International Coal Group, Inc.
Form 10-K/A
November 14, 2007

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-K/A

(Amendment No. 2)

(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, 2006

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 incorporation or organization)	**(I.R.S. Employer Identification No.)**

300 Corporate Centre Drive

Scott Depot, WV 25560

(Address of principal executive offices zip code)

(304) 760-2400

Registrant s telephone number, including area code

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

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

None.

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

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K/A or any amendment to this Form 10-K/A. Yes x No ¨

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

Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨

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

Aggregate market value of common stock held by non-affiliates of the registrant as of December 31, 2006, the last business day of the registrant s most recently completed fiscal year, at a closing price of $5.45 per share as reported by the New York Stock Exchange, was $695,347,869. 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 22, 2007 was 152,904,788.

DOCUMENTS INCORPORATED BY REFERENCE

Part III incorporates certain information by reference from the registrant s definitive proxy statement for the 2007 annual meeting of stockholders, which proxy statement was filed on April 17, 2007.

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EXPLANATORY NOTE

We are filing this Form 10-K/A Amendment No. 2 (this Amendment) to amend certain information that was included in our original Annual Report on Form 10-K for the year ended December 31, 2006 (the 2006 Form 10-K), as amended by Form 10-K/A Amendment No. 1, as described below. For the convenience of the reader, this Amendment sets forth the entire 2006 Form 10-K. However, this Amendment amends only Items 1 and 2 of Part I and Items 6, 7, 8 and 9A of Part II of the 2006 Form 10-K to:

- clarify on page 2 that we determine amounts of owned or controlled reserves disclosed in the 2006 Form 10-K based on management s estimates;

- amend the disclosure on page 2 to disclose how much of our tons sold as of December 31, 2006 were purchased through brokered coal contracts (coal purchased from third parties for resale), as well as the average sale price for such brokered coal;

- correct the row entitled Central Appalachia ICG Natural Resources in the table on page 49 to reflect that 14.71 million tons of the Jennie Creek reserves are assigned, and only 30.19 million tons are unassigned, as well as the table on page 50 to provide the related quality characteristics of the assigned and unassigned Jennie Creek reserves;

- rename our EBITDA financial measure Adjusted EBITDA throughout the document;

- expand the disclosures in Management s Discussion and Analysis of Financial Condition and Results of Operations to (i) include a discussion of coal sales revenues, Adjusted EBITDA and tons sold by segment , (ii) add disclosure regarding capital expenditures by segment and (iii) clarify that coal sales revenues are derived from sales of produced coal and brokered coal sales; and

- to correct certain amounts in our consolidated financial statements related to an immaterial overstatement of certain leasehold and ownership interests in land, accrued property taxes and certain other items as of and for the years ended December 31, 2006 and 2005 and for the period May 11, 2004 (inception) to December 31, 2004. See Note 24 to the consolidated financial statements included in Item 8 for further detail.

No other Items are being amended. Except as described in this Explanatory Note, this Amendment does not modify or update the disclosures in our 2006 Form 10-K. Therefore, this Amendment does not reflect any other events that occurred after the original March 1, 2007 filing date of the 2006 Form 10-K. Forward-looking statements in this Amendment have also not been updated from the 2006 Form 10-K that we filed on March 1, 2007. For updated information, please see the reports that we have filed with the SEC for subsequent periods. In addition, in connection with the filing of this Amendment and pursuant to Rules 12b-15 and 13a-14 under the Exchange Act, we are including with this Amendment currently dated certifications of our chief executive and financial officers.

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ON FORM 10-K/A

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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 was filed on April 17, 2007.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K/A 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 ongoing integration of the former Anker and CoalQuest entities into our business;
- 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 coal mining;

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;

competition;

railroad, barge, trucking and other transportation availability, performance and costs;

employee benefits costs and labor relations issues;

replacement of our reserves;

our assumptions concerning economically recoverable coal reserve estimates;

availability and costs of credit, surety bonds and letters of credit;

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;

the impairment of the value of our goodwill;

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- the ongoing effects of the Sago mine explosion;
- 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/A 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 2006 annual report to stockholders and our 2006 Annual Report on Form 10-K/A 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 ten 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 2006 due to a supply-demand imbalance that continues into 2007.

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 the corporate reorganization and acquired Anker and CoalQuest in November 2005, which further diversified our reserves.

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As of December 31, 2006, management estimates that we owned or controlled approximately 317 million tons of metallurgical quality coal reserves and approximately 746 million tons of steam coal reserves. Management s estimates were developed considering an initial independent 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 566 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, 2006, we sold 19.4 million tons of coal, of which approximately 16.2 million tons were produced from the Company s mining activities and approximately 3.2 million tons were purchased through brokered coal contracts (coal purchased from third parties for resale), at an average sale price of $42.80 and $44.38, respectively. Of the tons sold, 19.2 million tons were steam coal and 0.2 million tons were metallurgical coal. Our steam coal sales volume in 2006 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, 2006 were Georgia Power Company, Duke Power and Carolina Power & Light Company and we derived approximately 56% of our coal revenues from sales to our five largest customers. Revenues from sales to Georgia Power Company, Duke Power and Carolina Power & Light Company each accounted for more than 10% of coal revenues in 2006.

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, 2006 and 2005 and for the period May 13, 2004 (inception) to December 31, 2004 is included in Note 21 to our consolidated financial statements, and for the period January 1, 2004 to September 30, 2004 is included in Note 11 to the combined financial statements of Horizon, each included at the end of this report.

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.

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 2006, coal-fired plants generated approximately 50% 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.

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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 by far the cheapest 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 2006, approximately 34% of our produced and processed coal volume came from underground mining operations generally 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.

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Surface mining

Surface mining is used when coal is found close to the surface. In 2006, approximately 66% 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.

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.

Operations

As of December 31, 2006, we operated a total of 13 surface and 12 underground coal mines located in Kentucky, Maryland, West Virginia and Illinois. Approximately 66% of our production has come from surface mines, and the remaining production has come from our underground mines. These mining facilities include eight preparation plants, each of which receive, blend, process and ship coal that is produced from one or more of

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our 25 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, 2006.

			Number and Type of Mines					
Mining Complexes[(1)]	**Location**	**Preparation Plant(s)**	**Under-ground**	**Surface**	**Total**	**Mining Method[(2)]**	**Transportation**	**Tons Produced in 2006 (in thousands)**
ICG Eastern, LLC	Cowen, WV	1	0	1	1	MTR, DL, TSL	Rail	3,048.8
ICG Hazard, LLC	Hazard, KY	0	0	5	5	HW, MTR, TSL	Rail, Truck	3,709.9
Flint Ridge	Hazard, KY	1	2	1	3	CTR, TSL, R&P, HW	Rail, Truck	1,718.3
ICG Knott County, LLC	Kite, KY	2	5	0	5	R&P	Rail	1,515.2
ICG East Kentucky, LLC	Pike Co., KY	0	0	1	1	MTR, TSL	Rail	1,255.5
Vindex Energy Corporation[(7)]	Garrett Co., MD	1	0	3	3	CRM, CTR	Truck, Rail[(3)]	1,062.9
Patriot Mining Company	Monongalia Co., WV	0	0	2	2	CTR, TSL	Barge, Rail, Truck	888.3
Wolf Run Mining Buckhannon Division	Upshur Co., WV	1	2	0	2	R&P	Rail, Truck	820.7
Wolf Run Mining Philippi Development Division	Barbour Co., WV	1[(4)]	1	0	1	R&P	Rail	58.4
Sycamore Group	Harrison Co., WV	0	1	0	1	R&P	Truck	347.2[(5)(6)]
ICG Illinois, LLC	Williamsville, IL	1	1	0	1	R&P	Truck	2,084.2

(1) Does not include two inactive mining complexes: ICG Beckley and Juliana.
(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) Utilizing third-party loadout.
(4) Currently utilizing one circuit.
(5) Mine permitted but undeveloped.
(6) Represents Wolf Run Mining Company s (f/k/a Anker West Virginia Mining Company, Inc.) 50% share in The Sycamore Group LLC.
(7) Includes Vindex Division of Wolf Run Mining Company (formerly referred to as the Mt. Storm Division).

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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.

	2006		2005		2004	
Mining Complexes(1)	**Tons Produced**	**Sales Realizations(2)**	**Tons Produced**	**Sales Realizations(2)**	**Tons Produced**	**Sales Realizations(2)**
ICG Eastern, LLC	3,048,800	$ 43.92	2,766,365	$ 42.75	2,712,067	$ 34.12
ICG Hazard, LLC	3,709,924	$ 50.05	3,432,153	$ 44.49	3,978,038	$ 32.69
Flint Ridge(3)	1,718,300	$ 50.81	906,207	$ 46.17		$
ICG Knott County, LLC	1,515,187	$ 51.01	1,277,438	$ 46.74	1,386,554	$ 39.44
ICG East Kentucky, LLC	1,255,522	$ 53.28	1,441,236	$ 52.15	1,576,345	$ 40.36
Vindex Energy Corporation(4)*	1,062,925	$ 36.62	649,623	$ 45.00	170,745	$ 40.70
Patriot Mining Company*	888,265(5)	$ 23.52	700,762	$ 24.26	423,448(5)	$ 20.46
Wolf Run Mining Buckhannon Division*	820,688	$ 42.46	801,435	$ 37.05	1,213,851	$ 34.18
Wolf Run Mining Philippi Development Division*	58,403	$ 41.25	122,343	$ 51.62	255,439	$ 45.36
Sycamore Group*	347,241	$ 29.13	452,349	$ 27.48	259,270	$ 24.89
ICG Illinois, LLC	2,084,193	$ 24.68	2,325,370	$ 23.23	2,117,567	$ 22.44
	16,509,448		14,875,281		14,093,324	

* *Operated by Anker during 2004 and through November 18, 2005 and by us since November 19, 2005.*

(1) *Does not include two inactive mining complexes: ICG Beckley and Juliana.*

(2) *Excludes freight and handling revenue.*

(3) *Flint Ridge began production in 2005.*

(4) *Includes Vindex Division of Wolf Run Mining Company (formerly referred to as the Mt. Storm Division).*

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

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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 11.2 million tons of coal in 2006 and our mines in Northern Appalachia produced 3.2 million tons of coal in 2006. The coal produced in 2006 from our Northern and Central Appalachian mining operations was, on average, 12,050 Btu/lb., 1.4% sulfur and 13.6% ash by content. Shipments bound for electric utilities accounted for approximately 95% of the coal shipped by these mines in 2006 compared to 90% of shipments in 2005. 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, 2006, these mines had 1,718 employees.

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ICG Eastern, LLC

ICG Eastern, LLC 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, or Zeigler, in 1992, and was subsequently acquired by 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 11.5 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 to the reserve base.

Approximately 81% of the coal reserves are leased, while approximately 19% 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, shovel, 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 with origination by the A&O Railroad, a short-line operator.

ICG Hazard, LLC

ICG Hazard, LLC is comprised of two mining complexes: (i) ICG Hazard and (ii) Flint Ridge which together currently operate six surface mines, two underground mines, a unit train loadout (Kentucky River Loading), a preparation plant (Flint Ridge Plant) and other support facilities in eastern Kentucky, near Hazard. The coal reserves and operations were acquired in late-1997 and 1998 by AEI Resources.

ICG Hazard s five surface mines include: (i) East Mac & Nellie; (ii) Vicco; (iii) Rowdy Gap; (iv) Tip Top; and (v) Thunder Ridge. The coal from these mines is being extracted from the Hazard 11, Hazard 10, Hazard 9, Hazard 8, Hazard 7 and Hazard 5A seams. Nearly all of the coal is marketed run-of-mine. 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 ICG Hazard controls 38.8 million tons of coal reserves, plus 1.9 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 99.6% of ICG Hazard s reserves are leased. Most of the leased reserves are held by six lessors. In several cases, ICG 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 is currently operating two underground mines, one surface mine and one preparation plant. The Flint Ridge underground operations are room-and-pillar mining utilizing continuous miners and shuttle cars. The Flint Ridge surface/highwall mine utilizes front-end loaders, end dumps and bulldozers for the overburden removal. Once the contour is established and the coal is removed, the highwall miner will then complete the coal extraction from the exposed highwall. Coal from the underground mines and the highwall miner is trucked to the preparation plant, processed and hauled to the Kentucky River Loading rail loadout by on-highway trucks or directly to the customer. Coal from the contour mining operation is hauled directly to the Kentucky River Loading rail loadout.

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We estimate that Flint Ridge controls 30.6 million tons of coal reserves, plus 2.8 million tons of non-reserve coal deposits. Approximately 99.2% of Flint Ridge s reserves are leased, while 0.8% 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.

An existing preparation plant structure was extensively upgraded in early 2005. Since July 2005, it has been processing coal from ICG Hazard and Flint Ridge mining complexes.

ICG Knott County, LLC

ICG Knott County, LLC operates five underground mines, the Supreme Energy and Raven preparation plants and rail loadouts and other facilities necessary to support the mining operations in eastern Kentucky, near Kite. ICG Knott County was acquired by AEI Resources from Zeigler in 1998 with reserves acquired through a lease from Penn Virginia.

ICG Knott County is producing coal from the Hazard 4, Elkhorn 2 and Elkhorn 3 coalbeds. Three mines are operating in the Hazard 4 coalbed: Calvary, Clean Energy and Elk Hollow. The Raven and Classic mines are operating in the Elkhorn 2 and Elkhorn 3 coalbeds, respectively. We estimate these properties contain 16.0 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.

Approximately 26% of ICG Knott County s reserves are owned in fee, while approximately 74% 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.

ICG Knott County s five 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 and Raven preparation plants; some of the Hazard 4 run-of-mine coal is blended with the washed coal. ICG Knott County began operations at the Raven preparation plant during 2006 in conjunction with Loadout, LLC, an affiliate of Penn Virginia Resources Partners, L.P.

Nearly all of ICG Knott County s coal is transported by rail. The loadouts are served by CSX.

ICG East Kentucky, LLC

ICG East Kentucky, LLC is a surface mining operation located in Pike County, Kentucky, near Phelps. ICG East Kentucky currently operates the Blackberry surface mine and the Phelps Loadout. ICG East Kentucky was acquired by AEI Resources in the second quarter of 1999.

Blackberry is an area surface mine that produces coal from four separate coalbeds: (i) Taylor; (ii) Fireclay; (iii) Lower Fireclay; and (iv) Hamlin. All of the coal is sold run-of-mine.

We estimate that the Blackberry mine controls 0.8 million tons of coal reserves; no additional exploration is required. Overburden at the Blackberry mine is removed by front-end loaders, end dumps, bulldozers and blast casting. Coal from the pits is transported by truck to the Phelps Loadout.

After Blackberry is depleted, ICG East Kentucky intends to begin mining the Mount Sterling property, which contains an additional 5.0 million tons of coal reserves. Mount Sterling is located in Martin and Pike Counties, Kentucky near the Tug Fork River. Although Mount Sterling is expected to be mined by ICG East Kentucky, the property is held by ICG Natural Resources, LLC. 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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Vindex Energy Corporation

Vindex Energy Corporation operates three surface mines, the Carlos mine, the Douglas mine and the Jackson Mountain mine, all located in the Potomac Basin in Garrett County, Maryland. The Stony River underground mine was idled in the first quarter of 2006 and has now been reclaimed. In the first quarter of 2006, we commenced operations at the Carlos mine and idled the Island mine in the third quarter of 2006. The reserves at Vindex are leased from multiple landowners under leases that expire at varying times and are renewable on a year-by-year basis 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 utilizing dozers, hydraulic excavators, loaders and trucks. Operations are conducted with relatively new equipment and exploration and development is conducted on a continual basis ahead of mining.

Coal 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 New Hill East both located near Morgantown in Monongalia County, West Virginia. The majority of the coal and surface is leased under renewable contracts with small annual minimum holding costs. 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 either rail, truck or barge using our barge loading facility.

Buckhannon Division

Wolf Run Mining Company s Buckhannon Division currently consists of two active underground mines: the Sago mine and the Imperial mine, both located in Upshur County, West Virginia, near the town of Buckhannon. Both mines extract coal from the Middle Kittanning seam. Nearly all of the reserves in the Buckhannon Division are owned by us. The Sago mine, which was originally opened in 1999 as a contract mine, closed in 2002 and then reopened as a captive operation in the first quarter of 2004. The Sago mine neared full production in the fourth quarter of 2005. On January 2, 2006, an explosion occurred at the Sago mine resulting in the death of twelve miners and the critical injury of a thirteenth miner. As a result of the explosion, the Sago mine ceased active production during state and federal investigations into the cause of the explosion. The Sago mine resumed coal production on March 15, 2006.

The Imperial mine began producing in the second quarter of 2006 as a replacement for the Spruce No. 1 mine.

All of the coal extracted from the Sago mine and 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, as 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, is located in Harrison County, West Virginia, approximately ten miles west of Clarksburg. The Sycamore No. 2 mine began producing coal from the Pittsburgh seam by 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. It is expected that the Sycamore No. 2 mine will resume production during the third quarter of 2007.

The coal produced from the Sycamore No. 2 mine is expected to be sold on a raw basis and shipped to Allegheny Power Service Corporation s Harrison Power Station by truck.

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Philippi Development Division

Wolf Run Mining Company s Philippi Development Division operates the Sentinel mine in Barbour County, West Virginia near the town of Philippi. The mine was acquired by Anker in 1990 and has been operating ever since. Historically, coal was extracted from the Lower Kittanning seam; however, the mine was idled in the second quarter of 2006 to extend the slope and shafts to the underlying Clarion seam where development mining is currently being conducted using the room-and-pillar mining method. Initial production began in the Clarion seam in November 2006. The current operations are expected to be supplemented with a second continuous miner section in the first quarter of 2007.

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.

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, operates 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 is extracted from the Pittsburgh seam by room-and-pillar mining method with continuous miners and shuttle cars for coal extraction.

The majority of the coal is leased with an annual minimum holding cost. It is anticipated that this reserve will be depleted and the mine closed during the first quarter of 2007. All of The Sycamore Group LLC production is sold on a raw basis and shipped to Allegheny Power Service Corporation s Harrison Power Station by truck.

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 Hillman reserves are expected to support development of two longwall mining operations. Design and permitting of the first, the Tygart No. 1 mine, is nearing completion. To be situated in the reserve block east of the Tygart Valley Lake, this underground mine and preparation plant will be operated by ICG Tygart Valley, LLC. Developmental production from this complex is projected to begin in 2009.

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. The low product heat content limits the distance over which the fuel can be transported and sold; however, the low mining cost makes Upshur an attractive location for an on-site power plant. Some preliminary research, including air quality monitoring, has been completed in association with the potential 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, will be developed in the future as market conditions warrant. We receive an overriding royalty on coalbed methane production from this property.

Beckley Property

The Beckley Pocahontas mine (formerly referred to as the Bay Hill reserve), located in Central Appalachia, accesses a 29 million-ton deep reserve of high quality low-volatile metallurgical coal in the Pocahontas No. 3 seam in Raleigh County west of Beckley, West Virginia. The southwest portion of the reserve underlies part of the recently 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. Initial underground mine development is in progress via a completed shaft and commercial production is expected to commence in the second half of 2007 following completion of the slope portal and a second shaft. Construction of a new coal preparation plant is underway with completion scheduled for the fourth quarter of 2007. We plan to market the coal produced from the Beckley reserve to domestic steel producers and for export.

Juliana Complex

Mining on the Juliana property, located in Central Appalachia, in Webster County, West Virginia, began in 1979 and was stopped in December 1999. Contour and mountain top 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. A 500 TPH preparation facility with 100,000 tons of raw and clean coal storage and a unit-train loadout was used to process and load coal on the CSX railroad.

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 yard 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 is subject to the resolution of certain disputes with lessors arising out of the Horizon bankruptcy proceedings. These disputes are the subject of pending motions in the bankruptcy court. However, the resolution of such motions has been held in abeyance while such lessors and the Company engage in negotiation of a final binding settlement agreement pursuant to the terms of non-binding letters of understanding. Additionally, on September 22, 2006, the Company entered into a final settlement with one lessor that confirmed the validity of a lease of 10.3 million tons of surface mineable coal and 8.8 million tons of deep mineable coal. 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:

ICG Illinois, LLC 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 25.2 million tons of coal reserves, plus an additional 38.5 million tons of non-reserve coal deposits.

Approximately 61% of the coal reserves are leased, while 39% 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 shuttle cars. Management believes that ICG 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

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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 58% of coal sales.

On April 8, 2006, we suffered a fire at the Viper mine that idled the mine and forced replacement of its high angle conveyor belt. Repairs were completed and production resumed on May 8, 2006. Force Majeure notices were issued to affected customers, but coal continued to be shipped from existing inventory through May 2, 2006. No one was injured in the incident.

The underground equipment, infrastructure and preparation plant are well maintained. The majority of underground equipment will be replaced or rebuilt depending on the age and mechanical condition of the equipment.

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.

ICG ADDCAR Systems, LLC

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.

In a typical ADDCAR highwall mining system, there is 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 control 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 depths 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.

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ICG ADDCAR has recently developed a new narrow bench ADDCAR highwall mining system that adapts highwall mining technology to mining on narrower mine benches. Initial production of a narrow bench highwall mining system is underway.

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

Coalbed methane

CoalQuest has entered into a joint operating agreement pursuant to which it produces coalbed methane, which is pipeline quality gas that resides in coal seams, from its properties in Barbour, Harrison and Taylor counties in West Virginia. Drilling at the first production well site for coalbed methane, in Barbour County, began in November 2005 and was completed with initial marketable production of coalbed methane in June 2006. Production increased significantly during the fourth quarter of 2006. 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.

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, 2006 were Georgia Power Company, Duke Power and Carolina Power & Light Company and we derived approximately 56% of our coal revenues from sales to our five largest customers. Revenues from sales to Georgia Power Company, Duke Power and Carolina Power & Light Company each accounted for more than 10% of coal revenues in 2006.

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, 2006, approximately 77% 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 2007 and 2010 are expected to provide us a minimum of approximately 3.1 million tons of coal through the remaining lives of the contracts.

As a result of the Horizon bankruptcy process, we were able to renegotiate certain contracts at significantly higher prices that reflected the current pricing environment and not purchase unfavorable contracts. However, we do have certain contracts which are set below current market rates because Anker entered into these contracts before the rise in the coal prices in 2005. As the net costs associated with producing coal have increased due to higher energy, transportation and steel prices, the price adjustment mechanisms within several of our long-term contracts do not reflect current market prices. This has resulted in certain counterparties to these contracts benefiting from below-market prices for our coal.

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

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 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 2006, approximately 96% of our coal (both produced and purchased) from our Central Appalachian operations was delivered to our customers by rail on either the Norfolk Southern or CSX rail lines, with the remaining 4% 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 2006, we spent more than $284 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.

Competition

The coal industry is intensely competitive. Our main competitors are Massey Energy Company, Arch Coal, Consol Energy, Alpha Natural Resources, Foundation Coal Holdings 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 2005. 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, alternative fuels such as natural gas, oil and nuclear and alternative energy sources, such as hydroelectric power.

Employees

As of December 31, 2006, we had 2,222 employees of which 22% were salaried and 78% 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. These bonding companies, in turn, require that we backstop the surety bonds with cash and/or letters of credit. 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.

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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,

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depending on the size and complexity of the mine and may take six months to two years, 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.

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. This program expired on June 30, 2006. On December 7, 2006, the Abandoned Mine Land Program was extended for 15 years.

SMCRA stipulates compliance with many other major environmental statues, 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.

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.

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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

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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. 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. In addition, there have been efforts in Congress to legislatively disapprove the rule. Also subject to judicial challenge is the EPA s decision, which was announced concurrently with the rule, not to pursue regulation of mercury and other pollutants from coal-fired power plants under the Clean Air Act hazardous air pollutant program. The EPA recently stated that it is reconsidering this decision, but it declined to stay the implementation of the Clean Air Mercury Rule. On October 21, 2005, the EPA announced that it would seek additional public comments for 45 days on the Clean Air Mercury Rule and on portions of the decision not to regulate mercury and other pollutants emitted from power plants under the hazardous air pollutant program.

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.

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. The CWA establishes in-stream water quality standards and treatment standards for wastewater discharge through the

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

Permits under Section 404 of the CWA are required for coal companies to conduct dredging or filling activities in jurisdictional waters for the purpose of conducting any instream activities, including installing culverts, creating water impoundments, constructing refuse areas, 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. 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. A similar lawsuit 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. Additionally,

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in the aftermath of several fatal mining accidents in early 2006, including the Sago mine accident, West Virginia has enacted new mine safety legislation and numerous other states (including most of the states in which we operate) legislatures are considering similar legislation. The Mine Safety and Health Administration issued an emergency temporary standard addressing emergency mine evacuation, training and underground oxygen supplies on March 9, 2006 and the Federal Mine Improvement and New Emergency Response (MINER) Act of 2006 was signed into law on June 15, 2006. Implementation of the specific requirements of the MINER Act is currently underway. 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 2006, we recorded $11.2 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

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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.

Climate Change

Although the United States has refused to 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. The Bush Administration has proposed a package of voluntary emission reductions for greenhouse gases reduction targets which provide for certain incentives if targets are met. Some states, such as Massachusetts, have already issued regulations regulating greenhouse gas emissions from large power plants. 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, our nation would be required to reduce greenhouse gas emissions to 93% of 1990 levels in a series of phased reductions from 2008 to 2012.

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 $5.2 million at December 31, 2006.

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 use 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

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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 coal combustion by-products or CCBs , for reclamation can trigger certain reporting requirements for constituent trace elements contained in CCBs.

Additional Information

We file annual, quarterly and current reports, as well as amendments to those reports, proxy statements and other information with the Securities and Exchange Commission (SEC). You may access and read our SEC filings without charge through our website, www.intlcoal.com, or the SEC s website, www.sec.gov. You may also read and copy any document we file at the SEC s public reference room located at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 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 10,500 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 or ore 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.

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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 37.4% of total annual U.S. coal production.

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ITEM 1A. RISK FACTORS

Risks Relating To Our Business

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 Conditions and Results of Operations.

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 from methane.

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 2006 and the majority of our sales of steam coal in 2006 were to electric power generators. Domestic electric power generation accounted for approximately 92% of all U.S. coal consumption in 2005, 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 may result in more electric power generators shifting from coal to natural gas-fired plants. 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.

The capability and profitability of our operations may be adversely affected by the status of our long-term coal supply agreements, changes in purchasing patterns in the coal industry and the loss of certain brokered coal contracts that expired at the end of 2006.

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, 2006, approximately 77% of our revenues were derived from coal sales that were made under long-term coal supply agreements. As of that date, we had 37 long-term sales agreements with a volume-weighted average term of approximately 3.9 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. In addition, we had brokered coal contracts that expired at the end of 2006. These contracts were signed during a period of oversupply in the coal industry and contain pricing that, while acceptable to the sellers at that time, is significantly below today s market levels and, management believes, will not be able to be renegotiated or replaced in today s market. Assuming today s market conditions continue, we believe the loss of these contracts will have a significant impact on our earnings after 2006. For the years ended December 31, 2006 and 2005, these contracts provided $31.6 million and $33.4 million, respectively, in pre-tax net income. For additional information relating to these contracts, see Business Customers and Coal Contracts Long-term coal supply agreements.

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.

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.

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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, 2006 were Georgia Power Company, Duke Energy and Carolina Power & Light Company and we derived approximately 56% of our coal revenues from sales to our five largest customers. At December 31, 2006, we had coal supply agreements with these customers that expire at various times from 2007 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 below. 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 relating to us, 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, any claims that may be asserted against us that are not covered, in whole or in part, by our insurance policies and the outcome of the federal investigation into the cause of the explosion. We expect that there will be increased regulation of the mining industry as a whole, which may result in higher operating costs, which would, in turn, adversely affect our operating results. See Legal Proceedings.

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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We may not be able to continue to effectively integrate Anker and CoalQuest into our operations or realize the expected benefits of those acquisitions.

Our future success will depend largely on our ability to continue to consolidate and effectively integrate Anker s and CoalQuest s operations into our operations. We may not be able to do so successfully without substantial costs, delays or other difficulties.

If we are not successful in completing the integration of Anker and CoalQuest into our operations, if the integration takes longer or is more complex or expensive than anticipated, if we cannot operate the Anker and CoalQuest businesses as effectively as we anticipate, whether as a result of deficiency of the acquired business or otherwise, or if the integrated businesses fail to achieve market acceptance, our operating performance, margins, sales and reputation could be materially adversely affected.

Furthermore, we may not be able to realize the expected benefits of these acquisitions. For example, as a result of infrastructure weaknesses and geologic issues at some of the existing Anker operations, the transition period for implementation of various operational improvements has taken longer than originally anticipated. In addition, in September 2006, we idled our Sycamore No. 2 mine as a result of some of these geological issues. This extended transition resulted in, decreased coal production and increased production costs in the third and fourth quarters of 2005 and in 2006.

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 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.

When we acquire a business, we record an asset called goodwill if the amount we pay for the business, including liabilities assumed, is in excess of the fair value of the assets of the business we acquire. As of December 31, 2006, we have recorded $196.8 million of goodwill in connection with the acquisition of Horizon. The Financial Accounting Standards Board s (FASB) Statement of Financial Accounting Standards (SFAS) No. 142, *Goodwill and Other Intangible Assets*, requires that goodwill be tested at least annually (absent any

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impairment indicators). The testing includes comparing the fair value of each reporting unit with its carrying value. Fair value is determined using discounted cash flows, market multiples and market capitalization. Impairment adjustments, if any, are required to be recognized as operating expenses. We may have future impairment adjustments to our recorded goodwill. We performed an impairment test of the assets acquired from Horizon as of October 31, 2006. Any finding that the value of our goodwill has been impaired would require us to write-off the impaired portion, which could materially reduce the value of our assets and reduce our net income for the year in which the write-off occurs.

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, coal leases and other obligations. 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, 2006, we had $59.9 million of letters of credit in place, of which $50.0 million serves as collateral for reclamation surety bonds and $9.9 million secures miscellaneous obligations. Our amended and restated credit facility provides for a revolving credit facility of $325.0 million, of which up to $125.0 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 2005, 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.

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In order to obtain leases or mining contracts to conduct our mining operations on property where these defects exist, we may in the future have to incur unanticipated costs. In addition, we may not be able to successfully negotiate new leases or mining contracts for properties containing additional reserves, or maintain our leasehold interests in properties where we have not commenced mining operations during the term of the lease. Some leases have minimum production requirements. Failure to meet those requirements could result in losses of prepaid royalties and, in some rare cases, could result in a loss of the lease itself.

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

All of our coal production is from mines operated by union-free employees. However, our subsidiaries employees have the right at any time under the National Labor Relations Act to form or affiliate with a union. If the terms of a union collective bargaining agreement are significantly different from our current compensation arrangements with our employees, any unionization of our subsidiaries employees could adversely affect the stability of our production and reduce our profitability.

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;
- 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.

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. In addition, state and federal regulations impose strict standards for particulate matter emissions which may restrict our ability to develop new mines or could require us to modify our existing operations and increase our costs of doing business.

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.

New government regulations are expected as a result of recent mining accidents which could increase 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, we expect that additional federal and state health and safety regulations will be adopted that would increase operating costs and affect our mining operations. State and federal legislation has already been adopted that, among other things, requires additional oxygen supplies and communication and tracking devices. 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. 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 the mining operations and cost structures of these areas.

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

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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, depend 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. A challenge of specific Section 404 individual permits is awaiting decision in federal court in West Virginia. We cannot predict the final outcome of the legal challenges to Section 404 permits and other mountaintop mining permits. 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.

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.

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

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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.

Mining operations can also impact flows and water quality in surface water bodies and remedial measures may be required, such as lining of stream beds, to prevent or minimize such impacts. We are currently involved with state environmental authorities concerning impacts or alleged impacts of our mining operations on water flows in several surface streams. We are studying, or addressing, those impacts and we have not finally resolved those matters. Many of our mining operations take place in the vicinity of streams, and similar impacts could be asserted or identified at other streams in the future. The costs of our efforts at the streams we are currently addressing, and at any other streams that may be identified in the future, could be significant.

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.

Extensive environmental regulations affect our customers and could reduce the demand for coal as a fuel source and cause our sales to decline.

The Clean Air Act and similar state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, and other compounds emitted into the air from coke ovens and electric power plants, which are the largest end-users of our coal. Such regulations will require significant emissions control expenditures for many coal-fired power plants to comply with applicable ambient air quality standards. As a result, these generators may switch to other fuels that generate less of these emissions, possibly reducing future demand for coal and the construction of coal-fired power plants.

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The Federal Clean Air Act, including the Clean Air Act Amendments of 1990, and corresponding state laws that regulate emissions of materials into the air affect coal mining operations both directly and indirectly. Measures intended to improve air quality that reduce coal s share of the capacity for power generation could diminish our revenues and harm our business, financial condition and results of operations. The price of 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 March 2005, the EPA also adopted the Clean Air Mercury Rule to control mercury emissions from power plants, which could require coal-fired power plants to install new pollution controls or comply with a mandatory, declining cap on the total mercury emissions allowed from coal-fired power plants nationwide. The Clean Air Mercury Rule is subject to judicial challenge. 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.

The growing concern over climate change has focused attention on reducing the emission of carbon dioxide, a major by-product of burning coal, which is considered a greenhouse gas and is a major source of concern with respect to global warming. The Kyoto Protocol to the 1992 Framework Convention on Global Climate Change, which establishes a binding set of emission targets for greenhouse gases, became binding on ratifying countries on February 16, 2005. Four industrialized nations have refused to ratify the Kyoto Protocol Australia, Liechtenstein, Monaco and the United States. Although the targets vary from country to country, if the United States were to ratify the Kyoto Protocol, our nation would be required to reduce greenhouse gas emissions to 93% of 1990 levels in a series of phased reductions from 2008 to 2012.

Future regulation of greenhouse gases in the United States could occur, for example, pursuant to future U.S. treaty obligations, or statutory or regulatory changes under the Clean Air Act. Numerous legislative proposals

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have been introduced in Congress which reflects a wide variety of strategies for combating climate change. These strategies include mandating decreases in carbon dioxide emissions from coal-fired power plants, 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. The Bush Administration has proposed a package of voluntary emission reductions for greenhouse gases which provide for certain incentives if targets are met. Some states, such as Massachusetts, have already issued regulations regulating greenhouse gas emissions from large power plants.

Seven northeastern U.S. states have entered into a Memorandum of Understanding, to create a regional initiative to establish a cap-and-trade greenhouse gas program for electric generators, referred to as Regional Greenhouse Gas Initiative (RGGI). The model rule caps carbon dioxide emissions from electric generators on January 1, 2009 at projected 2009 levels until 2015, and then requires a 10% reduction in greenhouse gas emissions between 2015 and 2019. There are still a number of uncertainties regarding this initiative. The model rule, which was issued August 15, 2006, requires each state to formally implement the requirements of the model rule either through legislation or through its regulatory process.

Risks Relating To Our Common Stock

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.

As of December 31, 2006, 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.

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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.

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

As of December 31, 2006, we had 152,906,488 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. The remaining shares of common stock outstanding, including those issued to former Anker stockholders and CoalQuest members, are available for sale into the public market at various times in the future. 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.

In addition, under a registration rights agreement that we entered into with certain of our existing stockholders, certain of our stockholders have demand and piggyback registration rights in connection with future offerings of our common stock. Demand rights enable the holders to demand that their shares of common stock be registered and may require us to file a registration statement under the Securities Act at our expense. Piggyback rights require us to provide notice to the relevant holders of our stock if we propose to register any of our securities under the Securities Act and grant such holders the right to include their shares in our registration statement. We have also granted piggyback registration rights to the former Anker and CoalQuest holders who received shares of our common stock in the Anker and CoalQuest acquisitions. 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 236 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, LLC 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 827 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 64 years. The following table provides the location of our mining operations and the type of coal produced at those operations as of January 1, 2007:

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	7.85	0.00	7.85	7.74	0.11
	Unassigned	D	MD	S/UG	40.18	0.47	39.71	22.15	18.03
Total Vindex Energy Corp.					48.03	0.47	47.56	29.89	18.14
Patriot Mining Co.	Assigned	O	WV	S	2.27	0.80	1.47	2.27	0.00
	Unassigned	D	WV	S	0.00	0.00	0.00	0.00	0.00
Total Patriot Mining Co.					2.27	0.80	1.47	2.27	0.00
Wolf Run Mining Buckhannon Division	Assigned	O	WV	UG	17.18	16.55	0.63	0.00	17.18
	Unassigned	D	WV	UG	30.55	28.81	1.74	0.00	30.55
Total Wolf Run Mining Buckhannon Division					47.73	45.36	2.37	0.00	47.73
Sycamore Group	Assigned	O	WV	UG	17.41	0.23	17.18	17.41	0.00
Wolf Run Mining Philippi Development Division	Assigned	O	WV	UG	51.18	34.66	16.52	15.32	35.86
	Unassigned	D	WV	UG	4.94	4.94	0.00	0.00	4.94
Total Wolf Run Mining Philippi Development Division					56.12	39.60	16.52	15.32	40.80
CoalQuest Development LLC	Unassigned (Hillman)	D	WV	UG	186.04	186.04	0.00	32.71	153.33
Northern Appalachia Total					357.60	272.50	85.10	97.60	260.00
Central Appalachia									
ICG Eastern	Assigned	O	WV	S	11.45	3.37	8.08	11.45	0.00
	Unassigned	D	WV	S	6.71	0.00	6.71	6.71	0.00
Total ICG Eastern					18.16	3.37	14.79	18.16	0.00
ICG Hazard	Assigned	O	KY	S	36.77	0.18	36.59	36.77	0.00
	Unassigned	D	KY	S/UG	2.04	0.00	2.04	2.04	0.00
Total ICG Hazard					38.81	0.18	38.63	38.81	0.00
Flint Ridge	Assigned	O	KY	S/UG	30.57	0.23	30.34	30.57	0.00

ICG Knott County	Assigned	O	KY	UG	16.00	4.19	11.81	16.00	0.00
ICG East Kentucky	Assigned	O	KY	S	5.71	3.71	2.00	5.71	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
ICG Beckley[3]	Unassigned (Beckley)	D	WV	UG	28.97	1.28	27.69	0.00	28.97
White Wolf Energy, Inc. (f/k/a Anker Virginia Mining Company, Inc.)[3]	Unassigned (Big Creek)	D	V	UG	27.50	0.00	27.50	0.00	27.50
Central Appalachia Total					210.62	15.16	195.46	154.15	56.47
Other									
ICG Illinois	Assigned (Viper)	O	IL	UG	25.22	9.92	15.30	25.22	0.00
ICG Natural Resources	Unassigned	D	IL	UG	469.26	449.11	20.15	469.26	0.00
Total Other					494.48	459.03	35.45	494.48	0.00
Total Proven and Probable Reserves					1,062.70	746.69	316.01	746.23	316.47

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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) *ICG 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 the Vindex Energy, Buckhannon and Philippi Divisions. 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, 2007:

		As Received Quality					Total Reserves	
Mining Operations	**Assigned or Unassigned(1)**	**% Moisture**	**% Ash**	**% Sulfur**	**Btu/lb.**	**Lbs. SO(2)/ million Btu s**	**<1.2 lbs. SO(2) Compliance**	**>1.2 lbs SO(2) Non-Compliance**
Northern Appalachia								
Vindex Energy Corp.	Assigned	4.92	18.19	1.59	11,845	2.68	0.00	7.85
	Unassigned	6.00	13.63	1.81	12,547	2.88	3.63	36.55
Total Vindex Energy Corp.		5.82	14.41	1.77	12,427	2.85	3.63	44.40
Patriot Mining Co.	Assigned	6.00	16.40	2.07	11,672	3.54	0.00	2.27
	Unassigned	6.00	19.06	2.13	11,240	3.79	0.00	0.00
Total Patriot Mining Co.		6.00	16.40	2.07	11,672	3.54	0.00	2.27
Wolf Run Mining Buckhannon Division	Assigned	6.00	8.97	1.30	13,046	1.99	0.00	17.18
	Unassigned	6.00	8.92	0.99	13,069	1.52	0.00	30.55
Total Wolf Run Mining Buckhannon Division		6.00	8.94	1.10	13,060	1.68	0.00	47.73
Sycamore Group	Assigned	6.00	7.20	3.05	13,098	4.66	0.00	17.41
Philippi Development Division	Assigned	6.00	8.37	1.40	13,230	2.12	0.00	51.18
	Unassigned	6.00	8.04	1.44	13,353	2.15	0.00	4.94
Total Philippi Development Division		6.00	8.34	1.41	13,241	2.12	0.00	56.12
CoalQuest Development LLC	Unassigned (Hillman)	6.00	9.25	1.15	13,145	1.76	0.00	186.04
Northern Appalachia Total							3.63	353.97
Central Appalachia								
ICG Eastern	Assigned	6.00	14.42	1.24	11,964	2.07	0.00	11.45
	Unassigned	6.00	14.42	1.24	11,964	2.07	0.00	6.71
Total ICG Eastern		6.00	14.42	1.24	11,964	2.07	0.00	18.16
ICG Hazard	Assigned	6.00	13.42	1.40	11,976	2.33	0.00	36.77
	Unassigned	6.00	7.00	0.73	12,832	1.14	2.04	0.00
Total ICG Hazard		6.00	13.09	1.36	12,019	2.27	2.04	36.77
Flint Ridge	Assigned	6.00	8.15	1.39	12,768	2.17	0.00	30.57
ICG Knott County	Assigned	6.04	8.03	1.30	12,822	2.03	0.37	15.63
ICG East Kentucky	Assigned	5.74	9.60	0.92	12,474	1.48	0.00	5.71

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
ICG Beckley(2)	Unassigned (Beckley)	6.00	4.87	0.70	13,913	1.01	28.97	0.00
White Wolf Energy, Inc. (f/k/a Anker Virginia Mining Company, Inc.)(2)	Unassigned (Big Creek)	6.00	4.00	0.65	14,073	0.92	27.50	0.00
Central Appalachia Total							68.47	142.15
Other								
ICG Illinois	Assigned (Viper)	16.00	8.80	2.86	10,692	5.35	0.00	25.22
ICG Natural Resources	Unassigned	12.90	8.81	2.84	11,003	5.17	0.00	469.26
Total Other							0.00	494.48
Total Proven and Probable Reserves							72.10	990.60

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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) ICG 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 or sales of coal properties will also change the reserves. 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.

Periodically, we evaluate our reserve estimates. The most recent evaluation was completed as of January 1, 2005. Based on this evaluation, adjusted for production and estimates of additional reserves acquired during the years ended December 31, 2005 and 2006, we estimate that we controlled 1,063 million tons of reserves as of December 31, 2006.

We currently own approximately 70% 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 $1.99 per ton in 2006, representing approximately 4.6% (net of freight and handling) of our coal sales revenue in 2006. 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, 2007:

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
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
Wolf Run Mining Philippi Development Division	Assigned	O	WV	UG	1.64	1.64	0.00
	Unassigned	D	WV	UG	0.76	0.76	0.00
Total Wolf Run Mining Philippi Development Division					2.40	2.40	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							
ICG Eastern	Assigned	O	WV	S	0.02	0.02	0.00
ICG Hazard	Assigned	O	KY	S	1.94	1.94	0.00
Flint Ridge	Assigned	O	KY	S/UG	2.84	2.84	0.00
ICG Knott County	Assigned	O	KY	UG	0.00	0.00	0.00
ICG East Kentucky	Assigned (Blackberry)	O	KY	S	0.00	0.00	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	18.74	18.74	0.00
Wolf Run Mining Company (f/k/a Anker West Virginia	Unassigned)	D	WV	S/UG	3.10	3.10	0.00

Mining Company, Inc.)							
	(Juliana)						
ICG Beckley(3)	Unassigned	D	WV	UG	1.88	0.00	1.88
	(Beckley)						
White Wolf Energy, Inc. (f/k/a Anker Virginia Mining Company, Inc.)(3)	Unassigned	D	V	UG	2.57	2.57	0.00
	(Big Creek)						
Central Appalachia Total					66.68	64.80	1.88
Other							
ICG Illinois	Assigned	O	IL	UG	38.47	38.47	0.00
	(Viper)						
ICG Natural Resources	Unassigned		IL	UG	119.06	119.06	0.00
	(Illinois)						

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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					359.76	359.76	0.00
Total Non-Reserve Coal Deposits					565.54	563.66	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 the Vindex Energy, Buckhannon and Philippi Divisions. Similarly, we believe all production from Vindex Division and portions of Hillman can be sold on this metallurgical market.

(3) ICG Beckley and White Wolf Energy meet 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, 2007:

Mining Operations	Assigned or Unassigned[(1)]	As Received Quality % 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
Sycamore Group	Assigned	6.00	7.21	3.05	13,097	4.66
	Unassigned	N/A	N/A	N/A	N/A	N/A
Wolf Run Mining Philippi Development Division	Assigned	6.00	8.30	1.40	13,100	2.14
	Unassigned	6.00	8.30	1.40	13,100	2.14
Upshur Property	Unassigned (Upshur)	6.00	43.00	2.00	8,000	5.00
Central Appalachia						
ICG Eastern	Assigned	6.00	12.20	1.20	12,400	1.94
ICG Hazard	Assigned	6.00	13.07	1.23	12,045	2.04
Flint Ridge	Assigned	6.00	8.15	1.39	12,768	2.18
ICG Knott County	Assigned	N/A	N/A	N/A	N/A	N/A

ICG East Kentucky	Assigned (Blackberry)	N/A	N/A	N/A	N/A	N/A
ICG Natural Resources	Unassigned (Mt. Sterling)	6.00	11.63	1.93	11,774	3.28
ICG Natural Resources	Unassigned (Jennie Creek)	6.00	12.50	1.10	12,000	1.83
Wolf Run Mining Company (f/k/a Anker West Virginia Mining Company, Inc.)	Unassigned (Juliana)	6.00	7.50	0.82	13,100	1.25
ICG Beckley[(2)]	Unassigned (Beckley)	6.00	4.80	0.70	13,800	1.01
White Wolf Energy, Inc. (f/k/a Anker Virginia Mining Company, Inc.)[(2)]	Unassigned (Big Creek)	6.00	7.40	0.60	13,500	0.89

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Mining operations	Assigned or Unassigned(1)	% Moisture	% Ash	% Sulfur	Btu/ lb.	Lbs. SO(2)/ million Btu s
		As received quality				
Other						
ICG 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) ICG Beckley and White Wolf Energy meet historical metallurgical coal quality specifications.

ITEM 3. LEGAL PROCEEDINGS

On December 11, 2006, the West Virginia Office of Miners Health, Safety and Training (WVOMHST) released its report relating to the January 2, 2006 fatal explosion at the Sago mine, operated by our subsidiary, Wolf Run Mining Company (f/k/a Anker West Virginia Mining Company, Inc.). The report concluded that, consistent with our initial findings announced on March 14, 2006, the explosion was caused by an ignition of methane within a previously abandoned and sealed area of the mine and that the ignition was triggered by lightning. The federal Mine Safety Health Administration (MSHA) is still investigating the accident and has yet to issue its report.

On August 23, 2006, the survivor of the Sago mine accident, Randal McCloy, and the representatives of two miners who died in the Sago mine accident filed separate complaints in the Kanawha Circuit Court in Kanawha County, West Virginia. Since that time, twelve additional complaints have been filed in Kanawha Circuit Court by families of other miners who died in the Sago mine accident. The complaints allege various causes of action against us and our subsidiary, Wolf Run Mining Company, one of our shareholders, W.L. Ross & Co., and Wilbur L. Ross Jr., individually, related to the accident and seek compensatory and punitive damages. In addition, the plaintiffs also alleged 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 devices worn by the miners at the Sago mine. We believe that we are appropriately insured for potential claims and we have fully reserved our deductible applicable to our insurance policies. We will vigorously defend ourselves against the complaints.

On November 18, 2005, ICG, LLC, our wholly-owned subsidiary, filed a complaint in the United States District Court for the Eastern District of Kentucky, Ashland Division, against Massey Coal Sales Company, Inc. (Massey Coal Sales), seeking damages for breach of a coal supply agreement under which Massey Coal Sales supplies coal to ICG, LLC for resale to a customer of ICG, LLC. ICG, LLC has asserted various claims related to

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Massey Coal Sales failure to ship significant tonnages required to be shipped under the contract and the failure of numerous shipments to meet quality specifications set forth in the contract. On August 14, 2006, Massey Coal Sales asserted various counterclaims against ICG, LLC in the Federal Court litigation claiming that ICG, LLC failed to provide rail cars, that the contract should have been terminated and, as a result, ICG, LLC has been unjustly enriched. Massey Coal Sales has claimed damages in excess of $50 million. ICG, LLC denies any liability under the counterclaim and is vigorously defending itself against the counterclaim.

On June 1, 2006, ICG, LLC filed a complaint in Pike County, Kentucky, against Massey Energy Company and various of its affiliates seeking compensatory and punitive damages on account of the defendants tortious interference with ICG, LLC s contract and relationship with its customer. The defendants filed a motion to dismiss ICG, LLC s complaint and, on August 23, 2006, that motion was denied by the court.

Allegheny Energy Supply (Allegheny), the sole customer of coal produced at our subsidiary Wolf Run Mining Company s Sycamore No. 2 mine, filed a lawsuit against us in state court in Allegheny County, Pennsylvania on December 28, 2006. Allegheny claims that ICG and Wolf Run breached a coal supply contract when we declared force majeure under the contract upon idling the Sycamore No. 2 mine 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. In its complaint, Allegheny alleges that the production stoppages constitutes a breach of the contract and a breach of certain representations made upon entering into the contract in early 2005. Allegheny claims that it will incur costs in excess of $100 million to purchase replacement coal over the life of the contract. We dispute Allegheny s claims and will vigorously defend ourselves against the lawsuit.

In addition, from time to time, we are involved in legal proceedings arising in the ordinary course of business. We believe we have recorded adequate reserves for these liabilities and 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, 2006.

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PART II

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

Trading in our common stock commenced on the New York Stock Exchange on November 21, 2005 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	Stock Price Low
2005		
November 21, 2005 through December 31, 2005	$ 12.45	$ 9.50
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

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 22, 2007, there were approximately 218 holders of record of our common stock and an additional 32,839 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 plan and individual compensation arrangements as of December 31, 2006.

	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)]	1,495,250	$ 8.79	5,607,670
Equity compensation plans not approved by stockholders[(2)]	319,052	10.97	
	1,814,302	$ 9.17	5,607,670

(1) We have one compensation plan, the 2005 Equity and Performance Incentive Plan, which was approved by stockholders on October 24, 2005.

(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 14 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

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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.

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 and for the years ended December 31, 2006 and 2005, as of and for the period from May 13, 2004 to December 31, 2004, and the predecessor consolidated financial data for the nine months ended September 30, 2004, which have been audited and are included elsewhere 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 and as of and for the period ended May 10, 2002 to December 31, 2002 have been derived from the consolidated financial statements of Horizon, our predecessor, which have been audited and are not included in this report. The selected historical consolidated financial data is derived from the statement of operations of AEI Resources, the predecessor of Horizon, for the period January 1, 2002 to May 9, 2002, which have been audited and are not included in the 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.)			AEI Resources (predecessor to Horizon)
	Year ended December 31, 2006(3)	Year ended December 31, 2005(3)	Period from May 13, 2004 to December 31, 2004(3)	Period from January 1, 2004 to September 30, 2004(2)	Year ended December 31, 2003(2)	Period from May 10, 2002 to December 31, 2002(2)	Period from January 1, 2002 to May 9, 2002(2)
	(dollars in thousands, except per share data)						
Statement of Operations Data:							
Revenues:							
Coal sales revenues	$ 833,998	$ 619,038	$ 130,463	$ 346,981	$ 441,291	$ 264,235	$ 136,040
Freight and handling revenues	18,890	8,601	880	3,700	8,008	6,032	2,947
Other revenues	38,706	22,852	5,648	22,841	31,771	27,397	21,183
Total revenues	891,594	650,491	136,991	373,522	481,070	297,664	160,170
Costs and Expenses:							
Freight and handling costs	18,890	8,601	880	3,700	8,008	6,032	2,947
Cost of coal sales and other revenues	769,332	510,097	113,527	306,429	400,652	251,361	114,767
Depreciation, depletion and amortization	72,218	43,076	7,932	27,547	52,254	40,033	32,316
Selling, general and administrative	34,578	28,828	4,205	8,477	23,350	16,695	9,677
(Gain) loss on sale of assets	(1,125)	(502)	(10)	(226)	(4,320)	(39)	(93)
Writedowns and special items				10,018	9,100	729,953	8,323
Total costs and expenses	893,893	590,100	126,534	355,945	489,044	1,044,035	167,937
Income (loss) from operations	(2,299)	60,391	10,457	17,577	(7,974)	(746,371)	(7,767)
Interest and Other Income (Expense):							
Interest expense, net	(18,091)	(14,394)	(3,453)	(114,211)	(145,892)	(80,405)	(36,666)
Reorganization items				(12,471)	(23,064)	(4,075)	787,900
Other, net	2,113	3,302	16	1,442	187	1,256	499
Total interest and other income (expense)	(15,978)	(11,092)	(3,437)	(125,240)	(168,769)	(83,224)	751,733
Income (loss) before income taxes and minority interest	(18,277)	49,299	7,020	(107,663)	(176,743)	(829,595)	743,966
Income tax (expense) benefit	9,015	(16,986)	(2,660)				
Minority interest	(58)	15					
Net income (loss)	$ (9,320)	$ 32,328	$ 4,360	$ (107,663)	$ (176,743)	$ (829,595)	$ 743,966

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	International Coal Group, Inc.			Horizon (Predecessor to International Coal Group, Inc.)			AEI Resources (predecessor to Horizon)
	Year ended December 31, 2006[3]	Year ended December 31, 2005[3]	Period from May 13, 2004 to December 31, 2004[3]	Period from January 1, 2004 to September 30, 2004[2]	Year ended December 31, 2003[2]	Period from May 10, 2002 to December 31, 2002[2]	Period from January 1, 2002 to May 9, 2002[2]
Earnings Per Share[1]:							
Basic	$ (0.06)	$ 0.29	$ 0.04	$	$	$	$
Diluted	(0.06)	0.29	0.04				
Weighted-Average Common Shares Outstanding[1]:							
Basic	152,028,165	111,120,211	106,605,999				
Diluted	152,028,165	111,161,287	106,605,999				
Balance Sheet Data (at period end):							
Cash and cash equivalents	$ 18,742	$ 9,187	$ 23,967	$	$ 859	$ 114	$ 87,278
Total assets	1,316,891	1,051,403	457,045	539,606	576,372	623,800	1,521,318
Long-term debt and capital leases	180,035	45,462	175,681	29	315	1,157	933,106
Total liabilities and minority interest	658,541	384,917	302,534	1,422,290	1,351,393	1,222,219	1,286,318
Total stockholders equity (members deficit)	658,350	666,486	154,511	(882,684)	(775,021)	(598,419)	235,000
Total liabilities and stockholders equity (members deficit)	1,316,891	1,051,403	457,045	539,606	576,372	623,800	1,521,318
Statement of Cash Flows Data:							
Net cash from:							
Operating activities	$ 55,591	$ 77,319	$ 30,264	$ 28,085	$ 20,030	$ 76,378	$ (353,592)
Investing activities	(160,769)	(104,713)	(329,168)	3,437	(3,826)	(12,805)	44,555
Financing activities	114,733	12,614	322,871	(32,381)	(15,459)	(78,025)	259,011
Capital expenditures	165,658	108,231	5,583	6,624	16,937	13,435	10,963

(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.*

(2) *As restated. See Note 12 to the combined financial statements of Horizon included elsewhere in this report.*

(3) *As restated. See Note 24 to the consolidated financial statements of International Coal Group, Inc. included elsewhere in this report.*

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/A 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 and the audited and unaudited consolidated financial statements and notes thereto of Horizon NR, LLC, each appearing elsewhere in this Annual Report on Form 10-K/A.

As discussed in Note 12 to Horizon NR, LLC s combined financial statements, Horizon s financial statements have been restated. As discussed in Note 24 to International Coal Group, Inc. s consolidated financial statements, ICG s financial statements have been restated. The accompanying management discussion and analysis gives effect to these restatements.

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Overview

We produce, process and sell steam coal from 11 regional mining complexes, which, as of December 31, 2006 were supported by 12 active underground mines, 13 active surface mines and eight 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 and the audited consolidated financial statements and notes of Horizon and its predecessors, each 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 recent pricing environment for domestic steam coal is 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 may involve a higher degree of judgment or complexity:

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. Significant reclamation activities include reclaiming refuse and slurry ponds, reclaiming the pit and support acreage at surface mines and sealing portals at deep mines. We account for the costs of our reclamation activities in accordance with the provisions of SFAS No. 143, *Accounting for Asset Retirement Obligations*. We determine the future cash flows necessary to satisfy our reclamation obligations on a mine-by-mine basis based upon current permit requirements and various estimates and assumptions, including estimates of disturbed acreage, cost estimates and assumptions regarding productivity. Estimates of disturbed acreage are determined based on approved mining plans and related engineering data. Cost estimates are based upon third-party costs. Productivity assumptions are based on historical experience with the equipment that is expected to be utilized in the reclamation activities. We determine the fair value of our asset retirement obligations in accordance with the provisions of SFAS No. 143. In order to determine fair value, we must also estimate a discount rate and third-party margin. Each is discussed further below:

Discount rate. SFAS No. 143 requires that asset retirement obligations be recorded at fair value. In accordance with the provisions of SFAS No. 143, we utilize discounted cash flow techniques to estimate the fair value of our obligations. We base our discount rate on the rates of treasury bonds with maturities similar to expected mine lives, adjusted for our credit standing.

Third-party margin. SFAS No. 143 requires the measurement of an obligation to be based upon the amount a third-party would demand to assume the obligation. Because we plan to perform a significant amount of the reclamation activities with internal resources, a third-party margin was added to the estimated costs of these activities. This margin was estimated based upon our historical experience with contractors performing certain types of reclamation activities. The inclusion of this margin will result in a recorded obligation that is greater than our estimates of our cost to perform the reclamation activities. If our cost estimates are accurate, the excess of the recorded obligation over the cost incurred to perform the work will be recorded as a gain at the time that reclamation work is completed.

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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, 2006, we had recorded asset retirement obligation liabilities of $92.7 million, including amounts reported as current liabilities. While the precise amount of these future costs cannot be determined with certainty, as of December 31, 2006, we estimate that the aggregate undiscounted cost of final mine closure is approximately $135.3 million.

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, 2006, 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 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 5.75% for the year ended December 31, 2006. 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, 2006 was based on an assumed heath care inflationary rate of 9.4% 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, 2006 by $0.5 million and increase the accumulated postretirement benefit obligation at December 31, 2006 by $2.6 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, 2006 by $0.4 million and decrease the accumulated postretirement benefit obligation at December 31, 2006 by $2.2 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.

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, 2006, we have recorded an accrual of $21.0 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 $5.2 million at December 31, 2006. Prior to the business combination with Anker, we did not have any liability under the Coal Act.

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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, 2006, we had $196.8 million in goodwill, which represents the excess of costs over the fair value of the net assets acquired from Horizon. We test for impairment of goodwill annually as of October 31 to determine if the fair value of the underlying business units can support the amount of goodwill allocated to them. The goodwill tests include discounted cash flow models and a market valuation approach. The discounted cash flow models include assumptions about future market conditions and operating results of the business units. If an impairment test indicates the fair value of the underlying business units cannot support the amount of goodwill allocated to it, we will be required to write off the impaired portion. As a result, the value of the assets could be significantly reduced, which would increase operating expenses and reduce net income for the year in which the write-off occurs.

Results of Operations

Basis of Presentation

Certain assets of Horizon and its subsidiaries were acquired by ICG, Inc. as of September 30, 2004. Due to the change in ownership and the resultant application of purchase accounting, the historical financial statements of Horizon and ICG included in this report have been prepared on different bases for the periods presented and are not comparable.

The following provides a description of the basis of presentation during all periods presented:

Successor We were formed on March 31, 2005, as a wholly-owned subsidiary of ICG, Inc., in order to effect the corporate reorganization and the Anker and CoalQuest acquisitions, all of which were consummated on November 18, 2005. Financial presentation represents the consolidated financial position of International Coal Group, Inc. as of December 31, 2006 and consolidated results of operations and cash flows for the year then ended, the consolidated financial position of International Coal Group, Inc. as of December 31, 2005 and consolidated results of operations and cash flows for the period from November 19 through December 31, 2005 combined with the consolidated results of operations and cash flows of ICG, Inc. for the period from January 1 through November 18, 2005, and the consolidated financial position of ICG, Inc. as of December 31, 2004 and consolidated results of operations and cash flows for the period from May 13 (inception) through December 31, 2004. ICG, Inc. had no material assets, liabilities or results of operations until the acquisition of certain assets from Horizon as of September 30, 2004. ICG, Inc. s consolidated financial position at December 31, 2004 and its consolidated results of operations for the period ended December 31, 2004 reflect the purchase price allocation based on estimated fair values and actuarially determined employee benefit valuations. The application of purchase accounting to the acquired assets of Horizon resulted in increases to coal inventories and the asset arising from recognition of asset retirement obligations. It also resulted in increases to plant and equipment, coal supply agreements and goodwill and a decrease in deferred taxes.

Predecessors Represents the consolidated financial position and results of operations and cash flows for Horizon for the period January 1 through September 30, 2004. The Horizon accounts receivable, advance

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royalties, accounts payable and accrued expenses, intangibles, goodwill and other assets and long-term liabilities were estimates of management. The Horizon property, plant and equipment, coal lands and accrued reclamation obligations were based on estimated fair values while employee benefit valuations were actuarially determined. Management allocated amounts of the purchase price to these assets and liabilities based on these estimates.

The financial statements for the predecessor periods of Horizon have been prepared on a carve-out basis to include our assets, liabilities and results of operations that were previously included in the consolidated financial statements of Horizon. The financial statements for the Horizon predecessor periods include allocations of certain expenses, taxation charges, interest and cash balances relating to Horizon based on management s 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 predecessor period presented.

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

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$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 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 ICG ADDCAR, due to decreased production caused by varying mining conditions at the contracting parties mining complexes.

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,		Increase (Decrease)	
	2006	2005	$	%
	(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,		Increase (Decrease)	
	2006	2005	$	%
	(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

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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.

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		2005		Increase (Decrease)	
	$	%(1)	$	%(1)	$	%
	(in thousands, except percentages and per ton data)					
Cost of coal sales	$ 769,332	86%	$ 510,097	79%	$ 259,235	51%
Freight and handling costs	18,890	2%	8,601	1%	10,289	120%
Depreciation, depletion and amortization	72,218	8%	43,076	7%	29,142	68%
Selling, general and administrative expenses	34,578	4%	28,828	4%	5,750	20%
Gain on sale of assets	(1,125)	*	(502)	*	(623)	124%
Total costs and expenses	$ 893,893	100%	$ 590,100	91%	$ 303,793	51%
Total costs and expenses per ton sold(2)	$ 46.15		$ 39.99		$ 6.16	15%

* *Not meaningful.*

(1) *Amount as a percentage of total revenues.*

(2) *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

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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.

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.

Adjusted EBITDA by Segment

Adjusted EBITDA represents net income before deducting interest expense, income taxes, depreciation, depletion and amortization and minority interest. Adjusted EBITDA is presented because it is an important

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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 71 of this 10-K/A and in Note 21 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 ICG 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, 2006	2005	Increase (Decrease) $	%
	(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)%

Twelve Months Ended December 31, 2005 Compared to the Twelve Months Ended December 31, 2004 of International Coal Group, Inc. and Predecessor (Combined)

This discussion of the results of operations for the twelve months ended December 31, 2004 represents an addition of Horizon s actual results for the nine months ended September 30, 2004 together with International Coal Group, Inc. s actual results of operations for the three months ended December 31, 2004 (Combined).

Revenues

The following table reflects ICG s revenues for the year ended December 31, 2005 and depicts ICG s combined revenues for the year ended December 31, 2004 for the indicated categories:

	Year Ended December 31, 2005	Combined 2004	Increase (Decrease) $	%
	(in thousands, except percentages and per ton data)			
Coal sales revenues	$ 619,038	$ 477,444	$ 141,594	30%
Freight and handling revenues	8,601	4,580	4,021	88%
Other revenues	22,852	28,489	(5,637)	(20)%
Total revenues	$ 650,491	$ 510,513	$ 139,978	27%
Tons sold	14,755	14,003	752	5%
Coal revenue per ton	$ 41.95	$ 34.09	$ 7.86	23%

Coal sales revenues. Our coal sales revenue increased $141.6 million for the year ended December 31, 2005, or 30%, as compared to combined coal sales revenues for 2004. This increase was due to a $7.86 per ton increase in the average sales price of our coal (exclusive of amortization income on below-market coal supply agreements) and an increase in tons sold of 5% over the prior year. The increase in the average sales price of our coal was due to a general increase in coal prices during the year, as well as a favorable renegotiation of coal sales contracts as a result of Horizon s Chapter 11 bankruptcy. Our tons sold in 2005 increased by 0.8 million, or 5%, to 14.8 million, primarily due to the effect of our acquisitions of Anker and CoalQuest, which provided approximately 0.5 million additional tons compared to the prior year.

Freight and handling revenues. Freight and handling revenues increased $4.0 million to $8.6 million for year ended December 31, 2005 compared to 2004. 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 decreased in 2005 by $5.6 million, or 20%, to $22.9 million, as compared to 2004, due to a decrease in royalty and other miscellaneous income of $6.1 million, partially offset by increased ash disposal income of $1.0 million.

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Costs and expenses

The following table reflects ICG s cost of operations for the year ended December 31, 2005 and depicts ICG s combined cost of operations for the year ended December 31, 2004:

	Year Ended December 31,					
	2005		Combined 2004		Increase (Decrease)	
	$	%(1)	$	%(1)	$	%
	(in thousands, except percentages and per ton data)					
Cost of coal sales	$ 510,097	78%	$ 419,956	82%	$ 90,141	21%
Freight and handling costs	8,601	1%	4,580	1%	4,021	88%
Depreciation, depletion and amortization	43,076	7%	35,479	7%	7,597	21%
Selling, general and administrative expenses	28,828	4%	12,682	2%	16,146	127%
Gain on sale of assets	(502)	*	(236)	*	(266)	113%
Writedowns and other items		*	10,018	2%	(10,018)	100%
Total costs and expenses	$ 590,100	91%	$ 482,479	95%	$ 107,621	22%
Total costs and expenses per ton sold(2)	$ 39.99		$ 34.46		$ 5.53	16%

* *Not meaningful*

(1) *Amount as a percentage of total revenues.*

(2) *Included in total costs and expenses per ton sold were costs for ICG ADDCAR, highwall mining activities and shop services of $2.08 and $1.74 per ton for the years ended December 31, 2005 and 2004, respectively.*

Cost of coal sales and other revenues. In 2005, our cost of coal sales increased $90.1 million, or 21.0%, to $510.1 million compared to $420.0 million in the prior year. The increase in cost of coal sales is primarily a result of increases in prices for steel-related mine supplies, including increases in costs for roof control supplies of $1.7 million, increasing costs for conveyor belts and structure of $2.8 million, escalating diesel fuel costs, which were further heightened by Hurricane Katrina s devastation in Mississippi and Louisiana of $12.0 million, increasing costs for repairs and maintenance of $6.3 million, increasing site preparation and maintenance of $1.1 million and increasing purchase coal costs of $5.6 million. Variable sales-related costs, such as royalties and severance taxes, increased $11.7 million due to increased sales realizations. Trucking costs increased $11.0 million due to both escalating diesel fuel costs and increased driver compensation costs. In addition, salary and hourly payroll expense increased $14.1 million due to a highly-competitive labor market and the necessity to maintain a competitive compensation program. Approximately $22.3 million of the increase in the cost of coal sales was due to our acquisitions of Anker and CoalQuest. These increases were partially offset by decreases in equipment rental expense of $8.0 million due to the decision to purchase rather than lease to fulfill our equipment needs. The total costs and expenses per ton sold increased 16% from $34.46 per ton in 2004 to $39.99 per ton in 2005.

Freight and handling costs. Freight and handling costs increased $4.0 million to $8.6 million for the year ended December 31, 2005 compared to 2004. 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 $7.6 million to $43.1 million in 2005 compared to $35.5 million in 2004. Depreciation, depletion and amortization per ton increased from $2.53 per ton sold in 2004 to $2.92 per ton sold in 2005. The principal component of the increase was an increase in depreciation expense of $14.8 million in 2005 due to an increase in capital expenditures, as well as shortened depreciable asset lives of the Horizon equipment purchased by ICG, Inc. in September 2004. The cost increase was offset by a decrease in depletion of $3.1 million as a result of a revaluation of mineral reserves in connection with the purchase of Horizon s assets and amortization income on below market coal supply agreements of $1.0 million. Effective January 1, 2004, Horizon discontinued the accounting practice of capitalization of major repair costs in excess of $25,000 per occurrence. The decrease in amortization relating to this practice was $3.9 million.

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Selling, general and administrative expenses. Selling, general and administrative expenses for 2005 were $28.8 million compared to $12.7 million for 2004. The increase of $16.1 million is primarily attributable to increases in stock compensation expense and related payroll taxes of $10.4 million, administrative fees of $1.6 million, bonuses of $1.3 million and other costs of $2.8 million.

Gain on sale of assets. Gain on sale of assets increased $0.3 million from a gain of $0.2 million in 2004 to a gain of $0.5 million in 2005.

Writedowns and other items. The 2004 writedowns and other items were attributable to a loss of $13.3 million on the sale of coal lands, a gain of $7.7 million on a lease buyout, a loss on the retirement of a highwall mining system of $6.2 million and other gains of $1.8 million. We did not record any writedowns in 2005.

Total costs as a percentage of revenues. Total costs and expenses as a percentage of total revenues decreased to 91% for the year ended December 31, 2005 from 95% for the year ended December 31, 2004.

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 from time-to-time. Our primary sources of liquidity to meet these needs are cash flow from coal sales, other income, borrowings under our amended and restated credit facility and capital equipment finance arrangements.

We believe the principal indicators of our liquidity are our cash position and remaining availability under our amended and restated credit facility. As of December 31, 2006, our available liquidity was $283.8 million, including cash of $18.7 million and $265.1 million available under our amended and restated credit facility. Total debt represented 23.3% of our total capitalization at December 31, 2006. Our total capitalization represents our current short- and long-term debt combined with our total stockholders equity.

Cash paid for capital expenditures was approximately $165.7 million in 2006 and we currently expect our total capital expenditures will be approximately $164.5 million in 2007, of which 54% represents investments in new equipment and mining development operations. We have historically funded capital expenditures, and will fund future capital expenditures, from our internal operations, proceeds from our senior notes offering, borrowings under our amended and restated credit facility and our $50.0 million equipment revolving credit facility with Caterpillar Financial Services Corporation. We entered into the amended and restated credit facility in June 2006 and we expect that it will be sufficient to fund our anticipated capital expenditures under our current budget plan through 2012. Our amended and restated credit agreement was further amended in January 2007 to modify certain financial covenants, which we expect will give us increased flexibility in facilitating our growth strategy.

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, 2006, we spent $2.0 million to meet these standards and anticipate spending an additional $3.7 million in 2007. As we take advantage of planned expansion opportunities in 2007 and 2008, principally as a result of the Anker and CoalQuest acquisitions, we expect to spend approximately $330 million on capital expenditures. This estimate is based on our revised development plans which reflect the delayed development of certain new operations. However, our capital expenditures may be different than currently anticipated depending upon the size and nature of new business opportunities and actual cash flows generated by our operations.

Approximately $69.4 million of 2006 capital expenditures were attributable to our Central Appalachian operations. This amount represents investments of approximately $39.6 million in our newly developed Flint Ridge, Raven and East Mac and Nellie mines sites, as well as investment in the development of our future

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Beckley mining complex of approximately $7.5 million. Additionally, we expended approximately $22.3 million for upgrades and maintenance at our ICG Hazard, ICG Knott County, ICG East Kentucky and ICG Eastern operations.

We spent approximately $70.5 million for development and improvements of our Northern Appalachian operations in 2006. Approximately $7.8 million of the amount was due to the start-up of our Crown, Carlos and Imperial mines sites and approximately $11.7 million was for the purchase of our Jackson Mountain mine site. Additionally, we invested approximately $29.4 million in future operations at our Sentinel-Clarion, Tygart and Vindex mine sites and approximately $21.6 million for current operations at Buckhannon, Patriot, and Harrison.

Expenditures of approximately $7.4 million for our Illinois Basin operations were for on-going operational improvements and to rebuild equipment damaged in a fire during 2006.

Approximately $18.4 million of capital expenditures in 2006 were within our Ancillary segment. Approximately $8.3 million of the amount was attributable to the construction of a new building that houses our corporate headquarters. An additional $5.9 million was for our investment in a joint operating agreement for the purpose of exploration and development of coalbed methane. Additionally, we spent approximately $4.2 million for upgrades and maintenance at ICG ADDCAR and other subsidiaries.

We continue to be affected by increased costs for mine supplies, services, repair parts, tires and fuel. Our 2006 results were adversely impacted by the continued rising prices of crude oil and natural gas, as well as increased labor costs. We are exploring a range of options to try to address these issues. In addition, as a result of infrastructure weaknesses and short-term geologic issues at mines acquired in the Anker acquisition, the transition period for implementation of various operational improvements has taken longer than originally anticipated.

On January 2, 2006, an explosion occurred at our Sago mine in Tallmansville, West Virginia. The Sago mine is operated by our subsidiary Wolf Run Mining Company (f/k/a Anker West Virginia Mining Company, Inc.). Costs incurred related to the Sago mine accident totaled $13.0 million, including reserves established for legal 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.

On April 8, 2006, we suffered a fire at our Viper mine near Elkhart, Illinois, that idled the mine and forced replacement of its high angle conveyor belt. Repairs have been completed and we resumed production on May 8, 2006. Force Majeure notices were issued to affected customers, but coal continued to be shipped from existing inventory through May 2, 2006. No one was injured in the incident. We spent $1.6 million to replace fully depreciated fixed assets damaged in the fire and incurred an estimated $3.0 million in carrying costs while the mine was idle.

During 2006, we experienced additional operating issues that have had a negative impact on our outlook. The closure of Vindex Energy s Stony River mine became permanent after a major roof fall in early February 2006 prevented access to the remaining coal reserves. Mining activity at Wolf Run s Sycamore No. 2 mine suffered adverse geological conditions, which resulted in high production costs and reduced tonnage. As a result of high production costs, we implemented production cutbacks at the Sycamore No. 2 mine, as well as other operations, that total approximately 3.2 million annual tons. Our East Kentucky operation experienced rail service delays that resulted in our missing four trains and decreasing revenues by approximately $2.5 million. Similar delays may or may not occur in the future. Our performance in 2006 was also adversely affected by the bankruptcy of a key coal supplier for our Vindex operations and the ongoing effects of the Sago mine accident.

We had brokered coal contracts that expired at the end of 2006. These contracts were signed during a period of oversupply in the coal industry and contained pricing that, while acceptable to the sellers at that time, were significantly below today s market levels. The loss of these contracts will impact our earnings beginning in 2007. For the year ended December 31, 2006, these contracts provided $31.6 million in pre-tax net income. However,

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the loss of this revenue is expected to be mitigated somewhat as additional owned and controlled mining complexes are brought into production in 2007. For example, in the fourth quarter of 2006 we commenced operations at our Raven and Philippi complexes and entered into a number of long-term contracts with a key customer. Specifically, on October 27, 2006, our new Raven complex commenced operations at its new preparation plant. The mine is expected to reach full production by the end of 2007 and is expected to produce 1.2 million tons of high-quality steam coal annually for the Southeastern utility market. During the fourth quarter of 2006, we were also able to resume production at the Sentinel mine in our Philippi complex after we extended the mine shafts and slope access to encounter more favorable mining conditions in the recently acquired Clarion seam reserves. We expect this mine to produce over 1.5 million tons of high-volatile metallurgical and high-quality steam coal annually. During the fourth quarter of 2006, we also reached agreement on six new long-term steam coal contracts and agreed to extend three Central Appalachian contracts with a key customer. The agreements include a collared price feature that protects both ICG and the customer.

In addition, production related to our coalbed methane joint operating agreement increased significantly during the fourth quarter of 2006 and provided coalbed methane and royalty revenue totaling $2.3 million for 2006. We expect revenue related to this agreement to increase in 2007 due to a full year of operations and additional investments.

Our new ICG Beckley Complex is projected to begin production in the third quarter of 2007. The complex is expected to produce 1.3 million tons of high-quality, low-volatile metallurgical coal annually for both domestic and export steel markets.

Cash Flows

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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Net cash provided by operating activities was $77.3 million for the year ended December 31, 2005, an increase of $19.0 million from the same period in 2004. This increase is attributable to an increase in net income of $151.8 million after adjustment for non-cash charges. These increases were partially offset by the effects of a decrease in net operating assets and liabilities of $122.9 million and writedowns of $17.7 million. In the same period in 2004, there was a gain on a lease buyout option of $7.7 million related to our predecessor s bankruptcy filing.

Net income increased in 2005 primarily as a result of higher realization due to the strengthening of the coal market during the period. The increase in realization was partially offset by higher operating costs most notably diesel fuel, trucking costs due to increased diesel costs and increased driver compensation and labor costs due to the highly competitive labor market. Higher interest expense for the predecessor company also impacted net income in 2004.

For the year ended December 31, 2005, net cash used in investing activities was $104.7 million compared to cash used in investing activities of $325.7 million for the twelve months ended December 31, 2004. Cash used in investing activities for 2005 was $108.2 million in order to begin replacement of our aged mining equipment fleet compared to $12.2 million in 2004. Cash was returned from deposits of restricted cash used for collateral for reclamation and royalty bonds of $3.4 million in 2005 compared to cash deposited of $1.8 million in the same period of 2004. Proceeds of equipment sales were $0.6 million in 2005 compared to $4.1 million in the same period of 2004 and proceeds from lease buyouts of $7.7 million in 2004 had a positive impact on investing in 2004. Investment activities also includes cash paid (net of cash acquired) of $0.5 million related to the acquisition of Anker and CoalQuest in 2005 through the issuance of 24,090,909 million shares of common stock. In 2004, Horizon s assets were purchased for $323.6 million.

Net cash provided by financing activities of $12.6 million for the year ended December 31, 2005 was primarily due to $210.5 million of net proceeds from the issuance and sale of 21 million shares of common stock in our public offering in December 2005. The net proceeds of the public offering were used to repay $188.7 million of term loan debt and $21.2 million of borrowings under our revolving credit facility. Prior to the public offering, we made term loan payments of $1.7 million and borrowed an additional $35.0 million to consummate the mergers with Anker and CoalQuest. Also impacting our financing activities was financing costs of $0.4 million, capital lease payments of $0.5 million and proceeds of $0.2 million related to issuance of common stock to employees. In addition, we borrowed $42.5 million on our revolving credit facility to satisfy short-term operational needs and made net repayments of $55.5 million and $7.5 million on our long-term and short-term debt, respectively. In 2004, cash provided in financing activities of $290.5 million primarily due to $150.2 million in capital provided by the original investors as well as borrowings under a $175 million term loan. We also incurred capital lease repayments of $0.8 million in 2004. Other changes in financing activities in 2004 resulted in a use of funds of $35.6 million primarily related to the repayment of Horizon s DIP facility.

Credit Facility and Long-Term Debt Obligations

As of December 31, 2006, our total long-term indebtedness, including capital lease obligations, consisted of the following:

	December 31, 2006
10.25% Senior Notes, due 2014	$ 175,000
Equipment notes	4,619
Capital leases	416
Total	180,035
Less current portion	1,749
Long-term debt	$ 178,286

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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. The net proceeds were used to repay all amounts outstanding under our then existing revolving credit facility of $91.3 million and retire our then outstanding term loan facility of $19.5 million. We intend to use the remaining proceeds to fund future capital expenditures, as well as for general corporate purposes. Interest on the notes are payable semi-annually in arrears on July 15 and January 15 of each year, commencing on January 15, 2007. 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 Notes for publicly registered notes. The exchange offer expired on November 10, 2006 with 100% of the aggregate principal amount of the outstanding 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 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, 2006, we were in compliance with our covenants under the indenture.

Credit facility. On June 23, 2006, we entered into a second amended and restated credit agreement consisting of a revolving credit facility of $325.0 million, of which up to a maximum of $125.0 million may be used for letters of credit, and matures on June 23, 2011. As of December 31, 2006, we had letters of credit totaling $59.9 million outstanding leaving $265.1 million available for future borrowing capacity. Interest on the borrowings under the credit facility is payable, at our option, at either the base rate plus an applicable margin based on our leverage ratio of 0.75% to 1.25% or LIBOR plus an applicable margin based on our leverage ratio of 1.75% to 2.25%. We must pay an unused commitment fee based on our leverage ratio of 0.375% or 0.50%. We must also pay a letter of credit participation fee with respect to outstanding letters of credit in an amount equal to the interest rate margin applicable to LIBOR borrowings under the revolving credit facility and letter of credit fronting fee of 0.20% per annum. The credit facility contains customary affirmative and negative covenants, including, but not limited to, limitations on the incurrence of indebtedness, asset dispositions, acquisitions, investments, dividends and other restricted payments, liens and transactions with affiliates. The credit facility also requires us to meet certain financial tests, including a maximum leverage ratio, a minimum interest coverage ratio and a limit on capital expenditures. As of December 31, 2006, we are in compliance with the covenants under the credit facility. The credit facility contains customary events of default, including, but not limited to, failure to pay principal or interest, breach of covenants or representations and warranties, cross-default to other indebtedness, judgment default and insolvency. If an event of default occurs under the credit facility, the lenders under the agreement will be entitled to take various actions, including demanding payment for all amounts outstanding thereunder and foreclosing on any collateral. As a result of the amendment and restatement in June 2006, we incurred a write-off of $1.4 million of deferred financing expenses related to the prior credit agreement.

In January 2007, we entered into an amendment to the credit facility which modified certain financial covenants.

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, the historical results of our predecessors, as well as those of Anker and CoalQuest, 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, 2006:

	Payments due by period (in thousands)				
	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Long-term debt obligations[1]	$ 19,937	$ 38,671	$ 36,668	$ 228,812	$ 324,088
Operating leases	3,110	70	4		3,184
Coal purchase obligation[2]	19,842	30,609	8,075		58,526
Advisory Services Agreement[3]	2,000	4,000	3,500		9,500
Minimum royalties	7,316	14,475	14,140	30,647	66,578
Postretirement medical benefits	324	1,707	3,690	128,348	134,069
Total[4]	$ 52,529	$ 89,532	$ 66,077	$ 387,807	$ 595,945

(1) Amounts are inclusive of interest assuming interest rates of 10.25% for the senior 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.

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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 $100.0 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, 2006, we had outstanding surety bonds with third parties for post-mining reclamation totaling $95.4 million, plus $3.8 million for miscellaneous purposes. As of December, 31, 2006, we maintained letters of credit totaling $59.9 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 twelve months ended December 31, 2006, 2005 and 2004.

Recent Accounting Pronouncements

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. We are currently evaluating the effect that the adoption of SFAS No. 157 will have on our financial position, results of operations and cash flows.

Postretirement Benefits Other Than Pensions. In September 2006, the FASB issued 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)* (SFAS No. 158). SFAS No. 158 requires the recognition of the funded status of a defined benefit plan in the statement of financial position, requires that changes in the funded status be recognized through comprehensive income, changes the measurement date for defined benefit plan assets and obligations to the entity s fiscal year-end and expands disclosures. The recognition and disclosures under SFAS No. 158 are required as of the end of the fiscal year ending after December 15, 2006, while the new measurement date is effective for fiscal years ending after December 15, 2008. Adoption of SFAS No. 158 resulted in increases of $6,925 and $3,846 to our postretirement benefit obligation liability, and accumulated comprehensive loss, respectively, at December 31, 2006, and a decrease of $3,079 to our deferred tax liabilities at December 31, 2006.

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

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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 is currently evaluating the effect that the adoption of SFAS No. 159 will have on its 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. We are currently evaluating the effect that the adoption of FIN 48 will have on our financial position, results of operations and cash flows

Financial Statement Misstatements. In September 2006, the SEC issued Staff Accounting Bulletin No. 108 (SAB 108). SAB 108 was issued to provide interpretive guidance on how the effects prior year uncorrected misstatements should be considered when quantifying misstatements in current year financial statements. SAB 108 requires companies to quantify misstatements using a balance sheet and income statement approach and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. When the effect of initial adoption is material, companies will record the effect as a cumulative effect adjustment to beginning of year retained earnings. SAB 108 is to be applied to financial statements for fiscal years ending after November 15, 2006. Adoption of SAB 108 did not impact our financial position, results of operations or cash flows.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity price risk. We manage our commodity price risk for coal sales through the use of long-term coal supply agreements rather than through the use of derivative instruments. As of December 31, 2006, we had sales commitments for 79% of our planned 2007 production. Some of the products used in our mining activities, such as diesel fuel, are subject to price volatility. Through our suppliers, we utilize forward contracts to manage the exposure related to this volatility. A hypothetical increase of $0.10 per gallon for diesel f