International Coal Group, Inc.
Form 10-K
February 29, 2008

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, 2007

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	**20-2641185**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**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 x No ¨

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 x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No x

Aggregate market value of common stock held by non-affiliates of the registrant as of June 30, 2007, the last business day of the registrant s most recently completed second fiscal quarter, at a closing price of $5.98 per share as reported by the New York Stock Exchange, was $597,539,032. 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 February 15, 2008 was 152,987,711.

DOCUMENTS INCORPORATED BY REFERENCE

Part III incorporates certain information by reference from the registrant s definitive proxy statement for the 2008 annual meeting of stockholders, which proxy statement will be filed on or about April 11, 2008.

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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 11, 2008.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements that are not statements of historical fact and may involve a number of risks and uncertainties. We have used the words anticipate, believe, could, estimate, expect, intend, may, plan, predict, project 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 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;
- the consummation of financing, acquisition or disposition transactions and the effect thereof on our business;
- our plans and objectives for future operations and expansion or consolidation;
- our relationships with, and other conditions affecting, our customers;
- the availability and costs of key supplies or commodities such as diesel fuel, steel, explosives and tires;
- 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;
- 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;
- the ability to obtain and maintain all necessary governmental permits and authorizations;
- competition;
- railroad, barge, trucking and other transportation availability, performance and costs;
- employee benefits costs and labor relations issues;
- replacement of our coal reserves;
- our assumptions concerning economically recoverable coal reserve estimates;
- availability and costs of credit, surety bonds and letters of credit;
- 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 thereof, including with respect to safety enhancements and environmental initiatives relating to global warming;
- the impairment of the value of our goodwill and long-lived assets;
- the ongoing effects of the Sago mine accident;
- our liquidity, results of operations and financial condition;
- the adequacy and sufficiency of our internal controls; and
- legal and administrative proceedings, settlements, investigations and claims.

You should keep in mind that any forward-looking statement made by us in this Annual Report on Form 10-K speaks only as of the date on which we make it. 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. 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 2007 annual report to stockholders and our 2007 Annual Report on Form 10-K required under the federal securities laws.

In this annual report, the term Horizon refers to Horizon NR, LLC (the entity holding the operating subsidiaries of Horizon Natural Resources Company) and its consolidated subsidiaries, the term Anker refers to Anker Coal Group, Inc. and its consolidated subsidiaries, and the term CoalQuest refers to CoalQuest Development, LLC. References to the Anker and CoalQuest acquisitions refer to our acquisition, respectively, of each of Anker and CoalQuest, which occurred on November 18, 2005. Unless otherwise noted, all of our actual production and financial information includes the results of Anker and CoalQuest since November 19, 2005. On November 18, 2005, we and our subsidiaries also underwent a corporate reorganization in which we became the parent holding company and ICG, Inc., the prior parent holding company, became our subsidiary. 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, after giving effect to the corporate reorganization and the Anker and CoalQuest acquisitions.

For purposes of all financial disclosures contained in this report, Horizon (together with its predecessor AEI Resources Holding, Inc. and its consolidated subsidiaries) is the predecessor to ICG.

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 do 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 Appalachian mining complexes, which include 11 of our mining complexes, are located in West Virginia, Kentucky 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. Appalachian coal markets exhibited price volatility in 2007 due to a supply-demand imbalance that has continued into 2008.

ICG, Inc. was formed by WL Ross & Co. LLC (WLR), and other investors in May 2004 to acquire and operate competitive coal mining facilities. As of September 30, 2004, ICG, Inc. acquired certain key assets of Horizon through a bankruptcy auction. These assets are high quality reserves strategically located in Appalachia and the Illinois Basin, are union free, have limited reclamation liabilities and are substantially free of other legacy liabilities. Due to its initial capitalization, ICG, Inc. was able to complete the acquisition without incurring a significant level of indebtedness. Consistent with the WLR investor group s strategy to consolidate attractive coal assets, we completed a corporate reorganization (described below) and acquired Anker and CoalQuest in November 2005, which further diversified our reserves.

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As of December 31, 2007, management estimates that we owned or controlled approximately 316 million tons of metallurgical quality coal reserves and approximately 649 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 512 million tons of non-reserve coal deposits.

Steam coal is primarily consumed by large electric utilities and industrial customers as fuel for electricity generation. Demand for low sulfur steam coal has grown significantly since the introduction of certain controls associated with the Clean Air Act and the decline in coal production in the eastern half of the United States. Metallurgical coal is primarily used to produce coke, a key raw material used in the steel making process. Generally, metallurgical coal sells at a premium to steam coal because of its higher quality and its importance and value in the steel making process.

For the year ended December 31, 2007, we sold 18.3 million tons of coal, of which approximately 16.6 million tons were produced from our mining activities and approximately 1.7 million tons were purchased through brokered coal contracts (coal purchased from third parties for resale), at an average sale price of $41.70 and $45.04, respectively. Of the tons sold, 17.9 million tons were steam coal and 0.4 million tons were metallurgical coal. Our steam coal sales volume in 2007 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, 2007 were Georgia Power Company, Duke Energy Corporation and American Electric Power and we derived approximately 43% of our coal revenues from sales to our five largest customers. Revenues from sales to Georgia Power Company accounted for more than 10% of coal revenues in 2007.

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, 2007, 2006 and 2005 is included in Note 20 to our consolidated financial statements.

History

The Horizon Acquisition

On February 28, 2002, Horizon (at that time operating as AEI Resources Holdings, Inc.) filed a voluntary petition for Chapter 11 and its plan of reorganization became effective on May 8, 2002. However, Horizon s profit margins and cash flows were negatively impacted in fiscal year 2002 by, among other things, the falling price of coal and continued increases in certain operating expenses. Due to capital and permit constraints, Horizon had to mine in areas which produced coal at greatly reduced profit margins thus severely reducing cash flow.

As a result of its continuing financial and operational difficulties, Horizon filed a second voluntary petition for relief under Chapter 11 on November 13, 2002. Horizon obtained a debtor-in-possession financing facility of up to $350.0 million and was effective in rationalizing its operations, selling non-core assets, paying down outstanding borrowings and generating substantial operating profit. With stabilized operations and a significantly improved coal market, Horizon filed a joint plan of reorganization and a joint plan of liquidation under Chapter 11.

ICG, Inc. was formed by WLR and other investors in May 2004. The Horizon assets were sold through a bankruptcy auction on August 17, 2004. Presented as a combined $290.0 million cash bid with A.T. Massey, ICG, Inc. agreed to pay $285.0 million in cash plus the assumption of up to $5.0 million of liabilities to be paid to contract counterparties to cure the pre-sale defaults under the leases and contracts assumed and assigned to ICG, Inc. to acquire the assets. ICG, Inc. also contributed a credit bid of second lien Horizon bonds, and A.T. Massey agreed to pay $5.0 million in cash to acquire a separate group of assets associated with two Horizon subsidiaries. The credit bid included the cancellation of $482.0 million of certain Horizon bonds in return for which those Horizon bondholders received the right to participate in a rights offering to purchase ICG common stock. Shares issued in connection with the rights offering are included in our outstanding stock.

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In addition, Lexington Coal Company, LLC, a newly formed entity, was organized by the founding ICG, Inc. stockholders to assume certain reclamation liabilities and assets not otherwise being purchased by A.T. Massey or ICG, Inc. In order to provide support to Lexington Coal Company in consideration for assuming these liabilities, we agreed, among other things, to pay a 0.75% additional payment on the gross sales receipts for coal mined and sold from the assets we acquired from Horizon until the completion by Lexington Coal Company of all reclamation liabilities acquired from Horizon. Other than the initial limited commonality of ownership of ICG and Lexington Coal Company, there is no relationship between the entities.

The bankruptcy court confirmed the sale on September 16, 2004 as part of the completion of the Horizon bankruptcy proceedings. At closing, we increased the purchase price by $6.25 million, primarily to satisfy increased administrative expenses, and the sale was completed as of September 30, 2004.

The acquisition was financed through equity investments and borrowings under our senior secured credit facility, which we entered into at the closing of the Horizon acquisition.

The Anker and CoalQuest Acquisitions

On March 31, 2005, ICG, Inc. entered into a business combination agreement with us, Anker and ICG Merger Sub, Inc., our indirect wholly owned subsidiary, and Anker Merger Sub, Inc., our indirect wholly owned subsidiary. Under the terms of the business combination agreement, on November 18, 2005, ICG Merger Sub merged with and into ICG, Inc. and Anker Merger Sub merged with and into Anker, with each of ICG, Inc. and Anker surviving their respective mergers as our wholly owned subsidiaries and we became the new parent holding company. The stockholders of Anker, collectively, received 14,840,909 shares of our common stock.

On March 31, 2005, ICG, Inc. also entered into a business combination agreement with us, CoalQuest and CoalQuest Merger Sub LLC, our indirect wholly owned subsidiary, and the members of CoalQuest. Under the terms of the business combination agreement, on November 18, 2005, the members of CoalQuest contributed their interests in CoalQuest to us in exchange for shares of our common stock. As a result of this contribution, CoalQuest became our wholly owned subsidiary. The members of CoalQuest, collectively, received 9,250,000 shares of our common stock.

Our Reorganization and Public Offering

On November 18, 2005, International Coal Group, Inc. also completed a corporate reorganization. Prior to this reorganization, the top-tier parent holding company was ICG, Inc. Upon completion of this reorganization, International Coal Group, Inc. became the new top-tier parent holding company. In the corporate reorganization, the stockholders of ICG, Inc. received one share of International Coal Group, Inc. common stock for each share of ICG, Inc. common stock. On November 21, 2005, International Coal Group, Inc. common stock commenced trading on the New York Stock Exchange.

On December 12, 2005, we completed a public offering of 21 million shares of common stock. Net proceeds from the public offering were approximately $210.5 million. We used the proceeds to repay $188.7 million of our term loan debt and $21.2 million of borrowings under our revolving credit facility.

The Coal Industry

A major contributor to the world energy supply, coal represents over 25% 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 2007, 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 least expensive source of power fuel per million Btu, averaging less than one-third 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 techniques: room-and-pillar mining or longwall mining. In 2007, approximately 38% of our produced and processed coal volume came from underground mining operations using the room-and-pillar method with continuous mining equipment.

Room-and-Pillar Mining

In room-and-pillar mining, rooms are cut into the coalbed 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 generally 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 the longwall mining method. We do not currently have any longwall mining operations, but we expect to use this mining method in the development of our Hillman property in 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 2007, approximately 62% 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, loading out the coal, replacing the overburden and topsoil after the coal has been excavated and 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 three 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.

Dragline Mining

Dragline mining is a surface mining method that uses large capacity draglines to remove overburden to expose the coal seams. Shovels or loaders load coal in haul trucks for transportation to a preparation plant or unit train loadout facility. Seam recovery using the dragline method is typically 85% or more and productivity levels are similar to those for truck-and-shovel/loader mining.

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.

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 reducing the cost of meeting the quality requirements of specific customer contracts, thereby optimizing contract revenue.

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.

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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 seam to 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.

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 2025, an additional 27,000 megawatts of electric generation 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.

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Operations

As of December 31, 2007, we operated a total of 13 surface and 13 underground coal mines located in Kentucky, Maryland, West Virginia and Illinois. Approximately 62% of our production has come from surface mines, and the remaining production has come from our underground mines. These mining facilities include nine preparation plants, each of which receive, blend, process and ship coal that is produced from one or more of our 26 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. A dragline is employed as the prime earthmover at one of our surface mines. 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.

The following table provides summary information regarding our principal active operations as of December 31, 2007:

			Number and Type of Mines					
Mining Complexes[(1)]	**Location**	**Preparation Plant(s)**	**Under-ground**	**Surface**	**Total**	**Mining Method**[(2)]	**Transportation**	**Tons Produced in 2007 (in thousands)**
Eastern	Cowen, WV	1	0	1	1	MTR, DL, TSL	Rail	3,268.0
Hazard	Hazard, KY	0	0	6	6	HW, MTR, TSL	Rail, Truck	3,869.0
Flint Ridge	Hazard, KY	1	2	0	2	CTR, TSL, R&P, HW	Rail, Truck	1,306.4
Knott County	Kite, KY	1	4	0	4	R&P	Rail	1,039.7
Raven	Raven, KY	1	2	0	2	R&P	Rail	608.1
East Kentucky	Pike Co., KY	0	0	1	1	MTR, TSL	Rail	1,001.9
Beckley	Eccles, WV	1	1	0	1	R&P	Rail	39.7
Vindex Energy Corporation[(3)]	Garrett Co., MD	1	0	3	3	CRM, CTR	Truck, Rail	853.7
Patriot Mining Company	Monongalia Co., WV	0	0	2	2	CTR, TSL	Barge, Rail, Truck	885.1
Wolf Run Mining Buckhannon Division	Upshur Co., WV	1	1	0	1	R&P	Rail, Truck	636.0
Sentinel	Barbour Co., WV	1 (4)	1	0	1	R&P	Rail	681.8
Sycamore Group[(5)]	Harrison Co., WV	0	1	0	1	R&P	Truck	82.9 (6)
Illinois	Williamsville, IL	1	1	0	1	R&P	Truck	2,085.5

(1) *Does not include Juliana, an inactive mining complex.*
(2) *CRM = Cross Ridge Mining; CTR = Contour Mining; R&P = Room-and-pillar; LW = Longwall; MTR = Mountain Top Removal; DL = Dragline; HW = Highwall; TSL = Truck and Shovel/Loader.*
(3) *Includes Vindex Division of Wolf Run Mining Company.*
(4) *A portion of the complex currently utilizes one circuit.*
(5) *Represents Wolf Run Mining Company s (f/k/a Anker West Virginia Mining Company, Inc.) 50% share in The Sycamore Group LLC.*
(6) *The Sycamore #1 mine was depleted and reclaimed in 2007.*

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

	2007			2006			2005		
Mining Complexes[1]	Tons Produced	Sales Realizations[2]		Tons Produced	Sales Realizations[2]		Tons Produced	Sales Realizations[2]	
Eastern	3,268,000	$	42.15	3,048,800	$	43.92	2,766,365	$	42.75
Hazard	3,868,959	$	45.04	3,709,924	$	50.05	3,432,153	$	44.49
Flint Ridge	1,306,428	$	45.49	1,718,300	$	50.81	906,207	$	46.17
Knott County	1,039,714	$	46.41	1,268,617	$	51.51	1,277,438	$	46.74
Raven[3]	608,068	$	48.30	246,570	$	48.52		$	
East Kentucky	1,001,911	$	51.42	1,255,522	$	53.28	1,441,236	$	52.15
Beckley[4]	39,748	$	72.82		$			$	
Vindex Energy Corporation[5]*	853,695	$	36.83	1,062,925	$	36.62	649,623	$	45.00
Patriot Mining Company*	885,108	$	25.12	888,265 (6)	$	23.52	700,762	$	24.26
Wolf Run Mining Buckhannon Division*	636,002	$	41.94	820,688	$	42.46	801,435	$	37.05
Sentinel*	681,814	$	47.22	58,403	$	41.25	122,343	$	51.62
Sycamore Group*	82,904 (7)	$	30.14	347,241	$	29.13	452,349	$	27.48
Illinois	2,085,495	$	29.84	2,084,193	$	24.68	2,325,370	$	23.23
	16,357,846			16,509,448			14,875,281		

* *Operated by Anker through November 18, 2005 and by us since November 19, 2005.*

(1) *Does not include Juliana, an inactive mining complex.*

(2) *Excludes freight and handling revenue.*

(3) *Raven began production in 2006 and was formerly included in Knott County.*

(4) *Beckley began production in 2007.*

(5) *Includes Vindex Division of Wolf Run Mining Company.*

(6) *Does not include Patriot s waste fuel.*

(7) *The Sycamore #1 mine was depleted and reclaimed in 2007.*

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Northern and Central Appalachia Mining Operations

Below is a map showing the location and access to our coal operations in Northern and Central Appalachia:

Our Northern and Central Appalachian mining facilities and reserves are strategically located across West Virginia, Kentucky, Maryland and Virginia and are used to produce and ship coal to its 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 11.1 million tons of coal in 2007 and our mines in Northern Appalachia produced 3.2 million tons of coal in 2007. The coal produced in 2007 from our Northern and Central Appalachian mining operations was, on average, 12,204 Btu/lb., 1.3% sulfur and 12.7% ash by content. Shipments bound for electric utilities accounted for approximately 93% of the coal shipped by these mines in 2007 compared to 95% of shipments in 2006. 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 by the Norfolk Southern and CSX rail lines, although production may also be delivered by truck or barge, depending on the customer.

As of December 31, 2007, these mines had 1,772 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 started operations in 1990 under Shell Mining Company, was purchased by Zeigler Coal Holding Company (Zeigler) in 1992, and was subsequently acquired by Horizon s predecessor, AEI Resources, Inc., from Zeigler in 1998.

Birch River is extracting coal from five distinct coalbeds: (i) Freeport; (ii) Upper Kittanning; (iii) Middle Kittanning; (iv) Upper Clarion; and (v) Lower Clarion. We estimate that Birch River controls 8.2 million tons of coal reserves. Additional potential reserves 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.

Approximately 61.2% of the coal reserves are leased, while approximately 38.8% are owned in fee. Most of the leased reserves are held by four lessors. The leases are retained by annual minimum payments and by tonnage-based royalty payments. All leases can be renewed until all mineable and merchantable coal has been exhausted.

Overburden is removed by a dragline, 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 six surface mines, a unit train loadout (Kentucky River Loading) and other support facilities in eastern Kentucky, near Hazard. The coal reserves and operations were acquired in late-1997 and 1998 by AEI Resources.

Hazard s six surface mines include: (i) East Mac & Nellie; (ii) Vicco; (iii) Rowdy Gap; (iv) County Line; (v) Thunder Ridge; and (vi) Middle Fork. 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 blast casting. 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 49.9 million tons of coal reserves, plus 5.5 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 56.9% 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 leases can be renewed until all mineable and merchantable coal has been exhausted.

Flint Ridge

Flint Ridge is currently operating two underground mines and one preparation plant. Operations at the surface mine and highwall miner, which had been in operation since late 2005, were idled during the second quarter of 2007. We expect to reopen these operations once economic conditions become more favorable.

Flint Ridge s two underground mines are room-and-pillar operations, utilizing continuous miners and both battery powered ram cars and shuttle cars. All of the run-of-mine coal is processed at the Flint Ridge preparation plant, which is an existing preparation plant structure that was extensively upgraded in early 2005. Since July 2005, it has been processing coal from Hazard and Flint Ridge mining complexes.

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 29.6 million tons of coal reserves, plus 3.3 million tons of non-reserve coal deposits. Approximately 99.1% of Flint Ridge s reserves are leased, while 0.9% are owned in fee. The leases are retained by annual minimum payments and by tonnage-based royalty payments. Most leases can be renewed until all mineable and merchantable coal has been exhausted.

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Knott County

Knott County operates three 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 was acquired by AEI Resources from Zeigler in 1998 with reserves acquired through a lease from Penn Virginia.

Knott County is producing coal from the Hazard 4 and Elkhorn 3 coalbeds. Two mines are operating in the Hazard 4 coalbed: Calvary and Clean Energy. The Classic mine is operating in the Elkhorn 3 coalbed. Three additional properties are in the process of being permitted for underground mine development. We estimate this property contains 7.0 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 62.1% of Knott County s reserves are owned in fee, while approximately 37.9% are leased. 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.

Knott County s three 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 operates two underground mines and the Raven preparation plant. Raven s two underground mines are producing coal from the Elkhorn 2 coalbed. We estimate this property contains 10.7 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 100% leased from one lessor. 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. Operations at the Raven preparation plant began in 2006 in conjunction with Loadout, LLC, an affiliate of Penn Virginia Resources Partners, L.P. 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 surface mine and the Sandlick Loadout. East Kentucky was acquired by AEI Resources in the second quarter of 1999.

Mt. Sterling is an area surface mine that produces coal from five separate coalbeds: (i) Taylor; (ii) Coalburg; (iii) Winifrede; (iv) Buffalo; and (v) Stockton. All of the coal is sold run-of-mine.

We estimate that the Mt. Sterling mine controls 4.5 million tons of coal reserves, of which 79.1% are owned. No additional exploration is required. Overburden at the Mt. Sterling mine is removed by front-end loaders, end dumps, bulldozers and blast casting. Coal from the pits is transported by truck to the Sandlick Loadout.

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

Beckley

The Beckley Pocahontas Mine was placed into production in the fall of 2007. It is located in Central Appalachia in Raleigh County, West Virginia. The Beckley Pocahontas mine accesses a 32.4 million-ton deep reserve of high quality low-volatile metallurgical coal in the Pocahontas No. 3 seam. The southwest portion of the reserve underlies part of the closed BayBeck mine in the Beckley 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. Underground production is by means of the room-and-pillar method with continuous miners and shuttle cars. We are marketing the coal produced from the Beckley reserve to domestic steel producers and for export.

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 under leases that expire at varying times and are renewable with annual holding costs. Vindex Energy is a cross-ridge mining operation extracting coal from the Upper Freeport, Bakerstown, Middle Kittanning, Upper Kittanning, Pittsburgh and Redstone seams. All surface mines operated by Vindex Energy are truck-and-shovel/loader mining operations and are conducted with relatively new equipment. Exploration and development is conducted on a continual basis ahead of mining. In 2007, Vindex added the Cabin Run property to its reserve base. The total reserves for the assigned surface operations at Vindex amount to approximately 8.2 million tons.

Most of the surface mine production is shipped directly to the customer as run-of-mine product. 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 using a recently acquired rail loading facility.

Patriot Mining Company

Patriot Mining Company consists of two active surface mines: Crown No. 4 and Guston Run, both located near Morgantown in Monongalia County, West Virginia. The New Hill surface mine was depleted in the third quarter of 2007. The majority of the coal and surface is leased under renewable contracts with small annual minimum holding costs. Patriot s mines are extracting coal 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 our barge loading facility.

We estimate that Patriot Mining Company currently controls approximately 4.0 million tons of coal reserves, of which 10.1% are owned.

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 the Buckhannon Division are owned by us. The Buckhannon Division also owns the Sago mine, which was idled in March 2007. The Sago mine could be reopened if economic conditions were to become favorable.

The Imperial mine extracts coal from the Middle Kittanning seam. All of the coal extracted from the Imperial mine is processed through the nearby Sawmill Run preparation plant where coal is then primarily shipped by CSX rail with origination by the A&O Railroad, a short-line operator, 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 major landowner with an annual minimum holding cost and an automatic renewal based on an annual minimum production of 250,000 tons. Unexpected adverse mining conditions forced the idling of the Sycamore No. 2 mine during the third quarter of 2006; however, an independent contractor resumed production at the mine in 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

Wolf Run Mining Company s Sentinel mine was acquired by Anker in 1990 and has been operating ever since. Historically, coal was extracted from the Upper and Lower Kittanning seams; however, the mine was idled in the second quarter of 2006 to extend the slope and shafts to the underlying Clarion seam. Developmental mining in the Clarion seam began in November 2006 and the current operation now includes three continuous miner sections using the room-and-pillar mining method. Clarion coalbed reserves at the Sentinel mine amount to approximately 16.3 million tons, of which approximately 11.8% is owned and 88.2% is leased.

Coal is fed directly from the mine to our preparation plant and loadout facility served by the CSX railroad with origination by the A&O Railroad, as short-line operator. The product can be shipped to steam or metallurgical markets.

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Sycamore Group

Sycamore Group consists of The Sycamore Group LLC and the Harrison Division. The Sycamore Group LLC is a joint venture between ICG and Emily Gibson Coal Company. The joint venture, through an independent contract miner, operated one underground mine, the Sycamore No. 1 mine (a/k/a the Fairfax No. 3 mine), in Harrison County, West Virginia, approximately ten miles west of Clarksburg, where coal has been extracted from the Pittsburgh seam by room-and-pillar mining method with continuous miners and shuttle cars for coal extraction. This reserve was depleted and the mine closed during the first quarter of 2007.

New Appalachian Mine Developments

Hillman Property

The Hillman property, located in Northern Appalachia, includes approximately 186.0 million tons of deep coal reserves of both steam and metallurgical quality coal in the Lower Kittanning seam covering approximately 65,000 acres located predominantly in Taylor County, West Virginia, near Grafton. The reserve extends into parts of Barbour, Marion and Harrison Counties as well. ICG owns the Hillman 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, we also own significant non-reserve coal deposits in the Kittanning, Freeport, Clarion and Mercer seams on the Hillman property.

The West Virginia Department of Environmental Protection issued a permit on June 5, 2007 for the Tygart No. 1 underground longwall mine and preparation plant complex located on the Hillman Property. On appeal, the WV Surface Mining Board remanded the permit for additional modifications. The modified permit application has been resubmitted and is awaiting reissuance from WVDEP. We do not expect significant delay in the reissuance of the permit.

Construction of a bridge to access the site began in mid-2007 and was allowed to continue during the suspension of the mining permit. Major construction is expected to commence in mid-2008 and to continue throughout the year. Developmental production is projected to start in mid-2009. At full production, we expect Tygart No. 1 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 owned or controlled by us in the Middle and Lower Kittanning seams. The non-reserve coal deposits are surface mineable at a ratio of slightly greater than 2 to 1. Due to unique geologic characteristics and coal quality constraints, Upshur is a potentially attractive 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.

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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 27.5 million tons in the Jawbone, Greasy Creek 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.

Juliana Complex

Mining on the Juliana property, located in Central Appalachia, in Webster County, West Virginia, began in 1979 and ceased in December 1999. Contour and mountaintop removal surface mining methods were utilized to produce coal from the Kittanning and Upper Freeport seams. In addition, a substantial amount of deep-mined coal was produced from the Middle Kittanning seam.

Currently at Juliana, there are two Kittanning deep mine permits and one surface mine permit in place. Permitted deep and surface non-reserve coal deposits are 1.2 million tons and 1.9 million tons, respectively. The ratio for the surface reserve is 17.3 to 1 (bank cubic yards per clean ton).

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. A deep reserve in the high Btu, mid-sulfur Alma seam constitutes the largest block of coal at 30.2 million tons. Permitting is now in progress for a surface mine on this Central Appalachian property. Development of the entire Jennie Creek reserve had been subject to the resolution of certain disputes with lessors arising out of the Horizon bankruptcy proceedings. We resolved our litigation with the lessors of the Jennie Creek coal reserves in 2007. During 2007, an extensive core drilling project was completed on the property and its results are being used to update the mining permits. The coal will be produced by contouring, highwall mining and area mining.

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Illinois Basin Mining Operations

Below is a map showing the location and access to our coal operations in the Illinois Basin:

Illinois operates one large underground coal mine, the Viper mine, in central Illinois. Viper commenced mining operations in 1982 as a union free operation for Shell Oil Company. Viper was acquired by Ziegler in 1992 and subsequently acquired by AEI Resources in 1998.

The Viper mine is mining the Illinois No. 5 Seam, also referred to as the Springfield Seam. We estimate that Viper controls approximately 32.9 million tons of coal reserves, plus an additional 38.5 million tons of non-reserve coal deposits.

Approximately 70.5% of the coal reserves are leased, while 29.5% is owned in fee. 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.

The Viper mine is a room-and-pillar operation, utilizing continuous miners and battery coal haulers. Management believes that Illinois is one of the lowest cost and highest productivity mines in the Illinois Basin. All of the raw coal is processed at Viper s preparation plant. The clean coal is transported to utility and industrial customers located in North Central Illinois by on-highway trucks operated by independent trucking companies. 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 56% of coal sales.

The underground equipment, infrastructure and preparation plant are well maintained. Underground equipment is routinely replaced or rebuilt depending on the age and mechanical condition of the equipment. Illinois plans to develop a new portal facility that will allow it to eliminate the need to operate over five miles of underground beltlines and to maintain the extensive previously mined area.

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Other Operations

Coal sales

In addition to the coal we mine, from time to time we also opportunistically secure coal purchase agreements with other coal producers to take advantage of differences in market prices.

ADDCAR Systems

In our highwall mining business, we have six systems available for operations or lease 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 located at the rear of the launch vehicle. 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 tractive effort provided by the crawler drive of the continuous miner, the ADDCAR highwall mining system bolsters the cutting capability of the machine through an additional pumping force 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. The first ADDCAR narrow bench mining system was placed in operation in 2007.

We currently have the exclusive North American distribution rights for the ADDCAR highwall mining system.

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Coalbed methane

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 spot basis for some of our customers. Our three largest customers for the year ended December 31, 2007 were Georgia Power Company, Duke Energy Corporation and American Electric Power and we derived approximately 43% of our coal revenues from sales to our five largest customers. Revenues from sales to Georgia Power Company accounted for more than 10% of coal revenues in 2007.

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 volume and sales price. For the year ended December 31, 2007, approximately 69% of our 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 between 2008 and 2010 are expected to provide us a minimum of approximately 2.0 million tons of coal through the remaining lives of the contracts.

We have certain contracts which are set below current market rates because Anker entered into these contracts before the rise in the coal prices in 2006. 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.

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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.

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 many 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 trucking companies throughout the year.

In 2007, approximately 97% 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 3% 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 2007, we spent more than $279.8 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, Foundation Coal Holdings, 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 92% of domestic coal consumption in 2006. These coal consumption patterns are influenced by factors beyond our control, including the demand for electricity which is significantly dependent upon economic activity and summer and winter temperatures 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, 2007, we had 2,266 employees of which 23% were salaried and 77% were hourly. We believe our relationship with our employees is good. 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, 2007, the Company had $57.5 million in letters of credit supporting its 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 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. Applications for permits are subject to public comment and may be subject to litigation from environmental groups or other third parties seeking to deny issuance of a permit, which may also delay commencement or continuation of mining operations. 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 submit a reclamation plan for 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 several months before we plan to begin mining a new area. In our experience, mining permit approvals generally require 12 to 18 months after initial submission.

Surface Mining Control and Reclamation Act

The Surface Mining Control and Reclamation Act of 1977 (SMCRA), which is administered by the Office of Surface Mining Reclamation and Enforcement (OSM), establishes mining, environmental protection and reclamation standards for all aspects of surface mining, as well as many aspects 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 it 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.

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.

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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 (CERCLA or 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, federal and state workers compensation 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, 2007, the Company had $70.0 million in letters of credit supporting its 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. 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:

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.

Fine Particulate Matter and Ozone

The Clean Air Act requires the U.S. Environmental Protection Agency (the EPA) to set standards, referred to as National Ambient Air Quality Standards (NAAQS) for certain pollutants. Areas that are not in compliance with these standards (non-attainment areas) must take steps to reduce emissions levels. In 1997, the EPA revised the NAAQS for particulate matter and ozone; although previously subject to legal challenge, these revisions were subsequently upheld, but implementation was delayed for several years.

For ozone, these changes include replacement of the existing one-hour average standard with a more stringent eight-hour average standard. On April 15, 2004, the EPA announced that counties in 32 states failed to meet the new eight-hour standard for ozone. The EPA is also considering whether to revise the ozone standard. States which fail to meet the new standard will have until June 2007 to develop plans for pollution control measures that allow them to come into compliance with the standards.

For particulates, the changes include retaining the existing standard for particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM10) and adding a new standard for fine particulate matter with an aerodynamic diameter less than or equal to 2.5 microns (PM2.5). On December 17, 2004, the EPA announced that regions in 20 states and the District of Columbia did not achieve the fine particulate matter standard. 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. Under the Clean Air Act, individual states have up to twelve years from the date of designation to secure emissions reductions from sources contributing to the problem. In addition, on April 25, 2005, the EPA issued a finding that states have failed to submit State Implementation Plans that satisfy the requirements of the Clean Air Act with respect to the interstate transport of pollutants relative to the achievement of the 8-hour ozone and the PM2.5 standards. Because of this finding, the EPA must promulgate a Federal Implementation Plan for any state which does not submit its own plan. The EPA issued a new final rule for particulate matter which became effective December 18, 2006. Meeting the new PM2.5 standard may require reductions of nitrogen oxide and sulfur dioxide emissions. Future regulation and enforcement of these new 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.

NOx SIP Call

The NOx SIP Call program was established by the EPA in October of 1998 to reduce the transport of ozone on prevailing winds from the Midwest and South to states in the Northeast, which said they could not meet federal air quality standards because of migrating pollution. Under Phase I of the program, the EPA is requiring 900,000 tons of nitrogen oxide reductions from power plants in 22 states east of the Mississippi River and the District of Columbia beginning in May 2004. Phase II of the rule requires a further reduction of about 100,000 tons of nitrogen oxides per year by May 1, 2007. Installation of additional control measures, such as selective catalytic reduction devices, required under the final rules will make it more costly to operate coal-fired electricity generating plants, thereby making coal a less attractive fuel.

Clear Skies Initiative

The Bush Administration has proposed new legislation, commonly referred to as the Clear Skies Initiative, that could require dramatic reductions in nitrous oxide, sulfur dioxide, and mercury emissions by power plants through cap-and-trade programs similar to the existing acid rain regulations and current NOx budget programs. Congress has also considered several competing bills. It is not possible to predict with certainty what, if any, impact these potential changes could have on coal-buying decisions in the future.

Interstate Air Quality Rule

On March 10, 2005, the EPA adopted new rules for reducing emissions of sulfur dioxide and nitrogen oxides. This Clean Air Interstate Rule calls for power plants in 29 eastern states and the District of Columbia to reduce emission levels of sulfur dioxide and nitrous oxide. The rule regulates these pollutants under a cap and trade program similar to the system now in effect for acid deposition control and to that proposed by the Clear Skies Initiative. The stringency of the cap may require many coal-fired sources to install additional pollution control equipment, such as wet scrubbers. This increased sulfur emission removal capability caused by the rule could result in decreased demand for low sulfur coal, potentially driving down prices for low sulfur coal. Emissions would be permanently capped and could not increase. The rule seeks to cut sulfur dioxide emissions by 45% in 2010 and by 57% in 2015. The rule is subject to judicial challenge, which makes it difficult to determine its precise impact. Many of the challengers seek to impose more stringent rules. On March 15, 2006, the EPA issued federal implementation plans for this rule.

Clean Air Mercury Rule

On March 15, 2005, the EPA issued the Clean Air Mercury Rule to control mercury emissions from power plants. The rule sets a mandatory, declining cap on the total mercury emissions allowed from coal-fired power plants nationwide. This approach, which allows emissions trading, seeks to reduce mercury emissions by nearly 70% from current levels once facilities reach a final mercury cap, which takes effect in 2018. In February 2008, the U.S. Court of Appeals for the District of Columbia ruled that the Clean Air Mercury Rule violates the Clean Air Act. It also ruled that the EPA erred in delisting coal- and oil-fired electricity utility steam generating units as sources of hazardous air pollutants. The Court order subjects these sources to future regulation by the development of mercury emissions standards or, as some parties contend, case-by-case emission control based on the application of the 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. In addition, seven Northeastern states have prepared and submitted to the EPA a Northeast Regional Mercury Total Maximum Daily Load to reduce mercury in waterbodies by reducing air deposition of mercury primarily from coal-fired power plants in the Midwest.

Carbon Dioxide

In February 2003, a number of states notified the EPA that they planned to sue the agency to force it to set new source performance standards for utility emissions of carbon dioxide and to tighten existing standards for sulfur dioxide and particulate matter for utility emissions. In June 2003, three of these states sued the EPA seeking a court order requiring the EPA to designate carbon dioxide as a criteria pollutant and to issue a new NAAQS for carbon dioxide. If these lawsuits result in the issuance of a court order requiring the EPA to set emission limitations for carbon dioxide and/or lower emission limitations for sulfur dioxide and particulate matter, it could reduce the amount of coal our customers would purchase from us.

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. On July 6, 2005, the EPA issued regulations revising its regional haze program.

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 in-stream water quality standards and treatment standards for wastewater discharge through the National Pollutant Discharge Elimination System (NPDES). Regular monitoring, as well as compliance with reporting requirements and performance standards, are preconditions for the issuance and renewal of NPDES permits that govern the discharge of pollutants into water.

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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, 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.

In particular, permits under Section 404 of the CWA are required for coal companies to conduct dredging or filling activities in jurisdictional waters for the purpose of creating slurry ponds, water impoundments, refuse areas, valley fills or other mining activities. The Army Corps of Engineers (ACOE) authorizes in-stream 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, 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 in-stream activity.

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. The ACOE along with several intervenors appealed Judge Chambers decisions to the Fourth Circuit Court of Appeals, which has scheduled oral arguments for May 2008. If the decisions are upheld, substantial changes will be required in designing, permitting, and conducting coal mining operations in steep terrain.

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 Corps Louisville District wrongfully issued a Section 404 authorization to ICG Hazard s Thunder Ridge surface mine in Perry County, Kentucky. The plaintiffs, who are represented by the same counsel as the plaintiffs in the Chambers lawsuit, make essentially the same claims but add 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. We are cooperating with the ACOE in defending the ACOE s decision to issue the permit. Our Thunder Ridge surface mine continues to operate on previously permitted areas and, in accordance with an agreement reached among the parties, on certain portions of the newly permitted area.

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 in-stream 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. Although this case has been 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.

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.

Total Maximum Daily Load (TMDL) regulations established a process by which states designate these stream segments to be impaired (i.e., not meeting present water quality standards). Industrial dischargers, including coal mines, will be required to meet new TMDL effluent standards for these stream segments.

Under the CWA, states must conduct an anti-degradation review before approving permits for the discharge of pollutants to waters that have been designated as high quality beyond prescribed limits. A state s anti-degradation regulations prohibit the diminution of water quality in these streams. Several environmental groups and individuals recently challenged, in part successfully, West Virginia s anti-degradation policy. In general, waters discharged from coal mines to high quality streams will be required to meet or exceed new high quality standards. This could cause increases in the costs, time and difficulty associated with obtaining and complying with NPDES permits and could aversely affect our coal production.

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 (MINER) Act of 2006 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 2007, we recorded $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.

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

In May 2000, the EPA concluded that coal combustion by-products 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 coal combustion by-products 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. As long as the exemption remains in effect, it is not anticipated that regulation of coal combustion by-product will have any material effect on the amount of coal used by electricity generators. Most state hazardous waste laws also exempt coal combustion by-products and instead treat them as either a solid waste or a special waste. Any costs associated with handling or disposal of coal combustion by-products would increase our customers operating costs and potentially reduce their coal purchases. In addition, contamination caused by the past disposal of ash can lead to material liability.

Due to the hazardous waste exemption for coal combustion by-products such as ash, some of the coal combustion by-products are currently put to beneficial use. For example, at certain mines, the Company sometimes uses ash deposits from the combustion of coal as a beneficial use under its reclamation plan. The ash used for this purpose is mixed with lime and serves to help alleviate the potential for acid mine drainage.

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.

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Climate Change

Global climate change has a potentially far-reaching impact upon our business. 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 greenhouse gases, which include carbon dioxide and methane. These measures could impact the market for our coal and coal bed 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 which are underway to develop a treaty to require additional reductions in greenhouse gas emissions after 2012. The United States has yet to adopt a federal program for controlling greenhouse gas emissions. However, Congress is considering a variety of legislative proposals which would restrict and/or tax the emission of carbon dioxide 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. Even without new legislation, the emission of greenhouse gases may be restricted by future regulation, as the U.S. Supreme Court held in 2007 that the Environmental Protection Agency has authority under the Clean Air Act to regulate these gases. Federal regulation of the emission of carbon dioxide from coal-fired electric generating stations could adversely affect the demand for coal.

While advocating for comprehensive federal legislation, many states have adopted measures, sometimes as part of a regional collaboration, to reduce green house gases generated within their own jurisdiction. These measures include emission regulations, mandates for utilities to generate a portion of its 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.

In addition to impacting our markets, 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.

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. 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 $1.5 million at December 31, 2007.

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. Based on the species that have been identified to date and the current application of applicable laws and regulations, however, we do not believe there are any species protected under the Endangered Species Act that would materially 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.

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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 1 800 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.

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. 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.

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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. An underground coal mine.

Dragline. A large excavating machine used in the surface mining process to remove overburden (see Overburden). The dragline has a large bucket suspended from the end of a huge boom, which may be 275 feet long or larger. The bucket is suspended by cables and capable of scooping up vast amounts of overburden as it is pulled across the excavation area. The dragline, which can walk on huge pontoon-like feet, is one of the largest land-based machines in the world.

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.

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, 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.

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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.

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 60.0% and for surface mines approximately 80.0% to 90.0%. 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 tonne 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 charge 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. Declines in the prices we receive for our coal could adversely affect our operating results and our ability to generate the cash flows we require to improve our productivity and invest in our operations. The prices we receive for coal depend upon factors beyond our control, including:

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

- the 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;

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- 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;
- increased water entering mining areas and increased or accidental mine water discharges;
- increased or unexpected reclamation costs;
- interruptions due to transportation delays;
- the 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.

Steam coal accounted for nearly all of our coal sales volume in 2007 and the majority of our sales of steam coal in 2007 were to electric power generators. Domestic electric power generation accounted for approximately 92% of all U.S. coal consumption in 2006, according to the EIA. The amount of coal consumed for U.S. electric power generation is affected primarily by the overall demand for electricity, the location, availability, quality and price of competing fuels for power such as natural gas, nuclear, fuel oil and alternative energy sources such as hydroelectric power, technological developments, and environmental and other governmental regulations.

Although we expect that many new power plants will be built to produce electricity during peak periods of demand, we also expect that many of these new power plants will be fired by natural gas because gas-fired plants are cheaper to construct than coal-fired plants and because natural gas is a cleaner burning fuel. Gas-fired generation from existing and newly constructed gas-fired facilities has the potential to displace coal-fired generation, particularly from older, less efficient coal-powered generators. In addition, the increasingly stringent requirements of the Clean Air Act and the potential regulation of greenhouse gas emissions 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.

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.

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. 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.

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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, 2007, approximately 69% of our 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 4.6 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, particularly the Acid Rain regulations, the Clean Air Mercury Rule and the Clean Air Interstate Rule, although these latter two rules are subject to judicial challenge and the possible deregulation of their industry, 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 adverse economic conditions or may result in economic penalties upon a failure to meet specifications.

Price adjustment, price re-opener 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 re-opener 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 re-opener 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 Btu, 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.

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. In addition, we may not be able to successfully convert these sales commitments into 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.

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 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

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

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.

We depend heavily on a small number of large customers, the loss of any of which would adversely affect our operating results.

Our three largest customers for the year ended December 31, 2007 were Georgia Power Company, Duke Energy Corporation and American Electric Power and we derived approximately 43% of our coal revenues from sales to our five largest customers. At December 31, 2007, we had coal supply agreements with these customers that expire at various times from 2008 to 2011. We typically discuss extension of existing agreements or entering into long-term agreements with our customers, however these negotiations may not be successful and these customers may not continue to purchase coal from us pursuant to long-term coal supply agreements. If a number of these customers were to significantly reduce their purchases of coal from us, or if we were unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our financial condition and results of operations could suffer materially.

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. 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.

During 2005, we experienced brief periods of poor rail service, especially during the first half of the year. The service related issues resulted in missed shipments and adversely affected revenue. During the second half of 2005 and 2006, rail service steadily improved and did not significantly affect our shipment volumes. However, a return to the service related issues experienced in 2004 and early 2005 would affect our future operating results.

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.

On the other hand, 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.

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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.

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, including the roof bolts required by the room-and-pillar method of mining described previously. Scrap steel prices have risen significantly and, historically, the prices of scrap steel and petroleum have fluctuated. We have been adversely impacted by margin compressions due to cost increases for various commodities and services such as diesel fuel, explosives (ANFO) and coal trucking, influenced by the price variability of crude oil and natural gas. 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. The explosion tragically resulted in the deaths of twelve miners and the critical injury of another miner. As a result of the accident, the federal and state investigations and related matters, and civil litigation 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, any negative perceptions about our safety record affecting our ability to attract skilled labor, the impact of litigation commenced against us, any increased premiums for insurance and any claims that may be asserted against us that are not covered, in whole or in part, by our insurance policies.

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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 sponsor both in-house and vocational coal mining programs at the local level in order to train additional skilled laborers. In the event the shortage of experienced labor continues or worsens 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 and therefore have a material adverse effect on our earnings.

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

Our senior management team averages 23 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;
- the potential loss of key customers, management and employees of an acquired business;
- the 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; 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.

An 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. Recently, certain of our brokerage sources and contract miners have experienced adverse geologic mining and/or financial difficulties that have made their delivery of coal to us at the contractual price difficult or uncertain. 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.

If the value of our goodwill or long-lived assets becomes impaired, it could materially reduce the value of our assets and reduce our net income for the year in which the write-off occurs.

The Financial Accounting Standards Board s (the FASB) Statement of Financial Accounting Standard (SFAS) No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142), requires companies to cease amortizing goodwill and begin testing for impairment of goodwill at least annually (absent any impairment indicators). Impairment of goodwill is measured as the excess of the carrying value of the goodwill over its fair value. Fair value is estimated using present value techniques, such as discounted cash flows, or a weighting of income and market approaches. Any impairment losses under SFAS No. 142 are recorded as operating expenses. We performed an impairment test of the assets acquired from Horizon as of October 31, 2007. The results of the 2007 annual impairment tests of the goodwill for the Hazard, Eastern, East Kentucky and Knott County business units indicated that their estimated fair values were less than the carrying amounts of the respective business unit assets, including goodwill, and, therefore, were impaired. As a result, we recorded a $170.4 million non-cash impairment charge to reduce the carrying amount of these assets to their estimated fair value. The impairment test of our ADDCAR business unit indicated that the estimated fair value of its goodwill exceeded the carrying amount of its assets, including goodwill, and resulted in no impairment charge.

The FASB also requires, under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, long-lived assets to be assessed for impairment annually or whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. An impairment loss is measured and recognized if the estimated fair value is less than the carrying amount of the asset. Any impairments are recorded as a charge, resulting in a reduction in earnings in the quarter such impairment is identified and a corresponding reduction in our net asset value. Our long-lived assets were assessed and were determined not to be impaired as of December 31, 2007.

If, in the future, the estimated fair value of the goodwill were to decline or our long-lived assets are determined to be impaired, it would be necessary to record an additional non-cash impairment charge, which could materially reduce the value of our assets and reduce our net income for the year in which the write-off occurs.

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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 SFAS No. 109, *Accounting for Income Taxes,* 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, 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
- the 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, 2007, we had $70.0 million of letters of credit in place, of which $57.5 million serves as collateral for reclamation surety bonds and $12.5 million secures 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 substantial capital investment and maintenance expenditures, which we may be unable to provide.

Our business strategy will require additional substantial capital investment. We require capital 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 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.

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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 2006, however, the top ten coal producers share had increased to approximately 64% 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. 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 deregulation as utilities 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. In addition, 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 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.

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.

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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.

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 on of our customers related to the idling of our Sycamore No. 2 mine, and class action lawsuits that allege 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.

Because of our limited operating history, historical information regarding our company prior to October 1, 2004 is of little relevance in understanding our business as currently conducted.

We were incorporated in March 2005 as a holding company and ICG, Inc. was incorporated in May 2004 for the sole purpose of acquiring certain assets of Horizon. Until the completion of the Horizon asset acquisition, we had substantially no operations. As a result, historical information regarding our company prior to October 1, 2004, which does not include the historical financial information for Anker and CoalQuest, is of limited relevance in understanding our business as currently conducted. The financial statements for the Horizon predecessor periods have been prepared from the books and records of Horizon as if we had existed as a separate legal entity under common management for all periods presented (that is, on a carve-out basis). The financial statements for the Horizon predecessor periods include allocations of certain expenses, taxation charges, interest and cash balances relating to the predecessor based on management s estimates. In light of these allocations and estimates, the Horizon predecessor financial information is not necessarily indicative of our consolidated financial position, results of operations and cash flows if we had operated during the Horizon predecessor period presented. See Selected Financial Data and Management s Discussion and Analysis of Financial Condition and Results of Operations.

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 valley fills required for mining operations;

protection of human health, plantlife and wildlife;

the discharge of materials into the environment;

surface subsidence from underground mining; and

the effects of mining on groundwater quality and availability.

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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.

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. New regulations that took effect in 2001 could significantly increase our costs related to contesting and paying black lung claims. If new laws or regulations increase the number and award size of claims, it could substantially harm our business.

The costs, liabilities and requirements associated with these and other 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 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, or 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 or under more comprehensive individual permits have been instituted by environmental groups. The Fourth Circuit Court of Appeals recently rejected one such suit that was originally filed in West Virginia, concluding that the ACOE complied with the Clean Water Act in promulgating Nationwide Permit 21. A similar lawsuit filed in federal court in Kentucky is still pending. However, in a recent decision in a federal district court in West Virginia, the court ruled that the ACOE had inappropriately approved certain Section 404 permits issued to Massey Energy Company and rescinded those permits. An appeal of the court s decision has been filed in the Fourth Circuit Court of Appeals and a decision is expected in mid to late 2008. In the interim, the ACOE Huntington District has altered the permit process to address the court s decision and has resumed issuing Section 404 permits in the southern district of West Virginia. The Company currently has three subsidiaries in that jurisdiction of West Virginia that will require Section 404 permits within the next two years. 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 ICG Hazard s Thunder Ridge surface mine. That permit was suspended on December 26, 2007 to allow the ACOE to review the documentation on which the permit decision was based. All court proceedings are on hold in this case while the ACOE considers its decision. The ACOE s Louisville District is not expected to issue Section 404 permits for coal mining activities in Kentucky until the court rules in this case. The Company currently has two subsidiaries in that jurisdiction of Kentucky that will require Section 404 permits within the next two years. If permitting requirements are substantially increased or if mining methods at issue are limited or prohibited, it could greatly lengthen the time needed to permit new reserves, significantly increase our operational 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 we charge for coal to cover higher production costs without reducing customer demand for our coal.

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New government regulations as a result of recent mining accidents, including at our Sago mine, 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 recent mining accidents, including at our Sago mine, 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 also announced our intention to pursue new technology for worker safety, which will require us to incur additional expenses. 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.

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

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. 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 flow, and profitability.

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

The Surface Mining Control and Reclamation Act of 1977, or 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-closing 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. We adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, effective January 1, 2003. SFAS No. 143 requires that retirement obligations be 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.

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 toxic torts, 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 maintain extensive coal slurry impoundments at a number of our mines. Such impoundments are subject to 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. We have commenced 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 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.

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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.

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 higher 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 reductions in emissions from coal-fired utilities. For example, under the Clean Air Interstate Rule issued in March 2005, the U.S. Environmental Protection Agency, or EPA, has further regulated sulfur dioxide and nitrogen oxides from coal-fired power plants. Among other things, in affected states, the rule mandates reductions in sulfur dioxide emissions by approximately 45% below 2003 levels by 2010, and by approximately 57% below 2003 levels by 2015. The stringency of this cap may require many coal-fired sources to install additional pollution control equipment, such as wet scrubbers. Installation of additional pollution control equipment required by this proposed rule could result in a decrease in the demand for low sulfur coal (because sulfur would be removed by the new equipment), potentially driving down prices for low sulfur coal. In March 2006, the EPA denied petitions to reconsider the Clean Air Interstate Rule and promulgated federal implementation plans for this rule, which are subject to judicial challenge. In February 2008, the U.S. Court of Appeals for the District of Columbia ruled that the EPA s 2005 Clean Air Mercury Rule violates the Clean Air Act and gave the agency two years to develop mercury emissions standards. Some states, including Georgia and North Carolina, are adopting or proposing to adopt more stringent restrictions on mercury emissions than those contained in the Clean Air Mercury Rule. 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.

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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, state and local attention. Although the United States did not join the 1992 Framework Convention on Global Climate Change, commonly known as the Kyoto Protocol, future regulation of greenhouse gas could occur either pursuant to future U.S. treaty obligations or pursuant to statutory or regulatory changes under the Clean Air Act. Increased efforts to control greenhouse gas emissions, including the future joining of the Kyoto Protocol, could result in reduced demand for coal if electric power generators switch to lower carbon sources of fuel. If the United States were to ratify the Kyoto Protocol, the United States would be required to reduce greenhouse gas emissions to 93% of 1990 levels in a series of phased reductions from 2008 to 2012.

At the Group of Eight meeting in June 2007, President Bush announced a long-term strategy on climate change. The proposed strategy calls for consensus on long-term goals for reducing the greenhouse gases by a set amount by about 2050. These meetings could help result in post-Kyoto regulation, and could lead to United States inclusion in the global regulation of greenhouse emissions. Coal-fired power plants can generate large amounts of carbon emissions, and, as a result, have become subject to challenge by environmental groups seeking to curb the environmental effects of emissions of greenhouse gases. Various legislation has recently been 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 carbon dioxide emissions from coal-fired power plants, instituting a carbon tax on emissions of carbon dioxide, 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, financing the development of advanced coal burning plants which have greatly reduced carbon dioxide emissions. Other states are considering initiatives, and California has enacted policies, banning the purchase of power generated by the burning of coal. In addition, a number of states in the United States have taken steps to regulate greenhouse gas emissions. For example, seven northeastern states (New York, Vermont, New Hampshire, Maine, Connecticut, Delaware and New Jersey) entered into the Regional Greenhouse Gas Initiative (RGGI) agreement in December 2005 to reduce carbon dioxide emissions from power plants, and in August 2006 finalized a model rule to help implement the agreement; and Maryland, Massachusetts and Rhode Island subsequently agreed to join RGGI, and Pennsylvania remains an observer state. In addition, in Massachusetts v. Environmental Protection Agency, a U.S. Supreme Court decision in April 2007, the U.S. Supreme Court ruled in favor of twelve states and several cities of the United States against the EPA, and held that carbon dioxide and other greenhouse gases can qualify as pollutants under the Clean Air Act. As a result, the EPA may issue regulations related to greenhouse gas emissions.

Passage of additional state or federal laws or regulations regarding greenhouse gas emissions or other actions to limit carbon dioxide 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 carbon dioxide emissions from coal-fired power plants, imposing taxes on carbon emissions, requiring certain technology to capture and sequester carbon dioxide from new coal-fired power plants, and encouraging the production of non-coal-fired power plants. If measures such as these or other similar measures are ultimately imposed by federal or state governments or pursuant to international treaty on the coal industry, 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 carbon emissions, which could result in a reduction in the demand for coal and, therefore, our revenues.

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Risks Relating To Our Common Stock

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

Our total consolidated long-term debt as of December 31, 2007 was approximately $408.1 million and represented approximately 44% of our total capitalization, excluding current indebtedness of approximately $4.2 million, as of that date.

Our level of indebtedness 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 new debt is added to our and our subsidiaries current debt levels, 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.

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 indebtedness, including our outstanding senior and convertible notes.

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 indebtedness including anticipated interest on the notes, or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness on or before maturity. We may not be able to refinance any of our indebtedness 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 senior credit facility contains a number of financial covenants requiring us to meet financial ratios and financial condition 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.

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Our ability to borrow under our senior 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 indebtedness 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.

Changes in the accounting treatment of certain of our existing securities could decrease our earnings per share.

There may be, in the future, potentially new or different accounting pronouncements or regulatory rulings, which could impact the way we are required to account for our securities, and which may have an adverse impact on our future financial condition and results of operations. With respect to our convertible notes, we are required under accounting principles generally accepted in the United States of America, or GAAP, as presently in effect to include in outstanding shares for purposes of computing diluted earnings per share only a number of shares underlying the notes that, at the end of a given quarter, have a value in excess of the outstanding principal amount of the notes. This is because of the net share settlement feature of the notes, under which we are required to pay the principal amount of the notes in cash. The accounting method for net share settled convertible securities is currently under consideration by the Financial Accounting Standards Board (the FASB). Under consideration is a proposed method of accounting for net share settled convertible securities under which the debt and equity components of the security would be bifurcated and accounted for separately. The outcome of this process could result in our being required to recognize additional interest expense, increase the number of shares we count as outstanding for purposes of measuring earnings per share, or a combination of both, which would in turn reduce our earnings per share.

The conditional conversion feature of the notes could result in your receiving less than the value of the common stock into which a note would otherwise be convertible.

At certain times, the notes are convertible into cash and, if applicable, shares of our common stock only if specified conditions are met. If these conditions are not met, you will not be able to convert your notes at that time, and, upon a later conversion, you may not be able to receive the value of the common stock into which the convertible notes would otherwise have been convertible had such conditions been met.

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.

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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.

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, 2007, funds sponsored by WLR own approximately 16% of our common stock. Circumstances may occur in which WLR 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 invoke risks to our other holders of common stock or adversely affect us or other investors.

We may from time to time engage in transactions with related parties and affiliates that include, among other things, business arrangements, lease arrangements for certain coal reserves and the payment of fees or commissions for the transfer of coal reserves by one operating company to another. These transactions, if any, may adversely effect our sales volumes, margins and earnings.

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If our stockholders sell substantial amounts of our common stock, the market price of our common stock may decline.

As of December 31, 2007, we had 152,992,109 shares of common stock outstanding. The number of shares of common stock available for resale in the public market is limited in certain circumstances by restrictions under federal securities. All of the shares sold in our public offering, as well as all of the shares issued by us in the corporate reorganization, are freely tradable without restrictions or further registration under the Securities Act of 1933, as amended, except for any shares held by our affiliates, as defined in Rule 144 of the Securities Act. Additional shares of common stock underlying options granted or to be granted will become available for sale in the public market. We have also filed a registration statement on Form S-8 that registered 8,525,302 shares of common stock covering shares of restricted stock granted to our executives and the shares of common stock to be issued pursuant to the exercise of options we have granted or will grant under our employee stock option plan and a certain employment agreement. Our stock price could drop significantly if the holders of these restricted shares sell them or the market perceives they intend to sell them. These sales may also make it more difficult for us to sell securities in the future at a time and at a price we deem appropriate.

We may not pay dividends for the foreseeable future.

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 facilities limit 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 any dividends or make any distributions or payments with respect to our capital stock. 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

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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 277 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 688 million tons of mid to high Btu, low and high sulfur coal located in Kentucky, West Virginia, Maryland, Illinois and Virginia. 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 58 years. The following table provides the location of our mining operations and the type of coal produced at those operations as of January 1, 2008:

Mining Operations	Assigned or Unassigned[(1)]	Operating (O) or Development (D)	State	Mining Method Surface (S) or Underground (UG)	Total Proven and Probable Reserves[(2)] (in million tons)	Owned Proven and Probable Reserves (in million tons)	Leased Proven and Probable Reserves (in million tons)	Steam Proven and Probable Reserves (in million tons)	Metallurgical[(3)(4)] Proven and Probable Reserves (in million tons)
Northern Appalachia									
Vindex Energy Corp.	Assigned	O	MD	S	8.21	0.00	8.21	8.21	0.00
	Unassigned	D	MD	S/UG	43.56	0.47	43.09	25.15	18.41
Total Vindex Energy Corp.					51.77	0.47	51.30	33.36	18.41
Patriot Mining Co.	Assigned	O	WV	S	4.00	0.40	3.60	4.00	0.00
	Unassigned	D	WV	S	0.00	0.00	0.00	0.00	0.00
Total Patriot Mining Co.					4.00	0.40	3.60	4.00	0.00
Wolf Run Mining Buckhannon Division	Assigned	O	WV	UG	16.55	15.92	0.63	0.00	16.55
	Unassigned	D	WV	UG	30.55	28.82	1.73	0.00	30.55
Total Wolf Run Mining Buckhannon Division					47.10	44.74	2.36	0.00	47.10
Sentinel	Assigned	O	WV	UG	48.30	30.41	17.89	16.33	31.97
	Unassigned	D	WV	UG	4.94	4.94	0.00	0.00	4.94
Total Sentinel					53.24	35.35	17.89	16.33	36.91
Sycamore Group	Assigned	O	WV	UG	15.15	0.21	14.94	15.15	0.00
CoalQuest Development LLC	Unassigned (Hillman)	D	WV	UG	186.09	186.09	0.00	32.71	153.38
Northern Appalachia Total					**357.35**	**267.26**	**90.09**	**101.55**	**255.80**
Central Appalachia									
Eastern	Assigned	O	WV	S	8.18	3.17	5.01	8.18	0.00
	Unassigned	D	WV	S	6.71	0.00	6.71	6.71	0.00
Total Eastern					14.89	3.17	11.72	14.89	0.00
Hazard	Assigned	O	KY	S	47.91	21.49	26.42	47.91	0.00
	Unassigned	D	KY	S/UG	2.04	0.00	2.04	2.04	0.00
Total Hazard					49.95	21.49	28.46	49.95	0.00
Flint Ridge	Assigned	O	KY	S/UG	29.60	0.27	29.33	29.60	0.00
Knott County	Assigned	O	KY	UG	14.36	3.42	10.94	14.36	0.00
	Unassigned				3.30	0.90	2.40	3.30	0.00
Total Knott County					17.66	4.32	13.34	17.66	0.00
East Kentucky	Assigned	O	KY	S	4.55	3.60	0.95	4.55	0.00
ICG Natural Resources	Assigned	D	WV	S	14.71	0.00	14.71	14.71	0.00
	Unassigned (Jennie Creek)	D	WV	UG	30.19	2.20	27.99	30.19	0.00

Total ICG Natural Resources					44.90	2.20	42.70	44.90	0.00
Beckley[3]	Assigned	D	WV	UG	32.42	1.28	31.14	0.00	32.42
White Wolf Energy, Inc. [3]	Unassigned (Big Creek)	D	V	UG	27.50	0.00	27.50	0.00	27.50
Central Appalachia Total					**221.47**	**36.33**	**185.14**	**161.55**	**59.92**
Other									
Illinois	Assigned (Viper)	O	IL	UG	32.86	9.69	23.17	32.86	0.00
ICG Natural Resources	Unassigned	D	IL	UG	352.88	352.88	0.00	352.88	0.00
Total Other					**385.74**	**362.57**	**23.17**	**385.74**	**0.00**
Total Proven and Probable Reserves					**964.56**	**666.16**	**298.40**	**648.84**	**315.72**

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(1) *The proven and probable reserves indicated for each mine are Assigned. Unassigned proven and probable reserves for each mining complex are shown separately. 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 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 investments 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 meet historical metallurgical coal quality specifications.*

(4) *Currently, we report selling coal with ash and sulfur contents as high as 10% and 1.5%, respectively into the current metallurgical market from Vindex Energy, Buckhannon and Sentinel. Similarly, we believe all production from Vindex Division and portions of Hillman could be sold on this metallurgical market when production begins.*

The following table provides the quality (average moisture, ash, sulfur and Btu content, sulfur content and ash content per pound) of our coal reserves as of January 1, 2008:

		As Received Quality					Total Reserves	
Mining Operations	**Assigned or Unassigned[(1)]**	**% Moisture**	**% Ash**	**% Sulfur**	**Btu/lb.**	**Lbs. SO(2)/ million Btu**	**<1.2 lbs. SO(2) sCompliance**	**>1.2 lbs SO(2) Non-Compliance**
Northern Appalachia								
Vindex Energy Corp.	Assigned	4.68	19.25	1.78	11,703	3.04	0.00	8.21
	Unassigned	6.00	13.56	1.76	12,568	2.80	3.63	39.93
Total Vindex Energy Corp.		5.79	14.46	1.76	12,431	2.83	3.63	48.14
Patriot Mining Co.	Assigned	6.00	15.91	2.31	11,752	3.93	0.00	4.00
Wolf Run Mining Buckhannon Division	Assigned	6.00	8.95	1.30	13,050	1.99	0.00	16.55
	Unassigned	6.00	8.92	0.99	13,069	1.52	0.00	30.55
Total Wolf Run Mining Buckhannon Division		6.00	8.93	1.10	13,062	1.68	0.00	47.10
Sentinel	Assigned	6.00	8.39	1.48	13,183	2.25	0.00	48.30
	Unassigned	6.00	8.04	1.44	13,353	2.15	0.00	4.94
Total Sentinel		6.00	8.36	1.48	13,199	2.24	0.00	53.24
Sycamore Group	Assigned	6.00	7.21	3.05	13,097	4.66	0.00	15.15
CoalQuest Development LLC	Unassigned (Hillman)	6.00	9.25	1.15	13,145	1.76	0.00	186.09
Northern Appalachia Total							**3.63**	**353.72**
Central Appalachia								
Eastern	Assigned	6.00	14.42	1.24	11,964	2.07	0.00	8.18
	Unassigned	6.00	14.42	1.24	11,964	2.07	0.00	6.71
Total Eastern		6.00	14.42	1.24	11,964	2.07	0.00	14.89
Hazard	Assigned	6.00	12.86	1.39	12,038	2.31	0.00	47.91
	Unassigned	6.00	7.00	0.73	12,832	1.14	2.04	0.00
Total Hazard		6.00	12.62	1.36	12,070	2.26	2.04	47.91
Flint Ridge	Assigned	6.00	8.15	1.39	12,768	2.17	0.00	29.60
Knott County	Assigned	6.03	8.00	1.31	12,820	2.04	0.18	14.18
	Unassigned	6.00	7.08	1.82	13,037	2.80	0.00	3.30

Total Knott County		6.03	7.83	1.41	12,860	2.19	0.18	17.48
East Kentucky	Assigned	6.00	9.18	0.83	12,430	1.33	0.00	4.55
ICG Natural Resources	Assigned	7.00	9.65	0.75	12,281	1.22	9.59	5.12
	Unassigned	7.00	4.92	1.27	13,254	1.92	0.00	30.19
	(Jennie Creek)							
Total ICG Natural Resources		7.00	6.47	1.10	12,935	1.70	9.59	35.31
Beckley [(2)]	Assigned (Beckley)	6.00	4.87	0.70	13,913	1.01	32.42	0.00
White Wolf Energy, Inc. [(2)]	Unassigned (Big Creek)	6.00	4.00	0.65	14,073	0.92	27.50	0.00
Central Appalachia Total							**71.73**	**149.74**
Other								
Illinois	Assigned (Viper)	16.00	8.80	2.86	10,692	5.35	0.00	32.86
ICG Natural Resources	Unassigned	12.53	9.32	2.93	10,986	5.33	0.00	352.88
Total Other							**0.00**	**385.74**
Total Proven and Probable Reserves							**75.36**	**889.20**

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(1) *The proven and probable reserves indicated for each mine are Assigned. Unassigned proven and probable reserves for each mining complex are shown separately. 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 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 investments before production can begin.*

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

Our reserve estimate is 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 disposals of coal properties will also change the reserves. We estimate that we controlled 965 million tons of reserves at December 31, 2007. 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 69% 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 $2.30 per ton in 2007, representing approximately 4.8% (net of freight and handling) of our coal sales revenue in 2007. 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 either limited property control or 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 January 1, 2008:

Mining Operations	Assigned or Unassigned[1]	Operating (O) or Development (D)	State	Mining Method Surface (S) or Underground (UG)	Total Non-Reserve Coal Deposits (in million tons)	Steam Non-Reserve Coal Deposits (in million tons)	Metallurgical[2] Non-Reserve Coal Deposits (in million tons)
Northern Appalachia							
Patriot Mining Co	Assigned	O	WV	S	0.13	0.13	0.00
	Unassigned	D		S	1.77	1.77	0.00
Total Patriot Mining					1.90	1.90	0.00
Wolf Run Mining Buckhannon Division	Assigned	O	WV	UG	0.18	0.18	0.00
	Unassigned	D	WV	UG	2.24	2.24	0.00
Total Wolf Run Mining Buckhannon Division					2.42	2.42	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
Sycamore Group	Assigned	O	WV	UG	1.28	1.28	0.00
	Unassigned	D	WV	UG	0.00	0.00	0.00
Total Sycamore Group					1.28	1.28	0.00
CoalQuest Development LLC	Unassigned (Hillman)	D	WV	UG	38.14	38.14	0.00
Upshur Property	Unassigned (Upshur)		WV	S	92.96	92.96	0.00
Northern Appalachia Total					**139.10**	**139.10**	**0.00**
Central Appalachia							
Eastern	Assigned	O	WV	S	0.02	0.02	0.00
Hazard	Assigned	O	KY	S	5.53	5.53	0.00
Flint Ridge	Assigned	O	KY	S/UG	3.29	3.29	0.00
Knott County	Assigned	O	KY	UG	0.00	0.00	0.00
East Kentucky	Assigned (Mount Sterling)	O	KY	S	0.00	0.00	0.00
ICG Natural Resources	Assigned (Jennie CreeK)	D	WV	S	0.22	0.22	0.00
ICG Natural Resources	Unassigned (Martin Co., Muhlenberg Co.)		KY	S/UG	35.59	35.59	0.00
ICG Natural Resources	Unassigned (Mobil)		WV	UG	21.62	21.62	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.[3]	Unassigned (Big Creek)	D	VA	UG	2.57	2.57	0.00
Central Appalachia Total					**73.82**	**71.94**	**1.88**

Other							
Illinois	Assigned (Viper)	O	IL	UG	38.47	38.47	0.00
ICG Natural Resources	Unassigned (Illinois)		IL	UG	57.93	57.93	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 (in million tons)	Steam Non-Reserve Coal Deposits (in million tons)	Metallurgical(2) Non-Reserve Coal Deposits (in million tons)
ICG Natural Resources	Unassigned (Arkansas)		AR	S	39.15	39.15	0.00
	Unassigned (California)		CA	UG	10.00	10.00	0.00
	Unassigned (Ohio)		OH	UG	98.00	98.00	0.00
	Unassigned (Montana)		MT	S	12.00	12.00	0.00
	Unassigned (Washington)		WA	S	43.08	43.08	0.00
Total Other					**298.63**	**298.63**	**0.00**
Total Non-Reserve Coal Deposits					**511.55**	**509.67**	**1.88**

(1) Assigned non-reserve coal deposits mean coal which has been committed by the company to operating mine shafts, mining equipment, and plant facilities, and all coal which has been leased by the 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) Currently, ICG reports selling coal with ash and sulfur contents as high as 10% and 1.5%, respectively into the current metallurgical market from Vindex Energy, Buckhannon and Sentinel. Similarly, we believe all production from Vindex Division and portions of Hillman can be sold on this metallurgical market.

(3) White Wolf Energy, Inc. meets historical metallurgical coal quality specifications.

The following table provides the quality (average moisture, ash, sulfur and Btu content per pound) of our non-reserve coal deposits as of January 1, 2008:

		As Received Quality				
Mining Operations	Assigned or Unassigned(1)	% Moisture	% Ash	% Sulfur	Btu/ lb.	Lbs. SO(2)/ million Btu s
Northern Appalachia						
Patriot Mining Co	Assigned	N/A	N/A	N/A	N/A	N/A
	Unassigned	N/A	N/A	N/A	N/A	N/A
Wolf Run Mining Buckhannon Division	Assigned	6.00	9.00	1.20	13,000	1.85
	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
Sycamore Group	Assigned	6.00	7.21	3.05	13,097	4.66
	Unassigned	N/A	N/A	N/A	N/A	N/A
Upshur Property	Unassigned	6.00	43.00	2.00	8,000	5.00
Central Appalachia						
Eastern	Assigned	6.00	12.20	1.20	12,400	1.94
Hazard	Assigned	6.00	13.25	1.08	11,985	1.80
Flint Ridge	Assigned	6.00	8.15	1.39	12,768	2.18
Knott County	Assigned	N/A	N/A	N/A	N/A	N/A
East Kentucky	Assigned	N/A	N/A	N/A	N/A	N/A
	(Mt. Sterling)					
ICG Natural Resources	Assigned	7.00	7.78	0.63	12,609	1.01

	(Jennie Creek)					
ICG Natural Resources	Unassigned	6.00	11.47	1.91	11,780	3.24
	(Martin Co., Muhlenberg Co.)					
ICG Natural Resources	Unassigned					
	(Mobil)	6.00	12.50	1.10	12,000	1.83
Beckley	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	6.00	7.40	0.60	13,500	0.89
	(Big Creek)					

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Mining operations	Assigned or Unassigned(1)	% Moisture	% Ash	% Sulfur	Btu/ lb.	Lbs. SO(2)/ million Btu s
		As received quality				
Other						
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
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 (Ohio)	6.00	8.40	2.50	12,650	3.95
	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 company to operating mine shafts, mining equipment, and plant facilities, and all coal which has been leased by the 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 meet historical metallurgical coal quality specifications.

ITEM 3. LEGAL PROCEEDINGS

On August 23, 2006, the survivor of the Sago mine accident, Randal McCloy, filed a complaint in the Kanawha Circuit Court in Kanawha County, West Virginia. The claims brought by Randal McCloy and his family against us and certain of our subsidiaries, and against WLR, and Wilbur L. Ross, Jr., individually, were dismissed on February 14, 2008, after the parties reached a confidential settlement. Sixteen other complaints have been filed in Kanawha Circuit Court by the representatives of many of the miners who died in the Sago mine accident, and several of these plaintiffs have filed amended complaints to expand the group of defendants in the cases. The complaints allege various causes of action against us and our subsidiary, Wolf Run Mining Company, one of our shareholders, WLR, and Mr. Ross, individually, related to the accident and seek compensatory and punitive damages. In addition, the plaintiffs also allege causes of action against other third parties, including claims against the manufacturer of Omega block seals used to seal the area where the explosion occurred and against the manufacturer of self-contained self-rescuer (SCSR) devices worn by the miners at the Sago mine. The amended complaints add other of our subsidiaries to the cases, including ICG, Inc., ICG, LLC and Hunter Ridge Coal Company, unnamed parent, subsidiary and affiliate companies of us, WLR, and Mr. Ross, and other third parties, including a provider of electrical services and a supplier of components used in the SCSR devices. We believe that we are appropriately insured for these and other potential claims, and we have fully reserved our deductible applicable to our insurance policies. In addition to the dismissal of the McCloy claim, we have agreed on the terms of settlement of the claims of two other plaintiffs and are awaiting entry of dismissal orders. We will vigorously defend ourselves against the remaining complaints.

Allegheny Energy Supply (Allegheny), the sole customer of coal produced at our subsidiary Wolf Run Mining Company s (Wolf Run) Sycamore No. 2 mine, filed a lawsuit against Wolf Run, Hunter Ridge Holdings, Inc. (Hunter Ridge), and us in state court in Allegheny County, Pennsylvania on December 28, 2006, and amended its complaint on April 23, 2007. Allegheny claims that we breached a coal supply contract when we declared force majeure under the contract upon idling the Sycamore No. 2 in the third quarter of 2006. The Sycamore No. 2 mine was idled after encountering adverse geologic conditions and abandoned gas wells that were previously unidentified and unmapped. The amended complaint also alleges that the production stoppages constitute a breach of the guarantee agreement by Hunter Ridge and breach of certain representations made upon entering into the contract in early 2005, a claim that Allegheny has since voluntarily dropped. Allegheny claims that it will incur costs in excess of $100.0 million to purchase replacement coal over the life of the contract. We answered the amended complaint on August 13, 2007, disputing all of the remaining claims.

On April 5, 2007, the City of Ann Arbor Employees Retirement System filed a class action lawsuit in the U.S. District Court for the Southern District of West Virginia against us and certain of our officers, directors and underwriters. The amended complaint asserts claims under Sections 11, 12(a)(2) and 15 of the Securities Act of 1933 based on alleged false and misleading statements in the registration statements filed in connection with our November 2005 reorganization and December 2005 public offering of common stock. We filed a motion to dismiss the amended complaint on September 28, 2007, and that motion remains pending.

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On December 6, 2007, the Kentucky Waterways Alliance, Inc., and The Sierra Club sued the U.S. Army Corps of Engineers (the ACOE) in the United States District Court for the Western District of Kentucky, Louisville Division, asserting that a permit to construct five valley fills was issued unlawfully to our subsidiary, Hazard, for its Thunder Ridge Surface mine. The suit alleges that the ACOE failed to comply with the requirements of both Section 404 of the Clean Water Act and the National Environmental Policy Act. Hazard has intervened in the suit to protect our interests. If the Court finds that the permit is unlawful, production could be materially affected at the Thunder Ridge Surface mine and the process of obtaining ACOE permits for coal mining activities in Kentucky could become more difficult.

On January 7, 2008, Saratoga Advantage Trust filed a class action lawsuit in the U.S. District Court for the Southern District of West Virginia against us and certain of our officers and directors. The complaint asserts claims under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, and Rule 10b-5 promulgated thereunder, based on alleged false and misleading statements in the registration statements filed in connection with our November 2005 reorganization and December 2005 public offering of common stock. In addition, the complaint challenges other of our public statements regarding our operating condition and safety record.

In addition, from time-to-time, we are involved in legal proceedings arising in the ordinary course of business. These proceedings include assessments of penalties for citations and orders asserted by MSHA and other regulatory agencies, none of which are expected by management to, individually or in the aggregate, have a material adverse effect on us. In the opinion of management, we have recorded adequate reserves for liabilities arising in the ordinary course and it is management s belief there is no individual case or group of related cases pending that is likely to have a material adverse effect on our financial condition, results of operations or cash flows.

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, 2007.

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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 under the symbol ICO. The following table sets forth, for the quarterly periods indicated, the high and low sales prices per share at the end of the day of our common stock reported on the New York Stock Exchange.

	Stock Price	
	High	Low
2006		
January 1, 2006 through March 31, 2006	$ 10.65	$ 8.45
April 1, 2006 through June 30, 2006	11.02	6.53
July 1, 2006 through September 30, 2006	7.08	4.00
October 1, 2006 through December 31, 2006	5.58	4.02
2007		
January 1, 2007 through March 31, 2007	$ 5.61	$ 4.70
April 1, 2007 through June 30, 2007	6.48	5.24
July 1, 2007 through September 30, 2007	6.12	3.85
October 1, 2007 through December 31, 2007	5.57	4.45

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 February 15, 2008, there were approximately 229 holders of record of our common stock and an additional 46,256 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, 2007.

	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)	1,693,290	$ 8.34	6,324,009
Equity compensation plans not approved by stockholders(2)	319,052	10.97	
	2,012,342	$ 8.76	6,324,009

(1) We have two compensation plans: the 2005 Equity and Performance Incentive Plan, which was approved by stockholders on October 24, 2005, and the Director Compensation Plan.

(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 our audited consolidated financial statements included elsewhere in this report.

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

International Coal Group, Inc. was formed in March 2005 as wholly owned subsidiary of ICG, Inc. in order to effect a corporate reorganization. On November 18, 2005, we completed the reorganization. Prior to this reorganization, ICG, Inc. was the top-tier holding company. Upon completion of the reorganization, International Coal Group, Inc. became the new top-tier parent holding company. International Coal Group, Inc. is a holding company which does not have any independent external operations, assets or liabilities, other than through its operating subsidiaries. Prior to the acquisition of certain assets of Horizon as of September 30, 2004, ICG, Inc. did not have any material assets, liabilities or results of operations. The selected historical consolidated financial data is derived from International Coal Group, Inc. s audited consolidated financial statements as of December 31, 2007 and 2006 and for the years ended December 31, 2007, 2006 and 2005 which are included elsewhere in this report. The selected historical consolidated financial data of International Coal Group, Inc. as of December 31, 2005 and 2004, and for the period May 13, 2004 to December 31, 2004 have been derived from audited consolidated financial statements which are not included in this report. The selected historical consolidated financial data for the year ended December 31, 2003, as of September 30, 2004 and December 31, 2003 have been derived from the consolidated financial statements of Horizon, our predecessor, which have been audited and are not included in this report. In the opinion of management, the financial data reflect all adjustments, consisting of all normal and recurring adjustments, necessary for a fair presentation of the results for those periods. The results of operations for interim periods are not necessarily indicative of the results to be expected for the full year or for any future period. The financial statements for the predecessor periods have been prepared on a carve-out basis to include our assets, liabilities and results of operations that were previously included in financial statements of Horizon. The financial statements for the predecessor periods include allocations of certain expenses, taxation charges, interest and cash balances relating to the predecessor based on management s estimates. The predecessor financial information is not necessarily indicative of our consolidated financial position, results of operations and cash flows if we had operated during the predecessor periods presented.

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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 report, including the consolidated financial statements of International Coal Group, Inc. and Horizon (and its predecessor) and the related notes thereto.

	International Coal Group, Inc.				Horizon (Predecessor to International Coal Group, Inc.)	
	Year ended December 31, 2007	Year ended December 31, 2006	Year ended December 31, 2005	Period from May 13, 2004 to December 31, 2004	Period from January 1, 2004 to September 30, 2004	Year ended December 31, 2003
	(dollars in thousands, except per share data)					
Statement of Operations Data:						
Coal sales revenues	$ 770,663	$ 833,998	$ 619,038	$ 130,463	$ 346,981	$ 441,291
Freight and handling revenues	29,594	18,890	8,601	880	3,700	8,008
Other revenues	48,898	38,706	22,852	5,648	22,841	31,771
Total revenues	849,155	891,594	650,491	136,991	373,522	481,070
Costs and Expenses:						
Cost of coal sales and other revenues	766,158	769,332	510,097	113,527	306,429	400,652
Freight and handling costs	29,594	18,890	8,601	880	3,700	8,008
Depreciation, depletion and amortization	86,517	72,218	43,076	7,932	27,547	52,254
Selling, general and administrative	33,325	34,578	28,828	4,205	8,477	23,350
(Gain) loss on sale of assets	(38,656)	(1,125)	(502)	(10)	(226)	(4,320)
Impairment loss	170,402					
Writedowns and special items					10,018	9,100
Total costs and expenses	1,047,340	893,893	590,100	126,534	355,945	489,044
Income (loss) from operations	(198,185)	(2,299)	60,391	10,457	17,577	(7,974)
Interest and Other Income (Expense):						
Interest expense, net	(35,140)	(18,091)	(14,394)	(3,453)	(114,211)	(145,892)
Reorganization items					(12,471)	(23,064)
Other, net	319	2,113	3,302	16	1,442	187
Total interest and other income (expense)	(34,821)	(15,978)	(11,092)	(3,437)	(125,240)	(168,769)
Income (loss) before income taxes and minority interest	(233,006)	(18,277)	49,299	7,020	(107,663)	(176,743)
Income tax (expense) benefit	85,623	9,015	(16,986)	(2,660)		
Minority interest	349	(58)	15			
Net income (loss)	$ (147,034)	$ (9,320)	$ 32,328	$ 4,360	$ (107,663)	$ (176,743)

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	International Coal Group, Inc.				Horizon (Predecessor to International Coal Group, Inc.)	
	Year ended December 31, 2007	Year ended December 31, 2006	Year ended December 31, 2005	Period from May 13, 2004 to December 31, 2004	Period from January 1, 2004 to September 30, 2004	Year ended December 31, 2003
Earnings Per Share[1]:						
Basic	$ (0.97)	$ (0.06)	$ 0.29	$ 0.04	$	$
Diluted	(0.97)	(0.06)	0.29	0.04		
Weighted-Average Common Shares Outstanding [1] :						
Basic	152,304,461	152,028,165	111,120,211	106,605,999		
Diluted	152,304,461	152,028,165	111,161,287	106,605,999		
Balance Sheet Data (at period end):						
Cash and cash equivalents	$ 107,150	$ 18,742	$ 9,187	$ 23,967	$	$ 859
Total assets	1,303,563	1,316,891	1,051,403	457,045	539,606	576,372
Long-term debt and capital leases	412,330	180,035	45,462	175,681	29	315
Total liabilities and minority interest	789,192	658,541	384,917	302,534	1,422,290	1,351,393
Total stockholders equity (members deficit)	514,371	658,350	666,486	154,511	(882,684)	(775,021)
Total liabilities and stockholders equity (members deficit)	1,303,563	1,316,891	1,051,403	457,045	539,606	576,372
Statement of Cash Flows Data:						
Net cash from:						
Operating activities	$ 22,095	$ 55,591	$ 77,319	$ 30,264	$ 28,085	$ 20,030
Investing activities	(126,531)	(160,769)	(104,713)	(329,168)	3,437	(3,826)
Financing activities	192,844	114,733	12,614	322,871	(32,381)	(15,459)
Capital expenditures	160,431	165,658	108,231	5,583	6,624	16,937

(1) Earnings per share data and average shares outstanding are not presented for the year ended December 31, 2003 and the period from January 1, 2004 to September 30, 2004 because they were prepared on a carve-out basis. The financial statements prepared for predecessor periods are carve-out financial statements reflecting the operations and financial condition of the Horizon assets acquired by us as of September 30, 2004 (collectively, the combined companies). The predecessor financial statements were prepared from the separate accounts and records maintained by the combined companies. In addition, certain assets and expense items represent allocations from Horizon. The accounts allocated include vendor advances, reclamation deposits and selling, general and administrative expenses.

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 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 steam coal from 12 regional mining complexes, which, as of December 31, 2007 were supported by 13 active underground mines, 13 active surface mines and nine preparation plants located throughout West Virginia, Kentucky, 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 appearing elsewhere in this report. We also broker coal produced by others, the majority of which is shipped directly from the third-party producer to the ultimate customer. Our steam coal sales are primarily to large utilities and industrial customers in the Eastern region of the United States. 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.

ICG, Inc. was formed by WL Ross & Co. LLC (WLR) and other investors in May 2004 to acquire and operate competitive coal mining facilities. International Coal Group, Inc. was formed in March 2005 and became the parent holding company pursuant to a reorganization on November 18, 2005. Through the acquisition of key assets from the Horizon bankruptcy estate, the WLR investor group was able to target properties strategically located in Appalachia and the Illinois Basin with high quality reserves that are union free, have limited reclamation liabilities and are substantially free of legacy liabilities. With the proceeds of our December 2005 public offering, we retired substantially all of our then outstanding debt. Consistent with the WLR investor group s strategy to acquire attractive coal assets, the Anker and CoalQuest acquisitions further diversified our reserves in November 2005.

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 coal during 2007 was relatively weak. Further decreases in coal prices due to, among other reasons, the supply of domestic and foreign coal, the demand for electricity and the price and availability of alternative fuels for electricity generation could adversely affect our revenues and our ability to generate cash flows. In addition, our results of operations depend on the cost of coal production. We are experiencing increased operating costs for fuel and explosives, steel products, tires, health care and labor. We also expect to experience higher costs for surety bonds and letters of credit. In addition, historically low interest rates have had a negative impact on expenses related to our actuarially determined employee-related liabilities.

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. 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. Note 2 to our audited consolidated financial statements provides a description of all 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 at the time of shipment or delivery to the customer, at fixed or determinable prices 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, where coal is loaded to the rail, barge, truck or other transportation sources that deliver coal to its destination.

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 consist of equipment and parts sales, equipment rebuild and maintenance services, coal handling and processing, royalties, ash disposal services, coalbed methane sales, coal contract buydown income, contract mining and rental 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 apply the relevant accounting literature as appropriate 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 as coal is shipped or rental income is earned.

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 SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143). SFAS No. 143 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 each period, and the capitalized cost is depreciated over the useful life of the related asset. To settle the liability, the obligation is paid, and to the extent there is a difference between the liability and the amount of cash paid, a gain or loss upon settlement is recorded. 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, 2007, we had recorded asset retirement obligation liabilities of $85.9 million, including amounts reported as current liabilities. While the precise amount of these future costs cannot be determined with certainty, as of December 31, 2007, we estimate that the aggregate undiscounted cost of final mine closure is approximately $148.0 million.

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Depreciation, Depletion and Amortization

Property, plant, equipment and mine development, which includes coal lands, 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.

Coal land costs are depleted using the units-of-production method, based on estimated recoverable interest. The coal lands fair values are established by either using engineering studies or market values as established when coal lands are purchased on the open market. These values are then evaluated as to the number of recoverable tons contained in a particular mining area. Once the coal land values are established, and the number of recoverable tons contained in a particular coal land area is determined, a units-of-production depletion rate can be calculated. This rate is then utilized to calculate depletion expense for each period mining is conducted on a particular coal lands area.

Any uncertainty surrounding the application of the depletion policy is directly related to the assumptions as to the number of recoverable tons contained in a particular coal land area. The amount of compensation paid for the coal lands is a set amount; however, the recoverable tons contained in the coal land 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 a coal land area will result in a change in the depletion rate and corresponding depletion expense. For the year ended December 31, 2007, we recorded $0.9 million of depletion expense.

Mine development costs are amortized using the units-of-production method, based on estimated recoverable tons in the same manner described above.

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

Asset Impairments

We follow SFAS No. 144, *Accounting for the 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 the sum of projected cash flows is less than the carrying amount, impairment losses are 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 closing obligations are accelerated and the mine closing 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.

Postretirement Medical Benefits

Some of our subsidiaries have long- and short-term 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 high-quality fixed income debt instruments. The discount rate used to determine the net periodic benefit cost for postretirement medical benefits was 6.5% for the year ended December 31, 2007. We make assumptions related to future trends for medical care costs in the estimates of retiree health care and work-related injury and illness obligations. The future health care cost trend rate represents the rate at which health care costs are expected to increase over the life of the plan. The health care cost trend rate assumptions are determined primarily based upon our historical rate of change in retiree health care costs. The postretirement expense in the operating period ended December 31, 2007 was based on an assumed heath care inflationary rate of 8.9% in the operating period decreasing to 5.0% in 2015, which represents the ultimate health care cost trend rate for the remainder of the plan life. A one-percentage point increase in the assumed ultimate health care cost trend rate would increase the service and interest cost components of the postretirement benefit expense for the year ended December 31, 2007 by $0.7 million and increase the accumulated postretirement benefit obligation at December 31, 2007 by $3.5 million. A one-percentage point decrease in the assumed ultimate health care cost trend rate would decrease the service and interest cost components of the postretirement benefit expense for the year ended December 31, 2007 by $0.6 million and decrease the accumulated postretirement benefit obligation at December 31, 2007 by $3.0 million. If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could differ materially from our current estimates. Additionally, regulatory changes could increase our requirement to satisfy these or additional obligations.

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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.

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. At December 31, 2007, we have recorded an accrual of $24.8 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 $1.5 million at December 31, 2007. Prior to the business combination with Anker, we did not have any liability under the Coal Act.

Income Taxes

We account for income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes*, 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. SFAS No. 109 also requires that deferred tax assets be reduced by a valuation allowance, if it is more likely than not that some portion or all of the deferred tax asset will not be realized. In evaluating the need for a valuation allowance, we take into account various factors including the expected level of future taxable income 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.

Goodwill

In our consolidated balance sheet as of December 31, 2007, we had $30.2 million in goodwill, which represents the excess of costs over fair value of certain assets acquired and the liabilities assumed from Horizon on September 30, 2004. We assigned the goodwill to certain of the acquired reporting units based on their estimated fair values. Pursuant to SFAS No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142), goodwill and intangible assets that are determined to have an indefinite useful life are not amortized, but instead must be tested for impairment at least annually, and more frequently if a triggering event occurs. We perform our impairment test as of October 31st each year. The goodwill impairment test consists of two steps. The first identifies potential impairment by comparing the fair value of a reporting unit with its carrying amount, including goodwill. Fair value of a reporting unit is estimated using present value techniques, such as discounted cash flows of projected future operations developed by management or a weighting of income and market approaches. If the fair value of the reporting unit exceeds the carrying amount, goodwill is not considered impaired and the second step is not necessary. If the carrying value of the reporting unit exceeds the fair value, the second step is necessary to measure the amount of impairment loss by comparing the implied fair value of goodwill with its carrying amount. Implied fair value of goodwill is determined as the amount that the fair value of the assets of a business unit exceeds their carrying value, excluding goodwill. Impairment loss is measured as the amount of the carrying value of goodwill that exceeds its implied fair value. We measured impairment at October 31, 2007 and recorded a loss of $170.4 million.

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Results of Operations

Twelve Months Ended December 31, 2007 Compared to the Twelve Months Ended December 31, 2006

Revenues

The following table depicts revenues for the years ended December 31, 2007 and 2006 for the indicated categories:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Increase (Decrease) $	Increase (Decrease) %
	(in thousands, except percentages and per ton data)			
Coal sales revenues	$ 770,663	$ 833,998	$ (63,335)	(8)%
Freight and handling revenues	29,594	18,890	10,704	57%
Other revenues	48,898	38,706	10,192	26%
Total revenues	$ 849,155	$ 891,594	$ (42,439)	(5)%
Tons sold	18,343	19,371	(1,028)	(5)%
Coal revenue per ton	$ 42.01	$ 43.05	$ (1.04)	(2)%

Coal sales revenues. Coal sales revenues are derived from sales of produced coal and brokered coal contracts. Coal sales revenues decreased $63.3 million for the year ended December 31, 2007, or 8%, compared to 2006. This decrease was due to a 5% decrease in tons sold in 2007 compared to 2006 that resulted from a decrease of approximately 4.7 million tons sold related to the idling, closure or cutback of production at mines in 2007 as discussed below and the expiration of certain brokered coal contracts, as well as geologic issues at several other mines. The decrease in coal sales revenue from decreased sales tons was further impacted by a $1.04 per ton reduction in sales realization of our coal primarily sold pursuant to coal supply agreements. These decreases were partially offset by a 3.4 million ton increase in tons sold from new mines that commenced full production in 2007 and from mines that experienced a full year of production in 2007.

Freight and handling revenues. Freight and handling revenues represent dollar-for-dollar reimbursement for shipments from certain of our operations for which we initially pay the freight and handling costs and are then reimbursed by the customer. Freight and handling revenues and costs increased $10.7 million to $29.6 million for the year ended December 31, 2007 compared to 2006 due to an increase in shipments from locations operating under such agreements, as well as increased transportation rates and fuel surcharges.

Other revenues. Other revenues increased $10.2 million for the year ended December 31, 2007 compared to 2006. The increase was due to $6.8 million of revenue generated from coalbed methane wells owned jointly by our subsidiary, CoalQuest, and CDX, as well as increased revenue of $3.7 million from our highwall mining activities and shop services and $7.2 million from the sale of a narrow bench highwall mining system by ADDCAR. Partially offsetting these increases was a decrease in plant processing revenue of $1.1 million. Additionally, we recognized a $7.0 million gain in 2006 related to the termination of a contractual coal delivery obligation. No comparable gain was recognized in 2007.

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Coal sales revenues and tons sold by segment

The following table depicts coal sales revenues by operating segment for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		Increase (Decrease)	
	2007	2006	$	%
	(in thousands, except percentages)			
Central Appalachian	$ 512,352	$ 534,429	$ (22,077)	(4)%
Northern Appalachian	121,200	109,184	12,016	11%
Illinois Basin	60,368	49,842	10,526	21%
Ancillary	76,743	140,543	(63,800)	(45)%
Total coal sales revenues	$ 770,663	$ 833,998	$ (63,335)	(8)%

The following table depicts tons sold by operating segment for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		Increase (Decrease)	
	2007	2006	$	%
	(in thousands, except percentages)			
Central Appalachian	11,323	10,904	419	4%
Northern Appalachian	3,291	3,281	10	*%
Illinois Basin	2,025	2,020	5	*%
Ancillary	1,704	3,166	(1,462)	(46)%
Total tons sold	18,343	19,371	(1,028)	(5)%

* *Not meaningful.*

Coal sales revenues from our Central Appalachian segment decreased approximately $22.1 million, or 4%, for the year ended December 31, 2007 as compared to the year ended December 31, 2006. This decrease was primarily attributable to a decrease of $3.76 per ton in the average sales price of our coal primarily sold pursuant to coal supply agreements. The decrease in sales realization was partially offset by an increase in tons sold of approximately 0.4 million, or 4%, over 2006 due to various mines, principally at our Eastern and Raven locations, significantly increasing or reaching full production in 2007.

For the year ended December 31, 2007, our Northern Appalachian coal sales revenues increased approximately $12.0 million, or 11%, as compared to 2006 due to an increase in sales realization of $3.55 per ton as segment operations benefited from favorable pricing from its coal supply agreements, as well as an increase in sales of metallurgical coal at prevailing market prices. Tons sold from our Northern Appalachian operations remained constant as compared to the prior year.

Coal sales revenues from our Illinois Basin segment increased approximately $10.5 million, or 21%, as compared to 2006 due to an increase in coal sales revenue of $5.12 per ton resulting from more favorable terms on its coal supply agreements.

Our Ancillary segment s coal sales revenues are comprised of coal sold under brokered coal contracts. We experienced a decrease of $63.8 million, or 45%, due to a decrease of 1.5 million tons primarily resulting from the expiration of brokered coal contracts.

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Costs and expenses

The following table depicts cost of operations for the years ended December 31, 2007 and 2006 for the indicated categories:

	Year Ended December 31,		Increase (Decrease)	
	2007	2006	$	%
	(in thousands, except percentages and per ton data)			
Cost of coal sales	$ 732,112	$ 739,914	$ (7,802)	(1)%
Freight and handling costs	29,594	18,890	10,704	57%
Cost of other revenues	34,046	29,418	4,628	16%
Depreciation, depletion and amortization	86,517	72,218	14,299	20%
Selling, general and administrative expenses	33,325	34,578	(1,253)	(4)%
Net gain on sale of assets	(38,656)	(1,125)	(37,531)	*%
Goodwill impairment loss	170,402		170,402	100%
Total costs and expenses	$ 1,047,340	$ 893,893	$ 153,447	17%
Cost of coal sales per ton sold	$ 39.91	$ 38.20	$ 1.71	4%

* *Not meaningful.*

Cost of coal sales. For the year ended December 31, 2007, our total cost of coal sales decreased $7.8 million, or 1%, to $732.1 million compared to $739.9 million for the year ended December 31, 2006. The decrease in cost of coal sales was primarily the result of a 5% decrease in tons sold as described above which was partially offset by 4% increase in cost per ton.

Mining operations that significantly increased or reached full production in 2007 at our East Mac and Nellie, Flint Ridge Deep, Raven, Mt. Sterling, Guston Run, Crown Surface, Imperial, Sentinel, County Line and Middle Fork mines increased cost of coal sales by $144.0 million. Increased costs from new mining operations were partially offset by a decrease in costs of $111.9 million resulting from the closure or cutback of production at our higher cost Flint Ridge Surface, Rowdy Gap, Flint Ridge Highwall, Blackberry Creek, New Hill, Sago, Crown East II, Sycamore No. 1, Island, Tip Top and Elk Hollow mines. Cost of coal sales at existing mines, as well as from brokered coal contracts, decreased $40.5 million, primarily as a result of a 1.1 million ton decrease in coal sales.

Cost of coal sales per ton increased to $39.91 for the year ended December 31, 2007 compared to $38.20 in 2006, an increase of $1.71. The increase was mainly due to a $1.34 per ton increase in the average cost of produced coal sold. The increase in cost per ton of produced coal was caused by increases of: $0.46 per ton in labor and benefit costs; $0.27 per ton in contract labor; $0.44 per ton insurance and worker s compensation costs; $0.18 per ton in fuel, oil and lubricants; $0.26 per ton in blending material; $0.10 per ton in insurance; and $0.20 per ton in roof control supplies. The increases were partially offset by decreases of: $0.52 per ton in equipment and vehicle lease costs. Purchased coal increased $3.87 per ton, resulting in an increase of $0.38 per ton in the average cost of coal sold.

Cost of other revenues. For the year ended December 31, 2007, cost of other revenues increased $4.6 million, or 16%, to $34.0 million compared to $29.4 million for the year ended December 31, 2006. Of the increase, approximately $4.7 million was due to costs related to ADDCAR s sales of mining equipment during the year and exploration and development of coalbed methane resulted in an additional increase of $1.8 million.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased $14.3 million, or 20%, to $86.5 million for the year ended December 31, 2007 compared to $72.2 million in 2006. The principal component of the increase was an increase in depreciation and amortization expense of $14.5 million for the year ended December 31, 2007 related to increased property and equipment purchased to improve efficiency at existing operations and to equip new mine developments. Additional increases in depreciation and amortization expense were due to coalbed methane well development costs of $5.5 million. The increases were partially offset by an increase in amortization income on below-market coal supply agreements of $5.7 million during the year ended December 31, 2007.

Selling, general and administrative expenses. Selling, general and administrative expenses for the year ended December 31, 2007 were $33.3 million compared to $34.6 million for the year ended December 31, 2006. The decrease of $1.3 million was primarily attributable to gifts aggregating $2.0 million made in 2006 to the families of the thirteen miners involved in the Sago mine accident, partially offset by an increase of

$1.3 million in professional and legal fees.

Net gain on sale of assets. Net gain on sale of assets increased $37.5 million for the year ended December 31, 2007 from 2006, primarily due to a gain of approximately $36.8 million related to the sale of our Denmark property in the third quarter of 2007.

Goodwill impairment loss. The goodwill impairment loss reflects the negative impact of several contributing factors which resulted in a reduction in the forecasted cash flows used to estimate fair value. These factors include, but are not limited to, a significant decrease in the sales price of coal through our annual measurement date, increases in the cost of diesel fuel, explosives, tires, roofbolts and other materials used in mining coal, increased labor costs due to tightening labor markets, significant investments in the areas of safety and compliance and increased interest rates contributing to a higher discount rate. Furthermore, the business, regulatory and marketplace environments in which we currently operate differs significantly from the historical environments that drove the business cases used to value and record the acquisition of these business units. Accordingly, we have been unable to attain the forecasted projections that were used to initially value the business units at the date of acquisition. The goodwill impairment losses were at the following business units: $32.9 million at Hazard, $58.5 million at Eastern, $43.0 million at East Kentucky and $36.0 million at Knott County.

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Adjusted EBITDA by Segment

Adjusted EBITDA represents net income before deducting interest expense, income taxes, depreciation, depletion, amortization, impairment charges and minority 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. It is considered adjusted as we adjust EBITDA for impairment charges and minority interest. Adjusted EBITDA is calculated differently than the prior year in that it includes an adjustment for impairment charges. No impairment charges were incurred in the prior year. 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 70 of this Annual Report on Form 10-K and in Note 20 to our consolidated financial statements for the year ended December 31, 2007.

The following table depicts segment Adjusted EBITDA for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		Increase (Decrease)	
	2007	2006	$	%
	(in thousands, except percentages)			
Central Appalachian	$ 47,442	$ 108,598	$ (61,156)	(56)%
Northern Appalachian	(22,215)	(36,586)	14,371	39%
Illinois Basin	15,463	4,476	10,987	245%
Ancillary	18,363	(4,456)	22,819	512%
Total Adjusted EBITDA	$ 59,053	$ 72,032	$ (12,979)	(18)%

Adjusted EBITDA from our Central Appalachian segment decreased $61.2 million, or 56%, for the year ended December 31, 2007 as compared to the year ended December 31, 2006. The decrease was primarily due to the decreased realization per ton as discussed above. Also impacting the decrease were inflated operating costs per ton primarily resulting from regulatory issues and short-term mine constraints. The reduced realizations and increased costs resulted in a decrease in profit margins of $5.99 per ton. Additionally, activities incidental to our coal producing activities decreased by $1.5 million in 2007 further contributing to the decrease in Adjusted EBITDA.

The increase in Adjusted EBITDA from our Northern Appalachian segment of $14.4 million for the year ended December 31, 2007 was primarily due to an increase in coal sales revenue as of $3.55 per ton and decreased costs of $1.02 per ton resulting in increased profit margins of $4.57 per ton.

Adjusted EBITDA from our Illinois Basin segment increased $11.0 million during the year ended December 31, 2007 due to a $5.12 per ton increase in sales realization over 2006 with cost per ton remaining constant with prior year.

The increase in Adjusted EBITDA from our Ancillary segment of $22.8 million was primarily due to the sale of the Denmark property in September 2007, which resulted in a gain of $36.8 million, as well as from increased contributions to income from our investment in coalbed methane wells and from our ADDCAR subsidiary as discussed above. These increases were partially offset by a decrease in Adjusted EBITDA resulting from the expiration of brokered coal contracts.

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

The following tables reconcile Adjusted EBITDA to net income (loss) by segment for the years ended December 31, 2007 and 2006:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Increase (Decrease) $	Increase (Decrease) %
	(in thousands, except percentages)			
Central Appalachian				
Net income (loss)	$ (184,372)	$ 59,620	$ (243,992)	(409)%
Depreciation, depletion and amortization	60,015	48,050	11,965	25%
Interest expense, net	1,397	928	469	51%
Impairment loss	170,402		170,402	100%
Adjusted EBITDA	$ 47,442	$ 108,598	$ (61,156)	(56)%

	Year Ended December 31, 2007	Year Ended December 31, 2006	Increase (Decrease) $	Increase (Decrease) %
	(in thousands, except percentages)			
Northern Appalachian				
Net loss	$ (31,790)	$ (47,907)	$ 16,117	34%
Depreciation, depletion and amortization	9,467	10,822	(1,355)	(13)%
Interest expense, net	457	441	16	4%
Minority interest	(349)	58	(407)	(702)%
Adjusted EBITDA	$ (22,215)	$ (36,586)	$ 14,371	39%

	Year Ended December 31, 2007	Year Ended December 31, 2006	Increase (Decrease) $	Increase (Decrease) %
	(in thousands, except percentages)			
Illinois Basin				
Net income (loss)	$ 8,714	$ (1,978)	$ 10,692	541%
Depreciation, depletion and amortization	6,527	6,287	240	4%
Interest expense, net	222	167	55	33%
Adjusted EBITDA	$ 15,463	$ 4,476	$ 10,987	245%

	Year Ended December 31, 2007	Year Ended December 31, 2006	Increase (Decrease) $	Increase (Decrease) %
	(in thousands, except percentages)			
Ancillary				
Net income (loss)	$ 60,414	$ (19,055)	$ 79,469	417%
Depreciation, depletion and amortization	10,508	7,059	3,449	49%
Interest expense, net	33,064	16,555	16,509	100%
Income tax benefit	(85,623)	(9,015)	(76,608)	(850)%
Adjusted EBITDA	$ 18,363	$ (4,456)	$ 22,819	512%

	Year Ended December 31, 2007	Year Ended December 31, 2006	Increase (Decrease) $	Increase (Decrease) %

	(in thousands, except percentages)			
Consolidated				
Net loss	$ (147,034)	$ (9,320)	$ (137,714)	*%
Depreciation, depletion and amortization	86,517	72,218	14,299	20%
Interest expense, net	35,140	18,091	17,049	94%
Income tax benefit	(85,623)	(9,015)	(76,608)	(850)%
Impairment loss	170,402		170,402	100%
Minority interest	(349)	58	(407)	(702)%
Adjusted EBITDA	$ 59,053	$ 72,032	$ (12,979)	(18)%

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Twelve Months Ended December 31, 2006 Compared to the Twelve Months Ended December 31, 2005

Our results of operations for the twelve months ended December 31, 2006 and the period November 19, 2005 through December 31, 2005 include Anker and CoalQuest.

Revenues

The following table depicts revenues for the years ended December 31, 2006 and 2005 for the indicated categories:

	Year Ended December 31,		Increase (Decrease)	
	2006	2005	$	%
	(in thousands, except percentages and per ton data)			
Coal sales revenues	$ 833,998	$ 619,038	$ 214,960	35%
Freight and handling revenues	18,890	8,601	10,289	120%
Other revenues	38,706	22,852	15,854	69%
Total revenues	$ 891,594	$ 650,491	$ 241,103	37%
Tons sold	19,371	14,755	4,616	31%
Coal revenue per ton	$ 43.05	$ 41.95	$ 1.10	3%

Coal sales revenues. Coal sales revenues are derived from sales of produced coal and brokered coal sales. Coal sales revenues increased $215.0 million for the year ended December 31, 2006, or 35%, compared to the year ended December 31, 2005. This increase was due to an increase in tons sold of 31% over 2005 because of the Anker/CoalQuest acquisition and an increase of $1.10 per ton in the average sales price of our coal (exclusive of amortization income on below-market coal supply agreements) primarily sold pursuant to coal supply agreements. Tons sold in 2006 increased by 4.6 million to 19.4 million, primarily due to the effect of the Anker and CoalQuest acquisitions, which provided approximately 3.8 million additional tons over the prior year. Additionally, new mining complexes that commenced operations during 2006 provided an increase of approximately 1.6 million tons over 2005. These increases were partially offset by decreases in tons sold caused by unusual events at our Sago and Viper mines and operating difficulties leading to the idling of certain mining units during the second half of 2006.

Freight and handling revenues. Freight and handling revenues increased $10.3 million to $18.9 million for year ended December 31, 2006 compared to the year ended December 31, 2005. The increase is due to an increase in shipments for which we initially pay the freight and handling costs and are then reimbursed by the customer.

Other revenues. Other revenues increased for the year ended December 31, 2006 by $15.9 million, or 69%, to $38.7 million, as compared to the year ended December 31, 2005. The increase was due to a gain of $7.0 million related to the termination of a contractual coal delivery obligation, as well as increases of $2.4 million in processing revenue being performed in a preparation plant obtained in the Anker acquisition, $1.9 million generated from newly developed coalbed methane wells owned jointly by our subsidiary, CoalQuest, and CDX Gas, LLC (CDX), $2.3 million in royalty revenues primarily related to an increase in mining activities from our sublessors and the finalization of sublesaing agreements, $2.2 million in ash disposal revenue resulting from long-term ash disposal contracts assumed as part of the Anker acquisition and $1.6 million relating to a negotiated cash payment to us relating to a customer s tax credit pursuant to the state of Maryland s Mined Coal Tax Credit provision. The increases were partially offset by lower revenue of $1.6 million from our highwall mining activities and shop services, both performed by our subsidiary ADDCAR, due to decreased production caused by varying mining conditions at the contracting parties mining complexes.

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Coal sales revenues and tons sold by segment

The following table depicts coal sales revenues by operating segment for the years ended December 31, 2006 and 2005:

	Year Ended December 31, 2006	2005	Increase (Decrease) $	%
	(in thousands, except percentages)			
Central Appalachian	$ 534,429	$ 446,039	$ 88,390	20%
Northern Appalachian	109,184	11,186	97,998	876%
Illinois Basin	49,842	53,931	(4,089)	(8)%
Ancillary	140,543	107,882	32,661	30%
Total coal sales revenues	$ 833,998	$ 619,038	$ 214,960	35%

The following table depicts tons sold by operating segment for the years ended December 31, 2006 and 2005:

	Year Ended December 31, 2006	2005	Increase (Decrease) $	%
	(in thousands, except percentages)			
Central Appalachian	10,904	9,782	1,122	11%
Northern Appalachian	3,281	300	2,981	994%
Illinois Basin	2,020	2,322	(302)	(13)%
Ancillary	3,166	2,351	815	35%
Total tons sold	19,371	14,755	4,616	31%

Coal sales revenues from our Central Appalachian segment increased approximately $88.4 million, or 20%, for the year ended December 31, 2006 as compared to the year ended December 31, 2005. This increase was primarily attributable to an increase in tons sold of approximately 1.1 million, or 11%, over 2005 due to our East Mac and Nellie, Flint Ridge deep and Raven No. 1 underground mines that commenced operations in 2006, as well as various mines that significantly increased or reached full production during 2006. The increase was additionally impacted by an increase of $3.41 per ton in the average sales price of our coal primarily sold pursuant to coal supply agreements.

Our Northern Appalachian segment is comprised primarily of mines from the Anker/CoalQuest acquisition in November 2005. Coal sales revenues from our Northern Appalachian operations increased $98.0 million due to an increase of 3.0 million tons sold resulting from a full year of production from these mines.

Coal sales revenues from our Illinois Basin segment decreased approximately $4.1 million, or 8%, from 2005 primarily due to a 13% decrease in tons sold resulting from a fire at our Viper mine which led to the temporary idling of the mine during 2006. The decrease in tons sold was partially offset by an increase in coal sales revenue per ton of $1.45.

Coal sales revenues from the Ancillary segment are comprised of coal sold under brokered coal contracts. We experienced an increase of $32.7 million, or 30%, due to an increase of 0.8 million tons, or 35%, primarily from brokered coal contracts acquired from Anker in November 2005 which provided a full year of sales for 2006.

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Costs and expenses

The following table depicts cost of operations for the years ended December 31, 2006 and 2005 for the indicated categories:

	Year Ended December 31, 2006	Year Ended December 31, 2005	Increase (Decrease) $	Increase (Decrease) %
	(in thousands, except percentages and per ton data)			
Cost of coal sales and other revenues	$ 769,332	$ 510,097	$ 259,235	51%
Freight and handling costs	18,890	8,601	10,289	120%
Depreciation, depletion and amortization	72,218	43,076	29,142	68%
Selling, general and administrative expenses	34,578	28,828	5,750	20%
Net gain on sale of assets	(1,125)	(502)	(623)	124%
Total costs and expenses	$ 893,893	$ 590,100	$ 303,793	51%
Total costs and expenses per ton sold[1]	$ 46.15	$ 39.99	$ 6.16	15%

(1) Included in total costs and expenses per ton sold were costs for ICG ADDCAR, highwall mining activities and shop services of $1.61 and $2.07 per ton for the years ended December 31, 2006 and 2005, respectively.

Cost of coal sales and other revenues. For the year ended December 31, 2006, our cost of coal sales increased $259.2 million, or 51%, to $769.3 million compared to $510.1 million for the year ended December 31, 2005. The increase in cost of coal sales was primarily a result of our acquisitions of Anker and CoalQuest, which resulted in an increase in cost of coal sales of approximately $177.9 million, and includes several unusual events and operating difficulties adversely affecting the year, such as the closure of the Stony River deep mine, the bankruptcy of a key coal supplier for our Vindex operation, an extended construction outage at the Sentinel mine, adverse geological conditions encountered at the Sycamore No. 2 mine and the effects of the Sago mine accident in January 2006. Our performance was also adversely affected in the second quarter of 2006 by a fire at our Illinois mining complex. The start-up of our Flint Ridge, East Mac and Nellie, Raven, Crown, Carlos and Imperial mine sites, as well as the purchase of our Jackson Mountain mine site, increased cost of coal sales by $70.3 million. Other factors affecting cost of coal sales and other revenues for the year were increases in prices for diesel fuel and lube costs of $7.0 million, increased blasting supplies costs of $1.2 million, increased contract labor costs of $2.1 million and increased tire costs of $3.3 million. Variable sales-related costs, such as royalties and severance taxes increased $5.3 million due to increased sales realization. Trucking costs increased $2.8 million due to escalated diesel fuel costs. In addition, salary and hourly payroll expense and related employee benefits increased $8.4 million due to increased personnel and the necessity to maintain a competitive compensation program due to a highly-competitive labor market. These increases were partially offset by an increase in stockpile inventories which decreased cost of coal sales for the period by $8.9 million, decreases in equipment rental expense of $7.0 million due to the decision to purchase rather than lease needed equipment, decreased insurance costs of $1.5 million primarily caused by the change from a state run workers compensation program to a private insurance carrier and a decrease in purchase coal costs of $2.6 million.

Costs of coal sales for the year includes $13.0 million relating to the Sago mine accident, including reserves established for claims and other future costs and $4.7 million of carrying costs related to the mining operation prior to resuming operations at the end of the first quarter.

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Freight and handling costs. Freight and handling costs increased $10.3 million to $18.9 million for the year ended December 31, 2006 compared to the year ended December 31, 2005. The increase is due to an increase in shipments for which we initially pay the freight and handling costs and are then reimbursed by the customer.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased $29.1 million to $72.2 million for the year ended December 31, 2006 compared to $43.1 million for the year ended December 31, 2005. Depreciation, depletion and amortization per ton increased to $3.73 per ton sold in the year ended December 31, 2006 from $2.92 per ton sold for the year ended December 31, 2005. The principal component of the increase was an increase in depreciation, depletion and amortization expense of $41.3 million for the year ended December 31, 2006, $21.3 million of which was related to the acquisitions of Anker and CoalQuest, as well as an increase in capital expenditures and coalbed methane well costs. The increases were offset by a net increase in amortization income on above- and below-market coal supply agreements of $12.2 million during the year ended December 31, 2006.

Selling, general and administrative expenses. Selling, general and administrative expenses for the year ended December 31, 2006 were $34.6 million compared to $28.8 million for the year ended December 31, 2005. The net increase of $5.8 million was attributable to gifts aggregating $2.0 million made to the families of the thirteen miners involved in the Sago mine accident, increases in legal, professional and consulting fees of $5.2 million, $1.7 million for share-based compensation related restricted stock and stock options, $0.9 million in compensation expense and $0.6 million in insurance expense. Increases in legal, professional and consulting fees, as well as compensation and insurance expense, were related to being a public company. These increases were offset by a $5.4 million reduction in payroll taxes related to stock-based compensation. In 2005, certain recipients of restricted stock awards filed Section 83(b) elections, which resulted in full taxation of the award at the grant date rather than upon vesting.

Gain on sale of assets. Asset sales resulted in a gain of $1.1 million for the year ended December 31, 2006 compared to $0.5 million for the year ended December 31, 2005.

Total costs as a percentage of revenues. Total costs as a percentage of revenues increased to approximately 100% for the year ended December 31, 2006 from 91% for the year ended December 31, 2005, primarily as a result of weak coal prices in the second half of 2006, unanticipated operating difficulties at certain mine locations, mine accidents at two locations and increased operating costs. The softening of the coal market in the second half of 2006 caused a decrease in our profit margin earned on spot coal sales. Unanticipated adverse operating conditions experienced at the Stony River deep mine, Sentinel mine and Sycamore No. 2 resulted in increased operating expenses with a reduced amount or no corresponding production for the year. Due to the Sago mine accident as well as the mine fire at our Illinois mining complex we experienced production interruptions that decreased sales while still incurring holding costs as the mines were being repaired. Profit margins were further squeezed at all locations compared to the prior year by increased employee compensation as well as increased prices of operating parts, supplies and services as discussed above.

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Adjusted EBITDA by Segment

Adjusted EBITDA represents net income before deducting interest expense, income taxes, depreciation, depletion, amortization and minority interest. Adjusted EBITDA is presented because it is an important supplemental measure of our performance used by our chief operating decision maker. It is considered adjusted as we adjust EBITDA for minority interest. 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 76 of this Annual Report on Form 10-K and in Note 20 to our consolidated financial statements for the year ended December 31, 2006.

The following table depicts segment Adjusted EBITDA for the years ended December 31, 2006 and 2005:

	Year Ended December 31,		Increase (Decrease)	
	2006	2005	$	%
	(in thousands, except percentages)			
Central Appalachian	$ 108,598	$ 104,684	$ 3,914	4%
Northern Appalachian	(36,586)	(2,873)	33,713	1,173%
Illinois Basin	4,476	4,630	(154)	(3)%
Ancillary	(4,456)	328	(4,784)	(1,459)%
Total Adjusted EBITDA	$ 72,032	$ 106,769	$ (34,737)	(33)%

Adjusted EBITDA from our Central Appalachian segment increased $3.9 million, or 4%, for the year ended December 31, 2006 as compared to the year ended December 31, 2005. This increase was due primarily to an 11% increase in tons sold by our Central Appalachian operations. The increase in sales tons was partially offset by less favorable profit margins of approximately $0.60 per ton resulting from increased production costs. Additionally, activities incidental to our coal producing activities, such as coal processing and royalty income, increased by $2.4 million and $1.1 million, respectively, in 2006, contributing to the increase in Adjusted EBITDA.

The decrease in Adjusted EBITDA from our Northern Appalachian segment of $33.7 million was primarily the result of a full year of operations in 2006 by the mining complexes acquired from Anker and CoalQuest in November 2005. Additionally, several unusual events and operating difficulties, such as the closure of the Stony River deep mine, the bankruptcy of a key coal supplier for our Vindex operation, an extended construction outage at the Sentinel mine and adverse geological conditions encountered at the Sycamore No. 2 mine, adversely affected Adjusted EBITDA. Also impacting the decrease were the effects of the Sago mine accident in January 2006, which decreased Adjusted EBITDA by $13.0 million as a result of reserves established for claims and other future costs and $4.7 million of mine holding costs prior to resuming operations at the end of the first quarter.

Adjusted EBITDA from our Illinois Basin segment decreased $0.2 million, or 3%, due to a fire at our Viper mine which led to a temporary idling of the mine in 2006.

The decrease in Adjusted EBITDA from our Ancillary segment of $4.8 million was the result of decreased margins on contract mining activities performed by our subsidiary ADDCAR resulting from varying mining conditions at the contracting parties mining complexes and increased direct costs. Also impacting the decrease were increased selling, general and administrative expenses due to gifts aggregating $2.0 million made to the families of the thirteen miners involved in the Sago mine accident, expenses related to being a public company, including legal, professional and consulting fees of $5.2 million, share-based compensation of $1.7 million and compensation expense of $0.9 million. These increases were partially offset by a $5.4 million reduction in payroll taxes paid in 2005 related to stock based compensation.

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

The following tables reconcile Adjusted EBITDA to net income (loss) by segment for the years ended December 31, 2006 and 2005:

	Year Ended December 31,		Increase (Decrease)	
	2006	2005	$	%
	(in thousands, except percentages)			
Central Appalachian				
Net income	$ 59,620	$ 77,079	$ (17,459)	(23)%
Depreciation, depletion and amortization	48,050	27,085	20,965	77%
Interest expense, net	928	520	408	78%
Adjusted EBITDA	$ 108,598	$ 104,684	$ 3,914	4%

	Year Ended December 31,		Increase (Decrease)	
	2006	2005	$	%
	(in thousands, except percentages)			
Northern Appalachian				
Net loss	$ (47,907)	$ (3,868)	$ 44,039	1,139%
Depreciation, depletion and amortization	10,822	956	9,866	1,032%
Interest expense, net	441	54	387	717
Minority interest	58	(15)	73	487%
Adjusted EBITDA	$ (36,586)	$ (2,873)	$ 33,713	1,173%

	Year Ended December 31,		Increase (Decrease)	
	2006	2005	$	%
	(in thousands, except percentages)			
Illinois Basin				
Net loss	$ (1,978)	$ (19)	$ 1,959	10,311%
Depreciation, depletion and amortization	6,287	4,550	1,737	38%
Interest expense, net	167	99	68	69%
Adjusted EBITDA	$ 4,476	$ 4,630	$ (154)	(3)%

	Year Ended December 31,		Increase (Decrease)	
	2006	2005	$	%
	(in thousands, except percentages)			
Ancillary				
Net loss	$ (19,055)	$ (40,864)	$ (21,809)	(53)%
Depreciation, depletion and amortization	7,059	10,485	(3,426)	(33)%
Interest expense, net	16,555	13,721	2,834	21%
Income tax expense (benefit)	(9,015)	16,986	(26,001)	(153)%
Adjusted EBITDA	$ (4,456)	$ 328	$ (4,784)	(1,459)%

	Year Ended December 31,		Increase (Decrease)	
	2006	2005	$	%
	(in thousands, except percentages)			
Consolidated				
Net loss	$ (9,320)	$ 32,328	$ (41,648)	(129)%

Depreciation, depletion and amortization	72,218	43,076	29,142	68%
Interest expense, net	18,091	14,394	3,697	26%
Income tax expense (benefit)	(9,015)	16,986	(26,001)	(153)%
Minority interest	58	(15)	73	487%
Adjusted EBITDA	$ 72,032	$ 106,769	$ (34,737)	(33)%

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Liquidity and Capital Resources

Our business is capital intensive and requires substantial capital expenditures for, among other things, purchasing, upgrading and maintaining equipment used in developing and mining our coal lands, as well as remaining in compliance with environmental laws and regulations. Our principal liquidity requirements are to finance our coal production, fund capital expenditures and service our debt and reclamation obligations. We may also engage in acquisitions and/or divestitures from time-to-time. Our primary sources of liquidity to meet our needs are cash flows from sales of our coal, other income, borrowings under our senior credit facility, the proceeds of our convertible notes offering and capital equipment financing arrangements.

As of December 31, 2007, our total cash and cash equivalents was $107.2 million and we had $30.0 million available for borrowing under our $100 million senior credit facility. However, weak performance in the first half of the year led management to believe that we would not be able to meet the financial covenants in our senior credit facility at future required certification dates, thereby restricting access to the availability under our senior credit facility. Accordingly, management proactively sought additional sources of liquidity to provide financial flexibility and to avoid constraining our capital growth program for our Beckley, Sentinel and Tygart Valley projects. On July 16, 2007, we and our subsidiaries entered into a $25.0 million bridge loan facility with a certain fund affiliated with WL Ross & Co. LLC (WLR). We and our subsidiaries were jointly and severally liable for the loan, which was repaid in full on July 31, 2007 with a portion of the proceeds of the convertible notes offering described below.

On July 31, 2007, we completed a private offering of $195.0 million aggregate principal amount of 9.00% Convertible Senior Notes due 2012 pursuant to Rule 144A under the Securities Act of 1933. We granted the initial purchaser a 30-day over-allotment option pursuant to which we issued an additional $30.0 million of convertible notes on August 28, 2007. The convertible notes are our senior unsecured obligations and are guaranteed on a senior unsecured basis by our material future and current domestic subsidiaries. The convertible notes and the related guarantees rank equal in right of payment to all of our and the guarantors respective existing and future unsecured senior indebtedness. Interest is payable semi-annually on February 1 and August 1, commencing on February 1, 2008. We received aggregate proceeds of $218.3 million, after deducting the initial purchaser s discounts and commissions of $6.7 million. We used a portion of the net proceeds to repay in full the $25.0 million bridge loan due to WLR and the $65.0 million outstanding under our amended credit facility. The remaining $128.3 million will be used to fund capital expenditures, for general corporate purposes and other expenses related to the offering of $1.1 million. The principal amount of the convertible notes is payable in cash and amounts above the principal amount, if any, will be convertible into shares of our common stock or, at our option, cash. The convertible notes are convertible (i) prior to February 12, 2012 during any calendar quarter after September 30, 2007, if the closing sale price per share of our common stock for each of 20 or more trading days in a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter exceeds 130% of the conversion price in effect on the last trading day of the immediately preceding calendar quarter; (ii) prior to February 12, 2012 during the five consecutive business days immediately after any five consecutive trading day period in which the average trading price for the notes on each day during such five trading-day period was equal to or less than 97% of the closing sale price of our common stock on such day multiplied by the then current conversion rate; (iii) upon the occurrence of specified corporate transactions; and (iv) at any time from, and including February 1, 2012 until the close of business on the second business day immediately preceding August 1, 2012.

We entered into a registration rights agreement with initial purchaser of the convertible notes that required us to file a shelf registration statement to register the resale of convertible notes with the Securities and Exchange Commission by October 29, 2007. As a result of the restatement of our financial statements for the year ending December 31, 2006, 2005 and the period May 11, 2004 (inception) to December 31, 2004, we were delayed in filing the registration statement until November 15, 2007. As a result, we were required to pay additional interest at a per annum rate of 0.25%, or $23,000, until the shelf registration statement was filed. This additional interest did not materially impact our financial position, results of operations or cash flows.

Concurrent with the closing of the offering, we amended certain covenants under our senior credit facility to allow for additional flexibility under our financial covenants which include: a maximum leverage ratio, a minimum interest coverage ratio and maximum capital expenditures and to allow for the Offering. The amendment to our senior credit facility also reduced our total senior credit facility commitments by the same amount of the gross proceeds from the offering to $100.0 million.

On September 28, 2007, we completed the sale of our Denmark reserve in Southern Illinois for $39.0 million in cash and an overriding royalty totaling $4 million on certain future production. The sale resulted in a gain of $36.8 million and provided additional cash to execute our capital expenditure program.

The results of the 2007 annual impairment tests of goodwill conducted as of October 31, 2007 of the ICG Hazard, ICG Eastern, ICG East Kentucky and ICG Knott County business units indicated that their estimated fair values were less than the carrying amounts of the respective business unit assets, including goodwill, and, therefore, were impaired. As a result, we recorded a $170.4 million ($110.4 million net of tax) non-cash impairment charge to reduce the carrying amount of these assets to their estimated fair value. The impairment loss did not impact us under any of our borrowing arrangements.

Cash paid for capital expenditures was approximately $169.3 million for the year ended December 31, 2007 and we currently expect out total capital expenditures will be approximately $157.0 million and $192.0 million in 2008 and 2009, respectively. We have funded these capital expenditures from our internal operations, proceeds from our senior and convertible notes offerings in 2006 and 2007, respectively, borrowing under our credit facility and our $50.0 million equipment revolving credit facility with Caterpillar Financial Services Corporation. We believe that these sources of capital, as well as the proceeds from the offering and from the sale of our Denmark reserve, will be sufficient to fund our anticipated capital expenditures under our current budget plan through 2008. We currently anticipate needing to obtain additional financing in approximately the second quarter of 2009. The timing of seeking additional capital will be subject to market conditions and, to the extent necessary, management can control the timing of the need by managing the pace of capital spending.

Approximately $119.0 million of 2007 cash paid for capital expenditures were attributable to Central Appalachian operations. This amount represent investments of approximately $69.4 million in our Beckley mining complex, as well as additional investments of $8.8 million in our newly developed East Mac and Nellie, Flint Ridge No. 2, Raven and Mt. Sterling mine sites. Additionally, we expended approximately $40.8 million for upgrades and maintenance at our Hazard, Knott County, East Kentucky and Eastern operations.

We spent approximately $36.4 million for development and improvements of our Northern Appalachian operations in the year ended December 31, 2007. Approximately $19.9 million of the amount was investments in our Sentinel and Tygart mine site and approximately $6.1 million was expended for our operations at Jackson Mountain, Imperial and Guston Run mine sites. Additionally, we invested approximately $10.4 million for current operations at Vindex, Buckhannon, Patriot and Harrison mine sites.

Expenditures of approximately $2.6 million for our Illinois Basin operations were for ongoing operations improvements.

Approximately $11.3 million of cash paid for capital expenditures for the year ended December 31, 2007 were within our Ancillary segment. Approximately $8.8 million was for our investment in a joint operating agreement for the purpose of exploration and development of coalbed methane. The remaining $2.5 million is attributable to upgrades maintenance at various other subsidiaries.

As a result of recent accidents in the mining industry, new legislation has been announced that will require additional capital expenditures to meet enhanced safety standards. For the year ended December 31, 2007, we spent $3.3 million to meet these standards and anticipate spending an additional $4.6 million in 2008.

Cash Flows

Net cash provided by operating activities was $22.1 million for the year ended December 31, 2007, a decrease of $33.5 million from 2006. This decrease is attributable to an increase in net operating assets and liabilities of $41.1 million offset by a decrease in net loss of $74.6 million after adjustment for non-cash charges.

For the year ended December 31, 2007, net cash used in investing activities was $126.5 million compared to $160.8 million for the year ended December 31, 2006. For 2007, $169.3 million of cash was used to support existing mining operations and for development of new mining complexes compared to $165.7 million in 2006. Investing activities for 2007 also included cash paid of $3.8 million representing contingency payments related to the Horizon acquisition as compared to $4.7 million in 2006. Additionally, we collected proceeds from asset sales of $46.5 million during the year ended December 31, 2007 versus $3.8 million during 2006.

Net cash provided by financing activities of $192.8 million for the year ended December 31, 2007 was primarily due to proceeds of $225.0 million from our convertible senior notes offering. Additionally, we had borrowings of $65.0 million on our credit facility and an additional $26.1 million was provided by short-term notes entered into during the year. These borrowings were offset by repayments on our short-term and long-term debt and capital leases of $45.4 million and $68.6 million, respectively. Also impacting financing activities for the year ended December 31, 2007 was additional finance costs of $9.3 million related to the issuance of our convertible notes and amending our credit facility.

Net cash provided by operating activities was $55.6 million for the year ended December 31, 2006, a decrease of $21.7 million from 2005. This decrease is attributable to a decrease in earnings of $12.2 million, after adjustment for non-cash charges. The remaining decrease was due to the decrease in net operating assets and liabilities of $9.6 million.

Net income decreased in 2006 compared to 2005 primarily as a result of higher operating costs, most notably diesel fuel, trucking costs due to increased diesel costs, blasting supplies, roof bolts and plates, the effects of the Sago mine accident, the effects of the Viper mine fire, labor costs due to the highly-competitive labor market and other operating issues noted above. Also impacting the comparability of net income for 2006 compared with 2005 was the acquisition of Anker and CoalQuest in November 2005.

For the year ended December 31, 2006, net cash used in investing activities was $160.8 million compared to cash used in investing activities of $104.7 million for the year ended December 31, 2005. Cash used in investing activities for 2006 was $165.7 million to replace our aged mining equipment fleet and expand operations compared to $108.2 million in 2005. Cash was returned from deposits of collateral for reclamation and royalty bonds of $0.4 million in 2006 compared to $3.4 million in 2005. Positively affecting investing activities for 2006 were proceeds of asset sales of $3.8 million and proceeds received in connection with a sale-leaseback transaction of $5.4 million. Investing activities also include cash paid of $4.7 million for bonding payments and other items relating to the acquisitions of Anker and CoalQuest and the former Horizon companies.

Net cash provided by financing activities of $114.7 million for the year ended December 31, 2006 was primarily due to proceeds of $175.0 million related to our senior note offering, which closed on June 23, 2006. The proceeds were used to repay all amounts outstanding under the then existing revolving credit facility of $91.3 million, including $70.0 million of which was borrowed in the first six months of 2006, and retire the then outstanding term loan facility of $19.5 million. Simultaneous with the senior notes offering, our credit facility was amended and restated resulting in an increased credit facility of up to $325.0 million. The senior notes offering and the amended and restated credit facility resulted in issuance fees of approximately $9.4 million. In addition, we borrowed $81.9 million to fund capital expenditures and short-term operating needs. Cash was used in financing activities to repay short-term debt of $20.4 million in 2006 and other long-term debt and capital leases of $1.6 million.

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Credit Facility and Long-Term Debt Obligations

As of December 31, 2007, our total long-term indebtedness, including capital lease obligations, consisted of the following:

	December 31, 2007
9.00% Convertible senior notes, due 2012	$ 225,000
10.25% Senior notes, due 2014	175,000
Equipment notes	12,330
Total	412,330
Less current portion	4,234
Long-term debt	$ 408,096

Convertible senior notes. On July 31, 2007, we completed a private offering of $195.0 million aggregate principal amount of 9.00% Convertible Senior Notes due 2012 pursuant to Rule 144A under the Securities Act of 1933. We granted the initial purchaser a 30-day over-allotment option pursuant to which we issued an additional $30.0 million of convertible notes on August 28, 2007. The convertible notes are our senior unsecured obligations and are guaranteed on a senior unsecured basis by our material future and current domestic subsidiaries. The convertible notes and the related guarantees rank equal in right of payment to all of our and the guarantors respective existing and future unsecured senior indebtedness. Interest is payable semi-annually on February 1 and August 1, commencing on February 1, 2008. We received aggregate proceeds of $218.3 million, after deducting the initial purchaser s discounts and commissions of $6.7 million. We used a portion of the net proceeds to repay in full the $25.0 million bridge loan due to WLR and the $65.0 million outstanding under our amended credit facility. The remaining $128.3 million is being used to fund capital expenditures, for general corporate purposes and other expenses related to the offering of $1.1 million. The principal amount of the convertible notes is payable in cash and amounts above the principal amount, if any, will be convertible into shares of our common stock or, at our option, cash. The convertible notes are convertible (i) prior to February 12, 2012 during any calendar quarter after September 30, 2007, if the closing sale price per share of our common stock for each of 20 or more trading days in a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter exceeds 130% of the conversion price in effect on the last trading day of the immediately preceding calendar quarter; (ii) prior to February 12, 2012 during the five consecutive business days immediately after any five consecutive trading day period in which the average trading price for the notes on each day during such five trading-day period was equal to or less than 97% of the closing sale price of our common stock on such day multiplied by the then current conversion rate; (iii) upon the occurrence of specified corporate transactions; and (iv) at any time from, and including February 1, 2012 until the close of business on the second business day immediately preceding August 1, 2012.

We entered into a registration rights agreement with initial purchaser of the convertible notes that required us to file a shelf registration statement to register the resale of convertible notes with the Securities and Exchange Commission by October 29, 2007. As a result of the restatement of our financial statements for the year ending December 31, 2006, 2005 and the period May 11, 2004 (inception) to December 31, 2004, we were delayed in filing the registration statement until November 15, 2007. As a result, we were required to pay additional interest at a per annum rate of 0.25% until the shelf registration statement was filed. This additional interest did not materially impact our financial position, results of operations or cash flows.

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Senior notes. On June 23, 2006, we sold $175.0 million aggregate principal amount of our 10.25% senior notes due July 15, 2014 in a private placement pursuant to Rule 144A of the Securities Act, as amended, and Regulation S of the Securities Act, with net proceeds of approximately $171.5 million to us after deducting fees and other offering expenses. Interest on the notes is payable semi-annually in arrears on July 15 and January 15 of each year. The notes are senior unsecured obligations and are guaranteed on a senior unsecured basis by all of our current and future domestic subsidiaries that are material or that guarantee our amended and restated credit facility. The notes and the guarantees rank equally with all of our and the guarantors existing and future senior unsecured indebtedness, but are effectively subordinated to all of our and the guarantors existing and future senior secured indebtedness to the extent of the value of the assets securing that indebtedness and to all liabilities of our subsidiaries that are not guarantors. We have the option to redeem all or a portion of the notes at 100% of the aggregate principal amount at maturity at any time on or after July 15, 2010. At any time prior to July 15, 2010, we may also redeem all or a portion of the notes at a redemption price equal to 100% of the aggregate principal amount of the notes plus an applicable premium as of, and accrued and unpaid interest and additional interest, if any, to, but not including the date of redemption. At any time before July 15, 2009, we may also redeem up to 35% of the aggregate principal amount of the notes at a redemption price of 110.25% of the principal amount, plus accrued and unpaid interest, if any, to the date of redemption, with the proceeds of certain equity offerings. Upon a change of control, we may be required to offer to purchase the notes at a purchase price equal to 101% of the principal amount, plus accrued and unpaid interest.

On October 6, 2006, we commenced an exchange offer pursuant to a registration rights agreement with the initial purchasers to enable holders to exchange the privately placed senior notes for publicly registered senior notes. The exchange offer expired on November 10, 2007 with 100% of the aggregate principal amount of the outstanding senior notes being tendered for exchange. The terms of the exchange notes are identical to the terms of the original notes for which they were being exchanged, except that the registration rights and the transfer restrictions applicable to the original notes are not applicable to the exchange notes.

The indenture governing the senior notes contains covenants that limit our ability to, among other things, incur additional indebtedness, issue preferred stock, pay dividends, repurchase, repay or redeem our capital stock, make certain investments, sell assets and incur liens. As of December 31, 2007, we were in compliance with our covenants under the indenture.

Credit facility. In June 2006, we entered into a second amended and restated credit agreement (the Amended Credit Facility) consisting of a revolving credit facility which matures on June 23, 2011. In July 2007, concurrent with the issuance of the convertible notes, we further amended the Amended Credit Facility to reduce the commitments thereunder to $100 million, of which a maximum of $80 million may be used for letters of credit. The amendment, among other things, modified the maximum permitted leverage ratio, the minimum interest coverage ratio and the maximum amount of capital expenditures permitted. Further, the amendment also revised certain interest rate thresholds and unused commitment fee levels under the Amended Credit Facility. As of December 31, 2007, we had no borrowings outstanding and letters of credit totaling $70.0 million outstanding, leaving $30.0 million available for future borrowing capacity. Interest on the borrowings under the Amended Credit Facility is payable, at our option, at either the base rate plus an applicable margin based on our leverage ratio of 1.25% to 2.00% as of December 31, 2007 or LIBOR plus an applicable margin based on our leverage ratio of 2.25% to 3.00% as of December 31, 2007.

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Other

As a regular part of our business, we review opportunities for, and engage in discussions and negotiations concerning, the acquisition of coal mining assets and interests in coal mining companies, and acquisitions of, or combinations with, coal mining companies. When we believe that these opportunities are consistent with our growth plans and our acquisition criteria, we will make bids or proposals and/or enter into letters of intent and other similar agreements, which may be binding or nonbinding, that are customarily subject to a variety of conditions and usually permit us to terminate the discussions and any related agreement if, among other things, we are not satisfied with the results of our due diligence investigation. 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. There can be no assurance that additional financing will be available on terms acceptable to us, or at all.

Additionally, we have other long-term liabilities, including, but not limited to, mine reclamation and mine closure costs, below-market coal supply agreements and black lung costs, and some of our subsidiaries have long-term liabilities relating to retiree health and other employee benefits.

Our ability to meet our long-term debt obligations will depend upon our future performance, which in-turn, will depend upon general economic, financial and business conditions, along with competition, legislation and regulation factors that are largely beyond our control. Based upon our current operations, we believe that cash flow from operations, together with other available sources of funds, including additional borrowings under our credit facility, will be adequate for at least the next 12 months for making required payments of principal and interest on our indebtedness and for funding anticipated capital expenditures and working capital requirements. However, we cannot assure you that our operating results, cash flow and capital resources will be sufficient for repayment of our debt obligations in the future.

Contractual Obligations

The following is a summary of our significant future contractual obligations by year as of December 31, 2007:

	Payments due by period				
	Less than 1 year	1-3 years	3-5 years (in thousands)	More than 5 years	Total
Long-term debt obligations[1]	$ 43,055	$ 83,807	$ 294,144	$ 202,654	$ 623,660
Operating leases	96	90	6		192
Coal purchase obligation[2]	24,277	36,405			60,682
Advisory Services Agreement[3]	2,000	4,000	1,500		7,500
Minimum royalties	8,385	15,869	13,819	29,596	67,669
Postretirement medical benefits	306	1,675	3,574	185,740	191,295
Total[4]	$ 78,119	$ 141,846	$ 313,043	$ 417,990	$ 950,998

(1) *Amounts are inclusive of interest assuming interest rates of 10.25% for our senior notes, 9.0% for our convertible notes and ranging from 5.10% to 7.45% on our equipment notes.*

(2) *Reflects estimates of obligations.*

(3) *See Certain relationships and related party transactions.*

(4) *We are also a party to an employment agreement with each of our President and Chief Executive Officer and our Senior Vice President, General Counsel and Secretary.*

We have excluded from the table above uncertain tax liabilities as defined in FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, due to the immateriality of such amounts.

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Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements. These arrangements include guarantees and financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. No liabilities related to these arrangements are reflected in our consolidated balance sheets and we do not expect any material adverse effects on our financial condition, results of operations or cash flows to result from these off-balance sheet arrangements.

Federal and state laws require us to secure payment of certain long-term obligations, such as mine closure and reclamation costs, federal and state workers compensation, coal leases and other obligations. We typically secure these payment obligations by using surety bonds, an off-balance sheet instrument. The use of surety bonds is less expensive than posting an all cash bond or a bank letter of credit, either of which would require a greater use of our credit facility. We then use bank letters of credit to secure our surety bonding obligations as a lower cost alternative than securing those bonds with cash. We currently have a $130.4 million committed bonding facility pursuant to which we are required to provide bank letters of credit in an amount up to 50% of the aggregate bond liability. Recently, surety bond costs have increased, while the market terms of surety bonds have generally become less favorable. To the extent that surety bonds become unavailable, we would seek to secure our reclamation obligations with letters of credit, cash deposits or other suitable forms of collateral.

As of December 31, 2007, we had outstanding surety bonds with third parties for post-mining reclamation totaling $103.8 million, plus $4.7 million for miscellaneous purposes. As of December, 31, 2007, we maintained letters of credit totaling $70.0 million to secure reclamation surety bonds and other obligations.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on results of operations for the years ended December 31, 2007, 2006 and 2005. However, commodities prices have increased at a rate greater than that of the general economy, specifically prices for tires, roofbolts, explosives and healthcare.

Recent Accounting Pronouncements

Business Combinations. In December 2007, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 141 (Revised 2007), *Business Combinations* (SFAS No. 141R). SFAS No. 141R will significantly change the accounting for business combinations. Under SFAS No. 141R, an acquiring entity will be required to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions. SFAS No. 141R will change the accounting treatment for certain specific acquisition-related items including: (1) expensing acquisition-related costs as incurred; (2) valuing noncontrolling interests at fair value at the acquisition date; and (3) expensing restructuring costs associated with an acquired business. SFAS No. 141R also includes a substantial number of new disclosure requirements. SFAS No. 141R is to be applied to any business combination for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We are currently evaluating the effect, if any, that the adoption of SFAS No. 141R will have on our financial position, results of operations and cash flows.

Fair Value Measurements. In September 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* (SFAS No. 157). SFAS No. 157 clarifies the definition of fair value, establishes a framework for measuring fair value and expands the disclosures on fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. Adoption of SFAS No. 157 did not have a material impact on our financial position, results of operations or cash flows, however adoption will result in additional information being included in the footnotes accompanying our consolidated financial statements.

Fair Value Option. In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115* (SFAS No. 159). SFAS No. 159 provides entities with an option to report selected financial assets and liabilities at fair value and establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. We do not expect the adoption of SFAS No. 159 to have a material impact on our financial position, results of operations and cash flows.

Noncontrolling Interests. In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements* (SFAS No. 160). SFAS No. 160 establishes new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary (minority interest) is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements and separate from the parent company s equity. Among other requirements, this statement requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure, on the face of the consolidated statement of operations, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. We are currently evaluating the effect, if any, that the adoption of SFAS No. 160 will have on our financial position, results of operations and cash flows.

Income Taxes. In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). FIN 48 increases the relevancy and comparability of financial reporting by clarifying the way companies account for uncertainty in income taxes. FIN 48 is effective for fiscal years beginning after December 15, 2006. Adoption of FIN 48 resulted in a decrease of $0.1 million in our retained earnings balance as of January 1, 2007.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest rate risk. In May 2006, we entered into an Interest Rate Collar Agreement, which becomes effective on March 31, 2007 and expires March 31, 2009, to hedge our interest risk on an initial $100.0 million (increasing to $200.0 million in March 2008) notional amount of revolving debt. The interest rate collar is designed as a cash flow hedge to offset the impact of changes in the LIBOR interest rate above 5.92% and below 4.80%. This agreement was entered into in conjunction with our amended and restated credit facility dated June 23, 2006. We recognize the change in the fair value of this agreement in the income statement in the period of change. For the year ended December 31, 2007, we recorded a loss of $1.6 million related to changes in fair market value.

Market price risk. We are exposed to market price risk in the normal course of mining and selling coal. As of December 31, 2007, 85% of 2008 planned production is committed for sale, leaving approximately 15% uncommitted for sale. A hypothetical decrease of $1.00 per ton in the market price for coal would reduce pre-tax income by $2.9 million for 2008.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our financial statements and supplementary data are included at the end of this report beginning on page F-1.

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

There have been no changes in, or disagreements with, accountants on accounting and financial disclosure.

ITEM 9A. CONTROLS AND PROCEDURES

We maintain a set of disclosure controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in reports that we file or submit under the Securities Exchange Act of 1934 (the Exchange Act) is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. Our disclosure controls and procedures are also designed to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), to allow timely decisions regarding required disclosure. Periodically, we review the design and effectiveness of our disclosure controls and controls over financial reporting to ensure they remain effective. If such reviews identify a need, we will make modifications to improve the design and effectiveness of our control structure.

Control systems, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that control objectives are met. Because of inherent limitations in all control systems, no evaluation of controls can provide assurance that all control issues and instances of fraud, if any, within a company will be detected. Additionally, controls can be circumvented by individuals, by collusion of two or more people, or by management override. Over time, controls can become inadequate because of changes in conditions or the degree of compliance may deteriorate. Further, the design of any system of controls is based in part upon assumptions about the likelihood of future events. There can be no assurance that any design will succeed in achieving its stated goals under all future conditions. Because of the inherent limitations in any cost-effective control system, misstatements due to errors or fraud may occur and not be detected.

Restatement of Previously Issued Financial Statements

While finalizing our quarterly results for the period ended September 30, 2007, we identified that certain significant deficiencies in internal controls, when evaluated in the aggregate, resulted in a material weakness in the design and operation of our internal controls. As a result, we filed an amendment to our Annual Report on Form 10-K to restate our consolidated balance sheets, consolidated statements of operations and cash flows as of and for the two years ended December 31, 2006 and 2005, and for the period May 11, 2004 (inception) to December 31, 2004 to make the required corrections. These restatements primarily relate to amounts recorded on our opening balance sheets associated with acquisitions. In addition, the March 31, 2007 and June 30, 2007 financial statements have also been restated to reflect these corrections. The impact of the identified overstatements was immaterial on the results of operations in each period affected.

Evaluation of Disclosure Controls and Procedures

In response to these identified control deficiencies, we have implemented and refined our period end controls to review property-related balance sheet accounts, including land, equipment, advance royalties and associated accruals, to ensure that such controls are operating at a level of precision so as to detect errors that could be material to the consolidated financial statements.

As of December 31, 2007, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of our controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act). Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that the material weakness identified in prior periods no longer exists and that our controls and procedures were effective as of December 31, 2007.

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Management s Report on Internal Control Over Financial Reporting

Management is responsible for maintaining and establishing adequate internal control over financial reporting. Our internal control framework and processes were designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

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

Management conducted an assessment of the effectiveness of our internal control over financial reporting using the criteria set by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework.* Based on this assessment, management concluded that the company s internal control over financial reporting was effective as of December 31, 2007.

Our Independent Registered Public Accounting Firm, Deloitte & Touche LLP, has audited the effectiveness of our internal control over financial reporting, as stated in their attestation report included on page F-1 of Exhibit 15.

Changes in Internal Control Over Financial Reporting

Except as noted above, management did not make any changes in our internal controls over financial reporting during the fourth quarter of fiscal 2007 that would have materially affected, or would be reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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Part III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information requested by Items 401, 405 and 406 of Regulation S-K is incorporated herein by reference to the definitive Proxy Statement used in connection with the solicitation of proxies for our Annual Meeting of Stockholders to be held on May 14, 2008 (the Definitive Proxy Statement).

ITEM 11. EXECUTIVE COMPENSATION

The information requested by Item 402 of Regulation S-K is incorporated herein by reference to the Definitive Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information requested by Item 403 of Regulation S-K is incorporated herein by reference to the Definitive Proxy Statement.

See Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities Summary of Equity Compensation Plans on page 56 of this Annual Report for information required by Item 201(d) of Regulation S-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information requested by Item 404 of Regulation S-K is incorporated herein by reference to the Definitive Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICE

The information with respect to the fees and services related to our independent registered public accounting firm, Deloitte & Touche LLP, and the disclosure of the Audit Committee s pre-approval policies and procedures are contained in the Definitive Proxy Statement and will be incorporated herein by reference.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements:
The following financial statements are filed as part of this Annual Report on Form 10-K under Item 8:

(b) Exhibits.

(i) See the Exhibit Index.

(c) Financial Statement Schedules.

Schedules other than that noted above are omitted because of an absence of conditions under which they are required or because the information to be disclosed is presented in the financial statements or notes thereto.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

International Coal Group, Inc.

Scott Depot, West Virginia

We have audited the internal control over financial reporting of International Coal Group, Inc. and subsidiaries (the Company) as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2007 of the Company and our report dated February 29, 2008 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the adoption of Statement of Financial Accounting Standards No. 123(R), *Share-Based Payment*, as of January 1, 2006 and the recognition and related disclosure provisions of Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Benefit Plans,* as of December 31, 2006.

/s/ Deloitte & Touche LLP

Cincinnati, Ohio
February 29, 2008

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

International Coal Group, Inc.

Scott Depot, West Virginia

We have audited the accompanying consolidated balance sheets of International Coal Group, Inc. and subsidiaries (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the financial statements, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(R), Share-Based Payment, as of January 1, 2006 using the modified prospective method of application, and the recognition and related disclosure provisions of Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Benefit Plans, as of December 31, 2006.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 29, 2008 expressed an unqualified opinion on the Company s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Cincinnati, Ohio
February 29, 2008

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INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31, 2007 and 2006

(Dollars in thousands, except per share data)

	December 31, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 107,150	$ 18,742
Accounts receivable, net of allowances of $539 and $36	83,765	71,093
Inventories, net	40,679	40,587
Deferred income taxes	5,000	5,950
Prepaid insurance	10,618	10,986
Income taxes receivable	8,854	13,280
Prepaid expenses and other	9,138	7,444
Total current assets	265,204	168,082
PROPERTY, PLANT, EQUIPMENT AND MINE DEVELOPMENT, net	974,334	920,094
DEBT ISSUANCE COSTS, net	13,466	12,472
ADVANCE ROYALTIES, net	14,661	12,634
GOODWILL	30,237	196,757
OTHER NON-CURRENT ASSETS	5,661	6,852
Total assets	$ 1,303,563	$ 1,316,891
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 70,042	$ 56,391
Short-term debt		19,815
Current portion of long-term debt and capital leases	4,234	1,749
Current portion of reclamation and mine closure costs	7,333	4,198
Current portion of employee benefits	2,925	2,555
Accrued expenses and other	62,723	50,968
Total current liabilities	147,257	135,676
LONG-TERM DEBT AND CAPITAL LEASES	408,096	178,286
RECLAMATION AND MINE CLOSURE COSTS	78,587	88,472
EMPLOYEE BENEFITS	55,132	45,390
DEFERRED INCOME TAXES	52,355	141,553
BELOW-MARKET COAL SUPPLY AGREEMENTS	39,668	58,882
OTHER NON-CURRENT LIABILITIES	8,062	9,186
Total liabilities	789,157	657,445
MINORITY INTEREST	35	1,096
COMMITMENTS AND CONTINGENCIES		

STOCKHOLDERS EQUITY:		
Preferred stock-par value $0.01 200,000,000 shares authorized, none issued		
Common stock-par value $0.01 2,000,000,000 shares authorized, 152,992,109 and 152,906,488 shares issued and outstanding, respectively	1,530	1,529
Additional paid-in capital	639,160	633,937
Accumulated other comprehensive income	(5,903)	(3,846)
Retained earnings (deficit)	(120,416)	26,730
Total stockholders equity	514,371	658,350
Total liabilities and stockholders equity	$ 1,303,563	$ 1,316,891

See notes to consolidated financial statements.

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INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

Years ended December 31, 2007, 2006 and 2005

(Dollars in thousands, except per share data)

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
REVENUES:			
Coal sales revenues	$ 770,663	$ 833,998	$ 619,038
Freight and handling revenues	29,594	18,890	8,601
Other revenues	48,898	38,706	22,852
Total revenues	849,155	891,594	650,491
COSTS AND EXPENSES:			
Cost of coal sales, exclusive of amounts shown separately below	732,112	739,914	487,847
Freight and handling costs	29,594	18,890	8,601
Cost of other revenues, exclusive of amounts shown separately below	34,046	29,418	22,250
Depreciation, depletion and amortization	86,517	72,218	43,076
Selling, general and administrative	33,325	34,578	28,828
Gain on sale of assets	(38,656)	(1,125)	(502)
Goodwill impairment loss	170,402		
Total costs and expenses	1,047,340	893,893	590,100
Income (loss) from operations	(198,185)	(2,299)	60,391
INTEREST AND OTHER INCOME (EXPENSE):			
Interest expense, net	(35,140)	(18,091)	(14,394)
Other, net	319	2,113	3,302
Total interest and other income (expense)	(34,821)	(15,978)	(11,092)
Income (loss) before income taxes and minority interest	(233,006)	(18,277)	49,299
INCOME TAX (EXPENSE) BENEFIT	85,623	9,015	(16,986)
MINORITY INTEREST	349	(58)	15
Net income (loss)	$ (147,034)	$ (9,320)	$ 32,328
Earnings per share:			
Basic	$ (0.97)	$ (0.06)	$ 0.29
Diluted	$ (0.97)	$ (0.06)	$ 0.29
Weighted-average common shares outstanding:			
Basic	152,304,461	152,028,165	111,120,211
Diluted	152,304,461	152,028,165	111,161,287

See notes to consolidated financial statements.

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INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

Years ended December 31, 2007, 2006 and 2005

(Dollars in thousands)

	Common Stock			Unearned	Accumulated		
			Additional	Compensation	Other	Retained	
			Paid-in	Restricted	Comprehensive	Earnings	
	Shares	Amount	Capital	Stock	Income	(Deficit)	Total
Balance December 31, 2004	106,605,999	$ 11	$ 150,140	$	$	$ 4,360	$ 154,511
Net income						32,328	32,328
Issuance of restricted stock and stock awards	600,000		8,090	(8,090)			
Issuance of shares of common stock pursuant to compensation agreement	25,000		372				372
Compensation expense-restricted stock and stock awards				3,468			3,468
Compensation expense-stock options			288				288
Corporate reorganization (Note 1)		1,061	(1,061)				
Issuance of shares in Anker/CoalQuest acquisition	24,090,909	241	264,759				265,000
Issuance of shares of common stock in connection with public offering	21,000,000	210	210,309				210,519
Balance December 31, 2005	152,321,908	1,523	632,897	(4,622)		36,688	666,486
Net loss						(9,320)	(9,320)
Comprehensive loss							(9,320)
Effect of adoption of SFAS No. 158 (Note 2), net of tax of $3,079					(3,846)		(3,846)
Effect of adoption of EITF 04-6, net of tax of $400						(638)	(638)
Effect of adoption of SFAS No. 123(R) (Note 2)			(4,622)	4,622			
Issuance of restricted stock and stock awards, net of forfeitures	584,580	6	(6)				
Compensation expense on share-based awards			5,668				5,668
Balance December 31, 2006	152,906,488	1,529	633,937		(3,846)	26,730	658,350
Net loss						(147,034)	(147,034)
Pension and other benefit obligation adjustments, net of tax of $1,362					(2,231)		(2,231)
Amortization of accumulated postretirement benefit obligation, net of tax of $109					174		174
Comprehensive loss							(149,091)
Effect of adoption of FIN 48 (Note 2)						(112)	(112)
Issuance of restricted stock and stock awards, net of forfeitures	85,621	1	(1)				

Compensation expense on share-based awards			5,224				5,224
Balance December 31, 2007	152,992,109	$ 1,530	$ 639,160	$	$ (5,903)	$ (120,416)	$ 514,371

See notes to consolidated financial statements.

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INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31, 2007, 2006 and 2005

(Dollars in thousands)

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (147,034)	$ (9,320)	$ 32,328
Adjustments to reconcile net income (loss) to net cash from operating activities:			
Goodwill impairment loss	170,402		
Depreciation, depletion and amortization	86,517	72,218	43,076
Write-off and amortization of deferred finance costs included in interest expense	8,291	3,418	1,785
Amortization of accumulated postretirement benefit obligation	283		
Minority interest	(349)	58	(15)
Compensation expense on share-based awards	5,224	5,668	3,928
Gain on sale of assets, net	(38,656)	(1,125)	(502)
Provision for bad debt	503		
Deferred income taxes	(87,078)	3,239	5,721
Changes in Assets and Liabilities:			
Accounts receivable	(13,606)	(5,885)	(11,904)
Inventories	(92)	(20,958)	(1,470)
Prepaid expenses and other	3,202	(10,201)	4,210
Other non-current assets	(457)	(2,553)	50
Accounts payable	12,588	(1,832)	7,456
Accrued expenses and other	11,648	12,268	(5,496)
Reclamation and mine closure costs	5,509	5,014	(1,178)
Other liabilities	5,200	5,582	(670)
Net cash from operating activities	22,095	55,591	77,319
CASH FLOWS FROM INVESTING ACTIVITIES:			
Proceeds from the sale of assets	46,524	3,782	576
Net proceeds from sale-leaseback		5,413	
Additions to property, plant, equipment and mine development	(160,431)	(165,658)	(108,231)
Cash paid related to acquisitions, net	(12,717)	(4,721)	(458)
Withdrawals (deposits) of restricted cash	193	415	3,400
Distribution to joint venture	(100)		
Net cash from investing activities	(126,531)	(160,769)	(104,713)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings on short-term debt	26,082	10,375	
Repayments on short-term debt	(45,368)	(20,400)	(7,461)
Borrowings on long-term debt	65,000	71,543	77,500
Repayments on long-term debt and capital leases	(68,585)	(112,418)	(267,701)
Debt issuance costs	(9,285)	(9,367)	(443)
Proceeds from issuance of common stock			200
Proceeds from senior notes offering		175,000	
Proceeds from convertible notes offering	225,000		
Proceeds from public offering, net			210,519
Net cash from financing activities	192,844	114,733	12,614

NET CHANGE IN CASH AND CASH EQUIVALENTS		88,408		9,555		(14,780)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		18,742		9,187		23,967
CASH AND CASH EQUIVALENTS, END OF PERIOD	$	107,150	$	18,742	$	9,187
Supplemental information:						
Cash paid for interest (net of amount capitalized)	$	20,113	$	4,898	$	18,122
Cash received (paid) for income taxes	$	2,971	$	(150)	$	(17,277)
Supplemental disclosure of non-cash items:						
Acquisition of Anker and CoalQuest through issuance of common stock	$		$		$	265,000
Purchases of property, plant, equipment and mine development through accounts payable	$	547	$	5,145	$	8,597
Purchases of property, plant, equipment and mine development through financing arrangements	$	10,971	$	26,175	$	
Assets acquired through the assumption of liabilities	$	2,016	$		$	
Corporate reorganization	$		$		$	1,061

See notes to consolidated financial statements.

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INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2007, 2006 and 2005

(Dollars in thousands, except per share data)

1. ORGANIZATION

Entity Matters International Coal Group, Inc. (ICG or the Company) is a leading producer of coal in Northern and Central Appalachia and also has operations and reserves in the Illinois Basin. The Company s customers are primarily investment grade electric utilities, as well as domestic industrial and steel customers that demand a variety of coal products. The Company s ability to produce a comprehensive range of high Btu steam and metallurgical quality coal allows it to blend coal, which enables it to market differentiated coal products to a variety of customers with different coal quality demands.

ICG, Inc. was formed on May 13, 2004 by WL Ross & Co., LLC (WLR) and other investors to acquire and operate competitive coal mining facilities. On September 30, 2004, ICG, Inc. acquired certain properties and assets, and assumed certain liabilities, of Horizon Natural Resources Company (Horizon) through Section 363 asset sales of the United States Bankruptcy Court.

International Coal Group, Inc. was formed in March 2005, as a wholly owned subsidiary of ICG, Inc., in order to effect a corporate reorganization. On November 18, 2005, the reorganization was completed. Prior to this reorganization, ICG, Inc. was the top-tier holding company. Upon completion of the reorganization, International Coal Group, Inc. became the new top-tier parent holding company. In the corporate reorganization, the stockholders of ICG, Inc. received one share of International Coal Group, Inc. common stock for each share of ICG, Inc. common stock.

In addition, the Company completed acquisitions of Anker Coal Group, Inc. (Anker) and CoalQuest Development, LLC (CoalQuest), on November 18, 2005.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND GENERAL

Principles of Consolidation The consolidated financial statements include the accounts of ICG, whose subsidiaries are generally controlled through a majority voting interest, but may be controlled by means of a significant minority ownership, by contract, lease or otherwise. In certain cases, ICG subsidiaries (i.e., Variable Interest Entities (VIEs)) may also be consolidated based on a risks and rewards approach as required by the Financial Accounting Standards Board (FASB) revised Interpretation No. 46 (FIN 46(R)). See Note 14 to the consolidated financial statements for further discussion regarding the consolidation of VIEs. The Company accounts for its undivided interest in coalbed methane wells (see Note 8) using the proportionate consolidation method, whereby its share of assets, liabilities, revenues and expenses are included in the appropriate classification in the financial statements. The consolidated financial statements are presented in accordance with accounting principles generally accepted in the United States of America. Significant intercompany transactions and balances have been eliminated.

The accompanying consolidated financial statements include the results of operations of the properties and assets acquired from Anker and CoalQuest since November 18, 2005.

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INTERNATIONAL COAL GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the years ended December 31, 2007, 2006 and 2005

(Dollars in thousands, except per share data)

Cash and Cash Equivalents The Company considers all highly-liquid debt instruments with maturities of three months or less at the time of purchase to be cash equivalents. Cash equivalents consist of a money market fund. Because of the short maturity of these investments, the carrying amounts approximate the fair value.

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 is the Company s best estimate of the amount of probable credit losses in the Company s existing accounts receivable. The Company establishes provisions for losses on accounts receivable when it is probable that all or part of the outstanding balance will not be collected. The Company regularly reviews collectibility and establishes or adjusts the allowance as necessary using the specific identification method.

Inventories Inventories are stated at lower of average cost or market. Components of inventories consist of coal and parts and supplies, net of an allowance for obsolescence (see Note 4). Coal inventories represent coal contained in stockpiles, including those tons that have been mined and hauled to our load out 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. The majority of the Company s coal inventory does not require extensive processing prior to shipment. In most cases, processing consists of crushing or sizing the coal prior to loading into the truck or rail car for shipment to the customer.

Derivative Financial Instruments The Company uses interest rate swaps and caps to manage interest rate risk. The Company does not use derivative financial instruments for trading or speculative purposes. Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended (SFAS No. 133), establishes accounting and reporting standards for derivative instruments and hedging activities. To qualify for hedge accounting under SFAS No. 133, the effectiveness of each hedging relationship is assessed both at hedge inception and at each reporting period thereafter. Also, at the end of each reporting period, ineffectiveness in the hedging relationships is measured as the difference between the change in fair value of the derivative instruments and the change in fair value of either the hedged items (fair value hedges) or expected cash flows (cash flow hedges). Ineffectiveness, if any, is recorded in interest expense.

In May 2006, the Company entered into an Interest Rate Collar Agreement (the Collar Agreement), which became effective as of March 31, 2007 and will expire on March 31, 2009. The Company uses the Collar Agreement to hedge its interest rate risk on an initial $100,000 of revolving debt (escalating to $200,000 in March 2008). The interest rate collar is designed as a cash flow hedge to offset the impact of changes in the LIBOR interest rate above 5.92% and below 4.80%. The Company has not designated its derivatives as hedging instruments and recognizes the change in the fair value of its derivatives in the income statement in the period of change. The derivative liability, resulting from adjusting the Collar Agreement to its fair value of approximately $2,288, as well as the Company s initial net investment of $300, is included in other non-current liabilities in the Company s consolidated balance sheet at December 31, 2007. Such adjustment resulted in a loss of approximately $1,649 and $939 for years ended December 31, 2007 and 2006, respectively, and is included in interest expense.

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Advance Royalties The Company is 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. The Company has recorded net advance royalties of $20,188 and $16,510, the current portion of $5,528 and $3,876 is included in prepaid expense at December 31, 2007 and 2006, respectively. Unamortized deferred royalty costs are expensed when mining has ceased or a decision is made not to mine on such property. At December 31, 2007 and 2006, the Company has recorded allowances for such circumstances totaling $3,771 and $638, respectively.

Coal Supply Agreements Purchase price allocated to the Company s below-market coal supply agreements (sales contracts) acquired in the Anker acquisition accounted for as a business combination were capitalized and are being amortized on the basis of coal to be shipped over the term of the contracts. Purchase price allocated to the Company s above-market coal supply agreement was capitalized and is being reduced as related cash payments are received. Value was allocated to coal supply agreements based on discounted cash flows attributable to the difference between the above- or below-market contract price and the prevailing market price at the date of acquisition. The net book value of the Company s above-market coal supply agreement was $3,713 and $3,683 at December 31, 2007 and 2006, respectively. This amount is recorded in other assets in the Company s consolidated balance sheets. The net book value of the below-market coal supply agreements was $39,668 and $58,882 at December 31, 2007 and 2006, respectively. Amortization income on the below-market coal supply agreements was $19,214, $13,494 and $1,042 in 2007, 2006 and 2005, respectively. Amortization income is included in depreciation, depletion and amortization expense. Based on expected shipments related to these contracts, the Company expects to record annual amortization income on the below-market coal supply agreements in each of the next five years as reflected in the table below.

	Below-market contracts
2008	$ 7,087
2009	3,386
2010	3,386
2011	3,386
2012	3,386

Property, Plant, Equipment and Mine Development Property, plant, equipment and mine development costs, including coal lands, are recorded at cost, which includes construction overhead and capitalized interest. Interest cost applicable to major asset additions are capitalized during the construction period, including $5,057 and $990 for the years ended December 31, 2007 and 2006, respectively. Expenditures for major renewals and betterments are capitalized, while expenditures for maintenance and repairs are expensed as incurred. Coal land costs are depleted using the units-of-production method, based on estimated recoverable interest. Mine development costs are amortized using the units-of-production method, based on estimated recoverable interest. Other property, plant and equipment is depreciated using the straight-line method with estimated useful lives as follows:

	Years
Buildings	10 to 45
Mining and other equipment and related facilities	1 to 20
Land improvements	15
Transportation equipment	2 to 7

Furniture and fixtures	3 to 10

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Goodwill Goodwill represents the excess of costs over fair value of net assets of businesses acquired. Pursuant to SFAS No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142), goodwill and intangible assets that are determined to have an indefinite useful life are not amortized, but instead must be tested for impairment at least annually. The goodwill impairment test consists of two steps. The first identifies potential impairment by comparing the fair value of a reporting unit with its carrying amount, including goodwill. Fair value of a reporting unit is estimated using present value techniques, such as discounted cash flows of projected future operations developed by management, or a weighting of income and market approaches. If the fair value of the reporting unit exceeds the carrying amount, goodwill is not considered impaired and the second step is not necessary. If the carrying value of the reporting unit exceeds the fair value, the second step is necessary to measure the amount of impairment loss by comparing the implied fair value of goodwill with its carrying amount. Implied fair value of goodwill is determined as the amount that the fair value of the assets of a business unit exceeds their carrying value, excluding goodwill. Impairment loss is measured as the amount of the carrying value of goodwill that exceeds its implied fair value.

The Company performs its impairment test as of October 31^{st} of each year. See Note 6 to the Notes to Consolidated Financial Statements.

Debt Issuance Costs Debt issuance costs reflect fees incurred to obtain financing. Debt issuance costs are amortized (included in interest expense) using the straight-line method over the life of the related debt. Amortization expense for the years ended December 31, 2007 and 2006 was $8,291 and $3,418, respectively. Amortization expense for 2007 and 2006 includes $5,348 and $1,369, respectively, representing deferred financing fees written-off as a result of amending and restating the Company s prior credit agreements.

Restricted Cash Restricted cash includes amounts required by various royalty and reclamation agreements. Restricted cash of $1,563 and $1,756 at December 31, 2007 and 2006, respectively, is included in other non-current assets.

Coal Mine Reclamation and Mine Closure Costs The Company s 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. The Company records these reclamation obligations according to the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143). SFAS No. 143 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 each period, and the capitalized cost is depreciated over the useful life of the related asset. To settle the liability, the obligation is paid, and to the extent there is a difference between the liability and the amount of cash paid, a gain or loss upon settlement is recorded. On at least an annual basis, the Company reviews its entire reclamation liability and makes 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.

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Asset Impairments The Company follows SFAS No. 144, *Accounting for the 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 the sum of projected cash flows is less than the carrying amount, impairment losses are 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 closing obligations are accelerated and the mine closing 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.

Income Tax Provision The provision for income taxes includes federal, state and local income taxes currently payable and deferred taxes arising from temporary differences between the financial statement and tax basis of assets and liabilities. Income taxes are recorded under the liability method. Under this method, deferred income taxes are recognized for the estimated future tax effects of differences between the tax basis of assets and liabilities and their financial reporting amounts, as well as net operating loss carryforwards and tax credits based on enacted tax laws. Valuation allowances are established when necessary to reduce deferred tax assets to the amount expected to be realized.

Effective January 1, 2007, the Company adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). FIN 48 increases the relevancy and comparability of financial reporting by clarifying the way companies account for uncertainty related to income taxes. As a result of the adoption of FIN 48, the Company recognized a $109 increase in the liability for unrecognized income tax benefits and $3 in accrued interest, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings. As of the date of adoption, the total amount of unrecognized income tax benefits was $137. Included in the balance at January 1, 2007, are $109 of unrecognized income tax benefits that, if recognized, would affect the annual effective income tax rate. The Company has added $223 of additional unrecognized tax benefits since the date of the FIN 48 adoption. Unrecognized tax benefits totaled $360 at December 31, 2007. The change in the unrecognized tax benefit within the next 12 months is not expected to be material to the financial statements.

The Company files income tax returns in the U.S. and various states. With few exceptions, the Company is no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years before 2004. The Company is currently under examination by the Internal Revenue Service and the State of West Virginia for certain tax years pertaining to income taxes.

The Company recognizes interest expense and penalties related to unrecognized tax benefits as interest expense and other expense, respectively, in its consolidated statement of operations.

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Revenue Recognition Coal revenues result from sales contracts (long-term coal contracts or purchase orders) with electric utilities, industrial companies or other coal-related organizations, primarily in the eastern United States. Revenue is recognized and recorded at the time of shipment or delivery to the customer, 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, where coal is loaded to the rail, barge, truck or other transportation source that delivers coal to its destination.

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 consist of equipment and parts sales, equipment rebuild and maintenance services, coal handling and processing, royalties, ash disposal services, coalbed methane sales, income related to the termination of a coal supply agreement and contract mining income. With respect to other revenues recognized in situations unrelated to the shipment of coal, the Company carefully reviews the facts and circumstances of each transaction and applies the relevant accounting literature as appropriate and does 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 the collectibility is reasonably assured. Advance payments received are deferred and recognized in revenue as coal is shipped or rentals are earned.

Postretirement Benefits Other Than Pensions As prescribed by SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions* (SFAS No. 106), accruals are made, based on actuarially determined estimates, for the expected costs of providing postretirement benefits other than pensions for current and future retired employees and their dependents, which are primarily healthcare and life insurance benefits, during an employee s actual working career. Actuarial gains and losses are amortized over the estimated average remaining service period for active employees utilizing the minimum amortization method prescribed by SFAS No. 106. The Company s liability is reduced by the amount of Medicare prescription drug reimbursement that it expects to receive under the Drug, Improvement and Modernization Act of 2003. See Note 12.

As prescribed by SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106 and 132(R)*, changes in the funded status of the plan are recognized through other comprehensive income.

Workers Compensation and Black Lung Benefits The Company is liable under federal and state laws to pay workers compensation and pneumoconiosis (black lung) benefits to eligible employees. The Company utilizes a combination of participation in a state run program and insurance policies. For pneumoconiosis (black lung liabilities), provisions are made for actuarially determined estimated benefits. The Company follows SFAS No. 112, *Employers Accounting for Postemployment Benefits* for purposes of accounting for its black lung liabilities and assets.

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Stock-Based Compensation The Company accounts for its stock-based awards in accordance with SFAS No. 123(R), *Share Based Payment* (SFAS No. 123(R)). SFAS No. 123(R) establishes standards of accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity s equity instruments or that may be settled by the issuance of those equity instruments. Under the fair value recognition provisions of SFAS No. 123(R), the Company measures stock-based compensation cost based upon the grant date fair value of the award, which is recognized as expense on a straight-line basis over the corresponding vesting period. The Company uses the Black-Scholes option valuation model to determine the estimated fair value of its stock options at the date of grant. Determining the fair value of share-based awards at the grant date requires several assumptions. These assumptions include the expected life of the option, the risk-free interest rate, volatility of the price of the Company s common stock, expected dividend yield on the Company s common stock and the amount of share-based awards that are expected to be forfeited. See Note 13.

Prior to its adoption of SFAS No. 123(R) on January 1, 2006, the Company applied the provisions of Accounting Principles Board Opinion No. 25*, Accounting for Stock Issued to Employees* to account for stock-based awards issued under its equity and performance incentive plan. Adoption of SFAS No. 123(R) resulted in additional compensation expense related to stock option awards, which increased loss before income taxes and minority interest and net loss by $1,969 and $1,216, respectively, for the year ended December 31, 2006. The adoption of SFAS No. 123(R) did not require a cumulative effect adjustment. The adoption of SFAS No. 123(R) decreased basic and diluted earnings per share by $0.01 for the year ended December 31, 2006.

If compensation expense associated with the Company s stock-based awards for the year ended December 31, 2005 was determined in accordance with SFAS No. 123(R), the Company s net earnings and earnings per share would have been as follows:

		Year ended December 31, 2005
Net earnings, as reported	$	32,328
Add back compensation related to stock awards included in earnings, net of tax effects		2,479
Deduct effect of stock-based employee compensation, net of tax effects:		
Stock option awards		(1,051)
Restricted stock awards		(1,581)
Stock awards		(707)
Pro-forma net earnings	$	31,468
Earnings per share, as reported:		
Basic	$	0.29
Diluted	$	0.29
Pro forma net earnings per share:		
Basic	$	0.28

Diluted	$	0.28

The Black-Scholes option pricing model was used to calculate the estimated fair value of the options at the date of grant using the following assumptions: expected lives of 5 years, weighted-average volatility of 44.8% with volatilities ranging from 41.4% to 48.1% and risk-free interest rates ranging from 4.3% to 4.4%. The Company does not anticipate paying dividends during the terms of the options or forfeitures of options issued in 2005.

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Management s Use of Estimates The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant items subject to such estimates and assumptions include, but are not limited to, the allowance for doubtful accounts; inventories; coal lands; asset retirement obligations; employee benefit liabilities; future cash flows associated with assets; useful lives for depreciation, depletion and amortization; workers compensation claims; postretirement benefits other than pensions; income taxes; and fair value of financial instruments. Due to the subjective nature of these estimates, actual results could differ from those estimates.

Reclassifications Cost of other revenues totaling $29,418 and $22,250 for the years ended December 31, 2006 and 2005, respectively, which were included in cost of coal sales and other revenues in previously issued financial statements have been presented in a separate line item in the accompanying financial statements. Related disclosures have been reclassified to conform to the 2007 presentation.

Recent Accounting Pronouncements In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 141 (Revised 2007), *Business Combinations* (SFAS No. 141R). SFAS No. 141R will significantly change the accounting for business combinations. Under SFAS No. 141R, an acquiring entity will be required to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions. SFAS No. 141R will change the accounting treatment for certain specific acquisition-related items including: (1) expensing acquisition-related costs as incurred; (2) valuing noncontrolling interests at fair value at the acquisition date; and (3) expensing restructuring costs associated with an acquired business. SFAS No. 141R also includes a substantial number of new disclosure requirements. SFAS No. 141R is to be applied to any business combination for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The Company is currently evaluating the effect, if any, that the adoption of SFAS No. 141R will have on its financial position, results of operations and cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS No. 157). SFAS No. 157 clarifies the definition of fair value, establishes a framework for measuring fair value and expands the disclosures on fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. Adoption of SFAS No. 157 did not have a material impact on our financial position, results of operations or cash flows, however, adoption will result in additional information being included in the footnotes accompanying our consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115* (SFAS No. 159). SFAS No. 159 provides entities with an option to report selected financial assets and liabilities at fair value and establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. The Company does not expect the adoption of SFAS No. 159 to have a material impact on its financial position, results of operations and cash flows.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements* (SFAS No. 160). SFAS No. 160 establishes new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary (minority interest) is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements and separate from the parent company s equity. Among other requirements, this statement requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure, on the face of the consolidated statement of operations, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The Company is currently evaluating the effect, if any, that the adoption of SFAS No. 160 will have on its financial position, results of operations and cash flows.

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3. ACQUISITIONS

Anker and CoalQuest Acquisition On March 31, 2005, the Company entered into a business combination agreement with each of Anker and CoalQuest pursuant to which each of Anker and CoalQuest were to become the Company s wholly owned subsidiaries. On November 18, 2005, the business combination was consummated and the stockholders of Anker received 14,840,909 shares of the Company s common stock valued at $163,250 and the stockholders of CoalQuest received 9,250,000 shares of the Company s common stock valued at $101,750. The results of operations of Anker and CoalQuest since November 18, 2005 are included in the consolidated results of operations of the Company for the period ended December 31, 2005.

The acquisition was a strategic business move to consolidate the coal assets of Anker and CoalQuest with the Company. This combination is expected to allow the Company to maintain current production levels for an extended period of time and also to further diversify its reserves.

The following unaudited pro forma data reflects the consolidated results of operations of the Company as if the acquisition had taken place on January 1, 2005. The unaudited pro forma information incorporates the accounting for the acquisition, including but not limited to, the application of purchase accounting for coal supply agreements and mineral reserves, employee benefit liabilities and property, plant and equipment. The unaudited pro forma information may not be indicative of actual results.

	Year ended December 31, 2005 (unaudited)
Revenues	$ 782,599
Net income	23,603
Basic Earnings Per Share:	
Net income	$ 0.18
Basic common shares outstanding	132,307,011
Diluted Earnings Per Share:	
Net income	$ 0.18
Diluted common shares outstanding	132,348,087

Unaudited pro forma basic and diluted common shares outstanding include all shares issued in connection with the acquisition as if they were issued as of the beginning of the earliest period presented. Stock options totaling 325,000 were not included in the diluted earnings per share calculation since the strike price was less than the average market price of the shares during the periods presented.

4. INVENTORIES

As of December 31, 2007 and 2006, inventories consisted of the following:

	2007	2006
Coal	$ 19,855	$ 23,736
Parts and supplies	21,602	17,427

Reserve for obsolescence, parts and supplies	(778)	(576)
Total	$ 40,679	$ 40,587

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5. PROPERTY, PLANT, EQUIPMENT AND MINE DEVELOPMENT

As of December 31, 2007 and 2006, property, plant, equipment and mine development are summarized by major classification as follows:

	2007	2006
Land and land improvements	$ 18,112	$ 16,285
Mining and other equipment and related facilities	396,382	324,362
Mine development and contract costs	81,431	59,115
Coal lands	596,649	598,843
Coalbed methane well development costs	14,276	6,280
Mine development in process	46,708	12,274
Construction in process	51,352	37,012
	1,204,910	1,054,171
Less accumulated depreciation, depletion and amortization	(230,576)	(134,077)
Net property, plant and equipment	$ 974,334	$ 920,094

Depreciation, depletion and amortization expense related to property, plant, equipment and mine development for the years ended December 31, 2007, 2006 and 2005 was $105,726, $85,344 and $43,980, respectively.

On September 28, 2007, the Company sold its Denmark reserve in Southern Illinois for $39,000 in cash. As a result, the Company recognized a gain of $36,782 which is included in gain on sale of assets in its statement of operations for the year ended December 31, 2007. Under the terms of the transaction, the purchaser is also obligated to pay the Company an overriding royalty totaling $4,000 on certain future production that will be recognized as the reserves are mined.

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6. GOODWILL

The Company recorded goodwill related to its acquisition of certain assets and assumption of certain liabilities of Horizon on September 30, 2004. The Company assigned the goodwill to certain of the acquired reporting units based on their estimated fair values. In accordance with SFAS No. 142, the Company tests goodwill for impairment on an annual basis, at a minimum, and more frequently if a triggering event occurs. The 2007 goodwill testing identified impairment losses at the following business units: $32,914 at Hazard, $58,511 at Eastern, $42,941 at East Kentucky and $36,036 at Knott County.

The goodwill impairment loss reflects the negative impact of several contributing factors which resulted in a reduction in the forecasted cash flows used to estimate fair value. These factors include, but are not limited to, a significant decrease in the sales price of coal through the Company s annual measurement date, increases in the cost of diesel fuel, explosives, tires, roofbolts and other materials used in mining coal, increased labor costs due to tightening labor markets, significant investments in the areas of safety and compliance and increased interest rates contributing to a higher discount rate. Furthermore, the business, regulatory and marketplace environments in which the Company currently operates differs significantly from the historical environments that drove the business cases used to value and record the acquisition of these business units. Accordingly, the Company has been unable to attain the forecasted projections that were used to initially value the business units at the date of acquisition.

The changes in the carrying amount of goodwill were as follows:

Balance as of December 31, 2004	$ 188,481
Adjustments to purchase price allocation of Horizon	4,413
Bonding royalty	700
Anker/CoalQuest acquisition	150,800
Balance as of December 31, 2005	344,394
Adjustments to purchase price allocation of Horizon	(812)
Bonding royalty	3,975
Adjustments to purchase price allocation of Anker/CoalQuest	(150,800)
	&