims may arise, for example, out of current or former activities at sites that we own or operate currently, as well as at sites that we or predecessor entities owned or operated in the past, and at contaminated sites that have always been owned or operated by third parties. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the remediation costs or other damages, or even for the entire share. We have from time to time been subject to claims arising out of contamination at our own and other facilities and may incur such liabilities in the future.

We use, and in the past have used, alkaline CCBs during the reclamation process at certain of our mines to aid in preventing the formation of acid mine drainage and we have agreed to dispose of CCBs in some instances. Use of CCBs on a mined area is subject to regulatory approval and is allowed only after it is proved to be a beneficial use. The EPA has announced that it will issue a proposed rule to regulate the disposal of CCBs under the Resource Conservation and Recovery Act. If in the future CCBs were to be classified as a hazardous waste or if more stringent disposal requirements were to be otherwise established for these wastes, we may be required to cease using or disposing of CCBs at certain of our mines and find a replacement alkaline material for this purpose, which may add to the cost of mine reclamation or decrease our revenue generated from disposal contracts with certain of our customers.

We maintain extensive coal slurry impoundments at a number of our mines. Such impoundments are subject to stringent regulation. Slurry impoundments maintained by other coal mining operations have been known to fail, releasing large volumes of coal slurry. Structural failure of an impoundment can result in extensive damage to the environment and natural resources, such as bodies of water that the coal slurry reaches, as well as liability for related personal injuries and property damages and injuries to wildlife. Some of our impoundments overlie mined out areas, which can pose a heightened risk of failure and of damages arising out of failure, unless preventive measures are implemented in a timely manner. We have commenced such measures to modify our method of operation at one surface impoundment containing slurry wastes in order to reduce the risk of releases to the environment from it, a process that has been incorporated into the construction sequence of the impoundment and thus will take several years to complete. If one of our impoundments were to fail, we could be subject to substantial claims for the resulting environmental contamination and associated liability, as well as for fines and penalties.

These and other impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations and environmental conditions at our properties, could result in costs and liabilities that would materially and adversely affect us.

Extensive environmental regulations affect our customers and could reduce the demand for coal as a fuel source and cause 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 and other compounds emitted into the air from coke ovens and electric power plants, which are the largest end users of our coal. Such regulations will require significant emissions control expenditures for many coal-fired power plants to comply with applicable ambient air quality standards. 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.

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The Federal Clean Air Act, including the Clean Air Act Amendments of 1990, and corresponding state laws that regulate emissions of materials into the air affect coal mining operations both directly and indirectly. Measures intended to improve air quality that reduce coal’s share of the capacity for power generation could diminish our revenues and harm our business, financial condition and results of operations. The price of lower sulfur coal may decrease as more coal-fired utility power plants install additional pollution control equipment to comply with stricter sulfur dioxide emission limits, which may reduce our revenues and harm our results. In addition, regulatory initiatives including the nitrogen oxide rules, new ozone and particulate matter standards, regional haze regulations, new source review, regulation of mercury emissions and legislation or regulations that establish restrictions on greenhouse gas emissions or provide for other multiple pollutant reductions could make coal a less attractive fuel to our utility customers and substantially reduce our sales.

Various new and proposed laws and regulations may require further significant reductions in emissions from coal-fired utilities. More stringent emissions standards may require many coal-fired sources to install additional pollution control equipment, such as wet scrubbers. Increasingly, the EPA has been undertaking multi-pollutant rulemakings to reduce emissions from coal-fired utilities. The EPA has also announced that it will issue a proposed rule to regulate the disposal of CCBs under the Resource Conservation and Recovery Act. These and other future standards could have the effect of making the operation of coal-fired plants less profitable, thereby decreasing demand for coal. 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.

There have been several recent proposals in Congress that are designed to further reduce emissions of sulfur dioxide, nitrogen oxides and mercury from power plants, and certain ones could regulate additional air pollutants. If such initiatives are enacted into law, power plant operators could choose fuel sources other than coal to meet their requirements, thereby reducing the demand for 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.

New and pending laws regulating the environmental effects of emissions of greenhouse gases could impose significant additional costs to doing business for the coal industry and/or a shift in consumption to non-fossil fuels.

Greenhouse gas emissions have increasingly become the subject of a large amount of international, national, regional, state and local attention. Future regulation of greenhouse gas could occur pursuant to future U.S. treaty obligations, statutory or regulatory changes under the Clean Air Act or new climate change legislation, such as The American Clean Energy and Security Act of 2009, which was passed by the U.S. House of Representatives. Increased efforts to control greenhouse gas emissions, could result in reduced demand for coal if electric power generators switch to lower carbon sources of fuel.

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Coal-fired power plants can generate large amounts of greenhouse gas emissions, and, as a result, have become subject to challenge, including the opposition to any new coal-fired power plants or capacity expansions of existing plants, by environmental groups seeking to curb the environmental effects of emissions of greenhouse gases. Various legislation has been and will continue to be introduced in Congress which reflects a wide variety of strategies for reducing greenhouse gas emissions in the United States. These strategies include mandating decreases in greenhouse gas emissions from coal-fired power plants, instituting a tax on greenhouse gas emissions, banning the construction of new coal-fired power plants that are not equipped with technology to capture and sequester carbon dioxide, encouraging the growth of renewable energy sources (such as wind or solar power) or nuclear for electricity production, and financing the development of advanced coal burning plants which have greatly reduced greenhouse gas emissions. Most states in the United States have taken steps to regulate greenhouse gas emissions. Under the Clean Air Act, the EPA has published its finding that greenhouse gases pose a threat to public health and declared that a combination of six greenhouse gases constitutes an air pollutant. The EPA has already proposed regulations that would impact major stationary sources of greenhouse gas emissions, including coal-fired power plants, that could come into effect as early as March 2010.

These or additional state or federal laws or regulations regarding greenhouse gas emissions or other actions to limit greenhouse gas emissions could result in fuel switching, from coal to other fuel sources, by electric generators. Political and regulatory uncertainty over future emissions controls have been cited as major factors in decisions by power companies to postpone new coal-fired power plants. If measures such as these or other similar measures, like controls on methane emissions from coal mines, are ultimately imposed on the coal industry by federal or state governments or pursuant to international treaty, our operating costs may be materially and adversely affected. Similarly, alternative fuels (non-fossil fuels) could become more attractive than coal in order to reduce greenhouse gas emissions, which could result in a reduction in the demand for coal and, therefore, our revenues. Public concerns regarding climate change could, independent of regulatory developments, adversely affect our reputation and reduce demand for our coal.

Risks Relating to Our Common Stock

The market price of our common stock may be volatile, which could cause the value of our common stock to decline.

The market price of our common stock has experienced, and may continue to experience, significant volatility. Between January 1, 2008 and December 31, 2009, the trading price of our common stock on the New York Stock Exchange ranged from a low of $1.09 per share to a high of $13.90 per share. There are numerous factors contributing to the market price of our common stock, including many over which we have no control. These risks include, among other things:

- our operating and financial performance and prospects;
- our ability to repay our debt;
- investor perceptions of us and the industry and markets in which we operate;
- changes in earnings estimates or buy/sell recommendations by analysts; and
- general financial, domestic, international, economic and other market conditions.

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In addition, the stock market in recent years has experienced extreme price and trading volume fluctuations that often have been unrelated or disproportionate to the operating performance of individual companies. These broad market fluctuations may adversely affect the price of our common stock, regardless of our operating performance. Furthermore, stockholders may initiate securities class action lawsuits if the market price of our stock drops significantly, which may cause us to incur substantial costs and could divert the time and attention of our management.

Sales of additional shares of our common stock could cause the price of our common stock to decline.

Sales of substantial amounts of our common stock in the public market, or the perception that those sales may occur, could adversely affect the price of our common stock. In addition, future issuances of equity securities, including pursuant to our shelf registration statement or the exercise of options, could dilute the interests of our existing stockholders and could cause the market price for our common stock to decline. We may issue equity securities in the future for a number of reasons, including financing our operations and business strategy, to adjust our ratio of debt to equity, or to satisfy our obligations upon the exercise of outstanding warrants or options.

As of December 31, 2009, there were:

- 5,034,610 shares of common stock issuable upon the exercise of stock options outstanding at a weighted-average exercise price of $5.00;

- 1,148,479 shares of restricted stock subject to continuing vesting requirements; and

- 230,265 restricted share units issued to directors to be converted to common stock upon separation of service.

Our leverage may harm our financial condition and results of operations.

Our total consolidated long-term debt as of December 31, 2009 was approximately $366.5 million. Our level of debt could have important consequences on our future operations, including:

- making it more difficult for us to meet our payment and other obligations under our outstanding senior and convertible notes and our other outstanding debt;

- resulting in an event of default if we fail to comply with the financial and other restrictive covenants contained in our debt agreements, which could result in all of our debt becoming immediately due and payable;

- subjecting us to the risk of increased sensitivity to interest rate increases on our indebtedness with variable interest rates, including borrowings under our senior credit facility;

- reducing the availability of our cash flow to fund working capital, capital expenditures, acquisitions and other general corporate purposes, and limiting our ability to obtain additional financing for these purposes;

- limiting our flexibility in planning for, or reacting to, and increasing our vulnerability to, changes in our business, the industry in which we operate and the general economy; and

- placing us at a competitive disadvantage compared to our competitors that have less debt or are less leveraged.

If we or our subsidiaries incur additional debt, the related risks that we and they now face could intensify. In addition to the principal repayments on our outstanding debt, we have other demands on our cash resources, including, among others, capital expenditures and operating expenses.

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Our ability to pay principal and interest on and to refinance our debt depends upon the operating performance of our subsidiaries, which will be affected by, among other things, general economic, financial, competitive, legislative, regulatory and other factors, some of which are beyond our control. In particular, economic conditions could cause the price of coal to fall, our revenue to decline and hamper our ability to repay our debt.

Our business may not generate sufficient cash flow from operations and future borrowings may not be available to us under our senior credit facility or otherwise in an amount sufficient to enable us to pay our debt, or to fund our other liquidity needs. We may need to refinance all or a portion of our debt on or before maturity. We may not be able to refinance any of our debt on commercially reasonable terms, on terms acceptable to us or at all.

Our ability and the ability of some of our subsidiaries to engage in some business transactions or to pursue our business strategy may be limited by the terms of our existing debt.

Our credit facility contains a number of financial covenants requiring us to meet financial ratios and other financial tests. The indenture governing our outstanding senior notes and our senior credit facility also restrict our and our subsidiaries' ability to:

- incur additional debt or issue guarantees;
- pay dividends on, redeem or repurchase capital stock;
- allow our subsidiaries to issue new stock to any person other than us or any of our other subsidiaries;
- make certain investments;
- make acquisitions;
- incur, or permit to exist, liens;
- enter into transactions with affiliates;
- guarantee the debt of other entities, including joint ventures;
- merge or consolidate or otherwise combine with another company; and
- transfer or sell a material amount of our assets outside the ordinary course of business.

These covenants could adversely affect our ability to finance our future operations or capital needs or to execute preferred business strategies.

Our ability to borrow under our credit facility will depend upon our ability to comply with these covenants and our borrowing base requirements. Our ability to meet these covenants and requirements may be affected by events beyond our control and we may not meet these obligations. From time to time, we have amended or revised our financial covenants, and have also received waivers of covenant compliance under our senior credit facility. However, we may not continue to receive waivers from our lenders or be permitted to amend the financial covenants. Our failure to comply with these covenants and requirements could result in an event of default under the indenture governing our outstanding senior notes that, if not cured or waived, could permit acceleration of our outstanding convertible and senior notes and permit foreclosure on any collateral granted as security under our senior credit facility. If our debt is accelerated, we may not be able to repay the notes or borrow sufficient funds to refinance the notes. Even if we were able to obtain new financing, it may not be on commercially reasonable terms, on terms that are acceptable to us or at all. If our debt is in default for any reason, our business, financial condition and results of operations could be materially and adversely affected.

We are subject to limitations on capital expenditures under our senior credit facility. Because of these limitations, we may not be able to pursue our business strategy to replace our equipment fleet as it ages, develop additional mines or pursue additional acquisitions without additional financing.

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We may not be able to repurchase our convertible senior notes if noteholders convert prior to maturity.

Upon the occurrence of specific events, our convertible senior notes may become convertible, requiring us to settle in cash the principal amount of the note, and any excess conversion value may be settled in cash or in shares of our common stock, at our option, as provided by the terms of the indenture governing the convertible senior notes. The convertible senior notes are convertible at an initial conversion price, subject to adjustment, of $6.10 per share (approximately 163.8136 shares per $1,000 principal amount of the convertible senior notes). If we elect to settle any excess conversion value of the convertible senior notes in cash, the holder will receive, for each $1,000 principal amount, the conversion rate multiplied by a 20-day average closing price of the common stock as set forth in the indenture beginning on the third trading day after the convertible senior notes are surrendered. We have $161.5 million of principal amount of convertible senior notes outstanding. In the event that a holder elects to convert its convertible senior notes, we would need to seek a waiver or amendment from our lenders to fund any cash settlement of any such conversion from working capital and/or borrowings under our amended credit facility in excess of $25.0 million per year. There is no assurance we will have sufficient cash on hand or available to fund the $161.5 million or that we would receive a waiver or amendment, especially in light of the current credit environment. In addition, if a significant number of noteholders were to convert their notes prior to maturity, we may not have enough available funds at any particular time to make the required repayments. Our failure to repurchase converted notes at a time when noteholders have the right to convert would constitute a default under the indenture. This default would, in turn, constitute an event of default under our amended and restated credit facility and could constitute an event of default under our senior notes, any of which could cause repayment of the related debt to be accelerated after any applicable notice or grace periods. If debt repayment were to be accelerated, we may not have sufficient funds to repurchase the convertible senior notes or repay the debt. Alternatively, upon conversion, we may issue additional stock to satisfy the payment obligation related to any excess conversion value which could lead to immediate and potentially substantial dilution in net tangible book value per share.

Our money market fund is vulnerable to market-specific risks that could adversely affect our financial position, future earnings or cash flows.

We currently have a portion of our assets invested in a money market fund. This investment is subject to investment market risk and our income from this investment could be adversely affected by a decline in value. In the case of money market accounts and other fixed income investment products, which invest in high-quality short-term money market instruments, as well as other fixed income securities, the value of the assets may decline as a result of changes in interest rates, an issuer's actual or perceived creditworthiness or an issuer's ability to meet its obligations. A significant decrease in the net asset value of the securities underlying the money market fund could cause a material decline in our net income and cash flows.

Provisions of our debt could discourage an acquisition of us by a third-party.

Certain provisions of our debt could make it more difficult or more expensive for a third-party to acquire us. Upon the occurrence of certain transactions constituting a fundamental change, holders of both series of notes will have the right, at their option, to require us to repurchase, at a cash repurchase price equal to 100% of the principal amount plus accrued and unpaid interest on the notes, all of their notes or any portion of the principal amount of such notes in integral multiples of $1,000. We may also be required to issue additional shares of our common stock upon conversion of such notes in the event of certain fundamental changes.

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Anti-takeover provisions in our charter documents and Delaware corporate law may make it difficult for our stockholders to replace or remove our current board of directors and could deter or delay third parties from acquiring us, which may adversely affect the marketability and market price of our common stock.

Provisions in our amended and restated certificate of incorporation and bylaws and in Delaware corporate law may make it difficult for stockholders to change the composition of our board of directors in any one year, and thus prevent them from changing the composition of management. In addition, the same provisions may make it difficult and expensive for a third-party to pursue a tender offer, change in control or takeover attempt that is opposed by our management and board of directors. Public stockholders who might desire to participate in this type of transaction may not have an opportunity to do so. These anti-takeover provisions could substantially impede the ability of public stockholders to benefit from a change in control or change our management and board of directors and, as a result, may adversely affect the marketability and market price of our common stock.

We are also subject to the anti-takeover provisions of Section 203 of the Delaware General Corporation Law. Under these provisions, if anyone becomes an “interested stockholder,” we may not enter into a “business combination” with that person for three years without special approval, which could discourage a third-party from making a takeover offer and could delay or prevent a change of control. For purposes of Section 203, “interested stockholder” means, generally, someone owning more than 15% or more of our outstanding voting stock or an affiliate of ours that owned 15% or more of our outstanding voting stock during the past three years, subject to certain exceptions as described in Section 203.

Under any change of control, the lenders under our credit facilities would have the right to require us to repay all of our outstanding obligations under the facility.

There may be circumstances in which the interests of our major stockholders could be in conflict with the interests of a stockholder or noteholder.

As of December 31, 2009, funds sponsored by WL Ross & Co. LLC (“WLR”) own approximately 14% of our common stock and funds sponsored by Fairfax Financial Holdings Limited (“Fairfax”) own approximately 26% of our common stock. Circumstances may occur in which WLR, Fairfax or other major investors may have an interest in pursuing acquisitions, divestitures or other transactions, including among other things, taking advantage of certain corporate opportunities that, in their judgment, could enhance their investment in us or another company in which they invest. These transactions might involve risks to our other holders of common stock or adversely affect us or other investors.

Future sales of our common stock by our major stockholders may depress our share price and influence our management policies.

WLR and Fairfax, which respectively own approximately 14% and 26% of our common stock as of December 31, 2009, may seek alternatives for the disposition of shares of our common stock. We have previously granted each of WLR and Fairfax “demand” and “piggyback” registration rights relating to their shares of our common stock. Sales of substantial amounts of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, if either WLR or Fairfax were to sell its entire holdings to one person, that person could have significant influence over our management policies.

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

We have never declared or paid a cash dividend, and we currently do not anticipate paying any cash dividends in the foreseeable future, see "Dividend Policy." Our payment of any future dividends will be at the discretion of our board of directors after taking into account various factors, including our financial condition, operating results, cash needs, growth plans and the terms of any credit agreements that we may be a party to at the time. If we were to decide in the future to pay dividends, our ability to do so would be dependent on the ability of our subsidiaries to make cash available to us, by dividend, debt repayment or otherwise. Accordingly, investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize their investment.

## ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

## ITEM 2. PROPERTIES

### Coal Reserves

"Reserves" 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. "Proven (Measured) Reserves" are defined by SEC Industry Guide 7 as reserves for which (1) 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 (2) the sites for inspection, 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" are defined by SEC Industry Guide 7 as reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) 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 (measured) reserves, is high enough to assume continuity between points of observation.

We estimate that there are approximately 297 million tons of coal reserves that can be developed by our existing operations, which will allow us to maintain current production levels for an extended period of time. ICG Natural Resources and CoalQuest own and lease all of our reserves that are not currently assigned to, or associated with, one of our mining operations. These reserves contain approximately 793 million tons of mid- to high-Btu, low and high sulfur coal located in Kentucky, West Virginia, Maryland, Illinois, Virginia and Ohio. Our multi-region base and flexible product line allows us to adjust to changing market conditions and sustain high sales volume by supplying a wide range of customers.

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Our total coal reserves could support current production levels for more than 67 years. The following table provides the location of our mining operations and the type of coal produced at those operations as of December 31, 2009:

| ons | Assigned or Unassigned (1) | Operating (O) or Development (D) | State | Mining Method Surface (S) or Underground (UG) | Total Proven and Probable Reserves (2) | Owned Proven and Probable Reserves(2) | Leased Proven and Probable Reserves(2) | Steam Proven and Probable Reserves(2) | Metall F |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | (in million tons) | | |
| achian | | | | | | | | | |
| Corp. | Assigned | O | MD | S | 6.53 | 0.00 | 6.53 | 6.53 | |
| | Unassigned | D | MD | S/UG | 58.48 | 0.34 | 58.14 | 38.24 | |
| nergy Corp. | | | | | 65.01 | 0.34 | 64.67 | 44.77 | |
| Co. | Assigned | O | WV | S | 9.37 | 0.00 | 9.37 | 9.37 | |
| ng Buckhannon | Assigned | O | WV | UG | 27.44 | 12.38 | 15.06 | 14.50 | |
| | Unassigned | D | WV | UG | 30.55 | 28.82 | 1.73 | 0.00 | |
| Mining vision | | | | | 57.99 | 41.20 | 16.79 | 14.50 | |
| | Assigned | O | WV | UG | 45.40 | 30.13 | 15.27 | 0.00 | |
| | Unassigned | D | WV | UG | 4.94 | 4.94 | 0.00 | 0.00 | |
| | | | | | 50.34 | 35.07 | 15.27 | 0.00 | |
| elopment LLC | Unassigned (Tygart) | D | WV | UG | 186.09 | 186.09 | 0.00 | 32.71 | |
| sources | Unassigned (Paw Paw Creek) | D | OH | UG | 94.25 | 94.25 | 0.00 | 94.25 | |
| Appalachian | | | | | 463.05 | 356.95 | 106.10 | 195.60 | |
| chian | | | | | | | | | |
| | Assigned | O | WV | S | 7.47 | 0.14 | 7.33 | 7.47 | |
| | Unassigned | D | WV | UG | 2.18 | 0.00 | 2.18 | 2.18 | |
| | | | | | 9.65 | 0.14 | 9.51 | 9.65 | |
| | Assigned | O | KY | S | 54.09 | 23.11 | 30.98 | 54.09 | |
| | Unassigned | D | KY | UG | 10.40 | 0.65 | 9.75 | 10.40 | |
| | | | | | 64.49 | 23.76 | 40.73 | 64.49 | |
| | Assigned | O | KY | UG | 23.38 | 0.58 | 22.80 | 23.38 | |
| | Assigned | O | KY | UG | 14.77 | 4.21 | 10.56 | 14.77 | |
| | Unassigned | D | KY | UG | 3.36 | 0.85 | 2.51 | 3.36 | |
| unty | | | | | 18.13 | 5.06 | 13.07 | 18.13 | |
| | Assigned | O | KY | UG | 10.15 | 0.00 | 10.15 | 10.15 | |
| | Assigned | O | KY | S | 1.57 | 1.32 | 0.25 | 1.57 | |
| sources | Assigned | D | WV | S | 14.71 | 0.00 | 14.71 | 14.71 | |
| | Unassigned (Jennie Creek) | D | WV | UG | 30.19 | 2.20 | 27.99 | 30.19 | |
| ral Resources | | | | | 44.90 | 2.20 | 42.70 | 44.90 | |
| n | Assigned | O | VA | UG | 4.85 | 0.00 | 4.85 | 4.85 | |
| | Unassigned | D | VA | S/UG | 22.02 | 0.00 | 22.02 | 22.02 | |
| ell Mountain | | | | | 26.87 | 0.00 | 26.87 | 26.87 | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Assigned | O | WV | UG | 31.28 | 1.28 | 30.00 | 0.00 |
| ergy, Inc. | Unassigned (Big Creek) | D | VA | UG | 25.91 | 0.00 | 25.91 | 0.00 |
| ppalachian | | | | | 256.33 | 34.34 | 221.99 | 199.14 |
| | | | | | | | | |
| | Assigned (Viper) | O | IL | UG | 46.07 | 8.50 | 37.57 | 46.07 |
| sources | Unassigned | D | IL | UG | 324.60 | 324.60 | 0.00 | 324.60 |
| asin | | | | | 370.67 | 333.10 | 37.57 | 370.67 |
| d Probable Reserves | | | | | 1,090.05 | 724.39 | 365.66 | 765.41 |

(1) "Assigned reserves" means coal which has been committed by the coal company to operating mine shafts, mining equipment and plant facilities, and all coal which has been leased by the coal company to others. "Unassigned reserves" represent coal which has not been committed, and which would require new mineshafts, mining equipment or plant facilities before operations could begin in the property. The primary reason for this distinction is to inform investors which coal reserves will require substantial capital investment before production can begin.

(2) The proven and probable reserves are reported as recoverable reserves, which is that part of a coal deposit which could be economically and legally extracted or produced at the time of the reserve determination, taking into account mining recovery and preparation plant yield.

(3) Beckley and White Wolf Energy, Inc. meet historical metallurgical coal quality specifications.

(4) We sold coal with ash and sulfur contents as high as 10% and 1.5%, respectively, into the metallurgical market from Vindex Energy, Buckhannon and Sentinel in 2009. Similarly, we believe a portion of production from Tygart could be sold into the metallurgical market when production begins.

For a description of mining properties, see Item 1. Business under the headings "Northern and Central Appalachian Mining Operations" and "Illinois Basin Mining Operations."

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The following table provides the “quality” (average moisture, ash and sulfur contents and Btu per pound) of our coal reserves as of December 31, 2009:

| | | As Received Quality | | | | | Total Proven and Probabl Reserves(2) | |
|---|---|---|---|---|---|---|---|---|
| ning Operations | Assigned or Unassigned (1) | % Moisture | % Ash | % Sulfur | Btu/lb. | Lbs. SO2/ million Btus | <1.2 lbs. SO2 Compliance | >1.2 lbs SO2 Non-Complia |
| rthern Appalachian | | | | | | | | |
| dex Energy Corp.(4) | Assigned | 4.66 | 19.29 | 1.82 | 11,700 | 3.11 | 0.00 | 6 |
| | Unassigned | 6.00 | 13.37 | 1.85 | 12,563 | 2.94 | 0.00 | 58 |
| al Vindex Energy Corp. | | 5.87 | 13.96 | 1.84 | 12,477 | 2.96 | 0.00 | 65 |
| riot Mining Co. | Assigned | 6.00 | 14.66 | 3.08 | 11,869 | 5.19 | 0.00 | 9 |
| lf Run Mining Buckhannon Division(4) | Assigned | 6.00 | 8.05 | 2.22 | 13,071 | 3.40 | 0.00 | 27 |
| | Unassigned | 6.00 | 8.92 | 0.99 | 13,069 | 1.52 | 0.00 | 30 |
| al Wolf Run Mining Buckhannon Division | | 6.00 | 8.51 | 1.57 | 13,070 | 2.41 | 0.00 | 57 |
| tinel | Assigned | 6.00 | 8.43 | 1.47 | 13,180 | 2.24 | 0.00 | 45 |
| | Unassigned | 6.00 | 8.04 | 1.44 | 13,353 | 2.15 | 0.00 | 4 |
| al Sentinel | | 6.00 | 8.39 | 1.47 | 13,197 | 2.23 | 0.00 | 50 |
| lQuest Development LLC(4) | Unassigned (Tygart) | 6.00 | 9.25 | 1.15 | 13,145 | 1.76 | 0.00 | 186 |
| G Natural Resources | Unassigned (Paw Paw Creek) | 6.00 | 7.62 | 2.07 | 13,021 | 3.18 | 0.00 | 94 |
| al Northern Appalachian | | | | | | | 0.00 | 463 |
| ntral Appalachian | | | | | | | | |
| tern | Assigned | 6.00 | 14.37 | 1.23 | 11,974 | 2.05 | 0.00 | 7 |
| | Unassigned | 6.00 | 9.54 | 1.23 | 12,779 | 1.93 | 0.00 | 2 |
| al Eastern | | 6.00 | 13.28 | 1.23 | 12,156 | 2.02 | 0.00 | 9 |
| zard | Assigned | 6.00 | 12.67 | 1.40 | 12,055 | 2.33 | 0.00 | 54 |
| | Unassigned | 6.00 | 6.55 | 0.84 | 12,890 | 1.30 | 0.00 | 10 |
| al Hazard | | 6.00 | 11.69 | 1.31 | 12,190 | 2.15 | 0.00 | 64 |
| t Ridge | Assigned | 6.00 | 8.15 | 1.39 | 12,768 | 2.17 | 1.33 | 22 |
| ott County | Assigned | 6.02 | 6.94 | 1.56 | 13,056 | 2.39 | 0.05 | 14 |
| | Unassigned | 6.00 | 7.07 | 1.79 | 13,034 | 2.75 | 0.00 | 3 |
| al Knott County | | 6.01 | 6.96 | 1.60 | 13,052 | 2.45 | 0.05 | 18 |
| ven | Assigned | 6.00 | 7.21 | 1.35 | 12,912 | 2.10 | 0.00 | 10 |
| t Kentucky | Assigned | 5.94 | 9.28 | 0.85 | 12,441 | 1.37 | 0.00 | 1 |
| G Natural Resources | Assigned | 7.00 | 9.65 | 0.75 | 12,281 | 1.22 | 9.59 | 5 |
| | Unassigned (Jennie Creek) | 7.00 | 4.92 | 1.27 | 13,254 | 1.92 | 0.00 | 30 |
| al ICG Natural Resources | | 7.00 | 6.47 | 1.10 | 12,935 | 1.70 | 9.59 | 35 |
| vell Mountain | Assigned | 6.00 | 3.92 | 0.62 | 14,428 | 0.86 | 4.85 | 0 |
| | Unassigned | 6.00 | 8.38 | 2.01 | 13,194 | 3.04 | 6.46 | 15 |
| Total Powell Mountain | | 6.00 | 7.57 | 1.76 | 13,417 | 2.62 | 11.31 | 15 |
| ckley(3) | Assigned | 6.00 | 4.87 | 0.70 | 13,913 | 1.01 | 31.28 | 0 |
| ite Wolf Energy, Inc.(3) | Unassigned (Big Creek) | 6.00 | 4.09 | 0.63 | 14,150 | 0.89 | 25.91 | 0 |
| al Central Appalachian | | | | | | | 79.47 | 176 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| nois Basin | | | | | | | | |
| nois | Assigned (Viper) | 16.00 | 8.80 | 2.86 | 10,692 | 5.35 | 0.00 | 46 |
| G Natural Resources | Unassigned | 12.75 | 9.28 | 2.88 | 10,963 | 5.25 | 0.00 | 324 |
| al Illinois Basin | | | | | | | 0.00 | 370 |
| al Proven and Probable Reserves | | | | | | | 79.47 | 1,010 |

(1) "Assigned reserves" means coal which has been committed by the coal company to operating mine shafts, mining equipment and plant facilities, and all coal which has been leased by the coal company to others. "Unassigned reserves" represent coal which has not been committed, and which would require new mine shafts, mining equipment or plant facilities before operations could begin in the property. The primary reason for this distinction is to inform investors which coal reserves will require substantial capital investment before production can begin.

(2) The proven and probable reserves are reported as recoverable reserves, which is that part of a coal deposit which could be economically and legally extracted or produced at the time of the reserve determination, taking into account mining recovery and preparation plant yield.

(3) Beckley and White Wolf Energy, Inc. meet historical metallurgical coal quality specifications.

(4) We sold coal with ash and sulfur contents as high as 10% and 1.5%, respectively, into the metallurgical market from Vindex Energy, Buckhannon and Sentinel in 2009. Similarly, we believe a portion of production from Tygart could be sold into the metallurgical market when production begins.

For a description of mining properties, see Item 1. Business under the headings "Northern and Central Appalachian Mining Operations" and "Illinois Basin Mining Operations."

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Our reserve estimates are based on geological data assembled and analyzed by our staff of geologists and engineers. Reserve estimates are periodically updated to reflect past coal production, new drilling information and other geologic or mining data. Acquisitions, sales or dispositions of coal properties will also change the reserve estimates. We estimate that we controlled 1.1 billion tons of reserves at December 31, 2009. Changes in mining methods may increase or decrease the recovery basis for a coal seam, as will plant processing efficiency tests. We maintain reserve information in secure computerized databases, as well as in hard copy. The ability to update and/or modify the reserves is restricted to a few individuals and the modifications are documented.

Actual reserves may vary substantially from the estimates. Estimated minimum recoverable reserves are comprised of coal that is considered to be merchantable and economically recoverable by using mining practices and techniques prevalent in the coal industry at the time of the reserve study, based upon then-current prevailing market prices for coal. We use the mining method that we believe will be most profitable with respect to particular reserves. We believe the volume of our current reserves exceeds the volume of our contractual delivery requirements. Although the reserves shown in the table above include a variety of qualities of coal, we presently blend coal of different qualities to meet contract specifications. See “Risk Factors—Risks Relating To Our Business.”

We currently own approximately 66% of our coal reserves, with the remainder of our coal reserves subject to leases from third-party landowners. Generally, these leases convey mining rights to the coal producer in exchange for a percentage of gross sales in the form of a royalty payment to the lessor, subject to minimum payments. Leases generally last for the economic life of the reserves. The average royalties paid by us for coal reserves from our producing properties was $3.39 per ton in 2009, representing approximately 5.5% (net of freight and handling) of our coal sales revenue in 2009. Consistent with industry practice, we conduct only limited investigations of title to our coal properties prior to leasing. Title to lands and reserves of the lessors or grantors and the boundaries of our leased priorities are not completely verified until we prepare to mine those reserves.

Non-Reserve Coal Deposits

Non-reserve coal deposits are coal-bearing bodies that have been sufficiently sampled and analyzed in trenches, outcrops, drilling and underground workings to assume continuity between sample points and, therefore, warrant further exploration stage work. However, this coal does not qualify as a commercially viable coal reserve as prescribed by SEC standards until a final comprehensive evaluation based on unit cost per ton, recoverability and other material factors concludes legal and economic feasibility. Non-reserve coal deposits may be classified as such by limited property control, geologic limitations or both.

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The following table provides the location of our mining operations and the type and amount of non-reserve coal deposits at those complexes as of December 31, 2009:

| Mining Operations | Assigned or Unassigned (1) | Operating (O) or Development (D) | State | Mining Method Surface (S) or Underground (UG) | Total Non-Reserve Coal Deposits | Steam Non-Reserve Coal Deposits | Metallurgical(2)(3) Non-Reserve Coal Deposits |
|---|---|---|---|---|---|---|---|
| | | | | | (in million tons) | | |
| Northern Appalachian | | | | | | | |
| Vindex Energy Corp. | Unassigned | D | MD | S | 0.44 | 0.00 | 0.44 |
| Wolf Run Mining Buckhannon Division | Assigned | O | WV | UG | 1.45 | 1.45 | 0.00 |
| | Unassigned | D | WV | UG | 2.25 | 2.25 | 0.00 |
| Total Wolf Run Mining Buckhannon Division | | | | | 3.70 | 3.70 | 0.00 |
| Sentinel | Assigned | O | WV | UG | 1.64 | 1.64 | 0.00 |
| | Unassigned | D | WV | UG | 0.76 | 0.76 | 0.00 |
| Total Sentinel | | | | | 2.40 | 2.40 | 0.00 |
| CoalQuest Development LLC | Unassigned | D | WV | UG | 38.14 | 38.14 | 0.00 |
| | (Tygart) | | | | | | |
| Upshur Property | Unassigned | | WV | S | 92.96 | 92.96 | 0.00 |
| | (Upshur) | | | | | | |
| ICG Natural Resources | Unassigned | D | OH | UG | 5.77 | 5.77 | 0.00 |
| | (Paw Paw Creek) | | | | | | |
| Total Northern Appalachian | | | | | 143.41 | 142.97 | 0.44 |
| Central Appalachian | | | | | | | |
| Eastern | Assigned | O | WV | S | 0.02 | 0.02 | 0.00 |
| Hazard | Assigned | O | KY | S | 8.02 | 8.02 | 0.00 |
| Flint Ridge | Assigned | O | KY | UG | 0.94 | 0.94 | 0.00 |
| Knott County | Assigned | O | KY | UG | 0.48 | 0.48 | 0.00 |
| ICG Natural Resources | Assigned | D | WV | S | 0.22 | 0.22 | 0.00 |
| | (Jennie Creek) | | | | | | |
| ICG Natural Resources | Unassigned | D | KY | S/UG | 35.59 | 35.59 | 0.00 |
| | (Martin Co., Muhlenberg Co.) | | | | | | |
| ICG Natural Resources | Unassigned | | WV | S/UG | 21.62 | 21.62 | 0.00 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | (Mobil) | | | | | | |
| Powell Mountain | Unassigned | O | VA | UG | 46.07 | 46.07 | 0.00 |
| Beckley | Unassigned | D | WV | UG | 1.88 | 0.00 | 1.88 |
| Juliana Mining Co., Inc. | Unassigned | D | WV | S/UG | 3.10 | 3.10 | 0.00 |
| White Wolf Energy, Inc. | Unassigned | D | VA | UG | 2.57 | 2.57 | 0.00 |
| | (Big Creek) | | | | | | |
| Total Central Appalachian | | | | | 120.51 | 118.63 | 1.88 |
| Illinois Basin | | | | | | | |
| Illinois | Assigned | O | IL | UG | 38.47 | 38.47 | 0.00 |
| | (Viper) | | | | | | |
| ICG Natural Resources | Unassigned | | IL | UG | 57.92 | 57.92 | 0.00 |
| | (Illinois) | | | | | | |
| Total Illinois Basin | | | | | 96.39 | 96.39 | 0.00 |

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| Mining Operations | Assigned or Unassigned(1) | Operating (O) or Development (D) | State | Mining Method Surface (S) or Underground (UG) | Total Non-Reserve Coal Deposits | Steam Non-Reserve Coal Deposits | Metallurgical(2)(3) Non-Reserve Coal Deposits |
|---|---|---|---|---|---|---|---|
| | | | | | | (in million tons) | |
| Ancillary | | | | | | | |
| ICG Natural Resources | Unassigned (Arkansas) | | AR | S | 39.15 | 39.15 | 0.00 |
| | Unassigned (California) | | CA | UG | 10.00 | 10.00 | 0.00 |
| | Unassigned (Montana) | | MT | S | 12.00 | 12.00 | 0.00 |
| | Unassigned (Washington) | | WA | S | 9.86 | 9.86 | 0.00 |
| Total Ancillary | | | | | 71.01 | 71.01 | 0.00 |
| Total Non-Reserve Coal Deposits | | | | | 431.32 | 429.00 | 2.32 |

(1) "Assigned non-reserve coal deposits" mean coal which has been committed by the coal company to operating mine shafts, mining equipment and plant facilities, and all coal which has been leased by the coal company to others. "Unassigned non-reserve coal deposits" represent coal which has not been committed, and which would require new mine shafts, mining equipment or plant facilities before operations could begin in the property.

(2) Beckley and White Wolf Energy, Inc. meet historical metallurgical coal quality specifications.

(3) We sold coal with ash and sulfur contents as high as 10% and 1.5%, respectively, into the metallurgical market from Vindex Energy, Buckhannon and Sentinel in 2009. Similarly, we believe a portion of the production from Tygart can be sold into the metallurgical market.

For a description of mining properties, see Item 1. Business under the headings "Northern and Central Appalachian Mining Operations" and "Illinois Basin Mining Operations."

The following table provides the "quality" (average moisture, ash and sulfur contents and Btu per pound) of our non-reserve coal deposits as of December 31, 2009:

| | | As Received Quality | | | | |
|---|---|---|---|---|---|---|
| Mining Operations | Assigned or Unassigned (1) | % Moisture | % Ash | % Sulfur | Btu/ lb. | Lbs. SO2/ million Btus |
| Northern Appalachian | | | | | | |
| Vindex Energy Corp.(3) | Unassigned | 6.00 | 14.15 | 1.49 | 12,409 | 2.40 |
| Wolf Run Mining Buckhannon Division(3) | Assigned | 6.00 | 7.43 | 2.83 | 13,086 | 4.32 |
| | Unassigned | 6.00 | 9.00 | 1.20 | 13,000 | 1.85 |
| Sentinel | Assigned | 6.00 | 8.30 | 1.40 | 13,100 | 2.14 |
| | Unassigned | 6.00 | 8.30 | 1.40 | 13,100 | 2.14 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Upshur Property | Unassigned | 6.00 | 43.00 | 2.00 | 8,000 | 5.00 |
| | | | | | | |
| ICG Natural Resources | Unassigned (Paw Paw Creek) | 6.00 | 7.62 | 2.07 | 13,021 | 3.18 |
| Central Appalachian | | | | | | |
| Eastern | Assigned | 6.00 | 12.20 | 1.20 | 12,400 | 1.94 |
| Hazard | Assigned | 6.00 | 13.00 | 1.17 | 11,965 | 1.96 |
| Flint Ridge | Assigned | 6.00 | 8.15 | 1.39 | 12,768 | 2.18 |
| Knott County | Assigned | 6.00 | 6.82 | 1.90 | 13,040 | 2.91 |
| ICG Natural Resources | Assigned (Jennie Creek) | 7.00 | 7.78 | 0.63 | 12,609 | 1.01 |
| ICG Natural Resources | Unassigned (Martin Co., Muhlenberg Co.) | 6.00 | 11.47 | 1.91 | 11,780 | 3.24 |
| ICG Natural Resources | Unassigned (Mobil) | 6.00 | 12.50 | 1.10 | 12,000 | 1.83 |
| Powell Mountain | Unassigned | 6.00 | 5.78 | 1.21 | 13,348 | 1.81 |
| Beckley(2) | Unassigned | 6.00 | 4.80 | 0.70 | 13,800 | 1.01 |
| Juliana Mining Co., Inc. | Unassigned | 6.00 | 7.50 | 0.82 | 13,100 | 1.25 |
| White Wolf Energy, Inc.(2) | Unassigned (Big Creek) | 6.00 | 7.40 | 0.60 | 13,500 | 0.89 |

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| Mining operations | Assigned or Unassigned (1) | As received quality % Moisture | % Ash | % Sulfur | Btu/ lb. | Lbs. SO2/ million Btus |
|---|---|---|---|---|---|---|
| Illinois Basin | | | | | | |
| Illinois | Assigned (Viper) | 16.00 | 9.50 | 3.50 | 10,500 | 6.67 |
| ICG Natural Resources | Unassigned (Illinois) | 13.00 | 9.00 | 3.00 | 11,000 | 5.45 |
| Ancillary | | | | | | |
| ICG Natural Resources | Unassigned (Arkansas) | N/A | 8.00 | 0.40 | 5,650 | 1.42 |
| | Unassigned (California) | 6.00 | 13.00 | 3.50 | 11,700 | 5.98 |
| | Unassigned (Montana) | N/A | 8.00 | 0.30 | 8,900 | 0.67 |
| | Unassigned (Washington) | N/A | 8.00 | 0.50 | 7,025 | 1.42 |

(1) "Assigned non-reserve coal deposits" mean coal which has been committed by the coal company to operating mine shafts, mining equipment and plant facilities, and all coal which has been leased by the coal company to others. "Unassigned non-reserve coal deposits" represent coal which has not been committed, and which would require new mineshafts, mining equipment or plant facilities before operations could begin in the property.

(2) Beckley and White Wolf Energy, Inc. meet historical metallurgical coal quality specifications.

(3) We sold coal with ash and sulfur contents as high as 10% and 1.5%, respectively, into the metallurgical market from Vindex Energy, Buckhannon and Sentinel 2009. Similarly, we believe a portion of the production from Tygart can be sold into the metallurgical market.

For a description of mining properties, see Item 1. Business under the headings "Northern and Central Appalachian Mining Operations" and "Illinois Basin Mining Operations."

## ITEM 3. LEGAL PROCEEDINGS

See Note 16–Commitments and Contingencies–Legal Matters to the audited consolidated financial statements included in Item 15 of this Annual Report on Form 10-K relating to certain legal proceedings, which information is incorporated herein by reference.

## ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders during the quarter ended December 31, 2009.

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PART II

## ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange (the "NYSE") under the symbol "ICO." The following table sets forth, for the quarterly periods indicated, the high and low sales prices per share of our common stock as reported on the NYSE.

| | Stock Price High | Stock Price Low |
|---|---|---|
| 2009 | | |
| January 1, 2009 through March 31, 2009 | $3.24 | $1.09 |
| April 1, 2009 through June 30, 2009 | 3.70 | 1.54 |
| July 1, 2009 through September 30, 2009 | 4.59 | 2.24 |
| October 1, 2009 through December 31, 2009 | 5.35 | 3.47 |
| | | |
| 2008 | | |
| January 1, 2008 through March 31, 2008 | $7.17 | $4.75 |
| April 1, 2008 through June 30, 2008 | 13.90 | 6.00 |
| July 1, 2008 through September 30, 2008 | 13.37 | 5.52 |
| October 1, 2008 through December 31, 2008 | 6.19 | 1.50 |

These quotes are provided solely for informational purposes and may not be indicative of any price at which the shares of common stock may trade in the future.

As of January 15, 2010, there were approximately 249 holders of record of our common stock and an additional 46,574 stockholders whose shares were held for them in street name or nominee accounts.

Summary of Equity Compensation Plans

Shown below is information concerning our equity compensation plans and individual compensation arrangements as of December 31, 2009.

Equity Compensation Plan Information

| Plan Category | Number of Securities To Be Issued Upon Exercise of Outstanding Options | Weighted Average Exercise Price of Outstanding Options | Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans |
|---|---|---|---|
| Equity compensation plans approved by stockholders(1) | 4,715,558 | $ 4.60 | 10,911,409 |
| Equity compensation plans not approved by stockholders(2) | 319,052 | 10.97 | — |
| | 5,034,610 | $ 5.00 | 10,911,409 |

(1)

We have one compensation plan: the 2005 Equity and Performance Incentive Plan, as amended by stockholder approval on May 20, 2009.

(2) Represents stock option grant to purchase 319,052 shares of our common stock to our President and Chief Executive Officer pursuant to his employment agreement.

For additional information regarding our equity compensation plans, refer to the discussion in Note 13 to the audited consolidated financial statements included in Item 15 of this Annual Report on Form 10-K.

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Issuer Purchases of Equity Securities

| Period | Number of Shares Purchased (1) | Average Price Paid per Share(1) | Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| January 1, 2009 through January 31, 2009 | — | $ — | — | — |
| February 1, 2009 through February 28, 2009 | — | — | — | — |
| March 1, 2009 through March 31, 2009 | 4,768 | 1.76 | — | — |
| April 1, 2009 through April 30, 2009 | 2,165 | 1.99 | — | — |
| May 1, 2009 through May 31, 2009 | — | — | — | — |
| June 1, 2009 through June 30, 2009 | 388 | 2.86 | — | — |
| July 1, 2009 through July 31, 2009 | — | — | — | — |
| August 1, 2009 through August 31, 2009 | — | — | — | — |
| September 1, 2009 through September 30, 2009 | — | — | — | — |
| October 1, 2009 through October 31, 2009 | — | — | — | — |
| November 1, 2009 through November 30, 2009 | — | — | — | — |
| December 1, 2009 through December 31, 2009 | — | — | — | — |
| Total | 7,321 | $ 2.20 | — | — |

(1) During the year ended December 31, 2009, we withheld 7,321 shares of common stock from employees to satisfy estimated tax obligations upon the vesting of restricted stock under the terms of our 2005 Equity and Performance Incentive Plan. The value of the common stock that was withheld was based upon the closing price of our common stock on the applicable vesting dates.

Dividend Policy

We have never declared or paid a dividend on our common stock. We may retain any future earnings to support the development and expansion of our business or make additional payments under our credit facilities and, as a result, we may not pay cash dividends in the foreseeable future. Our payment of any future dividends will be at the discretion of our board of directors after taking into account various factors, including our financial condition, operating results, cash needs, growth plans and the terms of any credit agreements that we may be a party to at the time. Our credit facility and indenture governing the senior notes limits us from paying cash dividends or other payments or distributions with respect to our capital stock in excess of certain limitations. In addition, the terms of any future credit agreement may contain similar restrictions on our ability to pay dividends or make payments or distributions with respect to our capital stock.

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## ITEM 6. SELECTED FINANCIAL DATA

The selected historical consolidated financial data is derived from International Coal Group, Inc.'s audited consolidated financial statements as of December 31, 2009 and 2008 and for the years ended December 31, 2009, 2008 and 2007 which is included elsewhere in this Annual Report on Form 10-K. The selected historical consolidated financial data of International Coal Group, Inc. as of December 31, 2007, 2006 and 2005 and for the years ended December 31, 2006 and 2005 is derived from audited consolidated financial statements which are not included in this Annual Report on Form 10-K.

During the year ended December 31, 2009, we entered into a series of privately negotiated agreements pursuant to which we issued a total of 18,660,550 shares of our common stock in exchange for $63.5 million aggregate principal amount of our 9.00% Convertible Senior Notes due 2012. As a result of the exchanges, we recognized losses on extinguishment of the related debt totaling $13.3 million for the year ended December 31, 2009.

During the years ended December 31, 2008 and 2007, we recognized impairment losses of $37.4 million and $170.4 million, respectively. For 2008, $30.2 million of the loss related to impairment of goodwill at our ADDCAR subsidiary and $7.2 million related to impairment of long-lived assets. For 2007, the impairment loss related to impairment of goodwill at various of our business units. See Notes 4 and 5 to our audited consolidated financial statements included in Item 15 of this Annual Report on Form 10-K for further discussion of the impairment losses.

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You should read the following data in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and with the financial information included elsewhere in this Annual Report on Form 10-K, including the consolidated financial statements of International Coal Group, Inc. and the related notes thereto. Amounts shown are in thousands, except per share data.

| | Year ended December 31, 2009 | Year ended December 31, 2008 | Year ended December 31, 2007 | Year ended December 31, 2006 | Year ended December 31, 2005(1) |
|---|---|---|---|---|---|
| Statement of Operations Data: | | | | | |
| Coal sales revenues | $ 1,006,606 | $ 998,245 | $ 770,663 | $ 833,998 | $ 619,038 |
| Freight and handling revenues | 26,279 | 45,231 | 29,594 | 18,890 | 8,601 |
| Other revenues | 92,464 | 53,260 | 48,898 | 38,706 | 22,852 |
| Total revenues | 1,125,349 | 1,096,736 | 849,155 | 891,594 | 650,491 |
| Costs and Expenses: | | | | | |
| Cost of coal sales and other revenues | 868,303 | 918,655 | 766,158 | 769,332 | 510,097 |
| Freight and handling costs | 26,279 | 45,231 | 29,594 | 18,890 | 8,601 |
| Depreciation, depletion and amortization | 106,084 | 96,047 | 86,517 | 72,218 | 43,076 |
| Selling, general and administrative | 32,749 | 38,147 | 33,325 | 34,578 | 28,828 |
| Gain on sale of assets | (3,659) | (32,518) | (38,656) | (1,125) | (502) |
| Impairment loss | — | 37,428 | 170,402 | — | — |
| Total costs and expenses | 1,029,756 | 1,102,990 | 1,047,340 | 893,893 | 590,100 |
| Income (loss) from operations | 95,593 | (6,254) | (198,185) | (2,299) | 60,391 |
| Interest and Other Income (Expense): | | | | | |
| Loss on extinguishment of debt | (13,293) | — | — | — | — |
| Interest expense, net | (53,044) | (43,643) | (35,989) | (18,091) | (14,394) |
| Other, net | — | — | 319 | 2,113 | 3,302 |
| Total interest and other income (expense) | (66,337) | (43,643) | (35,670) | (15,978) | (11,092) |
| Income (loss) before income taxes | 29,256 | (49,897) | (233,855) | (18,277) | 49,299 |
| Income tax benefit (expense) | (7,732) | 23,670 | 85,944 | 9,015 | (16,986) |
| Net income (loss) | 21,524 | (26,227) | (147,911) | (9,262) | 32,313 |
| Net (income) loss attributable to noncontrolling interest | (66) | — | 349 | (58) | 15 |
| Net income (loss) attributable to International Coal Group, Inc. | $ 21,458 | $ (26,227) | $ (147,562) | $ (9,320) | $ 32,328 |

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| | Year ended December 31, 2009 | Year ended December 31, 2008 | Year ended December 31, 2007 | Year ended December 31, 2006 | Year ended December 31, 2005(1) |
|---|---|---|---|---|---|
| Earnings Per Share: | | | | | |
| Basic | $ 0.14 | $ (0.17) | $ (0.97) | $ (0.06) | $ 0.29 |
| Diluted | 0.14 | (0.17) | (0.97) | (0.06) | 0.29 |
| Weighted-Average Common Shares Outstanding: | | | | | |
| Basic | 153,630,446 | 152,632,586 | 152,304,461 | 152,028,165 | 111,120,211 |
| Diluted | 155,386,263 | 152,632,586 | 152,304,461 | 152,028,165 | 111,161,287 |
| Balance Sheet Data (at year end): | | | | | |
| Cash and cash equivalents | $ 92,641 | $ 63,930 | $ 107,150 | $ 18,742 | $ 9,187 |
| Total assets | 1,367,960 | 1,350,647 | 1,303,363 | 1,316,891 | 1,051,403 |
| Long-term debt and capital leases | 384,309 | 432,870 | 391,248 | 180,035 | 45,462 |
| Total liabilities | 758,726 | 841,530 | 771,595 | 655,326 | 383,879 |
| Total stockholders' equity | 609,234 | 509,117 | 531,768 | 661,565 | 667,524 |
| Total liabilities and stockholders' equity | 1,367,960 | 1,350,647 | 1,303,363 | 1,316,891 | 1,051,403 |
| Statement of Cash Flows Data: | | | | | |
| Net cash from: | | | | | |
| Operating activities | $ 115,754 | $ 78,729 | $ 22,471 | $ 55,591 | $ 77,319 |
| Investing activities | (73,158) | (124,040) | (126,907) | (160,769) | (104,713) |
| Financing activities | (13,885) | 2,091 | 192,844 | 114,733 | 12,614 |
| Capital expenditures | 66,345 | 132,800 | 160,807 | 165,658 | 108,231 |

(1) On November 18, 2005, we completed our reorganization and acquisition of Anker and CoalQuest Development LLC ("CoalQuest"). The results of operations are included in our consolidated results of operations since that date.

## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion contains forward-looking statements that include numerous risks and uncertainties. Actual results could differ materially from those discussed in the forward-looking statements as a result of these risks and uncertainties, including those set forth in this Annual Report on Form 10-K under "Special Note Regarding Forward-Looking Statements" and under "Risk Factors." You should read the following discussion in conjunction with

"Selected Financial Data" and the audited and unaudited consolidated financial statements and notes thereto of International Coal Group, Inc. and its subsidiaries appearing elsewhere in this Annual Report on Form 10-K.

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Overview

We produce, process and sell coal from 13 regional mining complexes, which, as of December 31, 2009 were supported by 11 active underground mines, 11 active surface mines and 10 preparation plants located throughout West Virginia, Kentucky, Virginia, Maryland and Illinois. We have three reportable business segments, which are based on the coal regions in which we operate: (i) Central Appalachian, comprised of both surface and underground mines, (ii) Northern Appalachian, also comprised of both surface and underground mines and (iii) Illinois Basin, representing one underground mine. For more information about our reportable business segments, please see our audited consolidated financial statements and the notes thereto included in Item 15 of this Annual Report on Form 10-K. We also broker coal produced by others, the majority of which is shipped directly from the third-party producer to the ultimate customer. Our coal sales are primarily to large utilities and industrial customers in the Eastern region of the United States and domestic and international steel companies and brokers. In addition, we generate other revenues from the manufacture and operation of highwall mining systems, parts sales and shop services relating to those systems and coal handling and processing fees.

Our primary expenses are wages and benefits, repair and maintenance expenditures, diesel fuel purchases, blasting supplies, coal transportation costs, cost of purchased coal, royalties, freight and handling costs and taxes incurred in selling our coal.

Certain Trends and Economic Factors Affecting the Coal Industry

Our revenues depend on the price at which we are able to sell our coal. The pricing environment for domestic steam and metallurgical coal during 2009 weakened from the relatively strong pricing experienced throughout much of 2008. Near the end of 2008 and continuing into 2009, coal prices dropped drastically due to decreased demand for metallurgical coal caused by the global economic crisis and decreased demand for steam coal caused by high inventory levels at utilities. Accordingly, we have experienced decreased costs for commodities, such as fuel, explosives and steel products. We did, however, see an increase in our labor and healthcare costs as a result of wage increases given in late 2008 in an effort to remain competitive in what had been a tight labor market and an increase in medical benefits over the prior year. While compensation related costs increased over 2008, we expect that current economic conditions will reduce the inflationary pressures that drove up such costs in recent years. Conversely, we expect to experience higher costs for surety bonds and letters of credit resulting from more stringent regulatory requirements.

For additional information regarding some of the risks and uncertainties that affect our business and the industry in which we operate, see Item 1A. Risk Factors.

Critical Accounting Policies and Estimates

Our financial statements are prepared in accordance with accounting principles that are generally accepted in the United States of America. The preparation of these financial statements requires management to make estimates and judgments that affect the reported amount of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities. Management evaluates its estimates on an on-going basis. Management bases its estimates and judgments on historical experience and other factors that are believed to be reasonable under the circumstances. Actual results may differ from the estimates used. Our actual results have generally not differed materially from our estimates. However, we monitor such differences and, in the event that actual results are significantly different from those estimated, we disclose any related impact on our results of operations, financial position and cash flows. Note 2 to our audited consolidated financial statements included in Item 15 of this Annual Report on Form 10-K provides a description of our significant accounting policies. We believe that of these significant accounting policies, the following involve a higher degree of judgment or complexity:

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Revenue Recognition

Coal revenues result from sales contracts (long-term coal agreements or purchase orders) with electric utilities, industrial companies or other coal-related organizations, primarily in the eastern United States. Revenue is recognized and recorded when shipment or delivery to the customer has occurred, prices are fixed or determinable and the title or risk of loss has passed in accordance with the terms of the sales agreement. Under the typical terms of these agreements, risk of loss transfers to the customers at the mine or port, when the coal is loaded on the rail, barge, truck or other transportation sources that deliver coal to its destination.

Coal sales revenues also result from the sale of brokered coal produced by others. The revenues related to brokered coal sales are included in coal sales revenues on a gross basis and the corresponding cost of the coal from the supplier is recorded in cost of coal sales in accordance with ASC Subtopic 605-45, Principal Agent Considerations (“ASC 605-45”).

Freight and handling costs paid to third-party carriers and invoiced to coal customers are recorded as freight and handling costs and freight and handling revenues, respectively.

Other revenues primarily consist of contract mining income, coalbed methane sales, ash disposal services, equipment and parts sales, equipment rebuild and maintenance services, royalties and coal handling and processing income. With respect to other revenues recognized in situations unrelated to the shipment of coal, we carefully review the facts and circumstances of each transaction and do not recognize revenue until the following criteria are met: persuasive evidence of an arrangement exists, delivery has occurred or services have been rendered, the seller’s price to the buyer is fixed or determinable and collectibility is reasonably assured. Advance payments received are deferred and recognized in revenue when earned.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not bear interest. The allowance for doubtful accounts represents management’s best estimate of the amount of probable credit losses in our existing accounts receivable. We establish provisions for losses on accounts receivable when it is probable that all or part of the outstanding balance will not be collected. Management regularly reviews collectability and establishes or adjusts the allowance as necessary. Although we believe the estimate of credit losses we have made is reasonable and appropriate, inability to collect outstanding accounts receivable amounts could materially impact our reported financial results.

Reclamation

Our asset retirement obligations arise from the Federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. We record these reclamation obligations according to the provisions of ASC Topic 410, Asset Retirement and Environmental Obligations (“ASC 410”). ASC 410 requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which the legal obligation associated with the retirement of the long-lived asset is incurred. Fair value of reclamation liabilities is determined based on the present value of the estimated future expenditures. 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, and the capitalized cost is depreciated over the useful life of the related asset. If the assumptions used to estimate the liability do not materialize as expected or regulatory changes were to occur, reclamation costs or obligations to perform reclamation and mine closure activities could be materially different than currently estimated. To settle the liability, the mine property is reclaimed and, to the extent there is a difference between the liability and the amount of cash paid to perform the reclamation, a gain or loss upon settlement is recognized. On at least an annual basis, we review our entire reclamation liability and make necessary adjustments for permit changes as granted by state authorities, additional costs resulting from accelerated mine closures and revisions to cost estimates and productivity assumptions to reflect current experience. At December 31, 2009, we had recorded asset retirement obligation liabilities of $75.0 million, including amounts reported as current liabilities. While the precise amount of these future costs cannot be determined with certainty, as of December 31, 2009, we estimate that the aggregate undiscounted cost of final mine closure is approximately $151 million.

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Advance Royalties

We are required, under certain royalty lease agreements, to make minimum royalty payments whether or not mining activity is being performed on the leased property. These minimum payments may be recoupable once mining begins on the leased property. The recoupable minimum royalty payments are capitalized and amortized based on the units-of-production method at a rate defined in the lease agreement once mining activities begin. Unamortized deferred royalty costs are expensed when mining has ceased or a decision is made not to mine on such property. We have recorded an allowance for such circumstances based upon management's plans for the continuing operation of existing mine sites or for when properties will be developed and/or mined. We believe the estimate for losses is appropriate. However, actual amounts that we recoup through mining activity could vary resulting in a material impact to our financial results.

Inventories

Coal inventories are stated at lower of average cost or market and represent coal contained in stockpiles, including those tons that have been mined and hauled to our loadout facilities, but not yet shipped to customers. These inventories are stated in clean coal equivalent tons and take into account any loss that may occur during the processing stage. Coal must be of a quality that can be sold on existing sales orders to be carried as coal inventory. Coal inventory volumes are determined through survey procedures. The surveys involve assumptions, inherent uncertainties and the application of management judgment.

Parts and supplies inventories are valued at average cost, less an allowance for obsolescence. We establish provisions for losses in parts and supplies inventory values through analysis of turnover of inventory items and adjust the allowance as necessary.

Although we believe the estimates we have made with respect to the valuation of our coal and parts and supplies inventories are reasonable and appropriate, changes in assumptions (coal inventories) or actual utilization of items (parts and supplies inventories) could materially impact our reported financial results.

Depreciation, Depletion and Amortization

Property, plant, equipment and mine development, which includes coal lands and mineral rights, are recorded at cost, which includes construction overhead and interest, where applicable. Expenditures for major renewals and betterments are capitalized while expenditures for maintenance and repairs are expensed as incurred.

Mine development, coal lands and mineral rights costs are amortized using the units-of-production method, based on estimated recoverable tons. There are uncertainties inherent in estimating quantities of recoverable tons related to particular mine development, coal lands and mineral rights areas. Recoverable tons contained in an area are based on engineering estimates which can, and often do, change as the tons are mined. Any change in the number of recoverable tons contained in mine development, coal lands and mineral rights areas will result in a change in the depletion rate and corresponding depletion expense. For the year ended December 31, 2009, we recognized $6.3 million of depletion expense.

Other property, plant and equipment are depreciated using the straight-line method based on estimated useful lives.

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Coal Reserves

There are numerous uncertainties inherent in estimating quantities of economically recoverable coal reserves, many of which 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 assembled by our internal engineers and geologists. Reserve estimates are periodically updated to reflect past coal production, new drilling information and other geologic or mining data. Acquisitions, sales or dispositions of coal properties will also change the amount of economically recoverable coal reserves. Some of the factors and assumptions that impact economically recoverable reserve estimates include geological conditions, historical production from the area compared with production from other producing areas, the assumed effects of regulations and taxes by governmental agencies, assumptions governing future prices and future operating costs.

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 the classifications of these reserves based on risk of recovery and estimates of future net cash flows, may vary substantially. Actual production, revenues and expenditures with respect to these reserves will likely vary from estimates, and these variances may be material. At December 31, 2009, we estimate that we had 1.1 billion tons of coal reserves.

Asset Impairments

We follow ASC Subtopic 360-10-45, Impairment or Disposal of Long-Lived Assets, which requires that projected future cash flows from use and disposition of assets be compared with the carrying amounts of those assets when impairment indicators are present. When the sum of projected cash flows is less than the carrying amount, impairment losses are indicated. If the fair value of the assets is less than the carrying amount of the assets, an impairment loss is recognized. In determining such impairment losses, discounted cash flows or asset appraisals are utilized to determine the fair value of the assets being evaluated. Also, in certain situations, expected mine lives are shortened because of changes to planned operations. When that occurs and it is determined that the mine’s underlying costs are not recoverable in the future, reclamation and mine closure obligations are accelerated and the mine closure accrual is increased accordingly. To the extent it is determined asset carrying values will not be recoverable during a shorter mine life, a provision for such impairment is recognized. Recognition of an impairment will decrease asset values, increase operating expenses and decrease net income. In December 2008, we made the decision to permanently close our Sago mine during the first quarter of 2009. Upon making this decision, we performed an impairment test of related mine development costs, which resulted in a $7.2 million non-cash impairment charge to reduce the carrying amount of these assets to their estimated fair value. There were no other impairment charges related to long-lived assets recognized in the periods covered by this Annual Report on Form 10-K as a result of our impairment tests.

Financial Instruments

Pursuant to ASC Subtopic 470-20-65-1, Transition Related to FASB Staff Position APB 14-1, Accounting for Convertible Debt Instruments That May be Settled in Cash Upon Conversion (Including Partial Cash Settlement) (“ASC 470-20-65-1”), our convertible notes are accounted for as convertible debt and the embedded conversion option in the convertible notes has been accounted for as a component of equity.

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Coal Supply Agreements

Our below-market coal supply agreements (sales contracts) represent coal supply agreements acquired through acquisitions accounted for as business combinations for which the prevailing market price for coal specified in the contract was in excess of the contract price. In accordance with ASC Topic 805, Business Combinations, value was based on discounted cash flows resulting from the difference between the below-market contract price and the prevailing market price at the date of acquisition. The below-market coal supply agreements are amortized on the basis of tons shipped over the term of the respective contract. Determination of fair value requires management's judgment and often involves the use of significant estimates and assumptions.

Share Based Compensation

We account for our share based awards in accordance with ASC Topic 718, Compensation—Stock Compensation ("ASC 718"). Share based compensation expense is generally measured at the grant date and recognized as expense over the vesting period of the award. We utilize restricted stock and stock options as part of our share based compensation program. Determining fair value requires us to make a number of assumptions, including expected term, risk-free rate and expected volatility. Due to our limited operating history, the expected term and volatility are estimated based on other companies in the coal industry. The risk-free interest rates are based on the rates of zero coupon U.S. Treasury bonds with similar maturities on the date of grant. The assumptions used in calculating the fair value of share based awards represent our best estimates and involve inherent uncertainties and the application of management judgment. Although we believe the assumptions and estimates we have made are reasonable and appropriate, different assumptions could materially impact our reported financial results.

Debt Issuance Costs

Debt issuance costs reflect fees incurred to obtain financing. Debt issuance costs related to our outstanding debt are amortized over the life of the related debt. From time to time, we write-off deferred financing fees as a result of amending or canceling related debt and/or credit agreements. Such write-offs could be material and occur in the period that the amendment or cancellation occurs.

Income Taxes

We account for income taxes in accordance with ASC Topic 740, Income Taxes ("ASC 740"), which requires the recognition of deferred tax assets and liabilities using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. ASC 740 also requires that deferred tax assets, if it is more likely than not that some portion or all of the deferred tax asset will not be realized, be reduced by a valuation allowance. In evaluating the need for a valuation allowance, we take into account various factors, including the timing of the realization of deferred tax liabilities, the expected level of future taxable income and available tax planning strategies. If future taxable income is lower than expected or if expected tax planning strategies are not available as anticipated, we may record a change to the valuation allowance through income tax expense in the period the determination is made.

A tax position is initially recognized in the financial statements when it is more likely than not the position will be sustained upon examination by applicable tax authorities. Such tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not to be realized upon ultimate settlement with the tax authority assuming full knowledge of the position and all relevant facts. The amount of our uncertain income tax positions, unrecognized benefits and accrued interest were immaterial at December 31, 2009 and 2008.

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Postretirement Medical Benefits

Some of our subsidiaries have liabilities for postretirement benefit cost obligations. Detailed information related to these liabilities is included in the notes to our consolidated financial statements included elsewhere in this report. Liabilities for postretirement benefits are not funded. The liability is actuarially determined and we use various actuarial assumptions, including the discount rate and future cost trends, to estimate the costs and obligations for postretirement benefits. The discount rate assumption reflects the rates available on a hypothetical portfolio of high-quality fixed income debt instruments whose cash flows match the timing and amount of expected benefit payments. Our estimates of these costs are adjusted based upon actuarially determined amounts using a rate of 5.75% as of December 31, 2009. We make assumptions related to future trends for medical care costs in the estimates of retiree healthcare and work-related injury and illness obligations. The future healthcare cost trend rate represents the rate at which healthcare costs are expected to increase over the life of the plan. The healthcare cost trend rate assumptions are determined primarily based upon our, and our predecessor's, historical rate of change in retiree healthcare costs. The postretirement expense in the operating period ended December 31, 2009 was based on an assumed heath care inflationary rate of 6.40% in the operating period decreasing to 4.50% in 2061, which represents the ultimate healthcare cost trend rate for the remainder of the plan life. A one-percentage point increase in the assumed ultimate healthcare cost trend rate would increase the service and interest cost components of the postretirement benefit expense for the year ended December 31, 2009 by $0.4 million and increase the accumulated postretirement benefit obligation at December 31, 2009 by $2.1 million. A one-percentage point decrease in the assumed ultimate healthcare cost trend rate would decrease the service and interest cost components of the postretirement benefit expense for the year ended December 31, 2009 by $0.4 million and decrease the accumulated postretirement benefit obligation at December 31, 2009 by $2.0 million. If our assumptions do not materialize as expected or if regulatory changes were to occur, actual cash expenditures and costs that we incur could differ materially from our current estimates.

Workers' Compensation

Workers' compensation is a system by which individuals who sustain personal injuries due to job-related accidents are compensated for their disabilities, medical costs and, on some occasions, for the costs of their rehabilitation, and by which the survivors of workers who suffer fatal injuries receive compensation for lost financial support. The workers' compensation laws are administered by state agencies with each state having its own rules and regulations regarding compensation that is owed to an employee who is injured in the course of employment or the beneficiary of an employee that suffers fatal injuries in the course of employment. Our operations are covered through a combination of participation in a state run program and insurance policies. Our estimates of these costs are adjusted based upon actuarially determined amounts using a discount rate of 4.75% as of December 31, 2009. The discount rate assumption reflects the rates available on a hypothetical portfolio of high-quality fixed income debt instruments whose cash flows match the timing and amount of expected benefit payments. If we were to decrease our estimate of the discount rate to 3.75%, the present value of our workers' compensation liability would increase by approximately $0.4 million. If we were to increase our estimate of the discount rate to 5.75%, the present value of our workers' compensation liability would decrease by approximately $0.3 million. At December 31, 2009, we have recorded an accrual of $10.3 million for workers' compensation benefits. Actual losses may differ from these estimates, which could increase or decrease our costs.

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Coal Workers' Pneumoconiosis

We are responsible under various federal statutes, and various states' statutes, for the payment of medical and disability benefits to eligible employees resulting from occurrences of coal workers' pneumoconiosis disease (black lung). Our operations are covered through a combination of participation in a state run program and insurance policies. We accrue for any self-insured liability by recognizing costs when it is probable that a covered liability has been incurred and the cost can be reasonably estimated. Our estimates of these costs are adjusted based upon actuarially determined amounts using a discount rate of 6.00% as of December 31, 2009. The discount rate assumption reflects the rates available on a hypothetical portfolio of high-quality fixed income debt instruments whose cash flows match the timing and amount of expected benefit payments. If we were to decrease our estimate of the discount rate to 5.00%, the present value of our black lung benefit liability would increase by approximately $4.8 million. If we were to increase our estimate of the discount rate to 7.00%, the present value of our black lung benefit liability would decrease by approximately $3.8 million. At December 31, 2009, we have recorded an accrual of $25.9 million for black lung benefits. Individual losses in excess of $0.5 million at the state level and $0.5 million at the federal level are covered by our large deductible stop loss insurance. Actual losses may differ from these estimates, which could increase or decrease our costs.

Coal Industry Retiree Health Benefit Act of 1992

The Coal Industry Retiree Health Benefit Act of 1992 (the "Coal Act") provides for the funding of health benefits for certain union retirees and their spouses or dependants. The Coal Act established the Combined Fund into which employers who are "signatory operators" and "related persons" are obligated to pay annual premiums for beneficiaries. The Coal Act also created a second benefit fund for miners who retired between July 21, 1992 and September 30, 1994 and whose former employers are no longer in business. Upon the consummation of the business combination with Anker, we assumed Anker's Coal Act liabilities, which were estimated to be $1.4 million at December 31, 2009. Actual losses may differ from these estimates, which could increase or decrease our costs. Our estimates of these costs are adjusted based upon actuarially determined amounts using a discount rate of 5.50% as of December 31, 2009. The discount rate assumption reflects the rates available on a hypothetical portfolio of high-quality fixed income debt instruments whose cash flows match the timing and amount of expected benefit payments. If we were to decrease our estimate of the discount rate to 4.50%, the present value of our Coal Act liability would increase by approximately $0.1 million. If we were to increase our estimate of the discount rate to 6.50%, the present value of our Coal Act liability would decrease by approximately $0.1 million. Prior to the business combination with Anker, we did not have any liability under the Coal Act.

Corporate Vacation Policy

During 2009, we changed our policy related to when employees are credited with vacation time. Under the original policy, employees earned their vacation in the year prior to vesting, and were vested with 100% of their annual vacation time on January 1st of each year. Under the revised policy, employees are vested in their vacation time ratably throughout the year as it is earned. Accordingly, we did not record accruals in 2009 for vacation time to be vested in 2010. If we continued to account for vacation under the old policy, we would have recognized additional cost of coal sales, cost of other revenues and selling, general and administrative expenses of $7.0 million, $0.4 million and $0.5 million, respectively, for the year ended December 31, 2009.

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Results of Operations

Year Ended December 31, 2009 Compared to the Year Ended December 31, 2008

Revenues, coal sales revenues by reportable segment and tons sold by reportable segment

The following table depicts consolidated revenues for the years ended December 31, 2009 and 2008 for the indicated categories:

| | Year ended December 31, 2009 | Year ended December 31, 2008 | Increase (Decrease) $ or Tons | % |
|---|---|---|---|---|
| | (in thousands, except percentages and per ton data) | | | |
| Coal sales revenues | $ 1,006,606 | $ 998,245 | $ 8,361 | 1% |
| Freight and handling revenues | 26,279 | 45,231 | (18,952) | (42)% |
| Other revenues | 92,464 | 53,260 | 39,204 | 74% |
| Total revenues | $ 1,125,349 | $ 1,096,736 | $ 28,613 | 3% |
| | | | | |
| Tons sold | 16,833 | 18,914 | (2,081) | (11)% |
| Coal sales revenue per ton | $ 59.80 | $ 52.78 | $ 7.02 | 13% |

The following table depicts coal sales revenues by reportable segment for years ended December 31, 2009 and 2008:

| | Year ended December 31, 2009 | Year ended December 31, 2008 | Increase (Decrease) $ | % |
|---|---|---|---|---|
| | (in thousands, except percentages) | | | |
| Central Appalachian | $ 682,088 | $ 672,077 | $ 10,011 | 1% |
| Northern Appalachian | 207,022 | 209,932 | (2,910) | (1)% |
| Illinois Basin | 75,817 | 69,796 | 6,021 | 9% |
| Ancillary | 41,679 | 46,440 | (4,761) | (10)% |
| Total coal sales revenues | $ 1,006,606 | $ 998,245 | $ 8,361 | 1% |

The following table depicts tons sold by reportable segment for the years ended December 31, 2009 and 2008:

| | Year ended December 31, 2009 | Year ended December 31, 2008 | Increase (Decrease) Tons | % |
|---|---|---|---|---|
| | (in thousands, except percentages) | | | |
| Central Appalachian | 9,984 | 11,617 | (1,633) | (14)% |
| Northern Appalachian | 3,803 | 3,937 | (134) | (3)% |
| Illinois Basin | 2,254 | 2,331 | (77) | (3)% |
| Ancillary | 792 | 1,029 | (237) | (23)% |
| Total tons sold | 16,833 | 18,914 | (2,081) | (11)% |

Coal sales revenues—Coal sales revenues are derived from sales of produced coal and brokered coal contracts. Coal sales revenues increased 1% for the year ended December 31, 2009 compared to the year ended December 31, 2008, primarily due to a 13% increase in sales realization per ton resulting from favorable pricing on sales contracts entered into throughout 2008. Partially offsetting the impact of the improved realization per ton was an 11% decrease in tons sold, primarily resulting from decreased participation in the spot market.

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Central Appalachian. Coal sales revenues from our Central Appalachian segment for the year ended December 31, 2009 increased over the year ended December 31, 2008, primarily due to an increase in sales realization of $10.47 per ton, which was driven by higher average contract prices of our coal. Partially offsetting the increase in realization was a 14% decrease in tons sold, largely driven by decreased spot market sales.

Northern Appalachian. For the year ended December 31, 2009, our Northern Appalachian coal sales revenues decreased over the same period in 2008 due to a 3% decrease in tons sold, primarily due to reduced spot market sales. Partially offsetting the decrease in tons sold was an increase in sales realization of $1.11 per ton resulting from higher average prices of coal sold under our coal supply contracts.

Illinois Basin. The increase in coal sales revenues from our Illinois Basin segment for the year ended December 31, 2009 was due to an increase in sales realization of $3.69 per ton, partially offset by a 3% decrease in tons sold.

Ancillary. Our Ancillary segment's coal sales revenues are comprised of coal sold under brokered coal contracts. For the year ended December 31, 2009, our Ancillary coal sales revenues decreased due to a 23% decrease in tons sold related to the expiration of certain coal supply agreements, as well as to decreased shipments on various remaining contracts. This decrease in tons sold was partially offset by an increase in sales realization of $7.53 per ton sold.

Freight and handling revenues and costs—Freight and handling revenues represent reimbursement of freight and handling costs for certain shipments for which we initially pay the costs and are then reimbursed by the customer. Freight and handling revenues and costs decreased for the year ended December 31, 2009 compared to the year ended December 31, 2008 primarily due to a decrease in sales volumes. Additionally, transportation rates and fuel surcharges have been reduced as a result of decreased fuel prices.

Other revenues—The increase in other revenues for the year ended December 31, 2009 compared to the year ended December 31, 2008 was due to $34.9 million in payments received for the early termination of coal supply agreements and the lost margin on pre-termination shipments and a $7.7 million non-cash gain on the termination of a below-market contract, as well as a sale of a highwall mining system during the year ended December 31, 2009. Partially offsetting these increases were decreases in coalbed methane revenue, contract mining income and sales of scrap materials.

Costs and expenses

The following table depicts cost of operations for the years ended December 31, 2009 and 2008 for the indicated categories:

| | Year ended December 31, | | Increase (Decrease) | |
|---|---|---|---|---|
| | 2009 | 2008 | $ | % |
| | (in thousands, except percentages and per ton data) | | | |
| Cost of coal sales | $ 832,214 | $ 882,983 | $ (50,769) | (6)% |
| Freight and handling costs | 26,279 | 45,231 | (18,952) | (42)% |
| Cost of other revenues | 36,089 | 35,672 | 417 | 1% |
| Depreciation, depletion and amortization | 106,084 | 96,047 | 10,037 | 10% |
| Selling, general and administrative expenses | 32,749 | 38,147 | (5,398) | (14)% |
| Gain on sale of assets | (3,659) | (32,518) | 28,859 | 89% |
| Impairment loss | — | 37,428 | (37,428) | (100)% |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Total costs and expenses | $ | 1,029,756 | $ | 1,102,990 | $ | (73,234) | (7)% |
| | | | | | | | |
| Cost of coal sales per ton | $ | 49.44 | $ | 46.68 | $ | 2.76 | 6% |

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The following table depicts cost of coal sales by reportable segment for the years ended December 31, 2009 and 2008:

| | Year ended December 31, | | Increase (Decrease) | |
|---|---|---|---|---|
| | 2009 | 2008 | $ | % |
| | (in thousands, except percentages) | | | |
| Central Appalachian | $ 554,368 | $ 595,683 | $ (41,315) | (7)% |
| Northern Appalachian | 182,607 | 193,389 | (10,782) | (6)% |
| Illinois Basin | 62,958 | 57,424 | 5,534 | 10% |
| Ancillary | 32,281 | 36,487 | (4,206) | (12)% |
| Cost of coal sales | $ 832,214 | $ 882,983 | $ (50,769) | (6)% |

Cost of coal sales—For the year ended December 31, 2009, our cost of coal sales decreased 6% compared to the year ended December 31, 2008, primarily as a result of an 11% decrease in tons sold. Partially offsetting the decrease in tons sold was a 6% increase in cost per ton.

Central Appalachian. Our Central Appalachian segment cost of coal sales decreased primarily as a result of a 14% decrease in tons sold. The decrease in cost of coal sales is due to decreased tons sold partially offset by an increase in costs to $55.53 per ton for the year ended December 31, 2009 from $51.28 per ton for the year ended December 31, 2008. The increase in cost of coal sales per ton is primarily due to increases in labor and benefit costs and royalties, taxes and fees. Labor and benefit costs per ton increased due to wage increases in the fourth quarter of 2008 in an effort to remain competitive in a tight labor market, lower production volumes associated with idled operations and an increase in medical benefits over the year ended December 31, 2008. Royalties, taxes and fees increased on a per ton basis as a result of increased sales realization per ton sold and increased royalty rates on certain leased reserves, as well as increased severance and property tax obligations.

Northern Appalachian. Cost of coal sales from our Northern Appalachian segment decreased for the year ended December 31, 2009 as a result of a decrease in costs of $1.11 per ton and a 3% decrease in tons sold compared to the year ended December 31, 2008. The decrease in cost per ton is primarily due to decreases in transportation, fuel, lubricants and chemicals and coal purchased for blending to meet customer specifications. Partially offsetting these decreases in cost per ton were increases in labor and benefits, reclamation and engineering costs and contract labor costs.

Illinois Basin. For the year ended December 31, 2009, our Illinois Basin cost of coal sales increased as a result of an increase in costs of $3.30 per ton primarily due to increased labor and benefits costs and repairs and maintenance costs. Labor and benefits increased subsequent to the year ended December 31 2008 as a result of increased wages in an effort to retain skilled miners. Additionally, repairs and maintenance costs were higher due to our increased utilization of underground mining equipment. Partially offsetting these increases in cost per ton was a 3% decrease in tons sold.

Ancillary. Cost of coal sales from our Ancillary segment decreased for the year ended December 31, 2009 primarily due to decreased purchased coal costs related to the expiration of certain brokered coal contracts, as well as to decreased shipments on various remaining contracts in 2009 as compared to 2008. These decreases were partially offset by an increase of $5.33 per ton sold, primarily as a result of increased reclamation and property tax expense at certain non-operating locations.

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Cost of other revenues—For the year ended December 31, 2009, cost of other revenues increased primarily due to the related costs of the highwall mining system sold during the year and increased labor and benefit costs at our ADDCAR subsidiary. Partially offsetting these increases in cost of other revenues were decreases in coalbed methane gathering fees, repairs and maintenance costs and water treatment costs.

Depreciation, depletion and amortization—Depreciation, depletion and amortization expense increased for the year ended December 31, 2009, primarily as a result of capital spending throughout 2008 and 2009. Further impacting the increase was increased depletion expense resulting from increased mining of company-owned reserves, as well as a decrease in amortization income related to the completion or termination of shipments on certain below-market contracts. These increases were partially offset by a decrease in amortization of coalbed methane well development costs.

Selling, general and administrative expenses—Selling, general and administrative expenses for the year ended December 31, 2009 decreased primarily due to the recovery of a potential bad debt and the favorable resolution of certain legal and tax matters.

Gain on sale of assets—Gain on sale of assets decreased significantly for the year ended December 31, 2009. During the year ended December 31, 2008, we recognized a $24.6 million pre-tax gain on exchange of coal reserves with a third-party and a $3.6 million gain related to the sale of a highwall mining system previously used in operations. These decreases were partially offset by a gain of $2.9 million in 2009 related to the sale of a loadout facility.

Impairment loss—The impairment loss reflects the write-off of goodwill in 2008 associated with our ADDCAR subsidiary as a result of the negative impact of several contributing factors, which resulted in a reduction in the forecasted cash flows used to estimate fair value. Additionally, as a result of making the decision to close the Sago mine, related development costs were deemed to be impaired and were written-off during 2008. No comparable impairment occurred during 2009.

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Adjusted EBITDA by Reportable Segment

Adjusted EBITDA represents net income before deducting interest, income taxes, depreciation, depletion, amortization, loss on extinguishment of debt, impairment charges and noncontrolling interest. Adjusted EBITDA is presented because it is an important supplemental measure of our performance used by our chief operating decision maker in such areas as capital investment and allocation of resources. Other companies in our industry may calculate Adjusted EBITDA differently than we do, limiting its usefulness as a comparative measure. Adjusted EBITDA is reconciled to its most comparable GAAP measure on page 79 of this Annual Report on Form 10-K and in Note 20 to our consolidated financial statements for the year ended December 31, 2009.

The following table depicts reportable segment Adjusted EBITDA for the years ended December 31, 2009 and 2008:

| | Year ended December 31, | | Increase (Decrease) | |
|---|---|---|---|---|
| | 2009 | 2008 | $ | % |
| | (in thousands, except percentages) | | | |
| Central Appalachian | $ 169,842 | $ 107,186 | $ 62,656 | 58% |
| Northern Appalachian | 31,005 | 23,687 | 7,318 | 31% |
| Illinois Basin | 14,405 | 14,784 | (379) | (3)% |
| Ancillary | (13,575) | (18,436) | 4,861 | 26% |
| Total Adjusted EBITDA | $ 201,677 | $ 127,221 | $ 74,456 | 59% |

Central Appalachian. Adjusted EBITDA for the year ended December 31, 2009 increased compared to the year ended December 31, 2008 primarily due to $27.5 million received for the early termination of two related coal supply agreements and lost margin on pre-termination shipments coupled with a $6.22 per ton increase in profit margins. Partially offsetting these increases was a decrease of approximately 1,633,000 tons sold.

Northern Appalachian. The increase in Adjusted EBITDA was due to improved profit margins of $2.22 per ton attributable to a combination of an increase in sales realization of $1.11 per ton and a decrease of $1.11 in cost per ton.

Illinois Basin. Adjusted EBITDA decreased during the year ended December 31, 2009 due to a decrease of approximately 77,000 tons sold. Partially offsetting this decrease in tons sold were increased profit margins of $0.39 per ton.

Ancillary. The increase in Adjusted EBITDA was primarily due to $7.4 million received for contract settlements and an increase in profit margins of $2.20 per ton due to an increase in sales realization of $7.53 per ton, offset by a $5.33 increase in cost per ton. Further contributing to the increase in Adjusted EBITDA from our Ancillary segment was the sale of a highwall mining system during the year ended December 31, 2009, offset by decreased revenue from coalbed methane wells and a decrease of approximately 237,000 tons sold related to the expiration of brokered coal contracts throughout 2008 and decreased shipments of various remaining contracts.

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Reconciliation of Adjusted EBITDA to Net income (loss) by Reportable Segment

The following tables reconcile Adjusted EBITDA to net income (loss) by reportable segment for the years ended December 31, 2009 and 2008:

| | Year ended December 31, | | Increase (Decrease) | |
|---|---|---|---|---|
| | 2009 | 2008 | $ | % |
| | (in thousands, except percentages) | | | |
| Central Appalachian | | | | |
| Net income attributable to International Coal Group, Inc. | $ 91,841 | $ 47,244 | $ 44,597 | 94% |
| Depreciation, depletion and amortization | 71,298 | 64,132 | 7,166 | 11% |
| Interest expense, net | 4,488 | 2,145 | 2,343 | 109% |
| Income tax (benefit) expense | 2,215 | (6,335) | 8,550 | *% |
| Adjusted EBITDA | $ 169,842 | $ 107,186 | $ 62,656 | 58% |

| | Year ended December 31, | | Increase (Decrease) | |
|---|---|---|---|---|
| | 2009 | 2008 | $ | % |
| | (in thousands, except percentages) | | | |
| Northern Appalachian | | | | |
| Net income attributable to International Coal Group, Inc. | $ 7,994 | $ 3,217 | $ 4,777 | 148% |
| Depreciation, depletion and amortization | 20,991 | 17,884 | 3,107 | 17% |
| Interest expense, net | 531 | 717 | (186) | (26)% |
| Income tax (benefit) expense | 1,423 | (5,322) | 6,745 | *% |
| Impairment loss | — | 7,191 | (7,191) | (100)% |
| Noncontrolling interest | 66 | — | 66 | 100% |
| Adjusted EBITDA | $ 31,005 | $ 23,687 | $ 7,318 | 31% |

| | Year ended December 31, | | Increase (Decrease) | |
|---|---|---|---|---|
| | 2009 | 2008 | $ | % |
| | (in thousands, except percentages) | | | |
| Illinois Basin | | | | |
| Net income attributable to International Coal Group, Inc. | $ 6,080 | $ 6,959 | $ (879) | (13)% |
| Depreciation, depletion and amortization | 7,957 | 7,342 | 615 | 8% |
| Interest expense, net | 579 | 327 | 252 | 77% |
| Income tax (benefit) expense | (211) | 156 | (367) | *% |
| Adjusted EBITDA | $ 14,405 | $ 14,784 | $ (379) | (3)% |

| | Year ended December 31, | | Increase (Decrease) | |
|---|---|---|---|---|
| | 2009 | 2008 | $ | % |

(in thousands, except percentages)

| | | | | |
|---|---|---|---|---|
| Ancillary | | | | |
| Net loss attributable to International Coal Group, Inc. | $ (84,457) | $ (83,647) | $ (810) | 1% |
| Depreciation, depletion and amortization | 5,838 | 6,689 | (851) | (13)% |
| Interest expense, net | 47,446 | 40,454 | 6,992 | 17% |
| Income tax (benefit) expense | 4,305 | (12,169) | 16,474 | *% |
| Loss on extinguishment of debt | 13,293 | — | 13,293 | 100% |
| Impairment loss | — | 30,237 | (30,237) | (100)% |
| Adjusted EBITDA | $ (13,575) | $ (18,436) | $ 4,861 | 26% |

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| | Year ended December 31, 2009 | Year ended December 31, 2008 | Increase (Decrease) $ | Increase (Decrease) % |
|---|---|---|---|---|
| | (in thousands, except percentages) | | | |
| Consolidated | | | | |
| Net income (loss) attributable to International Coal Group, Inc. | $ 21,458 | $ (26,227) | $ 47,685 | *% |
| Depreciation, depletion and amortization | 106,084 | 96,047 | 10,037 | 10% |
| Interest expense, net | 53,044 | 43,643 | 9,401 | 22% |
| Income tax (benefit) expense | 7,732 | (23,670) | 31,402 | *% |
| Loss on extinguishment of debt | 13,293 | — | 13,293 | 100% |
| Impairment loss | — | 37,428 | (37,428) | (100)% |
| Noncontrolling interest | 66 | — | 66 | 100% |
| Adjusted EBITDA | $ 201,677 | $ 127,221 | $ 74,456 | 59% |

* Not meaningful

Year Ended December 31, 2008 Compared to the Year Ended December 31, 2007

Revenues, coal sales revenues by reportable segment and tons sold by reportable segment

The following table depicts revenues for the years ended December 31, 2008 and 2007 for the indicated categories:

| | Year ended December 31, 2008 | Year ended December 31, 2007 | Increase (Decrease) $ or Tons | Increase (Decrease) % |
|---|---|---|---|---|
| | (in thousands, except percentages and per ton data) | | | |
| Coal sales revenues | $ 998,245 | $ 770,663 | $ 227,582 | 30% |
| Freight and handling revenues | 45,231 | 29,594 | 15,637 | 53% |
| Other revenues | 53,260 | 48,898 | 4,362 | 9% |
| Total revenues | $ 1,096,736 | $ 849,155 | $ 247,581 | 29% |
| | | | | |
| Tons sold | 18,914 | 18,343 | 571 | 3% |
| Coal sales revenue per ton | $ 52.78 | $ 42.01 | $ 10.77 | 26% |

The following table depicts coal sales revenues by reportable segment for years ended December 31, 2008 and 2007:

| | Year ended December 31, 2008 | Year ended December 31, 2007 | Increase (Decrease) $ | Increase (Decrease) % |
|---|---|---|---|---|
| | (in thousands, except percentages) | | | |
| Central Appalachian | $ 672,077 | $ 512,352 | $ 159,725 | 31% |
| Northern Appalachian | 209,932 | 121,200 | 88,732 | 73% |
| Illinois Basin | 69,796 | 60,368 | 9,428 | 16% |
| Ancillary | 46,440 | 76,743 | (30,303) | (39)% |
| Total coal sales revenues | $ 998,245 | $ 770,663 | $ 227,582 | 30% |

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The following table depicts tons sold by reportable segment for the years ended December 31, 2008 and 2007:

| | Year ended December 31, | | Increase (Decrease) | |
|---|---|---|---|---|
| | 2008 | 2007 | Tons | % |
| | (in thousands, except percentages) | | | |
| Central Appalachian | 11,617 | 11,323 | 294 | 3% |
| Northern Appalachian | 3,937 | 3,291 | 646 | 20% |
| Illinois Basin | 2,331 | 2,025 | 306 | 15% |
| Ancillary | 1,029 | 1,704 | (675) | (40)% |
| Total tons sold | 18,914 | 18,343 | 571 | 3% |

Coal sales revenues—Coal sales revenues are derived from sales of produced coal and brokered coal contracts. Coal sales revenues increased for the year ended December 31, 2008 compared to the year ended December 31, 2007 due to a 26% increase in sales realization per ton resulting from increased spot market and short-term contract sales entered into in order to capitalize on favorable market conditions during the first three quarters of 2008. Further impacting the increase in coal sales revenue was a 3% increase in tons sold compared to the same period of 2007. Partially offsetting the impact of improved realization per ton and the increase in tons sold was a decrease in coal sales revenues attributable to the expiration of certain brokered coal contracts.

Central Appalachian. Coal sales revenues from our Central Appalachian segment for the year ended December 31, 2008 increased over the same period in 2007 primarily due to an increase of $12.61 per ton, which was driven by higher average prices of our coal sold pursuant to short-term supply agreements and on the spot market, including increased sales of metallurgical coal, primarily from increased production at our new Beckley operation.

Northern Appalachian. For the year ended December 31, 2008, our Northern Appalachian coal sales revenues increased due to an increase of $16.50 per ton resulting from higher average prices of coal sold pursuant to coal supply agreements and from an increase in sales of metallurgical coal, particularly on the spot market which provided advantageous pricing throughout much of 2008. Additionally, we experienced an increase in tons sold at certain of our complexes. The increase in tons sold was mainly attributable to our Sentinel complex continuing to increase production output to target levels, the ramp up of production at the formerly idled Harrison operation during 2008 and increased production resulting from investments in capital improvements made during the year.

Illinois Basin. The increase in coal sales revenues from our Illinois Basin segment was due to a 15% increase in tons sold resulting from increased short-term contract sales.

Ancillary. Our Ancillary segment's coal sales revenues are comprised of coal sold under brokered coal contracts. We experienced a decrease in tons sold due to the expiration of certain brokered coal contracts.

Freight and handling revenues—Freight and handling revenues represent reimbursement of freight and handling costs for certain shipments for which we initially pay the costs and are then reimbursed by the customer. Freight and handling revenues and costs increased for the year ended December 31, 2008 compared to the same period in 2007 primarily due to increased fuel surcharges and transportation rates. Additionally, we have entered into new sales contracts during 2008 that have increased freight and handling revenues and costs.

Other revenues—The increase in other revenues for the year ended December 31, 2008 compared to the year ended December 31, 2007 was due to additional ash disposal income, royalty income, sales of scrap materials, contract mining revenues and an increase in revenue generated from coalbed methane wells owned jointly by our subsidiary, CoalQuest, and CDX. The increases were partially offset by a decrease in revenue from our ADDCAR subsidiary, primarily related to the sale of a narrow bench highwall mining system in 2007.

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Costs and expenses

The following table depicts cost of operations for the years ended December 31, 2008 and 2007 for the indicated categories:

| | Year ended December 31, | | Increase (Decrease) | |
|---|---|---|---|---|
| | 2008 | 2007 | $ | % |
| | (in thousands, except percentages and per ton data) | | | |
| Cost of coal sales | $ 882,983 | $ 732,112 | $ 150,871 | 21% |
| Freight and handling costs | 45,231 | 29,594 | 15,637 | 53% |
| Cost of other revenues | 35,672 | 34,046 | 1,626 | 5% |
| Depreciation, depletion and amortization | 96,047 | 86,517 | 9,530 | 11% |
| Selling, general and administrative expenses | 38,147 | 33,325 | 4,822 | 14% |
| Gain on sale of assets | (32,518) | (38,656) | 6,138 | 16% |
| Impairment loss | 37,428 | 170,402 | (132,974) | (78)% |
| Total costs and expenses | $ 1,102,990 | $ 1,047,340 | $ 55,650 | 5% |
| | | | | |
| Cost of coal sales per ton | $ 46.68 | $ 39.91 | | |