ARCH COAL INC
Form 10-K
February 29, 2012

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

Form 10-K

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

For the fiscal year ended December 31, 2011

Commission file number: 1-13105

Arch Coal, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**43-0921172**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
One CityPlace Drive, Ste. 300, St. Louis, Missouri	**63141**
(Address of principal executive offices)	(Zip code)

Registrant's telephone number, including area code: (314) 994-2700

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

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, $.01 par value	New York Stock Exchange
	Chicago 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 ý No o

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

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 ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such filed). Yes ý No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of the voting stock held by non-affiliates of the registrant (excluding outstanding shares beneficially owned by directors, officers and treasury shares) as of June 30, 2011 was approximately $5.6 billion.

On February 15, 2012, 213,292,678 shares of the company's common stock, par value $0.01 per share, were outstanding.

Portions of the registrant's definitive proxy statement for the annual stockholders' meeting to be held on April 26, 2012 are incorporated by reference into Part III of this Form 10-K.

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If you are not familiar with any of the mining terms used in this report, we have provided explanations of many of them under the caption "Glossary of Selected Mining Terms" on page 36 of this report. Unless the context otherwise requires, all references in this report to "Arch," "we," "us," or "our" are to Arch Coal, Inc. and its subsidiaries.

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION

This report contains forward-looking statements, within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, such as our expected future business and financial performance, and are intended to come within the safe harbor protections provided by those sections. The words "anticipates," "believes," "could," "estimates," "expects," "intends," "may," "plans," "predicts," "projects," "seeks," "should," "will" or other comparable words and phrases identify forward-looking statements, which speak only as of the date of this report. Forward-looking statements by their nature address matters that are, to different degrees, uncertain. Actual results may vary significantly from those anticipated due to many factors, including:

- market demand for coal and electricity;
- geologic conditions, weather and other inherent risks of coal mining that are beyond our control;
- competition within our industry and with producers of competing energy sources;
- excess production and production capacity;
- our ability to acquire or develop coal reserves in an economically feasible manner;
- inaccuracies in our estimates of our coal reserves;
- availability and price of mining and other industrial supplies;
- availability of skilled employees and other workforce factors;
- disruptions in the quantities of coal produced by our contract mine operators;
- our ability to collect payments from our customers;
- defects in title or the loss of a leasehold interest;
- railroad, barge, truck and other transportation performance and costs;
- our ability to successfully integrate the operations that we acquire;
- our ability to secure new coal supply arrangements or to renew existing coal supply arrangements;

our relationships with, and other conditions affecting, our customers;

the deferral of contracted shipments of coal by our customers;

our ability to service our outstanding indebtedness;

our ability to comply with the restrictions imposed by our credit facility and other financing arrangements;

the availability and cost of surety bonds;

failure by Magnum Coal Company, which we refer to as Magnum, a subsidiary of Patriot Coal Corporation, to satisfy certain below-market contracts that we guarantee;

our ability to manage the market and other risks associated with certain trading and other asset optimization strategies;

terrorist attacks, military action or war;

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- our ability to obtain and renew various permits, including permits authorizing the disposition of certain mining waste;

- existing and future legislation and regulations affecting both our coal mining operations and our customers' coal usage, governmental policies and taxes, including those aimed at reducing emissions of elements such as mercury, sulfur dioxides, nitrogen oxides, particulate matter or greenhouse gases;

- the accuracy of our estimates of reclamation and other mine closure obligations;

- the existence of hazardous substances or other environmental contamination on property owned or used by us; and

- the other factors affecting our business described below under the caption "Risk Factors."

All forward-looking statements in this report, as well as all other written and oral forward-looking statements attributable to us or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements contained in this section and elsewhere in this report. See Item 1A "Risk Factors," Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 7A "Quantitative and Qualitative Disclosures About Market Risk" for additional information about factors that may affect our businesses and operating results. These factors are not necessarily all of the important factors that could affect us. These risks and uncertainties, as well as other risks of which we are not aware or which we currently do not believe to be material, may cause our actual future results to be materially different than those expressed in our forward-looking statements. We do not undertake to update our forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by law.

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PART I

ITEM 1. BUSINESS.

Introduction

We are one of the world's largest coal producers. For the year ended December 31, 2011 (which includes sales of the former International Coal Group, Inc. after June 14, 2011), we sold approximately 156.9 million tons of coal, including approximately 5.5 million tons of coal we purchased from third parties, representing roughly 14% of the 2011 U.S. coal supply. We sell substantially all of our coal to power plants, steel mills and industrial facilities. At December 31, 2011, we operated, or contracted out the operation of, 46 active mines located in each of the major coal-producing regions of the United States. The locations of our mines and access to export facilities enable us to ship coal to most of the major coal-fueled power plants, industrial facilities and steel mills located within the United States and on four continents worldwide.

Significant federal and state environmental regulations affect the demand for coal. Existing environmental regulations limiting the emission of certain impurities caused by coal combustion and new regulations have had, and are likely to continue to have, a considerable impact on our business.

Our History

We were organized in Delaware in 1969 as Arch Mineral Corporation. In July 1997, we merged with Ashland Coal, Inc., a subsidiary of Ashland Inc. that was formed in 1975. As a result of the merger, we became one of the largest producers of low-sulfur coal in the eastern United States.

In June 1998, we expanded into the western United States when we acquired the coal assets of Atlantic Richfield Company, which we refer to as ARCO. This acquisition included the Black Thunder and Coal Creek mines in the Powder River Basin of Wyoming, the West Elk mine in Colorado and a 65% interest in Canyon Fuel Company, which operates three mines in Utah. In October 1998, we acquired a leasehold interest in the Thundercloud reserve, a 412-million-ton federal reserve tract adjacent to the Black Thunder mine.

In July 2004, we acquired the remaining 35% interest in Canyon Fuel Company. In August 2004, we acquired Triton Coal Company's North Rochelle mine adjacent to our Black Thunder operation. In September 2004, we acquired a leasehold interest in the Little Thunder reserve, a 719-million-ton federal reserve tract adjacent to the Black Thunder mine.

In December 2005, we sold the stock of Hobet Mining, Inc., Apogee Coal Company and Catenary Coal Company and their four associated mining complexes (Hobet 21, Arch of West Virginia, Samples and Campbells Creek) and approximately 455.0 million tons of coal reserves in Central Appalachia to Magnum.

On October 1, 2009, we acquired Rio Tinto's Jacobs Ranch mine complex in the Powder River Basin of Wyoming, which included 345 million tons of low-cost, low-sulfur coal reserves, and integrated it into the Black Thunder mine.

On June 15, 2011, we acquired International Coal Group, Inc., which owned and operated mines primarily in the Appalachian Region of the United States.

Coal Characteristics

In general, end users characterize coal as steam coal or metallurgical coal. Heat value, sulfur, ash, moisture content, and volatility in the case of metallurgical coal, are important variables in the marketing and transportation of coal. These characteristics help producers determine the best end use of a particular type of coal. The following is a description of these general coal characteristics:

Heat Value. In general, the carbon content of coal supplies most of its heating value, but other factors also influence the amount of energy it contains per unit of weight. The heat value of coal is commonly measured in Btus. Coal is generally classified into four categories, ranging from lignite, subbituminous, bituminous and anthracite, reflecting the progressive response of individual deposits of coal to increasing heat and pressure. Anthracite is coal with the highest carbon content and, therefore, the highest heat value, nearing 15,000 Btus per pound. Bituminous coal, used primarily to generate electricity and to make coke for the steel industry, has a heat value ranging between 10,500 and 15,500 Btus per pound. Subbituminous coal ranges from 8,300 to 13,000 Btus per pound and is generally used for electric power generation. Lignite coal is a geologically young coal which has the lowest carbon content and a heat value ranging between 4,000 and 8,300 Btus per pound.

Sulfur Content. Federal and state environmental regulations, including regulations that limit the amount of sulfur dioxide that may be emitted as a result of combustion, have affected and may continue to affect the demand for certain types of coal. The sulfur content of coal can vary from seam to seam and within a single seam. The chemical composition and concentration of sulfur in coal affects the amount of sulfur dioxide produced in combustion. Coal-fueled power plants can comply with sulfur dioxide emission regulations by burning coal with low sulfur content, blending coals with various sulfur contents, purchasing emission allowances on the open market and/or using sulfur-dioxide emission reduction technology.

All of our identified coal reserves have been subject to preliminary coal seam analysis to test sulfur content. Of these reserves, approximately 67% consist of compliance coal, while an additional approximately 5% could be sold as low-sulfur coal. The balance is classified as high-sulfur coal. Higher sulfur coal can be burned in plants equipped with sulfur-dioxide emission reduction technology, such as scrubbers, and in facilities that blend compliance and noncompliance coal.

Ash. Ash is the inorganic residue remaining after the combustion of coal. As with sulfur, ash content varies from seam to seam. Ash content is an important characteristic of coal because it impacts boiler performance and electric generating plants must handle and dispose of ash following combustion. The composition of the ash, including the proportion of sodium oxide and fusion temperature, are important characteristics of coal and help determine the suitability of the coal to end users. The absence of ash is also important to the process by which metallurgical coal is transformed into coke for use in steel production.

Moisture. Moisture content of coal varies by the type of coal, the region where it is mined and the location of the coal within a seam. In general, high moisture content decreases the heat value and increases the weight of the coal, thereby making it more expensive to transport. Moisture content in coal, on an as-sold basis, can range from approximately 2% to over 30% of the coal's weight.

Other. Users of metallurgical coal measure certain other characteristics, including fluidity, swelling capacity and volatility to assess the strength of coke produced from a given coal or the amount of coke that certain types of coal will yield. These characteristics may be important elements in determining the value of the metallurgical coal we produce and market.

The Coal Industry

Global Coal Supply and Demand. Recovery from the 2008 upheaval in the global financial markets remained uneven in 2011 with future prospects uncertain because of ongoing sovereign debt problems, mostly centered in the European Union. Economic growth rates were also uneven with emerging economies continuing to show relative strength, while advanced economies generally experienced only modest growth. International coal demand continued to show strength through the year; however, there were some signs of weakness toward the end of the year. The

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United States exported an estimated 107 million tons in 2011, based on Energy Information Administration data, the highest level since 1991.

Coal is traded globally and can be transported to demand centers by ship, rail, barge, and truck. Total hard coal production in 2010 increased 6.8% over 2009 to 6.2 billion tonnes, while global production of brown coal was relatively flat at 1.04 billion tonnes in 2010, according to the International Energy Agency (IEA). China remains the largest producer of coal in the world, producing over 3.16 billion tonnes in 2010, according to the IEA. The United States and India follow China with hard coal production of approximately 932 million tonnes and 538 million tonnes, respectively, in 2010. Despite being the largest producer of hard coal globally, China surpassed Japan in 2011 as the largest importer of coal with imports of more than 180 million tonnes. Japan imported 175 million tonnes, followed by South Korea with 125 tonnes. Total global cross-border hard coal trade rose in 2011 to over 1.2 billion tons.

Global coal demand grew by more than 11% in 2010. Power generation remains the main driver of global coal demand as projected in all of the IEA's World Energy Outlook scenarios. China and India account for over 67% of the projected demand increase in the IEA's New and Current Policies scenarios. Metallurgical or coking coal is used in the steel making process. The steel industry uses metallurgical coal, which is distinguishable from other types of coal by its high carbon content, low expansion pressure, low sulfur content and various other chemical attributes. As such, the price offered by steel makers for metallurgical coal is generally higher than the price offered by power plants and industrial users for steam coal. Coal is used in nearly 70% of global steel production. In 2011, approximately 1.5 billion tonnes of steel was produced, a 6.8% increase over 2010 and up nearly 23% over 2009's reduced levels.

Among the nations principally supplying coal to the global power and steel markets are Australia, historically the world's largest coal exporter with exports of approximately 300 million tonnes in 2010, as well as Indonesia, Russia, United States, Colombia, and South Africa. Indonesia, in particular, has seen substantial growth in its coal exports in the last few years; however, its growing domestic energy demand may result in a decrease in exports as it moves toward greater self-sufficiency. Total United States exports continued to grow in 2011 as discussed below, up approximately 30% over 2010 as global economic conditions improved and pressure remained on global coal supply networks. We expect continued improvements in the demand for U.S. coal exports as economic growth continues, especially in the Asia-Pacific region, and as traditional supply movements adjust to meet the Asia-Pacific region's demands.

U.S. Coal Consumption. In the United States, coal is used primarily by power plants 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 or processing facilities. Coal consumption in the United States increased from 398.1 million tons in 1960 to approximately 1.0 billion tons in 2011, according to the Energy Information Administration's (EIA) Short Term Energy Outlook. Although full-year data for 2011 is not yet available, coal consumption has improved over what was lost during the global downturn that affected U.S. coal consumption in 2009. In 2010, coal consumption in the United States improved through stronger electricity demand driven by both a recovering economy and favorable weather.

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The following chart shows historical and projected demand trends for U.S. coal by consuming sector for the periods indicated, according to the EIA:

Sector	Actual 2006	Estimated 2011	Forecast 2012	Forecast 2020	Forecast 2035	Annual Growth 2009-2035
	(Tons, in millions)					
Electric power	1,027	945	925	989	1,119	0.7%
Other industrial	59	49	48	49	47	0.1%
Coke plants	23	24	24	22	18	0.6%
Residential/commercial	3	3	4	3	3	-0.2%
Coal-to-liquids				13	128	n/a
Total U.S. coal consumption	1,112	1,020	1,002	1,076	1,315	1.1%

Source: EIA Annual Energy Outlook 2011
EIA Short Term Energy Outlook (January 2012)
EIA Monthly Energy Review (December 2011)

According to the EIA, coal accounted for approximately 42% of U.S. electricity generation from January through November 2011, and based on a projected 25% growth in electricity demand, coal consumption by the electric industry is expected to grow about 18% by 2035, reaching 1.1 billion tons. These amounts assume no future federal or state carbon emissions legislation is enacted and do not take into account subsequent market conditions. Historically, coal has been considerably less expensive than natural gas or oil.

The following chart shows the breakdown of U.S. electricity generation by energy source for January through November 2011, according to the EIA:

Source: EIA Electric Power Monthly (January 2012).

The average spot price for West Texas Intermediate oil in the United States averaged $94.86/barrel in 2011, and, according to the EIA, will increase to $100.25/barrel in 2012. Historically, volatile oil prices and global energy security concerns have increased interest in converting coal into liquid fuel, a process known as liquefaction. Liquid fuel produced from coal can be further refined to produce transportation fuels, such as low-sulfur diesel fuel, gasoline and other oil products, such as plastics and solvents. Currently, there are only a limited number of projects moving forward at this time.

U.S. Coal Production. The United States is the second largest coal producer in the world, exceeded only by China. According to the EIA, there is over 200 billion tons of recoverable coal in the United States. The U.S. Department of Energy estimates that current domestic recoverable coal reserves could supply enough electricity to

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satisfy domestic demand for approximately 200 years. Annual coal production in the United States has increased from 434 million tons in 1960 to approximately 1.1 billion tons in 2011.

Coal is mined from coal fields throughout the United States, with the major production centers located in the western United States, the Appalachian region and the Illinois Basin.

Major regions in the West include the Powder River Basin and the Western Bituminous region. According to the EIA, coal produced in the western United States increased from 408 million tons in 1994 to an estimated 638 million tons in 2011, as competitive mining costs and regulations limiting sulfur-dioxide emissions have continued to increase demand for low-sulfur coal over this period. The Powder River Basin is located in northeastern Wyoming and southeastern Montana. Coal from this region is sub-bituminous coal with low sulfur content ranging from 0.2% to 0.9% and heating values ranging from 8,000 to 9,500 Btu. The price of Powder River Basin coal is generally less than that of coal produced in other regions because Powder River Basin coal exists in greater abundance and is easier to mine and, thus, has a lower cost of production. In addition, Powder River Basin coal is generally lower in heat value, which requires some electric power generation facilities to blend it with higher Btu coal or retrofit some existing coal plants to accommodate lower Btu coal. The Western Bituminous region includes Colorado, Utah and southern Wyoming. Coal from this region typically has low sulfur content ranging from 0.4% to 0.8% and heating values ranging from 10,000 to 12,200 Btu.

Regions in the East include the north, central and southern Appalachian regions. According to the EIA, coal produced in the Appalachian region decreased from 445 million tons in 1994 to an estimated 339 million tons in 2011, primarily as a result of the depletion of economically attractive reserves, permitting issues, availability of lower cost competitive fuels, and increasing costs of production. Central Appalachia includes eastern Kentucky, Tennessee, Virginia and southern West Virginia. Coal mined from this region generally has a high heat value ranging from 11,400 to 13,200 Btu and a low sulfur content ranging from 0.2% to 2.0%. Northern Appalachia includes Maryland, Ohio, Pennsylvania and northern West Virginia. Coal from this region generally has a high heat value ranging from 10,300 to 13,500 Btu and a high sulfur content ranging from 0.8% to 4.0%. Southern Appalachia primarily covers Alabama and generally has a heat content ranging from 11,300 to 12,300 Btu and a sulfur content ranging from 0.7% to 3.0%.

The Illinois Basin includes Illinois, Indiana and western Kentucky and is the major coal production center in the interior region of the United States. According to the EIA, coal produced in the interior region decreased from 180 million tons in 1994 to approximately 166 million tons in 2011. Coal from the Illinois Basin generally has a heat value ranging from 10,100 to 12,600 Btu and has a high sulfur content ranging from 1.0% to 4.3%. Despite its high sulfur content, coal from the Illinois basin can generally be used by electric power generation facilities that have installed pollution control devices, such as scrubbers, to reduce emissions.

U.S. Coal Exports and Imports. U.S exports increased substantially in 2011 compared to 2010, supported by recovering global economies and continued growth in Chinese and Indian steel markets in particular. According to the EIA, exports of U.S. coal grew from 81 million tons in 2010 to 107 million tons in 2011. This is a trend we expect to continue as demand for U.S. coal grows in the seaborne market. Interest in access to the coal markets overseas has fueled considerable growth in developing new port capacity in the United States. We, along with other parties, have announced expanded or new port projects on the east coast, the Gulf coast and the west coast.

Historically, coal imported from abroad has represented a relatively small share of total U.S. coal consumption, and this remained the case in 2011. Imports did reach close to 36 million tons in 2007, but have fallen since then. According to the EIA, coal imports declined from 19 million tons in 2010 to 14 million in 2011. The decline is mostly attributed to more competitive pricing for domestic coal and stronger demand from non-U.S. markets for seaborne coal. Coal is imported into the United States primarily from Colombia, Indonesia and Venezuela. Imported coal generally serves coastal states along the Gulf of Mexico, such as Alabama and Florida, and states along the eastern seaboard. We expect imports into the United States to continue to decrease in the near-term as more and more global coal will likely be directed to Asia.

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Coal Mining Methods

The geological characteristics of our coal reserves largely determine the coal mining method we employ. We use two primary methods of mining coal: surface mining and underground mining.

Surface Mining. We use surface mining when coal is found close to the surface. We have included the identity and location of our surface mining operations below under "Our Mining Operations General." In 2011, approximately 81% of the coal that we produced came from surface mining operations.

Surface mining involves removing the topsoil then drilling and blasting the overburden (earth and rock covering the coal) with explosives. We then remove the overburden with heavy earth-moving equipment, such as draglines, power shovels, excavators and loaders. Once exposed, we drill, fracture and systematically remove the coal using haul trucks or conveyors to transport the coal to a preparation plant or to a loadout facility. We reclaim disturbed areas as part of our normal mining activities. After final coal removal, we use draglines, power shovels, excavators or loaders to backfill the remaining pits with the overburden removed at the beginning of the process. Once we have replaced the overburden and topsoil, we reestablish vegetation and plant life into the natural habitat and make other improvements that have local community and environmental benefits.

The following diagram illustrates a typical dragline surface mining operation:

Underground Mining. We use underground mining methods when coal is located deep beneath the surface. We have included the identity and location of our underground mining operations in the table "Our Mining Operations General." In 2011, approximately 19% of the coal that we produced came from underground mining operations.

Our underground mines are typically operated using one or both of two different mining techniques: longwall mining and room-and-pillar mining.

Longwall Mining. Longwall mining involves using a mechanical shearer to extract coal from long rectangular blocks of medium to thick seams. Ultimate seam recovery using longwall mining techniques can exceed 75%. In

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longwall mining, we use continuous miners to develop access to these long rectangular coal blocks. Hydraulically powered supports temporarily hold up the roof of the mine while a rotating drum mechanically advances across the face of the coal seam, cutting the coal from the face. Chain conveyors then move the loosened coal to an underground mine conveyor system for delivery to the surface. Once coal is extracted from an area, the roof is allowed to collapse in a controlled fashion. In 2011, approximately 14% of the coal that we produced came from underground mining operations generally using longwall mining techniques.

The following diagram illustrates a typical underground mining operation using longwall mining techniques:

Room-and-Pillar Mining. Room-and-pillar mining is effective for small blocks of thin coal seams. In room-and-pillar mining, we cut a network of rooms into the coal seam, leaving a series of pillars of coal to support the roof of the mine. We use continuous miners to cut the coal and shuttle cars to transport the coal to a conveyor belt for further transportation to the surface. The pillars generated as part of this mining method can constitute up to 40% of the total coal in a seam. Higher seam recovery rates can be achieved if retreat mining is used. In retreat mining, coal is mined from the pillars as workers retreat. As retreat mining occurs, the roof is allowed to collapse in a controlled fashion. We currently conduct retreat mining in certain underground mines. In 2011, the quantities of coal we recovered from retreat mining represented an insignificant portion of our total coal production. Once we finish mining in an area, we generally abandon that area and seal it from the rest of the mine.

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The following diagram illustrates our typical underground mining operation using room-and-pillar mining techniques:

Coal Preparation and Blending. We crush the coal mined from our Powder River Basin mining complexes and ship it directly from our mines to the customer. Typically, no additional preparation is required for a saleable product. Coal extracted from some of our underground mining operations contains impurities, such as rock, shale and clay occupying in a wide range of particle sizes. The majority of our mining operations in the Appalachia region and a few of our mines in the Western Bituminous region use a coal preparation plant located near the mine or connected to the mine by a conveyor. These coal preparation plants allow us to treat the coal we extract from those mines to ensure a consistent quality and to enhance its suitability for particular end-users. In addition, depending on coal quality and customer requirements, we may blend coal mined from different locations, including coal produced by third parties, in order to achieve a more suitable product.

The treatments we employ at our preparation plants depend on the size of the raw coal. For coarse material, the separation process relies on the difference in the density between coal and waste rock where, for the very fine fractions, the separation process relies on the difference in surface chemical properties between coal and the waste minerals. To remove impurities, we crush raw coal and classify it into various sizes. For the largest size fractions, we use dense media vessel separation techniques in which we float coal in a tank containing a liquid of a pre-determined specific gravity. Since coal is lighter than its impurities, it floats, and we can separate it from rock and shale. We treat intermediate sized particles with dense medium cyclones, in which a liquid is spun at high speeds to separate coal from rock. Fine coal is treated in spirals, in which the differences in density between coal and rock allow them, when suspended in water, to be separated. Ultra fine coal is recovered in column flotation cells utilizing the differences in surface chemistry between coal and rock. By injecting stable air bubbles through a suspension of ultra fine coal and rock, the coal particles adhere to the bubbles and rise to the surface of the column where they are removed. To minimize the moisture content in coal, we process most coal sizes through centrifuges. A centrifuge spins coal very quickly, causing water accompanying the coal to separate.

For more information about the locations of our preparation plants, you should see the section entitled "Our Mining Operations" below.

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Our Mining Operations

General. At December 31, 2011, we operated, or contracted out the operation of, 46 mines in the United States. We have three reportable business segments, which are based on the major coal producing basins in which the Company operates. The Company's reportable segments are the Powder River Basis (PRB) segment, with operations in Wyoming; the Western Bituminous (WBIT) segment, with operations in Utah, Colorado and southern Wyoming; the Appalachia (APP) segment, with operations in West Virginia, Kentucky, Maryland and Virginia; and our Other segment, which includes our operations in Illinois. Each of these reportable business segments includes a number of mine complexes. Geology, coal transportation routes to consumers, regulatory environments and coal quality are characteristic to a basin. These regional distinctions have caused market and contract pricing environments to develop by coal region and form the basis for the segmentation of our operations. We incorporate by reference the information about the operating results of each of our segments for the years ended December 31, 2011, 2010 and 2009 contained in Note 24 beginning on page F-45.

In general, we have developed our mining complexes and preparation plants at strategic locations in close proximity to rail or barge shipping facilities. Coal is transported from our mining complexes to customers by means of railroads, trucks, barge lines, and ocean-going vessels from terminal facilities. We currently own or lease under long-term arrangements a substantial portion of the equipment utilized in our mining operations. We employ sophisticated preventative maintenance and rebuild programs and upgrade our equipment to ensure that it is productive, well-maintained and cost-competitive. Our maintenance programs also employ procedures designed to enhance the efficiencies of our operations.

The following map shows the locations of our mining operations:

The following table provides a summary of information regarding our active mining complexes at December 31, 2011, the total sales associated with these complexes for the years ended December 31, 2009, 2010 and 2011, the total reserves associated with these complexes at December 31, 2011 and the Company's total

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unassigned reserves as of December 31, 2011. As indicated by the footnotes included in the table below, certain of the mining complexes listed below were acquired by us on June 15, 2011 as a result of our acquisition of International Coal Group, Inc. The amount disclosed below for the total cost of property, plant and equipment of each mining complex does not include the costs of the coal reserves that we have assigned to an individual complex. The information included in the following table describes in more detail our mining operations, the coal mining methods used, certain characteristics of our coal and the method by which we transport coal from our mining operations to our customers or other third parties.

Mining Complex	Captive Mines(1)	Contract Mines(1)	Mining Equipment	Railroad	Tons Sold(2) 2009	Tons Sold(2) 2010	Tons Sold(2) 2011	Total Cost of Property, Plant and Equipment at December 31, 2011	Assigned Reserves (Million tons)
					(Million tons)			($ in millions)	
Powder River Basin:									
Black Thunder	S		D, S	UP/BN	81.2	116.2	104.9	$1,147.4	1,298.0
Coal Creek	S		D, S	UP/BN	9.8	11.4	10.0	155.5	176.2
Western Bituminous:									
Arch of Wyoming	S		L	UP	0.1	0.1	0.1	22.7	
Dugout Canyon	U		LW, CM	UP	3.2	2.3	2.2	140.5	15.0
Skyline	U		LW, CM	UP	2.8	2.9	2.9	189.3	15.2
Sufco	U		LW, CM	UP	6.6	6.1	6.1	232.1	48.6
West Elk	U		LW, CM	UP	4.0	4.8	5.7	480.0	88.3
Appalachia:									
Coal-Mac	S	U	L, E	NS/CSX	2.9	3.2	3.3	188.1	28.3
Cumberland River	S, U(2)	U(3)	L, CM, HW	NS	1.6	1.5	2.2	181.3	28.5
Lone Mountain	U(4)		CM	NS/CSX	2.2	2.1	2.4	249.6	34.4
Mountain Laurel	U	S(2)	L, LW, CM	CSX	4.4	5.1	4.0	489.4	78.0
Eastern*	S, U		L, E, CM	CSX	N/A	N/A	0.8	61.6	8.4
Hazard/Flint Ridge*	S(4), U		L, S, CM	CSX	N/A	N/A	2.2	132.0	65.2
Knott County/Raven*	U(5)		CM	CSX	N/A	N/A	0.7	110.4	30.2
East Kentucky*	S		L	NS	N/A	N/A	0.3	25.5	1.2
Beckley*	U		CM	CSX	N/A	N/A	0.6	85.6	27.5
Vindex *	S(4), U		L, S	CSX	N/A	N/A	0.6	76.4	18.0
Patriot*	S		L	NS/CSX	N/A	N/A	0.3	29.2	4.1
Imperial*	U		CM	CSX	N/A	N/A	0.3	23.6	26.3
Sycamore No. 2*		U	CM	CSX	N/A	N/A	0.2	9.9	9.3
Sentinel*	U		CM	CSX	N/A	N/A	0.6	48.8	14.2
Tygart Valley*			CM, LW	CSX				77.5	166.0
Illinois:									
Viper*	U		CM		N/A	N/A	1.1	66.7	30.0
Totals					118.8	155.7	151.5	$4,223.1	2,210.9(3)

S = Surface mine	D = Dragline	UP = Union Pacific Railroad
U = Underground mine	L = Loader/truck	CSX = CSX Transportation
	S = Shovel/truck	BN = Burlington Northern-Santa Fe Railway
	E = Excavator/truck	NS = Norfolk Southern Railroad
	LW = Longwall	

CM = Continuous miner
HW = Highwall miner

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* Mining complex acquired on June 15, 2011 in connection with our acquisition of International Coal Group, Inc. The above table only shows tons sold from these mining complexes after June 14, 2011, and does not include tons sold by the prior owner in 2009, 2010 or 2011.

(1) Amounts in parentheses indicate the number of captive and contract mines at the mining complex at December 31, 2011. Captive mines are mines that we own and operate on land owned or leased by us. Contract mines are mines that other operators mine for us under contracts on land owned or leased by us.

(2) Tons of coal we purchased from third parties that were not processed through our loadout facilities are not included in the amounts shown in the table above.

(3) Total assigned reserves does not include reserves assigned to non-active mining complexes.

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Powder River Basin

Black Thunder. Black Thunder is a surface mining complex located on approximately 34,500 acres in Campbell County, Wyoming. The Black Thunder complex extracts steam coal from the Upper Wyodak and Main Wyodak seams.

We control a significant portion of the coal reserves through federal and state leases. The Black Thunder mining complex had approximately 1.3 billion tons of proven and probable reserves at December 31, 2011. The air quality permit for the Black Thunder mine allows for the mining of coal at a rate of 190 million tons per year. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2021 before annual output starts to significantly decline, although in practice production would drop in phases extending the ultimate mine life. Several large tracts of coal adjacent to the Black Thunder mining complex have been nominated for lease, and other potential large areas of unleased coal remain available for nomination by us or other mining operations. The U.S. Department of Interior Bureau of Land Management, which we refer to as the BLM, will determine if the tracts will be leased and, if so, the final boundaries of, and the coal tonnage for, these tracts.

The Black Thunder mining complex currently consists of seven active pit areas and three loadout facilities. We ship all of the coal raw to our customers via the Burlington Northern-Santa Fe and Union Pacific railroads. We do not process the coal mined at this complex. Each of the loadout facilities can load a 15,000-ton train in less than two hours.

Coal Creek. Coal Creek is a surface mining complex located on approximately 7,400 acres in Campbell County, Wyoming. The Coal Creek mining complex extracts steam coal from the Wyodak-R1 and Wyodak-R3 seams.

We control a significant portion of the coal reserves through federal and state leases. The Coal Creek mining complex had approximately 176.2 million tons of proven and probable reserves at December 31, 2011. The air quality permit for the Coal Creek mine allows for the mining of coal at a rate of 50 million tons per year. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2025 before annual output starts to significantly decline. One tract of coal adjacent to the Coal Creek mining complex has been nominated for lease, and other potential areas of unleased coal remain available for nomination by us or other mining operations. The BLM will determine if these tracts will be leased and, if so, the final boundaries of, and the coal tonnage for, these tracts.

The Coal Creek complex currently consists of two active pit areas and a loadout facility. We ship all of the coal raw to our customers via the Burlington Northern-Santa Fe and Union Pacific railroads. We do not process the coal mined at this complex. The loadout facility can load a 15,000-ton train in less than three hours.

Western Bituminous

Arch of Wyoming. Arch of Wyoming is a surface mining complex located in Carbon County, Wyoming. The complex currently consists of one active surface mine and four inactive mines located on approximately 55,100 acres that are in the final process of reclamation and bond release. The Arch of Wyoming mining complex extracts coal from the Johnson seam.

We control a significant portion of the coal reserves associated with this complex through federal, state and private leases. We currently do not have any tons assigned to the Arch of Wyoming mining operations. The air quality permit for the active Arch of Wyoming mining operation allows for the mining of coal at a rate of 2.5 million tons per year.

Dugout Canyon. Dugout Canyon mine is an underground mining complex located on approximately 18,600 acres in Carbon County, Utah. The Dugout Canyon mining complex has extracted steam coal from the Rock Canyon and Gilson seams.

We control a significant portion of the coal reserves through federal and state leases. The Dugout Canyon mining complex had approximately 15.0 million tons of proven and probable reserves at December 31, 2011. The coal seam currently being mined could sustain current production levels until approximately 2014, at which point we will need to transition to another coal seam to continue mining. We currently plan on idling longwall operations at the end of the current panel during the first quarter of 2012.

The complex currently consists of a longwall, two continuous miner sections and a truck loadout facility. We ship all of the coal to our customers via the Union Pacific railroad or by highway trucks. We wash a portion of the coal we produce at a 400-ton-per-hour preparation plant. The loadout facility can load approximately 20,000 tons of coal per day into highway trucks. Coal shipped by rail is loaded through a third-party facility capable of loading an 11,000-ton train in less than three hours.

Skyline. Skyline is an underground mining complex located on approximately 13,200 acres in Carbon and Emery Counties, Utah. The Skyline mining complex extracts steam coal from the Lower O'Conner A seam.

We control a significant portion of the coal reserves through federal leases and smaller portions through county and private leases. The Skyline mining complex had approximately 15.2 million tons of proven and probable reserves at December 31, 2011. The reserve area currently being mined could sustain current production levels through mid-2012, at which point we plan to transition to a new reserve area in order to continue mining.

The Skyline complex currently consists of a longwall, two continuous miner section and a loadout facility. We ship most of the coal raw to our customers via the Union Pacific railroad or by highway trucks. We process a portion of the coal mined at this complex at a nearby preparation plant. The loadout facility can load a 12,000-ton train in less than four hours.

Sufco. Sufco is an underground mining complex located on approximately 25,700 acres in Sevier County, Utah. The Sufco mining complex extracts steam coal from the Upper Hiawatha seam.

We control a significant portion of the coal reserves through federal and state leases. The Sufco mining complex had approximately 48.6 million tons of proven and probable reserves at December 31, 2011. The coal seam currently being mined could sustain current production levels through 2020, at which point a new coal seam will have to be accessed in order to continue mining.

The Sufco complex currently consists of a longwall, three continuous miner sections and a loadout facility located approximately 80 miles from the mine. We ship all of the coal raw to our customers via the Union Pacific railroad or by highway trucks. Processing at the mine site consists of crushing and sizing. The rail loadout facility is capable of loading an 11,000-ton train in less than three hours.

West Elk. West Elk is an underground mining complex located on approximately 17,800 acres in Gunnison County, Colorado. The West Elk mining complex extracts steam coal from the E seam.

We control a significant portion of the coal reserves through federal and state leases. The West Elk mining complex had approximately 88.3 million tons of proven and probable reserves at December 31, 2011. Without the addition of more coal reserves, the current reserves could sustain current production levels through 2021 before annual output starts to significantly decline.

The West Elk complex currently consists of a longwall, two continuous miner sections and a loadout facility. We ship most of the coal raw to our customers via the Union Pacific railroad. In 2010, we finished constructing a new coal preparation plant with supporting coal handling facilities at the West Elk mine site. The loadout facility can load an 11,000-ton train in less than three hours.

Appalachia

Coal-Mac. Coal-Mac is a surface and underground mining complex located on approximately 46,800 acres in Logan and Mingo Counties, West Virginia. Surface mining operations at the Coal-Mac mining complex extract steam coal primarily from the Coalburg and Stockton seams. Underground mining operations at the Coal-Mac mining complex extract steam coal from the Coalburg seam.

We control a significant portion of the coal reserves through private leases. The Coal-Mac mining complex had approximately 28.3 million tons of proven and probable reserves at December 31, 2011. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2018 before annual output starts to significantly decline.

The complex currently consists of one captive surface mine, one contract underground mine, a preparation plant and two loadout facilities, which we refer to as Holden 22 and Ragland. We ship coal trucked to the Ragland loadout facility directly to our customers via the Norfolk Southern railroad. The Ragland loadout facility can load a 10,000-ton train in less than four hours. We ship coal trucked to the Holden 22 loadout facility directly to our customers via the CSX railroad. We wash all of the coal transported to the Holden 22 loadout facility at an adjacent 600-ton-per-hour preparation plant. The Holden 22 loadout facility can load a 10,000-ton train in about four hours.

Cumberland River. Cumberland River is an underground and surface mining complex located on approximately 19,900 acres in Wise County, Virginia and Letcher County, Kentucky. Surface mining operations at the Cumberland River mining complex extract steam and metallurgical coal from approximately 20 different coal seams from the Imboden seam to the High Splint No. 14 seam. Underground mining operations at the Cumberland River mining complex extract steam and metallurgical coal from the Imboden, Taggart Marker, Middle Taggart, Upper Taggart, Owl, and Parsons seams.

We control a significant portion of the coal reserves through private leases. The Cumberland River mining complex had approximately 28.5 million tons of proven and probable reserves at December 31, 2011. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2022 before annual output starts to significantly decline.

The complex currently consists of five underground mines (two captive, three contract) operating seven continuous miner sections, one captive surface operation, one captive highwall miner, a preparation plant and a loadout facility. We ship approximately one-third of the coal raw. We process the remaining two-thirds of the coal through a 750-ton-per-hour preparation plant before shipping it to our customers via the Norfolk Southern railroad. The loadout facility can load a 12,000-ton train in about four hours.

Lone Mountain. Lone Mountain is an underground mining complex located on approximately 54,000 acres in Harlan County, Kentucky and Lee County, Virginia. The Lone Mountain mining complex extracts steam and metallurgical coal from the Kellioka, Darby and Owl seams.

We control a significant portion of the coal reserves through private leases. The Lone Mountain mining complex had approximately 34.4 million tons of proven and probable reserves at December 31, 2011. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2023 before annual output starts to significantly decline.

The complex currently consists of four underground mines operating a total of nine continuous miner sections. We process coal through a 1,200-ton-per-hour preparation plant. We then ship the coal to our customers via the Norfolk Southern or CSX railroad. The loadout facility can load a 12,500-ton unit train in less than four hours.

Mountain Laurel. Mountain Laurel is an underground and surface mining complex located on approximately 38,300 acres in Logan County and Boone County, West Virginia. Underground mining operations at the Mountain Laurel mining complex extract steam and metallurgical coal from the Cedar Grove and Alma seams. Surface mining operations at the Mountain Laurel mining complex extract coal from a number of different splits of the Five Block, Stockton and Coalburg seams.

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We control a significant portion of the coal reserves through private leases. The Mountain Laurel mining complex had approximately 78.0 million tons of proven and probable reserves at December 31, 2011. The longwall mine is expected to operate through at least 2018 and potentially longer. In addition, the existing reserve base should support continuous miner operations for many years beyond that date.

The complex currently consists of one underground mine operating a longwall and a total of four continuous miner sections, two contract surface operations, a preparation plant and a loadout facility. We process most of the coal through a 2,100-ton-per-hour preparation plant before shipping the coal to our customers via the CSX railroad. The loadout facility can load a 15,000-ton train in less than four hours.

Eastern. Eastern operates one surface mine and one underground mine, located on approximately 21,000 acres in Webster and Nicholas County, West Virginia. The Eastern complex is surface mining coal from the Freeport, Upper Kittanning, Middle Kittanning, Upper Clarion and Lower Clarion coal seams, and deep mining coal from the Stockton seam.

We control a significant portion of the coal reserves through private leases. The Eastern mining complex had approximately 8.4 million tons of proven and probable reserves at December 31, 2011. The mine is expected to operate through at least 2017.

Approximately twenty percent of the production from the surface mine is shipped direct, while the other eighty percent is washed at the complex's 700 ton-per-hour preparation plant. Coal is transported by conveyor belt from the preparation plant to the rail loadout, which is served by CSX via the A&O Railroad, a short-line carrier that is partially owned by CSX.

Hazard/Flint Ridge. Hazard/Flint Ridge is a mining complex that consists of four surface mines, an underground mining complex, a preparation plant, a unit train loadout and other support facilities located on approximately 115,000 acres in eastern Kentucky. The coal from Hazard's mines is being extracted from the Hazard 10, Hazard 9, Hazard 8, Hazard 7 and Hazard 5A seams. Nearly all of the surface-mined coal is marketed as a blend of shipped direct product with the remainder being processed at the Flint Ridge preparation plant. The underground coal is all processed. Coal is transported by on-highway trucks from the mines to the rail loadout, which is served by CSX. Some coal is direct shipped to the customer by truck.

A majority of the coal reserves are owned; the remainder are held through private leases. The mining complex had approximately 65.2 million tons of proven and probable reserves at December 31, 2011, which could sustain current production levels until at least 2030. The loadout facility can load a 12,500-ton train in less than 4 hours.

Knott County/Raven. Knott County operates five underground mines, two preparation plants, two rail loadouts and other facilities necessary to support the mining operations located on approximately 41,000 acres in Knott County, Kentucky. The mining complex is producing coal from the Elkhom 2, Elkhorn 3 and Amburgy coal seams. All of Knott County's coal is transported by rail from two loadouts served by CSX.

We control a significant portion of the coal reserves through private leases. As of December 31, 2011 we had approximately 30.2 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until at least 2030.

East Kentucky. East Kentucky is a surface mining operation located on approximately 13,500 acres in Martin and Pike Counties, Kentucky, near the Tug Fork River. East Kentucky consists of one surface mine and one loadout facility. The loadout is serviced by Norfolk Southern railroad. The East Kentucky mining complex extracts coal from the Taylor, Coalburg, Winifrede, Buffalo and Stockton coal seams.

We control the coal reserves assigned to the East Kentucky mining complex through private leases. As of December 31, 2011 we had approximately 1.2 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2014.

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Beckley. The Beckley mining complex is located on approximately 23,400 acres in Raleigh County, West Virginia. Beckley is extracting high quality, low-volatile metallurgical coal in the Pocahontas No. 3 seam.

A significant portion of the coal reserves are controlled through private leases. As of December 31, 2011 we had approximately 27.5 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2030. Coal is belted from the mine to a 600-ton-per-hour preparation plant before shipping the coal via the CSX railroad. The loadout facility can load a 10,000-ton train in less than four hours.

Vindex. The Vindex mining complex consists of four surface mines located on approximately 42,400 acres in Garrett and Allegany Counties, Maryland. Mining operations at these surface mines extract coal from the Upper Freeport, Middle Kittanning, Pittsburgh, Little Pittsburgh and Redstone seams. In addition, Vindex operates one underground mine, in the Bakerstown seam of coal, and a preparation plant located in Grant and Tucker Counties, West Virginia.

We control all of the coal reserves through private leases. As of December 31, 2011 we had approximately 17.9 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until at least 2025.

Patriot. The Patriot mining complex consists of one surface mine and loadout facility located on approximately 3,200 acres in Monongalia County, West Virginia. Mining operations extract coal from the Waynesburg seam.

All of the coal reserves are controlled through private leases. As of December 31, 2011 we had approximately 4.1 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2017.

Imperial. The Imperial mining complex is an active underground mine located on approximately 59,500 acres in Upshur County, West Virginia. Mining operations extract coal from the Middle Kittanning seam. The coal is processed through the Sawmill Run preparation plant and shipped by CSX rail to customers.

As of December 31, 2011, the Imperial mining complex had approximately 26.3 million tons of proven and probable reserves. Without the addition of additional coal reserves, the reserves could sustain current production levels until 2055.

Sycamore No. 2. The Sycamore No. 2 mining complex is an active underground mine operated by a contract miner located on approximately 8,900 acres in Harrison County, West Virginia. Mining operations extract coal from the Pittsburgh seam. The coal produced by this mining complex is sold on a raw basis and is transported to current customers by truck.

As of December 31, 2011, the Sycamore No. 2 mining complex had approximately 9.3 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2028.

Sentinel. The Sentinel mining complex consists of one underground mine, a preparation plant and a loadout facility located in Barbour County, West Virginia. Mining operations currently extract coal from the Clarion coal seam. Coal from the Sentinel mining complex is processed through the preparation plant and shipped by CSX rail to customers.

We control a significant portion of the Clarion seam coal reserves through private leases,. As of December 31, 2011 we had approximately 14.2 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2021.

Tygart Valley. The Tygart Valley property, located in Taylor County, West Virginia included approximately 165.9 million tons of deep coal reserves as of December 31, 2011 of both steam and metallurgical quality coal in the Lower Kittanning seam, covering approximately 68,300 acres.

Construction of the Tygart Valley mining complex began in June 2010 and initial coal production commenced in November, 2011. At full output, Tygart Valley is designed to have 3.5 million tons of capacity per year of high quality coal that is well suited to both the utility market and the high volatile metallurgical market.

Illinois

Viper. Viper mining complex consists of one underground coal mine and a preparation plant located on approximately 43,500 acres in central Illinois near the city of Springfield. Mining operations extract coal from the Illinois No. 5 seam, also referred to as the Springfield seam.

We control a signification portion of the coal reserves through private leases. As of December 31, 2011 we had approximately 30 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2026.

Sales, Marketing and Trading

Overview. Coal prices are influenced by a number of factors and vary materially by region. As a result of these regional characteristics, prices of coal by product type within a given major coal producing region tend to be relatively consistent with each other. The price of coal within a region is influenced by market conditions, coal quality, transportation costs involved in moving coal from the mine to the point of use and mine operating costs. For example, higher carbon and lower ash content generally result in higher prices, and higher sulfur and higher ash content generally result in lower prices within a given geographic region.

The cost of coal at the mine is also influenced by geologic characteristics such as seam thickness, overburden ratios and depth of underground reserves. It is generally cheaper to mine coal seams that are thick and located close to the surface than to mine thin underground seams. Within a particular geographic region, underground mining, which is the primary mining method we use in the Western Bituminous region and for certain of our Appalachian mines, is generally more expensive than surface mining, which is the mining method we use in the Powder River Basin, and for certain of our Appalachian mines and a Western Bituminous mine. This is the case because of the higher capital costs, including costs for construction of extensive ventilation systems, and higher per unit labor costs due to lower productivity associated with underground mining.

Our sales, marketing and trading functions are principally based in St. Louis, Missouri and consist of sales and trading, transportation and distribution, quality control and contract administration personnel as well as revenue management. We also have smaller groups of sales personnel in our Singapore and London offices. In addition to selling coal produced in our mining complexes, from time to time we purchase and sell coal mined by others, some of which we blend with coal produced from our mines. We focus on meeting the needs and specifications of our customers rather than just selling our coal production.

Customers. The Company markets its steam and metallurgical coal to domestic and foreign utilities and steel producers as well as industrial facilities. For the year ended December 31, 2011, we derived approximately 15% of our total coal revenues from sales to our three largest customers Tennessee Valley Authority, Donau Brennstoffkontor GmbH, and U.S. Steel and approximately 37% of our total coal revenues from sales to our 10 largest customers.

In 2011, we sold coal to domestic customers located in 39 different states. The locations of our mines enable us to ship coal to most of the major coal-fueled power plants in the United States.

In addition, in 2011 we also exported coal to North America, Europe, South America and Asia. Exports to foreign countries were $920.0 million, $471.5 million and $194.4 million for the years ended December 31, 2011,

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2010 and 2009, respectively. The increasing export revenues are primarily the result of an increase in metallurgical-quality coal sales volumes, although steam coal exports have also increased. As of December 31, 2011 and 2010, trade receivables related to metallurgical-quality coal sales totaled $117.4 million and $24.9 million, respectively, or 31% and 12%, of total trade receivables, respectively. We do not have foreign currency exposure for our international sales as all sales are denominated and settled in U.S. dollars.

The Company's foreign revenues by coal destination for the year ended December 31, 2011, were as follows:

	December 31, 2011 (In thousands)
Europe	$ 427,514
South America	120,842
North America	97,255
Asia	61,308
Brokered sales	213,087
Total	$ 920,006

Long-Term Coal Supply Arrangements

As is customary in the coal industry, we enter into fixed price, fixed volume long-term supply contracts, the terms of which are more than one year, with many of our customers. Multiple year contracts usually have specific and possibly different volume and pricing arrangements for each year of the contract. Long-term contracts allow customers to secure a supply for their future needs and provide us with greater predictability of sales volume and sales prices. In 2011, we sold approximately 72% of our coal under long-term supply arrangements. The majority of our supply contracts include a fixed price for the term of the agreement or a pre-determined escalation in price for each year. Some of our long-term supply agreements may include a variable pricing system. While most of our sales contracts are for terms of one to five years, some are as short as one month and other contracts have terms up to nine years. At December 31, 2011, the average volume-weighted remaining term of our long-term contracts was approximately 2.69 years, with remaining terms ranging from one to seven years. At December 31, 2011, remaining tons under long-term supply agreements, including those subject to price re-opener or extension provisions, were approximately 259 million tons.

We typically sell coal to customers under long-term arrangements through a "request-for-proposal" process. The terms of our coal sales agreements result from competitive bidding and negotiations with customers. Consequently, the terms of these contracts vary by customer, including base price adjustment features, price re-opener terms, coal quality requirements, quantity parameters, permitted sources of supply, future regulatory changes, extension options, *force majeure*, termination, damages and assignment provisions. Our long-term supply contracts typically contain provisions to adjust the base price due to new statutes, ordinances or regulations, such as the Mine Improvement and New Emergency Response Act of 2006, which we refer to as the MINER Act, that affect our costs related to performance of the agreement. Additionally, some of our contracts contain provisions that allow for the recovery of costs affected by modifications or changes in the interpretations or application of any applicable statute by local, state or federal government authorities. These provisions only apply to the base price of coal contained in these supply contracts. In some circumstances, a significant adjustment in base price can lead to termination of the contract.

Certain of our contracts contain index provisions that change the price based on changes in market based indices and or changes in economic indices. Certain of our contracts contain price re-opener provisions that may allow a party to commence a renegotiation of the contract price at a pre-determined time. Price re-opener provisions may automatically set a new price based on prevailing market price or, in some instances, require us to negotiate a new price, sometimes within a specified range of prices. In a limited number of agreements, if the parties do not agree on a new price, either party has an option to terminate the contract. Under some of our

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contracts, we have the right to match lower prices offered to our customers by other suppliers. In addition, certain of our contracts contain clauses that may allow customers to terminate the contract in the event of certain changes in environmental laws and regulations that impact their operations.

Coal quality and volumes are stipulated in coal sales agreements. In most cases, the annual pricing and volume obligations are fixed, although in some cases the volume specified may vary depending on the customer consumption requirements. Most of our coal sales agreements contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics such as heat content (for thermal coal contracts), volatile matter (for metallurgical coal contracts), and for both types of contracts, sulfur, ash and moisture content as well as others. Failure to meet these specifications can result in economic penalties, suspension or cancellation of shipments or termination of the contracts.

Our coal sales agreements also typically contain *force majeure* provisions allowing temporary suspension of performance by us or our customers, during the duration of events beyond the control of the affected party, including events such as strikes, adverse mining conditions, mine closures or serious transportation problems that affect us or unanticipated plant outages that may affect the buyer. Our contracts also generally provide that in the event a *force majeure* circumstance exceeds a certain time period, the unaffected party may have the option to terminate the purchase or sale in whole or in part. Some contracts stipulate that this tonnage can be made up by mutual agreement or at the discretion of the buyer. Agreements between our customers and the railroads servicing our mines may also contain *force majeure* provisions. Generally, our coal sales agreements allow our customer to suspend performance in the event that the railroad fails to provide its services due to circumstances that would constitute a *force majeure*.

In most of our contracts, we have a right of substitution (unilateral or subject to counterparty approval), allowing us to provide coal from different mines, including third-party mines, as long as the replacement coal meets quality specifications and will be sold at the same equivalent delivered cost.

In some of our coal supply contracts, we agree to indemnify or reimburse our customers for damage to their or their rail carrier's equipment while on our property, which result from our or our agents' negligence, and for damage to our customer's equipment due to non-coal materials being included with our coal while on our property.

Trading. In addition to marketing and selling coal to customers through traditional coal supply arrangements, we seek to optimize our coal production and leverage our knowledge of the coal industry through a variety of other marketing, trading and asset optimization strategies. From time to time, we may employ strategies to use coal and coal-related commodities and contracts for those commodities in order to manage and hedge volumes and/or prices associated with our coal sales or purchase commitments, reduce our exposure to the volatility of market prices or augment the value of our portfolio of traditional assets. These strategies may include physical coal contracts, as well as a variety of forward, futures or options contracts, swap agreements or other financial instruments.

We maintain a system of complementary processes and controls designed to monitor and manage our exposure to market and other risks that may arise as a consequence of these strategies. These processes and controls seek to preserve our ability to profit from certain marketing, trading and asset optimization strategies while mitigating our exposure to potential losses. You should see the section entitled "Quantitative and Qualitative Disclosures About Market Risk" for more information about the market risks associated with these strategies at December 31, 2011.

Transportation. We ship our coal to domestic customers by means of railcars, barges, vessels or trucks, or a combination of these means of transportation. We generally sell coal used for domestic consumption free on board (f.o.b.) at the mine or nearest loading facility. Our domestic customers normally bear the costs of transporting coal by rail, barge or vessel.

Historically, most domestic electricity generators have arranged long-term shipping contracts with rail or barge companies to assure stable delivery costs. Transportation can be a large component of a purchaser's total cost. Although the purchaser pays the freight, transportation costs still are important to coal mining companies because

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the purchaser may choose a supplier largely based on cost of transportation. Transportation costs borne by the customer vary greatly based on each customer's proximity to the mine and our proximity to the loadout facilities. Trucks and overland conveyors haul coal over shorter distances, while barges, Great Lake carriers and ocean vessels move coal to export markets and domestic markets requiring shipment over the Great Lakes and several river systems.

Most coal mines are served by a single rail company, but much of the Powder River Basin is served by two rail carriers: the Burlington Northern-Santa Fe railroad and the Union Pacific railroad. In the Western Bituminous region our customers are largely served by the Union Pacific railroad or by truck delivery. We generally transport coal produced at our Appalachian mining complexes via the CSX railroad or the Norfolk Southern railroad. Besides rail deliveries, some customers in the eastern United States rely on a river barge system. Our Arch Coal Terminal is located in Catlettsburg, Kentucky on a 111-acre site on the Big Sandy River above its confluence with the Ohio River. The terminal provides coal and other bulk material storage and can load and offload river barges and trucks at the facility. The terminal can provide up to 500,000 tons of storage and can load up to six million tons of coal annually for shipment on the inland waterways.

We generally sell coal to international customers at the export terminal, and we are usually responsible for the cost of transporting coal to the export terminals. We transport our coal to Atlantic or Pacific coast terminals or terminals along the Gulf of Mexico for transportation to international customers. Our international customers are generally responsible for paying the cost of ocean freight. We may also sell coal to international customers delivered to an unloading facility at the destination country.

We own a 22% interest in Dominion Terminal Associates, a partnership that operates a ground storage-to-vessel coal transloading facility in Newport News, Virginia. The facility has a rated throughput capacity of 20 million tons of coal per year and ground storage capacity of approximately 1.7 million tons. The facility serves international customers, as well as domestic coal users located along the Atlantic coast of the United States.

We also own a 38% interest in Millennium Bulk Terminals Longview, LLC (MBT), the owner of a bulk commodity terminal on the Columbia River near Longview, Washington. MBT is currently working to obtain the required approvals and necessary permits to complete dredging and other upgrades to enable coal, alumina and cementitious material shipments through the brownfield terminal.

Competition

The coal industry is intensely competitive. The most important factors on which we compete are coal quality, delivered costs to the customer and reliability of supply. Our principal domestic competitors include Alpha Natural Resources, Inc., Cloud Peak Energy, CONSOL Energy Inc., Patriot Coal Corporation, and Peabody Energy Corp. Some of these coal producers are larger than we are and have greater financial resources and larger reserve bases than we do. We also compete directly with a number of smaller producers in each of the geographic regions in which we operate. We also compete with companies that produce coal from one or more foreign countries, such as Colombia, Indonesia and Venezuela.

Additionally, coal competes with other fuels, such as natural gas, nuclear energy, hydropower, wind, solar and petroleum, for steam and electrical power generation. Costs and other factors relating to these alternative fuels, such as safety and environmental considerations, affect the overall demand for coal as a fuel.

Suppliers

Principal supplies used in our business include petroleum-based fuels, explosives, tires, steel and other raw materials as well as spare parts and other consumables used in the mining process. We use third-party suppliers for a significant portion of our equipment rebuilds and repairs, drilling services and construction. We use sole source suppliers for certain parts of our business such as explosives and fuel, and preferred suppliers for other parts at our business such as dragline and shovel parts and related services. We believe adequate substitute suppliers are

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available. For more information about our suppliers, you should see "Risk Factors Increases in the costs of mining and other industrial supplies, including steel-based supplies, diesel fuel and rubber tires, or the inability to obtain a sufficient quantity of those supplies, could negatively affect our operating costs or disrupt or delay our production."

Environmental and Other Regulatory Matters.

Federal, state and local authorities regulate the U.S. coal mining industry with respect to matters such as employee health and safety and the environment, including protection of air quality, water quality, wetlands, special status species of plants and animals, land uses, cultural and historic properties and other environmental resources identified during the permitting process. Reclamation is required during production and after mining has been completed. Materials used and generated by mining operations must also be managed according to applicable regulations and law. These laws have, and will continue to have, a significant effect on our production costs and our competitive position.

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. We cannot assure you that we have been or will be at all times in complete compliance with such laws and regulations. While it is not possible to accurately quantify the expenditures we incur to maintain compliance with all applicable federal and state laws, those costs have been and are expected to continue to be significant. Federal and state mining laws and regulations require us to obtain surety bonds to guarantee performance or payment of certain long-term obligations, including mine closure and reclamation costs, federal and state workers' compensation benefits, coal leases and other miscellaneous obligations. Compliance with these laws has substantially increased the cost of coal mining for domestic coal producers.

Future laws, regulations or orders, as well as future interpretations and more rigorous enforcement of existing laws, regulations or orders, may require substantial increases in equipment and operating costs and delays, interruptions or a termination of operations, the extent to which we cannot predict. Future laws, regulations or orders may also cause coal to become a less attractive fuel source, thereby reducing coal's share of the market for fuels and other energy sources used to generate electricity. As a result, future laws, regulations or orders may adversely affect our mining operations, cost structure or our customers' demand for coal.

The following is a summary of the various federal and state environmental and similar regulations that have a material impact on our business:

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. When we apply for 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. For example, in order to obtain a federal coal lease, an environmental impact statement must be prepared to assist the BLM in determining the potential environmental impact of lease issuance, including any collateral effects from the mining, transportation and burning of coal. The authorization, permitting and implementation requirements imposed by federal, state and local authorities may be costly and time consuming and may delay commencement or continuation of mining operations. In the states where we operate, the applicable laws and regulations also provide that a mining permit or modification can be delayed, refused or revoked if officers, directors, shareholders with specified interests or certain other affiliated entities with specified interests in the applicant or permittee have, or are affiliated with another entity that has, outstanding permit violations. Thus, past or ongoing violations of applicable laws and regulations could provide a basis to revoke existing permits and to deny the issuance of additional permits.

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In order to obtain mining permits and approvals from federal and 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 or other authorized use. Typically, we submit the necessary permit applications several months or even years before we plan to begin mining a new area. Some of our required permits are becoming increasingly more difficult and expensive to obtain, and the application review processes are taking longer to complete and becoming increasingly subject to challenge, even after a permit has been issued.

Under some circumstances, substantial fines and penalties, including revocation or suspension of mining permits, may be imposed under the laws described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws.

Surface Mining Control and Reclamation Act. The Surface Mining Control and Reclamation Act, which we refer to as SMCRA, establishes mining, environmental protection, reclamation and closure standards for all aspects of surface mining as well as many aspects of underground mining. Mining operators must obtain SMCRA permits and permit renewals from the Office of Surface Mining, which we refer to as OSM, or from the applicable state agency if the state agency has obtained regulatory primacy. A state agency may achieve primacy if the state regulatory agency develops a mining regulatory program that is no less stringent than the federal mining regulatory program under SMCRA. All states in which we conduct mining operations have achieved primacy and issue permits in lieu of OSM.

In 1999, a federal court in West Virginia ruled that the stream buffer zone rule issued under SMCRA prohibited most excess spoil fills. While the decision was later reversed on jurisdictional grounds, the extent to which the rule applied to fills was left unaddressed. On December 12, 2008, OSM finalized a rulemaking regarding the interpretation of the stream buffer zone provisions of SMCRA which confirmed that excess spoil from mining and refuse from coal preparation could be placed in permitted areas of a mine site that constitute waters of the United States. On November 30, 2009, OSM announced that it would re-examine and reinterpret the regulations finalized eleven months earlier. We cannot predict how the regulations may change or how they may affect coal production, though there are reports that drafts of OSM's preferred alternative rule would, if finalized, curtail surface mining operations in and near streams especially in central Appalachia.

SMCRA permit provisions include a complex set of requirements which include, among other things, coal prospecting; mine plan development; topsoil or growth medium removal and replacement; selective handling of overburden materials; mine pit backfilling and grading; disposal of excess spoil; protection of the hydrologic balance; subsidence control for underground mines; surface runoff and drainage control; establishment of suitable post mining land uses; and revegetation. We begin the process of preparing a mining permit application by collecting baseline data to adequately characterize the pre-mining environmental conditions of the permit area. This work is typically conducted by third-party consultants with specialized expertise and includes surveys and/or assessments of the following: cultural and historical resources; geology; soils; vegetation; aquatic organisms; wildlife; potential for threatened, endangered or other special status species; surface and ground water hydrology; climatology; riverine and riparian habitat; and wetlands. The geologic data and information derived from the other surveys and/or assessments are used to develop the mining and reclamation plans presented in the permit application. The mining and reclamation plans address the provisions and performance standards of the state's equivalent SMCRA regulatory program, and are also used to support applications for other authorizations and/or permits required to conduct coal mining activities. Also included in the permit application is information used for documenting surface and mineral ownership, variance requests, access roads, bonding information, mining methods, mining phases, other agreements that may relate to coal, other minerals, oil and gas rights, water rights, permitted areas, and ownership and control information required to determine compliance with 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 an administrative completeness review and a thorough technical review. Also, before a SMCRA permit is issued, a mine operator must submit a bond or otherwise secure the performance of all reclamation obligations. After the application is submitted, a public notice or advertisement of the proposed permit is required to be given, which begins a notice period that is followed by a public comment period before a permit can be issued. It is not uncommon for a SMCRA mine permit application to take over a year to prepare, depending on the size and complexity of the mine, and anywhere from six months to two years or even longer for the permit to be issued. The variability in time frame required to prepare the application and issue the permit can be attributed primarily to the various regulatory authorities' discretion in the handling of comments and objections relating to the project received from the general public and other agencies. Also, it is not uncommon for a permit to be delayed as a result of litigation related to the specific permit or another related company's permit.

In addition to the bond requirement for an active or proposed permit, the Abandoned Mine Land Fund, which was created by SMCRA, requires a fee on all coal produced. The proceeds of the fee are used to restore mines closed or abandoned prior to SMCRA's adoption in 1977. The current fee is $0.315 per ton of coal produced from surface mines and $0.135 per ton of coal produced from underground mines. In 2011, we recorded $42.0 million of expense related to these reclamation fees.

Surety Bonds. Mine operators are often required by federal and/or state laws, including SMCRA, to assure, usually through the use of surety bonds, payment of certain long-term obligations including mine closure or reclamation costs, federal and state workers' compensation costs, coal leases and other miscellaneous obligations. Although surety bonds are usually noncancelable during their term, many of these bonds are renewable on an annual basis.

The costs of these bonds have fluctuated in recent years while the market terms of surety bonds have generally become more unfavorable to mine operators. These changes in the terms of the bonds have been accompanied at times by a decrease in the number of companies willing to issue surety bonds. In order to address some of these uncertainties, we use self-bonding to secure performance of certain obligations in Wyoming. As of December 31, 2011, we have self-bonded an aggregate of approximately $420.5 million and have posted an aggregate of approximately $301.5 million in surety bonds for reclamation purposes. In addition, we had approximately $277.8 million of surety bonds and letters of credit outstanding at December 31, 2011 to secure workers' compensation, coal lease and other obligations.

Mine Safety and Health. Stringent safety and health standards have been imposed by federal legislation since Congress adopted the Mine Safety and Health Act of 1969. The Mine Safety and Health Act of 1977 significantly expanded the enforcement of safety and health standards and imposed comprehensive safety and health standards on all aspects of mining operations. In addition to federal regulatory programs, all of the states in which we operate also have programs aimed at improving mine safety and health. Collectively, federal and state safety and health regulation in the coal mining industry is among the most comprehensive and pervasive systems for the protection of employee health and safety affecting any segment of U.S. industry. In reaction to recent mine accidents, federal and state legislatures and regulatory authorities have increased scrutiny of mine safety matters and passed more stringent laws governing mining. For example, in 2006, Congress enacted the MINER Act. The MINER Act imposes additional obligations on coal operators including, among other things, the following:

- development of new emergency response plans that address post-accident communications, tracking of miners, breathable air, lifelines, training and communication with local emergency response personnel;
- establishment of additional requirements for mine rescue teams;
- notification of federal authorities in the event of certain events;
- increased penalties for violations of the applicable federal laws and regulations; and
- requirement that standards be implemented regarding the manner in which closed areas of underground mines are sealed.

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In 2008, the U.S. House of Representatives approved additional federal legislation which would have required new regulations on a variety of mine safety issues such as underground refuges, mine ventilation and communication systems. Although the U.S. Senate failed to pass that legislation, it is possible that similar legislation may be proposed in the future. Various states, including West Virginia, have also enacted new laws to address many of the same subjects. The costs of implementing these new safety and health regulations at the federal and state level have been, and will continue to be, substantial. In addition to the cost of implementation, there are increased penalties for violations which may also be substantial. Expanded enforcement has resulted in a proliferation of litigation regarding citations and orders issued as a result of the regulations.

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, 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 coal mined in underground operations and up to $0.55 per ton for coal mined in surface operations. These amounts may not exceed 4.4% of the gross sales price. This excise tax does not apply to coal shipped outside the United States. In 2011, we recorded $85.4 million of expense related to this excise tax.

We are committed to the safety of our employees. In 2011, we spent approximately $25.3 million on MINER Act compliance and other safety improvement matters. Our combined 2011 safety record was approximately 3.5 times better than the national coal industry average as measured by lost-time incident rates. In addition, our operations and facilities were honored with 25 national and state safety accolades in 2011, including three Sentinels of Safety honors from the U.S. Department of Labor's Mine Safety and Health Administration.

One way we work towards meeting a zero injury rate is developing and maintaining strong safety programs. Our subsidiaries launched behavior-based safety programs in 2006, which expanded our employees' involvement in our prevention process and in identifying at-risk behaviors before incidents occur. In 2011, we began implementing these programs in the operations we acquired from ICG. Since adopting these programs, our rates for total incidents and lost-time incidents have improved by approximately 39% and 45%, respectively. In addition, we routinely conduct regular safety drills and exercises with state safety and MSHA officials.

Clean Air Act. The federal Clean Air Act and similar state and local laws that regulate air emissions affect coal mining directly and indirectly. Direct impacts on coal mining and processing operations include Clean Air Act permitting requirements and emissions control requirements relating to particulate matter which may include controlling fugitive dust. The Clean Air Act also indirectly affects coal mining operations by extensively regulating the emissions of fine particulate matter measuring 2.5 micrometers in diameter or smaller, sulfur dioxide, nitrogen oxides, mercury and other compounds emitted by coal-fueled power plants and industrial boilers, which are the largest end-users of our coal. Continued tightening of the already stringent regulation of emissions is likely, such as the Cross State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standard (MATS), finalized in 2011 and discussed in more detail below. Regulation of additional emissions, such as greenhouse gases, has been announced for early 2012 by the U.S. Environmental Protection Agency, which we refer to as EPA, and those regulations will apply to new coal-fueled power plants. Other greenhouse gas regulations may apply to industrial boilers (see discussion of Climate Change, below). This application could eventually reduce the 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, promulgated in 1990, imposed a two-phase reduction of sulfur dioxide emissions by electric utilities. Phase II became effective in 2000 and applies to all coal-fueled power plants with a capacity of more than 25-megawatts. Generally, the affected power plants have sought to comply with these requirements by switching to lower sulfur fuels, installing pollution control devices, reducing electricity generating levels or purchasing or trading sulfur dioxide emissions allowances. Although we cannot accurately predict the future effect of this Clean Air Act provision on our operations, we believe that implementation of Phase II has been factored into the pricing of the coal market.

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Particulate Matter. The Clean Air Act requires the EPA to set national ambient air quality standards, which we refer to as NAAQS, for certain pollutants associated with the combustion of coal, including sulfur dioxide, particulate matter, nitrogen oxides and ozone. Areas that are not in compliance with these standards, referred to as non-attainment areas, must take steps to reduce emissions levels. For example, NAAQS currently exist for particulate matter measuring 10 micrometers in diameter or smaller (PM10) and for fine particulate matter measuring 2.5 micrometers in diameter or smaller (PM2.5). The EPA designated all or part of 225 counties in 20 states as well as the District of Columbia as non-attainment areas with respect to the PM2.5 NAAQS. Those designations have been challenged. Individual states must 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 12 years from the date of designation to secure emissions reductions from sources contributing to the problem. In addition, EPA announced, in February of 2011, that it intends to propose a revision to the PM2.5 NAAQS; although, the revision has not yet been proposed. Future regulation and enforcement of the new PM2.5 standard will affect many power plants, especially coal-fueled power plants, and all plants in non-attainment areas.

Ozone. Significant additional emission control expenditures will be required at coal-fueled power plants to meet the new NAAQS for ozone. Nitrogen oxides, which are a byproduct of coal combustion, are classified as an ozone precursor. As a result, emissions control requirements for new and expanded coal-fueled power plants and industrial boilers will continue to become more demanding in the years ahead. For example, on March 27, 2008, EPA promulgated a new 75 parts per billion (ppb) ozone primary NAAQS. On September 16, 2009, EPA announced that it will reconsider the new standard, and on January 19, 2010, EPA proposed its reconsidered NAAQS (75 Fed Reg 2938), proposing to adopt a new, more stringent primary ambient air quality standard for ozone and to change the way in which the secondary standard is calculated. However, following an announcement by the President that the new ozone standard would undergo additional review, EPA Administrator Jackson announced on September 2, 2011, that the next ozone NAAQS review will occur in 2013. If a new ozone NAAQS is promulgated, additional emission control expenditures will likely be required at coal-fueled power plants.

NOx SIP Call. The NOx SIP Call program was established by the EPA in October 1998 to reduce the transport of ozone on prevailing winds from the Midwest and South to states in the Northeast, which said that they could not meet federal air quality standards because of migrating pollution. The program was designed to reduce nitrous oxide emissions by one million tons per year in 22 eastern states and the District of Columbia. Phase II reductions were required by May 2007. As a result of the program, many power plants have been or will be required to install additional emission control measures, such as selective catalytic reduction devices. Installation of additional emission control measures will make it more costly to operate coal-fueled power plants, which could make coal a less attractive fuel.

Clean Air Interstate Rule. The EPA finalized the Clean Air Interstate Rule, which we refer to as CAIR, in March 2005. CAIR calls for power plants in 28 Eastern states and the District of Columbia to reduce emission levels of sulfur dioxide and nitrous oxide pursuant to a cap and trade program similar to the system now in effect for acid deposition control and to that proposed by the Clean Skies Initiative. The stringency of the cap may require some coal-fueled power plants to install additional pollution control equipment, such as wet scrubbers, which could decrease the demand for low-sulfur coal at these plants and thereby potentially reduce market prices for low-sulfur coal. Emissions are permanently capped and cannot increase. In July 2008, in *State of North Carolina v. EPA* and consolidated cases, the U.S. Court of Appeals for the District of Columbia Circuit disagreed with the EPA's reading of the Clean Air Act and vacated CAIR in its entirety. In December 2008, the U.S. Court of Appeals for the District of Columbia Circuit revised its remedy and remanded the rule to the EPA. EPA proposed a revised transport rule on August 2, 2010, (75 Fed Reg 45209) and received thousands of comments on the proposal. The rule was finalized as the Cross State Air Pollution Rule (CSAPR) on July 6, 2011, with compliance required for SO2 reductions beginning January 1, 2012 and compliance with NOx reductions required by May 1, 2012. Numerous appeals of the rule were filed and, on December 30, 2011, the Federal Court of Appeals for the District of Columbia Circuit stayed the rule. The appeal is scheduled to be heard in April of 2012. If the CSAPR is upheld, the additional controls required under the CSAPR may affect the market for coal inasmuch as multiple existing coal fired units are expected to be retired rather than having required controls installed.

Mercury. In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA's Clean Air Mercury Rule (CAMR) and remanded it to the EPA for reconsideration. In response to the vacatur, EPA announced an EGU Mercury and Air Toxics Standard (MATS) on December 16, 2011. The MATS is expected to be finalized in March or April of 2012. In addition, before the court decision vacating the CAMR, some states had either adopted the CAMR or adopted state-specific rules to regulate mercury emissions from power plants that are more stringent than the CAMR. The result of the EGU MATS and state mercury and air toxics controls is that these rules may adversely affect the demand for coal.

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, particularly those located in the southwest and southeast United States. Under the Regional Haze Rule, affected states were required to submit regional haze SIP's by December 17, 2007, that, among other things, was to identify facilities that would have to reduce emissions and comply with stricter emission limitations. The vast majority of states failed to submit their plans by December 17, 2007, and EPA issued a Finding of Failure to Submit plans on January 15, 2009 (74 Fed. Reg. 2392), which could trigger Federal implementation plans. EPA has taken no enforcement action against states to finalize implementation plans and is slowly dealing with the state Regional Haze SIPs that were submitted. Nonetheless, this program may result in additional emissions restrictions from new coal-fueled power plants whose operations may impair visibility at and around federally protected areas. This program may also require certain existing coal-fueled 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.

New Source Review. A number of pending regulatory changes and court actions are affecting the scope of the EPA's new source review program, which under certain circumstances requires existing coal-fueled power plants to install the more stringent air emissions control equipment required of new plants. The changes to the new source review program may impact demand for coal nationally, but as the final form of the requirements after their revision is not yet known, we are unable to predict the magnitude of the impact.

Climate Change. One by-product of burning coal is carbon dioxide, which is considered a greenhouse gas and is a major source of concern with respect to global warming. In November 2004, Russia ratified the Kyoto Protocol to the 1992 Framework Convention on Global Climate Change, which establishes a binding set of emission targets for greenhouse gases. With Russia's acceptance, the Kyoto Protocol became binding on all those countries that had ratified it in February 2005. The United States has refused to ratify the Kyoto Protocol. Although the Kyoto targets varied from country to country, the United States Kyoto Protocol target reductions of greenhouse gas emissions would be to 93% of 1990 levels. Following the Kyoto meeting, multiple Conferences of the Parties have been held. None to date, including the most recent Conference of the Parties in Cancun, Mexico, in late November and early December of 2010, have resulted in any mandatory reduction requirements for the United States, but any such future conference may do so.

Future regulation of greenhouse gases in the United States could occur pursuant to future U.S. treaty obligations, statutory or regulatory changes under the Clean Air Act, federal or state adoption of a greenhouse gas regulatory scheme, or otherwise. The U.S. Congress has considered various proposals to reduce greenhouse gas emissions, but to date, none have become law. In April 2007, the U.S. Supreme Court rendered its decision in Massachusetts v. EPA, finding that the EPA has authority under the Clean Air Act to regulate carbon dioxide emissions from automobiles and can decide against regulation only if the EPA determines that carbon dioxide does not significantly contribute to climate change and does not endanger public health or the environment. On December 15, 2009, EPA published a formal determination that six greenhouse gases, including carbon dioxide and

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methane, endanger both the public health and welfare of current and future generations. In the same Federal Register rulemaking, EPA found that emission of greenhouse gases from new motor vehicles and their engines contribute to greenhouse gas pollution. Although Massachusetts v. EPA did not involve the EPA's authority to regulate greenhouse gas emissions from stationary sources, such as coal-fueled power plants, the decision is likely to impact regulation of stationary sources.

For example, a challenge in the U.S. Court of Appeals for the District of Columbia with respect to the EPA's decision not to regulate greenhouse gas emissions from power plants and other stationary sources under the Clean Air Act's new source performance standards was remanded to the EPA for further consideration in light of Massachusetts v. EPA. Other pending cases regarding greenhouse gases may affect the market for coal. In AEP v. Connecticut (582 F. 3d, 309, 2d Cir, 2009) the Second Circuit Court of Appeals held that States and private plaintiffs may maintain actions under federal common law alleging that five electric utilities have created a "public nuisance" by contributing to global warming, and may seek injunctive relief capping the utilities' CO_2 emissions at judicially-determined levels. However, the Supreme Court granted certiorari (10-174, US) on December 6, 2010, and reversed and remanded the Second Circuit Court's opinion on June 20, 2011.

On October 27, 2009, the EPA announced how it will establish thresholds for phasing-in and regulating greenhouse gas emissions under various provisions of the Clean Air Act. Three days later, on October 30, 2009, the EPA published a final rule in the Federal Register that requires the reporting of greenhouse gas emissions from all sectors of the American economy, and reporting of emissions from underground coal mines and coal suppliers was promulgated on July 12, 2010 (75 Fed Reg 39736). In addition, EPA has announced that it will establish permitting requirements for greenhouse gas emissions from electric utilities in early 2012. Those permitting rules may also decrease the demand for coal.

In the absence of federal legislation or regulation, many states and regions have adopted greenhouse gas initiatives. These state and regional climate change rules will likely require additional controls on coal-fueled power plants and industrial boilers and may even cause some users of coal to switch from coal to a lower carbon fuel. There can be no assurance at this time that a carbon dioxide cap and trade program, a carbon tax or other regulatory regime, if implemented by the states in which our customers operate or at the federal level, will not affect the future market for coal in those regions. The permitting of new coal-fueled power plants has also recently been contested by state regulators and environmental organizations based on concerns relating to greenhouse gas emissions. Increased efforts to control greenhouse gas emissions could result in reduced demand for coal.

We believe that a diverse suite of clean coal technologies represents an essential tool for ultimately stabilizing greenhouse gas concentrations in the atmosphere. As a result, we have invested in several projects seeking to advance a variety of clean coal technologies, and will continue to evaluate additional opportunities for potential investment. We currently own a 24% interest in DKRW Advanced Fuels LLC, which is developing a facility to convert coal into gasoline, while capturing much of the carbon dioxide produced in the conversion process for use in enhanced oil recovery (EOR) applications. In addition, we own a 35% interest in Tenaska Trailblazer Partners, LLC, which is planning to construct a pulverized coal-fueled electric generating station in West Texas targeting a post-combustion capture of 85% 90% of the carbon dioxide.

Clean Water Act. The federal Clean Water Act and corresponding state and local laws and regulations affect coal mining operations by restricting the discharge of pollutants, including dredged and fill materials, into waters of the United States. The Clean Water Act provisions and associated state and federal regulations are complex and subject to amendments, legal challenges and changes in implementation. Recent court decisions and regulatory actions have created uncertainty over Clean Water Act jurisdiction and permitting requirements that could variously increase or decrease the cost and time we expend on Clean Water Act compliance.

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

Wastewater Discharge. Section 402 of the Clean Water Act creates a process for establishing effluent limitations for discharges to streams that are protective of water quality standards through the National

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Pollutant Discharge Elimination System, which we refer to as the NPDES, or an equally stringent program delegated to a state regulatory agency. Regular monitoring, reporting and compliance with performance standards are preconditions for the issuance and renewal of NPDES permits that govern discharges into waters of the United States, especially on selenium, sulfate and specific conductance. Discharges that exceed the limits specified under NPDES permits can lead to the imposition of penalties, and persistent non-compliance could lead to significant penalties, compliance costs and delays in coal production. In addition, the imposition of future restrictions on the discharge of certain pollutants into waters of the United States could increase the difficulty of obtaining and complying with NPDES permits, which could impose additional time and cost burdens on our operations. You should see Item 3 Legal Proceedings for more information about certain regulatory actions pertaining to our operations.

Discharges of pollutants into waters that states have designated as impaired (i.e., as not meeting present water quality standards) are subject to Total Maximum Daily Load, which we refer to as TMDL, regulations. The TMDL regulations establish a process for calculating the maximum amount of a pollutant that a water body can receive while maintaining state water quality standards. Pollutant loads are allocated among the various sources that discharge pollutants into that water body. Mine operations that discharge into water bodies designated as impaired will be required to meet new TMDL allocations. The adoption of more stringent TMDL-related allocations for our coal mines could require more costly water treatment and could adversely affect our coal production.

The Clean Water Act also requires states to develop anti-degradation policies to ensure that non-impaired water bodies continue to meet water quality standards. The issuance and renewal of permits for the discharge of pollutants to waters that have been designated as "high quality" are subject to anti-degradation review that may increase the costs, time and difficulty associated with obtaining and complying with NPDES permits.

Dredge and Fill Permits. Many mining activities, such as the development of refuse impoundments, fresh water impoundments, refuse fills, valley fills, and other similar structures, may result in impacts to waters of the United States, including wetlands, streams and, in certain instances, man-made conveyances that have a hydrologic connection to such streams or wetlands. Under the Clean Water Act, coal companies are required to obtain a Section 404 permit from the Army Corps of Engineers, which we refer to as the Corps, prior to conducting such mining activities. The Corps is authorized to issue general "nationwide" permits for specific categories of activities that are similar in nature and that are determined to have minimal adverse effects on the environment. Permits issued pursuant to Nationwide Permit 21, which we refer to as NWP 21, generally authorize the disposal of dredged and fill material from surface coal mining activities into waters of the United States, subject to certain restrictions. Since March 2007, permits under NWP 21 were reissued for a five-year period with new provisions intended to strengthen environmental protections. There must be appropriate mitigation in accordance with nationwide general permit conditions rather than less restricted state-required mitigation requirements, and permitholders must receive explicit authorization from the Corps before proceeding with proposed mining activities.

Notwithstanding the additional environmental protections designed in the 2007 NWP 21, on July 15, 2009, the Corps proposed to immediately suspend the use of the NWP 21 in six Appalachian states, including West Virginia, Kentucky and Virginia where the Company conducts operations. In addition, in the same notice, the Corps proposed to modify the NWP 21 following the receipt and review of public comments to prohibit its further use in the same states during the remaining term of the permit which is March 12, 2012. On June 17, 2010, the Corps announced that it had suspended the use of NWP 21 in the same six states it continues to be available elsewhere. The Corps' decision, however, does not prevent the Company's operations from seeking an individual permit under § 404 of the CWA, nor does it restrict an operation from utilizing another version of the nationwide permit authorized for small underground coal mines that must construct fills as part of their mining operations.

The use of nationwide permits to authorize stream impacts from mining activities has been the subject of significant litigation. You should see Item 3 Legal Proceedings for more information about certain litigation pertaining to our permits.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act, which we refer to as RCRA, may affect coal mining operations through its requirements for the management, handling, transportation and disposal of hazardous wastes. Currently, certain coal mine wastes, such as overburden and coal cleaning wastes, are exempted from hazardous waste management. In addition, Subtitle C of RCRA exempted fossil fuel combustion wastes from hazardous waste regulation until the EPA completed a report to Congress and made a determination on whether the wastes should be regulated as hazardous. In its 1993 regulatory determination, the EPA addressed some high volume-low toxicity coal combustion products generated at electric utility and independent power producing facilities, such as coal ash, and left the exemption in place. In May 2000, the EPA concluded that coal combustion products do not warrant regulation as hazardous waste under RCRA and again retained the hazardous waste exemption for these wastes. The EPA also determined that national non-hazardous waste regulations under RCRA Subtitle D are needed for coal combustion products disposed in surface impoundments and landfills and used as mine-fill. In March of 2007 the Office of Surface Mining and EPA proposed regulations regarding the management of coal combustion products. The EPA concluded that beneficial uses of these wastes, other than for mine-filling, pose no significant risk and no additional national regulations are needed. As long as this exemption remains in effect, it is not anticipated that regulation of coal combustion waste will have any material effect on the amount of coal used by electricity generators. A final rule has not been promulgated. Most state hazardous waste laws also exempt coal combustion products, and instead treat it as either a solid waste or a special waste. Any costs associated with handling or disposal of hazardous wastes would increase our customers' operating costs and potentially reduce their ability to purchase coal. In addition, contamination caused by the past disposal of ash can lead to material liability. In another development regarding coal combustion wastes, EPA conducted an assessment of impoundments and other units that manage residuals from coal combustion and that contain free liquids following a massive coal ash spill in Tennessee in 2008, EPA contractors conducted site assessments at many impoundments and is requiring appropriate remedial action at any facility that is found to have a unit posing a risk for potential failure. EPA is posting utility responses to the assessment on its web site as the responses are received. Future regulations resulting from the EPA coal combustion refuse assessments may impact the ability of the Company's utility customers to continue to use coal in their power plants.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, which we refer to as CERCLA, and similar state laws affect coal mining operations by, among other things, imposing cleanup requirements for threatened or actual releases of hazardous substances that may endanger public health or welfare or the environment. Under CERCLA and similar state laws, joint and several liability may be imposed on waste generators, site owners and lessees and others regardless of fault or the legality of the original disposal activity. Although the EPA excludes most wastes generated by coal mining and processing operations from the hazardous waste laws, such wastes can, in certain circumstances, constitute hazardous substances for the purposes of CERCLA. In addition, the disposal, release or spilling of some products used by coal companies in operations, such as chemicals, could trigger the liability provisions of the statute. Thus, coal mines that we currently own or have previously owned or operated, and sites to which we sent waste materials, may be subject to liability under CERCLA and similar state laws. In particular, we may be liable under CERCLA or similar state laws for the cleanup of hazardous substance contamination at sites where we own surface rights.

Endangered Species. The Endangered Species Act and other related federal and state statutes protect species threatened or endangered with possible extinction. Protection of threatened, endangered and other special status 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. A number of species indigenous to our properties are protected under the Endangered Species Act or other related laws or regulations. Based on the species that have been identified to date and the current

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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. We have been able to continue our operations within the existing spatial, temporal and other restrictions associated with special status species. Should more stringent protective measures be applied to threatened, endangered or other special status species or to their critical habitat, then we could experience increased operating costs or difficulty in obtaining future mining permits.

Use of Explosives. Our surface mining operations are subject to numerous regulations relating to blasting activities. Pursuant to these regulations, we incur costs to design and implement blast schedules and to conduct pre-blast surveys and blast monitoring. In addition, the storage of explosives is subject to strict regulatory requirements established by four different federal regulatory agencies. For example, pursuant to a rule issued by the Department of Homeland Security in 2007, facilities in possession of chemicals of interest, including ammonium nitrate at certain threshold levels, must complete a screening review in order to help determine whether there is a high level of security risk such that a security vulnerability assessment and site security plan will be required.

Other Environmental Laws. We are required to comply with numerous other federal, state and local environmental laws in addition to those previously discussed. These additional laws include, for example, the Safe Drinking Water Act, the Toxic Substance Control Act and the Emergency Planning and Community Right-to-Know Act.

Employees

At February 15, 2012, we employed a total of approximately 7,442 full and part-time employees, approximately 275 of whom are represented by the Scotia Employees Association. We believe that our relations with all employees are good.

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Executive Officers

The following is a list of our executive officers, their ages as of February 28, 2012 and their positions and offices during the last five years:

Name	Age	Position
C. Henry Besten, Jr.	63	Mr. Besten has served as our Senior Vice President Strategic Development since 2002.
John T. Drexler	42	Mr. Drexler has served as our Senior Vice President and Chief Financial Officer since April 2008. Mr. Drexler served as our Vice President Finance and Accounting from March 2006 to April 2008. From March 2005 to March 2006, Mr. Drexler served as our Director of Planning and Forecasting. Prior to March 2005, Mr. Drexler held several other positions within our finance and accounting department.
John W. Eaves	54	Mr. Eaves has served as our President and Chief Operating Officer since April 2006. Mr. Eaves has also been a director since February 2006. From 2002 to April 2006, Mr. Eaves served as our Executive Vice President and Chief Operating Officer. Mr. Eaves also serves on the board of directors of ADA-ES, Inc. and CoaLogix.
Sheila B. Feldman	57	Ms. Feldman has served as our Vice President Human Resources since 2003. From 1997 to 2003, Ms. Feldman was the Vice President Human Resources and Public Affairs of Solutia Inc.
Robert G. Jones	55	Mr. Jones has served as our Senior Vice President Law, General Counsel and Secretary since August 2008. Mr. Jones served as Vice President Law, General Counsel and Secretary from 2000 to August 2008.
Paul A. Lang	51	Mr. Lang has served as our Executive Vice President Operations since August 2011. Mr. Lang served as Senior Vice President Operations from December 2006 through August 2011, as President of Western Operations from July 2005 through December 2006 and President and General Manager of Thunder Basin Coal Company, L.L.C. from 1998 through July 2005.
Steven F. Leer	59	Mr. Leer has served as our Chairman and Chief Executive Officer since April 2006. Mr. Leer served as our President and Chief Executive Officer from 1992 to April 2006. Mr. Leer also serves on the board of directors of the Norfolk Southern Corporation, USG Corp., the Business Roundtable, the BRT, the University of the Pacific and Washington University and is past chairman of the Coal Industry Advisory Board. Mr. Leer is a past chairman and continues to serve on the board of directors of the Center for Energy and Economic Development, the National Coal Council and the National Mining Association.
Deck S. Slone	48	Mr. Slone has served as our Vice President Government, Investor and Public Affairs since August 2008. Mr. Slone served as our Vice President Investor Relations and Public Affairs from 2001 to August 2008.
Jeffrey W. Strobel	49	Mr. Strobel has served as our Vice President of Business Development and Strategy since October, 2011. Prior to joining Arch, Mr. Strobel held the following positions: Director of Energy Investment Banking for Wells Fargo Securities, LLC, from 2008 to 2011; Director of Energy Investment Banking for Wachovia Capital Markets, LLC, from 2007 to 2008; and Director, Vice President and Associate for A.G. Edwards Capital Markets from 2000 to 2007.
David N. Warnecke	56	Mr. Warnecke has served as our Senior Vice President Marketing and Trading since March 2011. Mr. Warnecke served as Vice President Marketing and Trading from August 2005 through March 2011, President of our Arch Coal Sales Company, Inc. subsidiary from June 2005 until March 2007, and as Executive Vice President of Arch Coal Sales Company, Inc. from April 2004 until June 2005. Prior to June 2004, Mr. Warnecke was Senior Vice President Sales, Trading and Transportation of Arch Coal Sales Company, Inc.

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Available Information

We file annual, quarterly and current reports, and amendments to those reports, proxy statements and other information with the Securities and Exchange Commission. You may access and read our filings without charge through the SEC's website, at 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.

We also make the documents listed above available without charge through our website, archcoal.com, as soon as practicable after we file or furnish them with the SEC. You may also request copies of the documents, at no cost, by telephone at (314) 994-2700 or by mail at Arch Coal, Inc., One CityPlace Drive, Suite 300, St. Louis, Missouri, 63141 Attention: Vice President   Government, Investor and Public Affairs. The information on our website is not part of this Annual Report on Form 10-K.

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GLOSSARY OF SELECTED MINING TERMS

Certain terms that we use in this document are specific to the coal mining industry and may be technical in nature. The following is a list of selected mining terms and the definitions we attribute to them.

Assigned reserves	Recoverable reserves designated for mining by a specific operation.
Btu	A measure of the energy required to raise the temperature of one pound of water one degree of Fahrenheit.
Compliance coal	Coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million Btus, requiring no blending or other sulfur dioxide reduction technologies in order to comply with the requirements of the Clean Air Act.
Continuous miner	A machine used in underground mining to cut coal from the seam and load it onto conveyors or into shuttle cars in a continuous operation.
Dragline	A large machine used in surface mining to remove the overburden, or layers of earth and rock, covering a coal seam. The dragline has a large bucket, suspended by cables from the end of a long boom, which is able to scoop up large amounts of overburden as it is dragged across the excavation area and redeposit the overburden in another area.
Longwall mining	One of two major underground coal mining methods, generally employing two rotating drums pulled mechanically back and forth across a long face of coal.
Low-sulfur coal	Coal which, when burned, emits 1.6 pounds or less of sulfur dioxide per million Btus.
Preparation plant	A facility used for crushing, sizing and washing coal to remove impurities and to prepare it for use by a particular customer.
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.
Proven reserves	Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for 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.
Reclamation	The restoration of land and environmental values to a mining site after the coal is extracted. The process commonly includes "recontouring" or shaping the land to its approximate original appearance, restoring topsoil and planting native grass and ground covers.
Recoverable reserves	The amount of proven and probable reserves that can actually be recovered from the reserve base taking into account all mining and preparation losses involved in producing a saleable product using existing methods and under current law.
Reserves	That part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.
Room-and-pillar mining	One of two major underground coal mining methods, utilizing continuous miners creating a network of "rooms" within a coal seam, leaving behind "pillars" of coal used to support the roof of a mine.
Unassigned reserves	Recoverable reserves that have not yet been designated for mining by a specific operation.

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ITEM 1A. RISK FACTORS.

Our business involves certain risks and uncertainties. In addition to the risks and uncertainties described below, we may face other risks and uncertainties, some of which may be unknown to us and some of which we may deem immaterial. If one or more of these risks or uncertainties occur, our business, financial condition or results of operations may be materially and adversely affected.

Risks Related to Our Operations

Coal prices are subject to change and a substantial or extended decline in prices could materially and adversely affect our profitability and the value of our coal reserves.

Our profitability and the value of our coal reserves depend upon the prices we receive for our coal. The contract prices we may receive in the future for coal depend upon factors beyond our control, including the following:

- the domestic and foreign supply and demand for coal;
- the quantity and quality of coal available from competitors;
- competition for production of electricity from non-coal sources, including the price and availability of alternative fuels;
- domestic air emission standards for coal-fueled power plants and the ability of coal-fueled power plants to meet these standards by installing scrubbers or other means;
- adverse weather, climatic or other natural conditions, including natural disasters;
- domestic and foreign economic conditions, including economic slowdowns;
- legislative, regulatory and judicial developments, environmental regulatory changes or changes in energy policy and energy conservation measures that would adversely affect the coal industry, such as legislation limiting carbon emissions or providing for increased funding and incentives for alternative energy sources;
- the proximity to, capacity of and cost of transportation and port facilities; and
- market price fluctuations for sulfur dioxide emission allowances.

A substantial or extended decline in the prices we receive for our future coal sales contracts could materially and adversely affect us by decreasing our profitability and the value of our coal reserves.

Our coal mining operations are subject to operating risks that are beyond our control, which could result in materially increased operating expenses and decreased production levels and could materially and adversely affect our profitability.

We mine coal at underground and surface mining operations. Certain factors beyond our control, including those listed below, could disrupt our coal mining operations, adversely affect production and shipments and increase our operating costs:

- poor mining conditions resulting from geological, hydrologic or other conditions that may cause instability of highwalls or spoil piles or cause damage to nearby infrastructure or mine personnel;

a major incident at the mine site that causes all or part of the operations of the mine to cease for some period of time;

mining, processing and plant equipment failures and unexpected maintenance problems;

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adverse weather and natural disasters, such as heavy rains or snow, flooding and other natural events affecting operations, transportation or customers;

unexpected or accidental surface subsidence from underground mining;

accidental mine water discharges, fires, explosions or similar mining accidents; and

competition and/or conflicts with other natural resource extraction activities and production within our operating areas, such as coalbed methane extraction or oil and gas development.

If any of these conditions or events occurs, particularly at our Black Thunder mining complex, which accounted for approximately 67% of the coal volume we sold in 2011, our coal mining operations may be disrupted, we could experience a delay or halt of production or shipments or our operating costs could increase significantly. In addition, if our insurance coverage is limited or excludes certain of these conditions or events, then we may not be able to recover any of the losses we may incur as a result of such conditions or events, some of which may be substantial.

Competition within the coal industry could put downward pressure on coal prices and, as a result, materially and adversely affect our revenues and profitability.

We compete with numerous other coal producers in various regions of the United States for domestic sales. International demand for U.S. coal also affects competition within our industry. The demand for U.S. coal exports depends upon a number of factors outside our control, including the overall demand for electricity in foreign markets, currency exchange rates, ocean freight rates, port and shipping capacity, the demand for foreign-priced steel, both in foreign markets and in the U.S. market, general economic conditions in foreign countries, technological developments and environmental and other governmental regulations. Foreign demand for Central Appalachian coal has increased in recent periods. If foreign demand for U.S. coal were to decline, this decline could cause competition among coal producers for the sale of coal in the United States to intensify, potentially resulting in significant downward pressure on domestic coal prices.

In addition, during the mid-1970s and early 1980s, increased demand for coal attracted new investors to the coal industry, spurred the development of new mines and resulted in additional production capacity throughout the industry, all of which led to increased competition and lower coal prices. Increases in coal prices over the past several years have encouraged the development of expanded capacity by coal producers and may continue to do so. Any resulting overcapacity and increased production could materially reduce coal prices and therefore materially reduce our revenues and profitability.

Decreases in demand for electricity resulting from economic, weather changes or other conditions could adversely affect coal prices and materially and adversely affect our results of operations.

Our coal is primarily used as fuel for electricity generation. Overall economic activity and the associated demand for power by industrial users can have significant effects on overall electricity demand. An economic slowdown can significantly slow the growth of electrical demand and could result in contraction of demand for coal. Declines in international prices for coal generally will impact U.S. prices for coal. During the past several years, international demand for coal has been driven, in significant part, by fluctuations in demand due to economic growth in China and India as well as other developing countries. Significant declines in the rates of economic growth in these regions could materially affect international demand for U.S. coal, which may have an adverse effect on U.S. coal prices.

Weather patterns can also greatly affect electricity demand. 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 sources of power generation when deciding which generation sources to dispatch. Any downward pressure on coal prices, due to decreases in overall demand or otherwise, including changes in weather patterns, would materially and adversely affect our results of operations.

The use of alternative energy sources for power generation could reduce coal consumption by U.S. electric power generators, which could result in lower prices for our coal. Declines in the prices at which we sell our coal could reduce our revenues and materially and adversely affect our business and results of operations.

In 2011, approximately 91% of the tons we sold were to domestic electric power generators. The amount of coal consumed for U.S. electric power generation is affected by, among other things:

- the location, availability, quality and price of alternative energy sources for power generation, such as natural gas, fuel oil, nuclear, hydroelectric, wind, biomass and solar power; and

- technological developments, including those related to alternative energy sources.

Gas-fueled generation has the potential to displace coal-fueled generation, particularly from older, less efficient coal-powered generators. We expect that many of the new power plants needed to meet increasing demand for electricity generation will be fueled by natural gas because gas-fired plants are cheaper to construct and permits to construct these plants are easier to obtain as natural gas is seen as having a lower environmental impact than coal-fueled generators. In addition, state and federal mandates for increased use of electricity from renewable energy sources could have an impact on the market for our coal. Several states have enacted legislative mandates requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power. There have been numerous proposals to establish a similar uniform, national standard although none of these proposals have been enacted to date. Possible advances in technologies and incentives, such as tax credits, to enhance the economics of renewable energy sources could make these sources more competitive with coal. Any reduction in the amount of coal consumed by domestic electric power generators could reduce the price of coal that we mine and sell, thereby reducing our revenues and materially and adversely affecting our business and results of operations.

Our inability to acquire additional coal reserves or our inability to develop coal reserves in an economically feasible manner may adversely affect our business.

Our profitability depends substantially on our ability to mine and process, in a cost-effective manner, coal reserves that possess the quality characteristics desired by our customers. As we mine, our coal reserves decline. As a result, our future success depends upon our ability to acquire additional coal that is economically recoverable. If we fail to acquire or develop additional coal reserves, our existing reserves will eventually be depleted. We may not be able to obtain replacement reserves when we require them. If available, replacement reserves may not be available at favorable prices, or we may not be capable of mining those reserves at costs that are comparable with our existing coal reserves. Our ability to obtain coal reserves in the future could also be limited by the availability of cash we generate from our operations or available financing, restrictions under our existing or future financing arrangements, and competition from other coal producers, the lack of suitable acquisition or lease-by-application, or LBA, opportunities or the inability to acquire coal properties or LBAs on commercially reasonable terms. If we are unable to acquire replacement reserves, our future production may decrease significantly and our operating results may be negatively affected. In addition, we may not be able to mine future reserves as profitably as we do at our current operations.

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

Our future performance depends on, among other things, the accuracy of our estimates of our proven and probable coal reserves. We base our estimates of reserves on engineering, economic and geological data assembled, analyzed and reviewed by internal and third-party engineers and consultants. We update our estimates of the quantity and quality of proven and probable coal reserves annually to reflect the production of coal from the

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reserves, updated geological models and mining recovery data, the tonnage contained in new lease areas acquired and estimated costs of production and sales prices. There are numerous factors and assumptions inherent in estimating the quantities and qualities of, and costs to mine, coal reserves, including many factors beyond our control, including the following:

- quality of the coal;
- geological and mining conditions, which may not be fully identified by available exploration data and/or may differ from our experiences in areas where we currently mine;
- the percentage of coal ultimately recoverable;
- the assumed effects of regulation, including the issuance of required permits, taxes, including severance and excise taxes and royalties, and other payments to governmental agencies;
- assumptions concerning the timing for the development of the reserves; and
- assumptions concerning equipment and productivity, future coal prices, operating costs, including for critical supplies such as fuel, tires and explosives, capital expenditures and development and reclamation costs.

As a result, estimates of the quantities and qualities of economically recoverable coal attributable to any particular group of properties, classifications of reserves based on risk of recovery, estimated cost of production, and estimates of future net cash flows expected from these properties as prepared by different engineers, or by the same engineers at different times, may vary materially due to changes in the above factors and assumptions. Actual production recovered from identified reserve areas and properties, and revenues and expenditures associated with our mining operations, may vary materially from estimates. Any inaccuracy in our estimates related to our reserves could result in decreased profitability from lower than expected revenues and/or higher than expected costs.

Increases in the costs of mining and other industrial supplies, including steel-based supplies, diesel fuel and rubber tires, or the inability to obtain a sufficient quantity of those supplies, could negatively affect our operating costs or disrupt or delay our production.

Our coal mining operations use significant amounts of steel, diesel fuel, explosives, rubber tires and other mining and industrial supplies. The cost of roof bolts we use in our underground mining operations depend on the price of scrap steel. We also use significant amounts of diesel fuel and tires for the trucks and other heavy machinery we use, particularly at our Black Thunder mining complex. If the prices of mining and other industrial supplies, particularly steel-based supplies, diesel fuel and rubber tires, increase, our operating costs could be negatively affected. In addition, if we are unable to procure these supplies, our coal mining operations may be disrupted or we could experience a delay or halt in our production.

Disruptions in the quantities of coal produced by our contract mine operators or purchased from other third parties could temporarily impair our ability to fill customer orders or increase our operating costs.

We use independent contractors to mine coal at certain of our mining complexes, including select operations in our Appalachian segment. In addition, we purchase coal from third parties that we sell to our customers. Operational difficulties at contractor-operated mines or mines operated by third parties from whom we purchase coal, changes in demand for contract miners from other coal producers and other factors beyond our control could affect the availability, pricing, and quality of coal produced for or purchased by us. Disruptions in the quantities of coal produced for or purchased by us could impair our ability to fill our customer orders or require us to purchase coal from other sources in order to satisfy those orders. If we are unable to fill a customer order or if we are required to purchase coal from other sources in order to satisfy a customer order, we could lose existing customers and our operating costs could increase.

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

We have contracts to supply coal to energy trading and brokering companies under which they purchase the coal for their own account or resell the coal to end users. Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. If we determine that a customer is not creditworthy, we may not be required to deliver coal under the customer's coal sales contract. If this occurs, we may decide to sell the customer's coal on the spot market, which may be at prices lower than the contracted price, or we may be unable to sell the coal at all. Furthermore, the bankruptcy of any of our customers could materially and adversely affect our financial position. In addition, our customer base may change 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 for customer payment default. These new power plant owners may have credit ratings that are below investment grade, or may become below investment grade after we enter into contracts with them. In addition, competition with other coal suppliers could force us to extend credit to customers and on terms that could increase the risk of payment default.

A defect in title or the loss of a leasehold interest in certain property could limit our ability to mine our coal reserves or result in significant unanticipated costs.

We conduct a significant part of our coal mining operations on properties that we lease. A title defect or the loss of a lease could adversely affect our ability to mine the associated coal reserves. We may not verify title to our leased properties or associated coal reserves until we have committed to developing those properties or coal reserves. We may not commit to develop property or coal reserves until we have obtained necessary permits and completed exploration. As such, the title to property that we intend to lease or coal reserves that we intend to mine may contain defects prohibiting our ability to conduct mining operations. Similarly, our leasehold interests may be subject to superior property rights of other third parties. In order to conduct our mining operations on properties where these defects exist, we may incur unanticipated costs. In addition, some leases require us to produce a minimum quantity of coal and require us to pay minimum production royalties. Our inability to satisfy those requirements may cause the leasehold interest to terminate.

The availability and reliability of transportation facilities and fluctuations in transportation costs could affect the demand for our coal or impair our ability to supply coal to our customers.

We depend upon barge, ship, rail, truck and belt transportation systems, as well as seaborne vessels and port facilities, to deliver coal to our customers. Disruptions in transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks, and other events could impair our ability to supply coal to our customers. As we do not have long-term contracts with transportation providers to ensure consistent and reliable service, decreased performance levels over longer periods of time could cause our customers to look to other sources for their coal needs. In addition, increases in transportation costs, including the price of gasoline and diesel fuel, could make coal a less competitive source of energy when compared to alternative fuels or could make coal produced in one region of the United States less competitive than coal produced in other regions of the United States or abroad. If we experience disruptions in our transportation services or if transportation costs increase significantly and we are unable to find alternative transportation providers, our coal mining operations may be disrupted, we could experience a delay or halt of production or our profitability could decrease significantly.

Our profitability depends upon the long-term coal supply agreements we have with our customers. Changes in purchasing patterns in the coal industry could make it difficult for us to extend our existing long-term coal supply agreements or to enter into new agreements in the future.

We sell a portion of our coal under long-term coal supply agreements, which we define as contracts with terms greater than one year. Under these arrangements, we fix the prices of coal shipped during the initial year and may adjust the prices in later years. As a result, at any given time the market prices for similar-quality coal may exceed

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the prices for coal shipped under these arrangements. Changes in the coal industry may cause some of our customers not to renew, extend or enter into new long-term coal supply agreements with us or to enter into agreements to purchase fewer tons of coal than in the past or on different terms or prices. In addition, uncertainty caused by federal and state regulations, including the Clean Air Act, could deter our customers from entering into long-term coal supply agreements.

Because we sell a portion of our coal production under long-term coal supply agreements, our ability to capitalize on more favorable market prices may be limited. Conversely, at any given time we are subject to fluctuations in market prices for the quantities of coal that we have produced but which we have not committed to sell. As described above under "A substantial or extended decline in coal prices could negatively affect our profitability and the value of our coal reserves," the market prices for coal may be volatile and may depend upon factors beyond our control. Our profitability may be adversely affected if we are unable to sell uncommitted production at favorable prices or at all. For more information about our long-term coal supply agreements, you should see the section entitled "Long-Term Coal Supply Arrangements."

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

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. We decide whether to mine, process and market these coals as metallurgical or steam coal based on management's assessment as to which market is likely to provide us with a higher margin. We consider a number of factors when making this assessment, including the difference between the current and anticipated future market prices of steam coal and metallurgical coal and the increased costs incurred in producing coal for sale in the metallurgical market instead of the steam market. A decline in the metallurgical market relative to the steam market could cause us, as well as our competitors, to shift coal from the metallurgical market to the steam market, thereby reducing our revenues and profitability and increasing the availability of coal to customers in the steam market.

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

For the year ended December 31, 2011, we derived approximately 15% of our total coal revenues from sales to our three largest customers and approximately 37% of our total coal revenues from sales to our ten largest customers. We expect to renew, extend or enter into new long-term coal supply agreements with those and other customers. However, we may be unsuccessful in obtaining long-term coal supply agreements with those customers, and those customers may discontinue purchasing coal from us. If any of those customers, particularly any of our three largest customers, was to significantly reduce the quantities of coal it purchases from us, or if we are unable to sell coal to those customers on terms as favorable to us as the terms under our current long-term coal supply agreements, our profitability could suffer significantly. We have limited protection during adverse economic conditions and may face economic penalties if we are unable to satisfy certain quality specifications under our long-term coal supply agreements.

Our long-term coal supply agreements typically contain *force majeure* provisions allowing the parties to temporarily suspend performance during specified events beyond their control. Most of our long-term coal supply agreements also contain provisions requiring us to deliver coal that satisfies certain quality specifications, such as heat value, sulfur content, ash content, hardness and ash fusion temperature. These provisions in our long-term coal supply agreements could result in negative economic consequences to us, including price adjustments, purchasing replacement coal in a higher-priced open market, the rejection of deliveries or, in the extreme, contract termination. Our profitability may be negatively affected if we are unable to seek protection during adverse economic conditions or if we incur financial or other economic penalties as a result of these provisions of our long-term supply agreements.

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Failure to obtain or renew surety bonds on acceptable terms could affect our ability to secure reclamation and coal lease obligations and, therefore, our ability to mine or lease coal.

Federal and state laws require us to obtain surety bonds to secure performance or payment of certain long-term obligations, such as mine closure or reclamation costs, federal and state workers' compensation costs, coal leases and other obligations. We may have difficulty procuring or maintaining our surety bonds. Our bond issuers may demand higher fees, additional collateral, including letters of credit or other terms less favorable to us upon those renewals. Because we are required by state and federal law to have these bonds in place before mining can commence or continue, or failure to maintain surety bonds, letters of credit or other guarantees or security arrangements would materially and adversely affect our ability to mine or lease coal. That failure could result from a variety of factors, including lack of availability, higher expense or unfavorable market terms, the exercise by third party surety bond issuers of their right to refuse to renew the surety and restrictions on availability on collateral for current and future third party surety bond issuers under the terms of our financing arrangements.

Our profitability may be adversely affected if we must satisfy certain below-market contracts with coal we purchase on the open market or with coal we produce at our remaining operations.

We have agreed to guarantee Magnum's obligations to supply coal under certain coal sales contracts that we sold to Magnum. In addition, we have agreed to purchase coal from Magnum in order to satisfy our obligations under certain other contracts that have not yet been transferred to Magnum, the longest of which extends to the year 2017. If Magnum cannot supply the coal required under these coal sales contracts, we would be required to purchase coal on the open market or supply coal from our existing operations in order to satisfy our obligations under these contracts. At December 31, 2011, if we had purchased the 10.5 million tons of coal required under these contracts over their duration at market prices then in effect, we would have incurred a loss of approximately $214.7 million.

We may incur losses as a result of certain marketing, trading and asset optimization strategies.

We seek to optimize our coal production and leverage our knowledge of the coal industry through a variety of marketing, trading and other asset optimization strategies. We maintain a system of complementary processes and controls designed to monitor and control our exposure to market and other risks as a consequence of these strategies. These processes and controls seek to balance our ability to profit from certain marketing, trading and asset optimization strategies with our exposure to potential losses. While we employ a variety of risk monitoring and mitigation techniques, those techniques and accompanying judgments cannot anticipate every potential outcome or the timing of such outcomes. In addition, the processes and controls that we use to manage our exposure to market and other risks resulting from these strategies involve assumptions about the degrees of correlation or lack thereof among prices of various assets or other market indicators. These correlations may change significantly in times of market turbulence or other unforeseen circumstances. As a result, we may experience volatility in our earnings as a result of our marketing, trading and asset optimization strategies.

Recent international growth in our operations adds new and unique risks to our business.

Within the past year we opened offices in Singapore and the United Kingdom. The international expansion of our operations increases our exposure to country and currency risks. In addition, our international offices are selling our coal to new customers and customers in new countries, whose business practices and reputations are not as well known to us. We are also challenged by political risks by expanding internationally, including the potential for expropriation of assets and limits on the repatriation of earnings. In the event that we are unable to effectively manage these new risks, our results of operations, financial position or cash flow could be adversely affected by these activities.

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We may not be able to fully integrate the operations of ICG into our existing operations.

We believe that the acquisition of ICG will result in various benefits or synergies, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Arch Coal and ICG can be integrated in an efficient and effective manner. In addition, the combined company may experience unanticipated issues, expenses and liabilities.

It is possible that the integration process could take longer than anticipated or cost more than anticipated and could result in the loss of valuable employees, the disruption of each company's ongoing businesses, processes and systems or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, any of which could adversely affect our ability to achieve the anticipated benefits and synergies of the merger. The integration process is subject to a number of uncertainties, and no assurance can be given that the anticipated benefits will be realized or, if realized, the timing or cost of their realization. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect our future business, financial condition, operating results and prospects, and may cause the combined company's stock price to decline.

Risks Related to our Indebtedness

The amount of indebtedness we have incurred could significantly affect our business.

At December 31, 2011, we had consolidated indebtedness of approximately $4.0 billion. We also have significant lease and royalty obligations. Our ability to satisfy our debt, lease and royalty obligations, and our ability to refinance our indebtedness, will depend upon our future operating performance. Our ability to satisfy our financial obligations may be adversely affected if we incur additional indebtedness in the future. In addition, the amount of indebtedness we have incurred could have significant consequences to us, such as:

- limiting our ability to obtain additional financing to fund growth, such as new LBA acquisitions or other mergers and acquisitions, working capital, capital expenditures, debt service requirements or other cash requirements
- exposing us to the risk of increased interest costs if the underlying interest rates rise;
- limiting our ability to invest operating cash flow in our business due to existing debt service requirements;
- making it more difficult to obtain surety bonds, letters of credit or other financing, particularly during weak credit markets;
- causing a decline in our credit ratings;
- limiting our ability to compete with companies that are not as leveraged and that may be better positioned to withstand economic downturns;
- limiting our ability to acquire new coal reserves and/or plant and equipment needed to conduct operations; and
- limiting our flexibility in planning for, or reacting to, and increasing our vulnerability to, changes in our business, the industry in which we compete and general economic and market conditions.

If we further increase our indebtedness, the related risks that we now face, including those described above, could intensify. In addition to the principal repayments on our outstanding debt, we have other demands on our cash resources, including capital expenditures and operating expenses. Our ability to pay our debt depends upon our operating performance. In particular, economic conditions could cause our revenues to decline, and hamper our ability to repay our indebtedness. If we do not have enough cash to satisfy our debt service obligations, we may be

required to refinance all or part of our debt, sell assets or reduce our spending. We may not be able to, at any given time, refinance our debt or sell assets on terms acceptable to us or at all.

A failure of a financial institution to fulfill their commitments under our credit facility could adversely affect our business.

As of December 31, 2011, we had borrowings of $375 million under our $2 billion dollar revolving credit facility. This facility is provided by a syndicate of financial institutions, with each institution agreeing severally (and not jointly) to make revolving credit loans to us in accordance with the terms of the credit agreement. In the event one or more of these financial institutions were to default on their obligation to fund their respective portion of the commitment under the credit agreement, the portion of the facility provided by such defaulting financial institution would not be available to us and would result in a decrease in our available borrowing capacity under our credit agreement.

We may be unable to comply with restrictions imposed by our credit facilities and other financing arrangements.

The agreements governing our outstanding financing arrangements impose a number of restrictions on us. For example, the terms of our credit facilities, leases and other financing arrangements contain financial and other covenants that create limitations on our ability to borrow the full amount under our credit facilities, effect acquisitions or dispositions and incur additional debt and require us to maintain various financial ratios and comply with various other financial covenants. Our ability to comply with these restrictions may be affected by events beyond our control. A failure to comply with these restrictions could adversely affect our ability to borrow under our credit facilities or result in an event of default under these agreements. In the event of a default, our lenders and the counterparties to our other financing arrangements could terminate their commitments to us and declare all amounts borrowed, together with accrued interest and fees, immediately due and payable. If this were to occur, we might not be able to pay these amounts, or we might be forced to seek an amendment to our financing arrangements which could make the terms of these arrangements more onerous for us. As a result, a default under one or more of our existing or future financing arrangements could have significant consequences for us. For more information about some of the restrictions contained in our credit facilities, leases and other financial arrangements, you should see the section entitled "Liquidity and Capital Resources."

Risks Related to Environmental, Other Regulations and Legislation

Extensive environmental regulations, including existing and potential future regulatory requirements relating to air emissions, affect our customers and could reduce the demand for coal as a fuel source and cause coal prices and sales of our coal to materially decline.

Coal contains impurities, including but not limited to sulfur, mercury, chlorine, carbon and other elements or compounds, many of which are released into the air when coal is burned. The operations of our customers are subject to extensive environmental regulation particularly with respect to air emissions. For example, the federal 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 electric power plants, which are the largest end-users of our coal. A series of more stringent requirements relating to particulate matter, ozone, haze, mercury, sulfur dioxide, nitrogen oxide and other air pollutants are expected to be proposed or become effective in coming years. In addition, concerted conservation efforts that result in reduced electricity consumption could cause coal prices and sales of our coal to materially decline.

Considerable uncertainty is associated with these air emissions initiatives. The content of regulatory requirements in the United States is in the process of being developed, and many new regulatory initiatives remain subject to review by federal or state agencies or the courts. Stringent air emissions limitations are either in place or are likely to be imposed in the short to medium term, and these limitations will likely require significant emissions control expenditures for many coal-fueled power plants. As a result, these power plants may switch to other fuels

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that generate fewer of these emissions or may install more effective pollution control equipment that reduces the need for low sulfur coal, possibly reducing future demand for coal and a reduced need to construct new coal-fueled power plants. The EIA's expectations for the coal industry assume there will be a significant number of as yet unplanned coal-fired plants built in the future which may not occur. Any switching of fuel sources away from coal, closure of existing coal-fired plants, or reduced construction of new plants could have a material adverse effect on demand for and prices received for our coal. Alternatively, less stringent air emissions limitations, particularly related to sulfur, to the extent enacted could make low sulfur coal less attractive, which could also have a material adverse effect on the demand for and prices received for our coal.

You should see "Environmental and Other Regulatory Matters" for more information about the various governmental regulations affecting us.

Our failure to obtain and renew permits necessary for our mining operations could negatively affect our business.

Mining companies must obtain numerous permits that impose strict regulations on various environmental and operational matters in connection with coal mining. These include permits issued by various federal, state and local agencies and regulatory bodies. The permitting rules, and the interpretations of these rules, are complex, change frequently and are often subject to discretionary interpretations by the regulators, all of which may make compliance more difficult or impractical, and may possibly preclude the continuance of ongoing operations or the development of future mining operations. The public, including non-governmental organizations, anti-mining groups and individuals, have certain statutory rights to comment upon and submit objections to requested permits and environmental impact statements prepared in connection with applicable regulatory processes, and otherwise engage in the permitting process, including bringing citizens' lawsuits to challenge the issuance of permits, the validity of environmental impact statements or performance of mining activities. Accordingly, required permits may not be issued or renewed in a timely fashion or at all, or permits issued or renewed may be conditioned in a manner that may restrict our ability to efficiently and economically conduct our mining activities, any of which would materially reduce our production, cash flow and profitability.

Federal or state regulatory agencies have the authority to order certain of our mines to be temporarily or permanently closed under certain circumstances, which could materially and adversely affect our ability to meet our customers' demands.

Federal or state regulatory agencies have the authority under certain circumstances following significant health and safety incidents, such as fatalities, to order a mine to be temporarily or permanently closed. If this occurred, we may be required to incur capital expenditures to re-open the mine. In the event that these agencies order the closing of our mines, our coal sales contracts generally permit us to issue *force majeure* notices which suspend our obligations to deliver coal under these contracts. However, our customers may challenge our issuances of *force majeure* notices. If these challenges are successful, we may have to purchase coal from third-party sources, if it is available, to fulfill these obligations, incur capital expenditures to re-open the mines and/or negotiate settlements with the customers, which may include price reductions, the reduction of commitments or the extension of time for delivery or terminate customers' contracts. Any of these actions could have a material adverse effect on our business and results of operations.

Extensive environmental regulations impose significant costs on our mining operations, and future regulations could materially 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 environmental matters such as:

- limitations on land use;

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- mine permitting and licensing requirements;
- reclamation and restoration of mining properties after mining is completed;
- management of materials generated by mining operations;
- the storage, treatment and disposal of wastes;
- remediation of contaminated soil and groundwater;
- air quality standards;
- water pollution;
- protection of human health, plant-life and wildlife, including endangered or threatened species;
- protection of wetlands;
- the discharge of materials into the environment;
- the effects of mining on surface water and groundwater quality and availability; and
- the management of electrical equipment containing polychlorinated biphenyls.

The costs, liabilities and requirements associated with the laws and regulations related to these and other environmental matters may be costly and time-consuming and may delay commencement or continuation of exploration or production operations. We cannot assure you that we have been or will be at all times in compliance with the applicable laws and regulations. Failure to comply with these laws and 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 incur material costs and liabilities resulting from claims for damages to property or injury to persons arising from our operations. If we are pursued for sanctions, costs and liabilities in respect of these matters, our mining operations and, as a result, our profitability could be materially and adversely affected.

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 to change operations significantly or incur increased costs. Such changes could have a material adverse effect on our financial condition and results of operations. You should see the section entitled "Environmental and Other Regulatory Matters" for more information about the various governmental regulations affecting us.

If the assumptions underlying our estimates of reclamation and mine closure obligations are inaccurate, our costs could be greater than anticipated.

SMCRA and counterpart state laws and regulations establish operational, reclamation and closure standards for all aspects of surface mining, as well as most aspects of underground mining. We base our estimates of reclamation and mine closure liabilities on permit requirements, engineering studies and our engineering expertise related to these requirements. Our management and engineers periodically review these estimates. The estimates can change significantly if actual costs vary from our original assumptions or if governmental regulations change significantly. We are required to record new obligations as liabilities at fair value under generally accepted accounting principles. In estimating fair value, we considered the estimated current costs of reclamation and mine closure and applied inflation rates and a third-party profit, as required. The third-party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. The resulting estimated reclamation and mine closure obligations could change significantly if actual amounts change significantly from our assumptions, which could have a material adverse effect on our results of operations and financial condition.

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

Our operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time. We could become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and clean up of soil, surface water, groundwater, and other media. Such claims may arise, for example, out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or even for the entire share.

We maintain extensive coal refuse areas and slurry impoundments at a number of our mining complexes. Such areas and impoundments are subject to extensive regulation. Slurry impoundments have been known to fail, releasing large volumes of coal slurry into the surrounding environment. 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. 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.

Drainage flowing from or caused by mining activities can be acidic with elevated levels of dissolved metals, a condition referred to as "acid mine drainage," which we refer to as AMD. The treating of AMD can be costly. Although we do not currently face material costs associated with AMD, it is possible that we could incur significant costs in the future.

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

Judicial rulings that restrict how we may dispose of mining wastes could significantly increase our operating costs, discourage customers from purchasing our coal and materially harm our financial condition and operating results.

To dispose of mining overburden generated by our surface mining operations, we often need to obtain permits to construct and operate valley fills and surface impoundments. Some of these permits are Clean Water Act § 404 permits issued by the Army Corps of Engineers. Two of our operating subsidiaries were identified in an existing lawsuit, which challenged the issuance of such permits and asked that the Corps be ordered to rescind them. Two of our operating subsidiaries intervened in the suit to protect their interests in being allowed to operate under the issued permits, and one of them thereafter was dismissed. On February 13, 2009, the U.S. Court of Appeals for the Fourth Circuit ruled on appeals from decisions rendered prior to our intervention, which may have a favorable impact on our permits. The matter is pending before the U.S. District Court for the Southern District of West Virginia on Mingo Logan's motion for summary judgment.

Changes in the legal and regulatory environment could complicate or limit our business activities, increase our operating costs or result in litigation.

The conduct of our businesses is subject to various laws and regulations administered by federal, state and local governmental agencies in the United States. These laws and regulations may change, sometimes dramatically, as a result of political, economic or social events or in response to significant events. Certain recent developments particularly may cause changes in the legal and regulatory environment in which we operate and may impact our results or increase our costs or liabilities. Such legal and regulatory environment changes may include changes in: the processes for obtaining or renewing permits; costs associated with providing healthcare benefits to employees; health and safety standards; accounting standards; taxation requirements; and competition laws.

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For example, in April 2010, the EPA issued comprehensive guidance regarding the water quality standards that EPA believes should apply to certain new and renewed Clean Water Act permit applications for Appalachian surface coal mining operations. Under the EPA's guidance, applicants seeking to obtain state and federal Clean Water Act permits for surface coal mining in Appalachia must perform an evaluation to determine if a reasonable potential exists that the proposed mining would cause a violation of water quality standards. According to the EPA Administrator, the water quality standards set forth in the EPA's guidance may be difficult for most surface mining operations to meet. Additionally, the EPA's guidance contains requirements for the avoidance and minimization of environmental and mining impacts, consideration of the full range of potential impacts on the environment, human health and local communities, including low-income or minority populations, and provision of meaningful opportunities for public participation in the permit process. EPA's guidance is subject to several pending legal challenges related to its legal effect and sufficiency including consolidated challenges pending in Federal District Court in the District of Columbia led by the National Mining Association. We may be required to meet these requirements in the future in order to obtain and maintain permits that are important to our Appalachian operations. We cannot give any assurance that we will be able to meet these or any other new standards.

In response to the April 2010 explosion at Massey Energy Company's Upper Big Branch Mine and the ensuing tragedy, we expect that safety matters pertaining to underground coal mining operations will be the topic of new legislation and regulation, as well as the subject of heightened enforcement efforts. For example, federal and West Virginia state authorities have announced special inspections of coal mines to evaluate several safety concerns, including the accumulation of coal dust and the proper ventilation of gases such as methane. In addition, both federal and West Virginia state authorities have announced that they are considering changes to mine safety rules and regulations which could potentially result in additional or enhanced required safety equipment, more frequent mine inspections, stricter and more thorough enforcement practices and enhanced reporting requirements. Any new environmental, health and safety requirements may increase the costs associated with obtaining or maintain permits necessary to perform our mining operations or otherwise may prevent, delay or reduce our planned production, any of which could adversely affect our financial condition, results of operations and cash flows.

Further, mining companies are entitled a tax deduction for percentage depletion, which may allow for depletion deductions in excess of the basis in the mineral reserves. The deduction is currently being reviewed by the federal government for repeal. If repealed, the inability to take a tax deduction for percentage depletion could have a material impact on our financial condition, results of operations, cash flows and future tax payments.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

Our Properties

General

At December 31, 2011, we owned or controlled primarily through long-term leases approximately 32,135 acres of coal land in Ohio, 25,037 acres of coal land in Maryland, 33,238 acres of coal land in Virginia, 371,071 acres of coal land in West Virginia, 105,667 acres of coal land in Wyoming, 242,390 acres of coal land in Illinois, 62,822 acres of coal land in Utah, 234,401 acres of coal land in Kentucky, 19,267 acres of coal land in Montana, 21,802 acres of coal land in New Mexico, and 18,443 acres of coal land in Colorado. In addition, we also owned or controlled through long-term leases smaller parcels of property in Alabama, Indiana, Washington, Arkansas, California, and Texas. We lease approximately 123,505 acres of our coal land from the federal government and approximately 36,295 acres of our coal land from various state governments. Certain of our preparation plants or loadout facilities are located on properties held under leases which expire at varying dates over the next 30 years.

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Most of the leases contain options to renew. Our remaining preparation plants and loadout facilities are located on property owned by us or for which we have a special use permit.

Our executive headquarters occupy approximately 92,900 square feet of leased space at One CityPlace Drive, in St. Louis, Missouri. Our subsidiaries currently own or lease the equipment utilized in their mining operations. You should see "Our Mining Operations" for more information about our mining operations, mining complexes and transportation facilities.

Our Coal Reserves

We estimate that we owned or controlled approximately 5.33 billion tons of proven and probable recoverable reserves at December 31, 2011. This does not include an estimated 222 million tons of coal reserves in the South Hilight tract in Wyoming, for which we were awarded a federal coal lease in December 2011 but which has not yet been finalized. Our coal reserve estimates at December 31, 2011 were prepared by our engineers and geologists and reviewed by Weir International, Inc., a mining and geological consultant. Our coal reserve estimates are based on data obtained from our drilling activities and other available geologic data. Our coal reserve estimates are periodically updated to reflect past coal production and other geologic and mining data. Acquisitions or sales of coal properties will also change these estimates. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam.

Our coal reserve estimates include reserves that can be economically and legally extracted or produced at the time of their determination. In determining whether our reserves meet this standard, we take into account, among other things, our potential inability to obtain a mining permit, the possible necessity of revising a mining plan, changes in estimated future costs, changes in future cash flows caused by changes in costs required to be incurred to meet regulatory requirements and obtaining mining permits, variations in quantity and quality of coal, and varying levels of demand and their effects on selling prices. We use various assumptions in preparing our estimates of our coal reserves. You should see "Inaccuracies in our estimates of our coal reserves could result in decreased profitability from lower than expected revenues or higher than expected costs" contained under the heading "Risk Factors."

The following tables present our estimated assigned and unassigned recoverable coal reserves at December 31, 2011:

Total Assigned Reserves
(Tons in millions)

				Sulfur Content (lbs. per million Btus)				Reserve Control		Mining Method		Past Reserve Estimates[2]	
	Total Assigned Recoverable Reserves	Proven	Probable	<1.2	1.2-2.5	>2.5	As Received Btus per lb.[1]	Leased	Owned	Surface	Under-ground	2009	2010
Wyoming	1,474	1,454	20	1,396	78		8,837	1,474		1,474		1,733	1,605
Montana													
Utah	79	50	29	71	7	1	11,405	78	1		79	105	84
Colorado	88	76	12	88			11,374	88			88	75	64
Central App.	308	262	46	92	177	39	12,778	277	31	133	175	167	175
Northern App.	238	115	123		215	23		45	193	14	224		
Illinois	30	17	13			30	10,808	26	4		30		
Total	2,217	1,974	243	1,647	477	93	10,058	1,988	229	1,621	596	2,080	1,928

(1) As received Btus per lb. includes the weight of moisture in the coal on an as sold basis.

(2) Past Reserve Estimates does not include former ICG operations acquired on June 15, 2011.

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Total Unassigned Reserves
(Tons in millions)

	Total Unassigned Recoverable Reserves	Proven	Probable	Sulfur Content (lbs. per million Btus) <1.2	1.2-2.5	>2.5	As Received Btus per lb.[1]	Reserve Control Leased	Owned	Mining Method Surface	Under-ground
Wyoming	494	410	84	442	52		9,637	384	110	319	175
Montana	1,353	1,041	312	1,353			8,575	1,353		1,353	
Utah	38	20	18	34	4		11,024	37	1		38
Colorado	23	18	5	23			11,347	23			23
Central App.	320	187	133	96	167	57	12,988	259	61	50	270
Northern App.	198	95	103	2	92	104		47	151	6	192
Illinois	692	336	356			692	10,960	73	619	2	690
Total	3,118	2,107	1,011	1,950	315	853	10,046	2,176	942	1,730	1,388

(1) As received Btus per lb. includes the weight of moisture in the coal on an as sold basis.

Federal and state legislation controlling air pollution affects the demand for certain types of coal by limiting the amount of sulfur dioxide which may be emitted as a result of fuel combustion and encourages a greater demand for low-sulfur coal. All of our identified coal reserves have been subject to preliminary coal seam analysis to test sulfur content. Of these reserves, approximately 67.4% consist of compliance coal, or coal which emits 1.2 pounds or less of sulfur dioxide per million Btus upon combustion, while an additional 5.2% could be sold as low-sulfur coal. The balance is classified as high-sulfur coal. Most of our reserves are suitable for the domestic steam coal markets. A substantial portion of the low-sulfur and compliance coal reserves at a number of our Appalachian mining complexes may also be used as metallurgical coal.

The carrying cost of our coal reserves at December 31, 2011 was $5.7 billion, consisting of $108.6 million of prepaid royalties and a net book value of coal lands and mineral rights of $5.6 billion.

Reserve Acquisition Process

We acquire a significant portion of the coal we control in the western United States through LBA process. Under this process, before a mining company can obtain new coal reserves, the coal tract must be nominated for lease, and the company must win the lease through a competitive bidding process. The LBA process can last anywhere from two to five years from the time the coal tract is nominated to the time a final bid is accepted by the BLM. After the LBA is awarded, the company then conducts the necessary testing to determine what amount can be classified as reserves.

To initiate the LBA process, companies wanting to acquire additional coal must file an application with the BLM's state office indicating interest in a specific coal tract. The BLM reviews the initial application to determine whether the application conforms to existing land-use plans for that particular tract of land and that the application would provide for maximum coal recovery. The application is further reviewed by a regional coal team at a public meeting. Based on a review of the available information and public comment, the regional coal team will make a recommendation to the BLM whether to continue, modify or reject the application.

If the BLM determines to continue the application, the company that submitted the application will pay for a BLM-directed environmental analysis or an environmental impact statement to be completed. This analysis or impact statement is subject to publication and public comment. The BLM may consult with other governmental agencies during this process, including state and federal agencies, surface management agencies, Native American tribes or bands, the U.S. Department of Justice or others as needed. The public comment period for an analysis or impact statement typically occurs over a 60-day period.

After the environmental analysis or environmental impact statement has been issued and a recommendation has been published that supports the lease sale of the LBA tract, the BLM schedules a public competitive lease sale. The BLM prepares an internal estimate of the fair market value of the coal that is based on its economic analysis

and comparable sales analysis. Prior to the lease sale, companies interested in acquiring the lease must send sealed bids to the BLM. The bid amounts for the lease are payable in five annual installments, with the first 20% installment due when the mining operator submits its initial bid for an LBA. Before the lease is approved by the BLM, the company must first furnish to the BLM an initial rental payment for the first year of rent along with either a bond for the next 20% annual installment payment for the bid amount, or an application for history of timely payment, in which case the BLM may waive the bond requirement if the company successfully meets all the qualifications of a timely payor. The bids are opened at the lease sale. If the BLM decides to grant a lease, the lease is awarded to the company that submitted the highest total bid meeting or exceeding the BLM's fair market value estimate, which is not published. The BLM, however, is not required to grant a lease even if it determines that a bid meeting or exceeding the fair market value of the coal has been submitted. The winning bidder must also submit a report setting forth the nature and extent of its coal holdings to the U.S. Department of Justice for a 30-day antitrust review of the lease. If the successful bidder was not the initial applicant, the BLM will refund the initial applicant certain fees it paid in connection with the application process, for example the fees associated with the environmental analysis or environmental impact statement, and the winning bidder will bear those costs. Coal won through the LBA process and subject to federal leases are administered by the U.S. Department of Interior under the Federal Coal Leasing Amendment Act of 1976. In addition, we occasionally add small coal tracts adjacent to our existing LBAs through an agreed upon lease modification with the BLM. Once the BLM has issued a lease, the company must also complete the permitting process before it can mine the coal. You should see the section entitled "Environmental and Other Regulatory Matters."

Most of our federal coal leases have an initial term of 20 years and are renewable for subsequent 10-year periods and for so long thereafter as coal is produced in commercial quantities. These leases require diligent development within the first ten years of the lease award with a required coal extraction of 1.0% of the total coal under the lease by the end of that 10-year period. At the end of the 10-year development period, the lessee is required to maintain continuous operations, as defined in the applicable leasing regulations. In certain cases a lessee may combine contiguous leases into a logical mining unit, which we refer to as an LMU. This allows the production of coal from any of the leases within the LMU to be used to meet the continuous operation requirements for the entire LMU. Some of our mines are also subject to coal leases with applicable state regulatory agencies and have different terms and conditions that we must adhere to in a similar way to our federal leases. Under these federal and state leases, if the leased coal is not diligently developed during the initial 10-year development period or if certain other terms of the leases are not complied with, including the requirement to produce a minimum quantity of coal or pay a minimum production royalty, if applicable, the BLM or the applicable state regulatory agency can terminate the lease prior to the expiration of its term.

Title to Coal Property

Title to coal properties held by lessors or grantors to us and our subsidiaries and the boundaries of properties are normally verified at the time of leasing or acquisition. However, in cases involving less significant properties and consistent with industry practices, title and boundaries are not completely verified until such time as our independent operating subsidiaries prepare to mine such reserves. If defects in title or boundaries of undeveloped reserves are discovered in the future, control of and the right to mine such reserves could be adversely affected. You should see "A defect in title or the loss of a leasehold interest in certain property could limit our ability to mine our coal reserves or result in significant unanticipated costs" contained under the heading "Risk Factors" for more information.

At December 31, 2011, approximately 21.9% of our coal reserves were held in fee, with the balance controlled by leases, most of which do not expire until the exhaustion of mineable and merchantable coal. Under current mining plans, substantially all reported leased reserves will be mined out within the period of existing leases or within the time period of assured lease renewals. Royalties are paid to lessors either as a fixed price per ton or as a percentage of the gross sales price of the mined coal. The majority of the significant leases are on a percentage royalty basis. In some cases, a payment is required, payable either at the time of execution of the lease or in annual installments. In most cases, the prepaid royalty amount is applied to reduce future production royalties.

From time to time, lessors or sublessors of land leased by our subsidiaries have sought to terminate such leases on the basis that such subsidiaries have failed to comply with the financial terms of the leases or that the mining and related operations conducted by such subsidiaries are not authorized by the leases. Some of these allegations relate to leases upon which we conduct operations material to our consolidated financial position, results of operations and liquidity, but we do not believe any pending claims by such lessors or sublessors have merit or will result in the termination of any material lease or sublease.

We leased approximately 40,911 acres of property to other coal operators in 2011. We received royalty income of $8.2 million in 2011 from the mining of approximately 2.9 million tons, $4.1 million in 2010 from the mining of approximately 1.8 million tons, and $6.3 million in 2009 from the mining of approximately 2.2 million tons on those properties. We have included reserves at properties leased by us to other coal operators in the reserve figures set forth in this report.

ITEM 3. LEGAL PROCEEDINGS.

In addition to the following matters, we are involved in various claims and legal actions arising in the ordinary course of business, including employee injury claims. After conferring with counsel, it is the opinion of management that the ultimate resolution of these claims, to the extent not previously provided for, will not have a material adverse effect on our consolidated financial condition, results of operations or liquidity.

Permit Litigation Matters

Surface mines at our Mingo Logan and Coal-Mac mining operations were identified in an existing lawsuit brought by the Ohio Valley Environmental Coalition (OVEC) in the U.S. District Court for the Southern District of West Virginia as having been granted Clean Water Act § 404 permits by the Army Corps of Engineers ("Corps"), allegedly in violation of the Clean Water Act and the National Environmental Policy Act. The lawsuit, brought by OVEC in September 2005, originally was filed against the Corps for permits it had issued to four subsidiaries of a company unrelated to us or our operating subsidiaries. The suit claimed that the Corps had issued permits to the subsidiaries of the unrelated company that did not comply with the National Environmental Policy Act and violated the Clean Water Act.

The court ruled on the claims associated with those four permits in orders of March 23 and June 13, 2007. In the first of those orders, the court rescinded the four permits, finding that the Corps had inadequately assessed the likely impact of valley fills on headwater streams and had relied on inadequate or unproven mitigation to offset those impacts. In the second order, the court entered a declaratory judgment that discharges of sediment from the valley fills into sediment control ponds constructed in-stream to control that sediment must themselves be permitted under a different provision of the Clean Water Act, § 402, and meet the effluent limits imposed on discharges from these ponds. Both of the district court rulings were appealed to the U.S. Court of Appeals for the Fourth Circuit.

Before the court entered its first order, the plaintiffs were permitted to amend their complaint to challenge the Coal-Mac and Mingo Logan permits. Plaintiffs sought preliminary injunctions against both operations, but later reached agreements with our operating subsidiaries that have allowed mining to progress in limited areas while the district court's rulings were on appeal. The claims against Coal-Mac were thereafter dismissed.

In February 2009, the Fourth Circuit reversed the District Court. The Fourth Circuit held that the Corps' jurisdiction under Section 404 of the Clean Water Act is limited to the narrow issue of the filling of jurisdictional waters. The court also held that the Corps' findings of no significant impact under the National Environmental Policy Act and no significant degradation under the Clean Water Act are entitled to deference. Such findings entitle the Corps to avoid preparing an environmental impact statement, the absence of which was one issue on appeal.

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These holdings also validated the type of mitigation projects proposed by our operations to minimize impacts and comply with the relevant statutes. Finally, the Fourth Circuit found that stream segments, together with the sediment ponds to which they connect, are unitary "waste treatment systems," not "waters of the United States," and that the Corps' had not exceeded its authority in permitting them.

OVEC sought rehearing before the entire appellate court, which was denied in May, 2009, and the decision was given legal effect in June 2009. An appeal to the U.S. Supreme Court was then filed in August 2009. On August 3, 2010 OVEC withdrew its appeal.

Mingo Logan filed a motion for summary judgment with the district court in July 2009, asking that judgment be entered in its favor because no outstanding legal issues remained for decision as a result of the Fourth Circuit's February 2009 decision. By a series of motions, the United States obtained extensions and stays of the obligation to respond to the motion in the wake of its letters to the Corps dated September 3 and October 16, 2009 (discussed below). By order dated April 22, 2010, the District Court stayed the case as to Mingo Logan for the shorter of either six months or the completion of the U.S. Environmental Protection Agency's (the "EPA") proposed action to deny Mingo Logan the right to use its Corps' permit (as discussed below). The stay currently remains in effect.

On October 15, 2010, the United States moved to extend the existing stay for an additional 120 days (until February 22, 2011) while the EPA Administrator reviewed the "Recommended Determination" issued by the EPA Region 3. By Memorandum Opinion and Order dated November 2, 2010, the court granted the United States' motion. On January 13, 2011, the EPA issued its "Final Determination" to withdraw the specification of two of the three watersheds as a disposal site for dredged or fill material approved under the current Section 404 permit. The court has been notified of the Final Determination and by order dated March 21, 2011 stayed further proceedings in the case until further order of the court, in light of the challenge to the EPA's "Final Determination" currently pending in federal court in Washington, DC (as described below).

EPA Actions Related to Water Discharges from the Spruce Permit

By letter of September 3, 2009, the EPA asked the Corps of Engineers to suspend, revoke or modify the existing permit it issued in January 2007 to Mingo Logan under Section 404 of the Clean Water Act, claiming that "new information and circumstances have arisen which justify reconsideration of the permit." By letter of September 30, 2009, the Corps of Engineers advised the EPA that it would not reconsider its decision to issue the permit. By letter of October 16, 2009, the EPA advised the Corps that it has "reason to believe" that the Mingo Logan mine will have "unacceptable adverse impacts to fish and wildlife resources" and that it intends to issue a public notice of a proposed determination to restrict or prohibit discharges of fill material that already are approved by the Corps' permit. By federal register publication dated April 2, 2010, the EPA issued its "Proposed Determination to Prohibit, Restrict or Deny the Specification, or the Use for Specification of an Area as a Disposal Site: Spruce No. 1 Surface Mine, Logan County, WV" pursuant to Section 404(c) of the Clean Water Act, the EPA accepted written comments on its proposed action (sometimes known as a "veto proceeding"), through June 4, 2010 and conducted a public hearing, as well, on May 18, 2010. We submitted comments on the action during this period. On September 24, 2010, the EPA Region 3 issued a "Recommended Determination" to the EPA Administrator recommending that the EPA prohibit the placement of fill material in two of the three watersheds for which filling is approved under the current Section 404 permit. Mingo Logan, along with the Corps, West Virginia DEP and the mineral owner, engaged in a consultation with the EPA as required by the regulations, to discuss "corrective action" to address the "unacceptable adverse effects" identified. On January 13, 2011, the EPA issued its "Final Determination" pursuant to Section 404(c) of the Clean Water Act to withdraw the specification of two of the three watersheds approved in the current Section 404 permit as a disposal site for dredged or fill material. By separate action, Mingo Logan sued the EPA on April 2, 2010 in federal court in Washington, D.C. seeking a ruling that the EPA has no authority under the Clean Water Act to veto a previously issued permit (Mingo Logan Coal Company, Inc. v. USEPA, No. 1:10-cv-00541(D.D.C.)). The EPA moved to dismiss that action, and we responded to that motion. The court has been notified of the "Final Determination" and on February 23, 2011 entered a scheduling order for summary disposition of the case.

Summary judgment motions by both parties have been fully briefed. On November 30, 2011, the court heard arguments from the parties limited only to the threshold issue of whether the EPA had the authority under Section 404(c) of the Clean Water Act to withdraw the specification of the disposal site after the Corps had already issued a permit under Section 404(a). The court deferred consideration of the remaining issue (i.e. whether the EPA's "Final Determination" is otherwise lawful) until after consideration of the threshold issue. The case has been submitted on the limited, threshold issue and is pending before the court.

Clean Water Act Request for Information

In January 2008, we received a request from the EPA for certain information related to compliance with effluent limitations and water quality standards under Section 308 of the Clean Water Act applicable to our eastern mining complexes located in West Virginia, Virginia and Kentucky. The request focuses on our compliance with water quality standards and effluent limitations at numerous outfalls as identified in the various NPDES permits applicable to our eastern mining complexes for the period beginning on January 1, 2003 through January 1, 2008. The compliance reporting mechanism is contained in Discharge Monitoring Reports which are required to be prepared and submitted quarterly to state environmental agencies and contain detailed monthly compliance data. In July 2008, the EPA referred the request to the U.S. Department of Justice. We negotiated a compromise with the Department of Justice, the EPA, the West Virginia Department of Environmental Protection and Kentucky Energy and Environment Cabinet to fully and finally resolve the issues identified in the EPA's Section 308 Request for Information. The compromise is contained in a consent decree which includes certain elements of injunctive relief and a penalty in the amount of $4 million. By Memorandum Opinion and Order dated November 7, 2011, the U.S. District Court for the Southern District of West Virginia approved and entered the consent decree.

Sago Mine Litigation Matters

On August 23, 2006, a survivor of the Sago mine accident, Randal McCloy, filed a complaint in the Kanawha Circuit Court in Kanawha County, West Virginia. The claims brought by Randal McCloy and his family against ICG and certain of its subsidiaries, and against W.L. Ross & Co., and Wilbur L. Ross, Jr., individually, were dismissed on February 14, 2008, after the parties reached a confidential settlement. Sixteen other complaints were filed in Kanawha Circuit Court by the representatives of many of the miners who died in the Sago mine accident, and several of these plaintiffs filed amended complaints to expand the group of defendants in the cases. The complaints alleged various causes of action against ICG and its subsidiary, Wolf Run Mining Company, one of its 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 ("SCSR") devices worn by the miners at the Sago mine. Some of these third parties have been dismissed from the actions upon settlement. The amended complaints added other of ICG's subsidiaries to the cases, including ICG, Inc., ICG, LLC and Hunter Ridge Coal Company, unnamed parent, subsidiary and affiliate companies of ICG, W.L. Ross & Co., and Wilbur L. Ross, Jr., and other third parties, including a provider of electrical services and a supplier of components used in the SCSR devices. In addition to the dismissal of the McCloy claim, ICG previously settled and dismissed five other actions. These settlements required the release of ICG, its subsidiaries, W.L. Ross & Co., and Wilbur L. Ross, Jr. The court scheduled the matter for trial on all remaining claims and ordered the parties to mediate. The parties reached a confidential settlement on all remaining claims after engaging in mediation and the Court approved the settlement.

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Allegheny Energy Contract Matter

Allegheny Energy Supply ("Allegheny"), the sole customer of coal produced at our subsidiary Wolf Run Mining Company's ("Wolf Run") Sycamore No. 2 mine, filed a lawsuit against Wolf Run, Hunter Ridge Holdings, Inc. ("Hunter Ridge"), and ICG in state court in Allegheny County, Pennsylvania on December 28, 2006, and amended its complaint on April 23, 2007. Allegheny claimed that Wolf Run breached a coal supply contract when it declared force majeure under the contract upon idling the Sycamore No. 2 mine in the third quarter of 2006, and that Wolf Run continued to breach the contract by failing to ship in volumes referenced in the contract. The Sycamore No. 2 mine was idled after encountering adverse geologic conditions and abandoned gas wells that were previously unidentified and unmapped.

After extensive searching for gas wells and rehabilitation of the mine, it was re-opened in 2007, but with notice to Allegheny that it would necessarily operate at reduced volumes in order to safely and effectively avoid the many gas wells within the reserve. The amended complaint also alleged that the production stoppages constitute a breach of the guarantee agreement by Hunter Ridge and breach of certain representations made upon entering into the contract in early 2005. Allegheny voluntarily dropped the breach of representation claims later. Allegheny claimed that it would incur costs in excess of $100 million to purchase replacement coal over the life of the contract. ICG, Wolf Run and Hunter Ridge answered the amended complaint on August 13, 2007, disputing all of the remaining claims.

On November 3, 2008, ICG, Wolf Run and Hunter Ridge filed an amended answer and counterclaim against the plaintiffs seeking to void the coal supply agreement due to, among other things, fraudulent inducement and conspiracy. On September 23, 2009, Allegheny filed a second amended complaint alleging several alternative theories of liability in its effort to extend contractual liability to ICG, which was not a party to the original contract and did not exist at the time Wolf Run and Allegheny entered into the contract.

No new substantive claims were asserted. ICG answered the second amended complaint on October 13, 2009, denying all of the new claims. The Company's counterclaim was dismissed on motion for summary judgment entered on May 11, 2010. Allegheny's claims against ICG were also dismissed by summary judgment, but the claims against Wolf Run and Hunter Ridge were not. The court conducted a non-jury trial of this matter beginning on January 10, 2011 and concluding on February 1, 2011. At the trial, Allegheny presented its evidence for breach of contract and claimed that it is entitled to past and future damages in the aggregate of between $228 million and $377 million. Wolf Run and Hunter Ridge presented their defense of the claims, including evidence with respect to the existence of force majeure conditions and excuse under the contract and applicable law. Wolf Run and Hunter Ridge presented evidence that Allegheny's damages calculations were significantly inflated because it did not seek to determine damages as of the time of the breach and in some instances artificially assumed future nondelivery or did not take into account the apparent requirement to supply coal in the future. On May 2, 2011, the trial court entered a Memorandum and Verdict determining that Wolf Run had breached the coal supply contract and that the performance shortfall was not excused by force majeure. The trial court awarded total damages and interest in the amount of $104.1 million. ICG and Allegheny filed post-verdict motions in the trial court and on August 23, 2011, the court denied the parties' motions. The court entered a final judgment on August 25, 2011, in the amount of $104.1 million, which included pre-judgment interest. The parties appealed the lower court's decision to the Superior Court of Pennsylvania. Wolf Run and Hunter Ridge have filed an appeal bond in the amount of $124.9 million. Briefing is underway and will be completed in early 2012.

Saratoga Class Action Matter

On January 7, 2008, Saratoga Advantage Trust ("Saratoga") filed a class action lawsuit in the U.S. District Court for the Southern District of West Virginia against ICG and certain of its officers and directors seeking unspecified damages. The complaint asserts claims under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, and Rule 10b-5 promulgated thereunder, based on alleged false and misleading statements in the registration statements filed in connection with ICG's November 2005 reorganization and December 2005 public offering of common stock. In addition, the complaint challenges other of ICG's public statements regarding its operating condition and safety record. On July 6, 2009, Saratoga filed an amended complaint asserting essentially the same claims but seeking to add an individual co-plaintiff. ICG has filed a motion to dismiss the amended complaint. In June 2011, ICG agreed to settle this matter for a total of $1.375 million. On August 1, 2011, the court issued its order preliminarily approving settlement and conducted a settlement fairness hearing on November 14, 2011. The matter is pending Court approval.

ICG Eastern

On June 11, 2010, the West Virginia Department of Environmental Protection ("WVDEP") filed suit against ICG Eastern, LLC ("ICG Eastern") alleging violations of the West Virginia Water Pollution Control/National Pollutant Discharge Elimination System ("WVNPDES") and Surface Mine Permits for ICG Eastern's Birch River surface mine. The WVDEP alleges that ICG Eastern has failed to fully comply with the effluent limits for aluminum, manganese, pH, iron and selenium contained in its WVNPDES permit. The complaint further alleges that violations of the WVNPDES permit effluent limits have caused violations of water quality standards for the same parameters in the streams receiving the discharges from this mine. The WVDEP also alleges that violations of the effluent limits in the WVNPDES permits are also violations of the regulations governing surface mining in West Virginia. ICG Eastern and the WVDEP executed a settlement agreement that will require ICG Eastern to pay a monetary penalty of $0.2 million and accept the imposition of a compliance schedule related to selenium and other water quality parameters. The settlement agreement was submitted to the Webster County Circuit Court on December 30, 2010, was made available for public comment by the WVDEP and was thereafter entered by the court on April 18, 2011. The settlement agreement resolves all of the WVDEP's claims in the suit. In a supplemental consent decree, WVDEP and ICG negotiated and agreed to a resolution related to certain alleged selenium effluent limit violations beginning after April 5, 2010 which were reserved from the original consent decree due to both administrative appeal board and state circuit court stays. The court approved and entered the supplemental consent decree by order dated November 4, 2011 and filed November 7, 2011.

ICG Hazard

The Sierra Club, on December 3, 2010, filed a Notice of Intent ("NOI") to sue ICG Hazard, LLC ("Hazard") alleging violations of the Clean Water Act and the Surface Mining Control and Reclamation Act of 1977 at Hazard's Thunder Ridge surface mine. The NOI, which was supplemented by a revised filing on February 24, 2011, claims that Hazard is discharging selenium and contributing to conductivity levels in the receiving streams in violation of state and federal regulations. On May 24, 2011, the Sierra Club sued Hazard in U.S. District Court for the Eastern District of Kentucky under the Citizens Suit provisions of the Clean Water Act and the Surface Mining Control and Reclamation Act seeking civil penalties, injunctive relief and attorneys' fees.

Kentucky Energy and Environment Cabinet

On December 3, 2010, the Kentucky Energy and Environment Cabinet ("Cabinet") filed suit against Hazard, ICG Knott County, LLC, ICG East Kentucky, LLC and Powell Mountain Energy, LLC (collectively, "KY Operations") alleging that the KY Operations failed to comply with the terms and conditions of the Kentucky Pollutant Discharge Elimination System ("KPDES") permits issued by the Cabinet's Division of Water to the KY Operations. Among the claims lodged by the Cabinet were allegations that contract water monitoring laboratories retained by the KY Operations did not adhere to the practices and procedures required for conducting KPDES monitoring, the contract laboratories failed to properly document and maintain records of the monitoring and the KY Operations submitted quarterly Discharge Monitoring Reports that sometimes contained inaccurate, incomplete and erroneous information. The KY Operations and the Cabinet entered a proposed Consent Judgment contemporaneously with the filing of the complaint that, if approved by the Franklin County (KY) Circuit Court, will require the KY Operations to pay a monetary penalty of $0.4 million, to prepare and implement a Corrective Action Plan that corrects the deficiencies in the respective KPDES monitoring programs, to identify the responsible

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corporate officers for each KPDES permit and to provide specific detailed information in support of the Discharge Monitoring Reports to be filed for the fourth quarter 2010 and first quarter 2011. Final resolution of this matter is pending approval by the court. On February 11, 2011, the court entered an order allowing certain anti-mining groups to intervene in the action to contest the validity of the Consent Judgment. The hearing on the entry of the Consent Judgment was held beginning August 30, 2011 and the matter is pending a decision from the court.

By letter dated June 28, 2011, Appalachian Voices, Inc., Waterkeeper Alliance, Inc., Kentuckians for the Commonwealth, Inc., Kentucky Riverkeeper, Inc., Ms. Pat Banks, Ms. Lanny Evans, Mr. Thomas H. Bonny, and Mr. Winston Merrill Combs (collectively, "Appalachian Voices") filed a NOI to sue the KY Operations for alleged violations of the Clean Water Act. The NOI claims that ICG has violated and continues to violate effluent standards or limitations under the Clean Water Act in reference to KPDES Coal General Permit. The NOI also alleges a lack of diligent prosecution related to the lawsuit filed by the Kentucky Energy and Environment Cabinet (as referenced and described above). On October 25, 2011, Appalachian Voices sued the KY Operations in U.S. District Court for the Eastern District of Kentucky under the Citizens Suit provisions of the Clean Water Act seeking civil penalties, injunctive relief and attorneys' fees.

ITEM 4. MINE SAFETY DISCLOSURES.

The statement concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95 to this Annual Report on Form 10-K for the fiscal year ended December 31, 2011.

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PART II

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

Market for Registrant's Common Equity and Related Stockholder Matters

Our common stock is listed and traded on the New York Stock Exchange under the symbol "ACI". On February 15, 2012, our common stock closed at $14.05 on the New York Stock Exchange. On that date, there were approximately 7,100 holders of record of our common stock.

Holders of our common stock are entitled to receive dividends when they are declared by our board of directors. When dividends are declared on common stock, they are usually paid in mid-March, June, September and December. We paid dividends on our common stock totaling $80.7 million, or $0.43 per share, in 2011 and $63.4 million, or $0.39 per share, in 2010. There is no assurance as to the amount or payment of dividends in the future because they are dependent on our future earnings, capital requirements and financial condition. You should see the section entitled "Liquidity and Capital Resources" for more information about restrictions on our ability to declare dividends.

The following table sets forth for each period indicated the dividends paid per common share, the high and low sale prices of our common stock and the closing price of our common stock on the last trading day for each of the quarterly periods indicated.

	2011			
	March 31	**June 30**	**September 30**	**December 30**
Dividends per common share	$ 0.10	$ 0.11	$ 0.11	$ 0.11
High	20.15	18.90	15.73	18.08
Low	19.96	18.56	15.19	17.88
Close	20.05	18.86	15.22	17.91

	2010			
	March 31	**June 30**	**September 30**	**December 31**
Dividends per common share	$ 0.09	$ 0.10	$ 0.10	$ 0.10
High	28.34	28.52	27.08	35.52
Low	20.07	19.26	19.09	24.20
Close	22.85	19.81	26.71	35.06

Stock Price Performance Graph

The following performance graph compares the cumulative total return to stockholders on our common stock with the cumulative total return on two indices: a peer group, consisting of CONSOL Energy, Inc., Alpha Natural Resources, Inc., Massey Energy Company and Peabody Energy Corp., and the Standard & Poor's (S&P) 400 (Midcap) Index. The graph assumes that:

- you invested $100 in Arch Coal common stock and in each index at the closing price on December 31, 2006;
- all dividends were reinvested;
- annual reweighting of the peer groups; and
- you continued to hold your investment through December 31, 2011.

You are cautioned against drawing any conclusions from the data contained in this graph, as past results are not necessarily indicative of future performance. The indices used are included for comparative purposes only and do

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not indicate an opinion of management that such indices are necessarily an appropriate measure of the relative performance of our common stock.

*$100 invested on 12/31/06 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

	12/06	12/07	12/08	12/09	12/10	12/11
Arch Coal, Inc	100.00	150.79	55.22	77.01	123.38	52.07
S&P Midcap 400	100.00	107.98	68.86	94.60	119.80	117.72
Industry Peer Group	100.00	187.50	73.56	144.51	183.12	102.25

Issuer Purchases of Equity Securities

In September 2006, our board of directors authorized a share repurchase program for the purchase of up to 14,000,000 shares of our common stock. There is no expiration date on the current authorization, and we have not made any decisions to suspend or cancel purchases under the program. As of December 31, 2011, we have purchased 3,074,200 shares of our common stock under this program. We did not purchase any shares of our common stock under this program during the quarter ended December 31, 2011. Based on the closing price of our common stock as reported on the New York Stock Exchange on February 15, 2012, there is approximately $153.5 million of our common stock that may yet be purchased under this program.

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ITEM 6. SELECTED FINANCIAL DATA.

	2011(1)	2010(2)(3)	2009(4)	2008	2007(5)
Statement of Operations Data:					
Revenues	$ 4,285,895	$ 3,186,268	$ 2,576,081	$ 2,983,806	$ 2,413,644
Change in fair value of coal derivatives and trading activities, net	2,907	(8,924)	12,056	55,093	7,292
Acquisition and transition costs	(54,676)		(13,726)		
Income from operations	413,576	323,984	123,714	461,270	230,631
Non-operating expenses	(51,448)	(6,776)			(2,273)
Net income attributable to Arch Coal	141,683	158,857	42,169	354,330	174,929
Basic earnings per common share	$ 0.75	$ 0.98	$ 0.28	$ 2.47	$ 1.23
Diluted earnings per common share	$ 0.74	$ 0.97	$ 0.28	$ 2.45	$ 1.21
Balance Sheet Data:					
Total assets	$ 10,213,959	$ 4,880,769	$ 4,840,596	$ 3,978,964	$ 3,594,599
Working capital	162,106	207,568	55,055	46,631	(35,370)
Long-term debt, less current maturities	3,762,297	1,538,744	1,540,223	1,098,948	1,085,579
Other long-term obligations	864,667	566,728	544,578	482,651	412,484
Noncurrent deferred income tax liability	976,753				
Arch Coal stockholders' equity	3,578,040	2,237,507	2,115,106	1,728,733	1,531,686
Common Stock Data:					
Dividends per share	$ 0.4300	$ 0.3900	$ 0.3600	$ 0.3400	$ 0.2700
Shares outstanding at year-end	211,671	162,605	162,441	142,833	143,158
Cash Flow Data:					
Cash provided by operating activities	$ 642,242	$ 697,147	$ 382,980	$ 679,137	$ 330,810
Depreciation, depletion and amortization, including amortization of acquired sales contracts, net	444,518	400,672	321,231	292,848	242,062
Capital expenditures	540,936	314,657	323,150	497,347	488,363
Acquisitions of businesses, net of cash acquired	2,894,339		768,819		
Net proceeds from the issuance of long term debt	1,906,306	500,000	570,322		
Net proceeds from the sale of common stock	1,267,933		326,452		
Payments to retire debt, including redemption premium	605,178	505,627			
Net increase (decrease) in borrowings under lines of credit and commercial paper program	424,396	(196,549)	(85,815)	13,493	133,476
Dividend payments	80,748	63,373	54,969	48,847	38,945
Operating Data:					
Tons sold	156,897	162,763	126,116	139,595	135,010
Tons produced	151,829	156,282	119,568	133,107	126,624
Tons purchased from third parties	5,557	6,825	7,477	6,037	8,495

(1) On June 15, 2011, we completed our acquisition of ICG, a leading coal producer, adding 12 mining complexes in Appalachia, one complex in the Illinois Basin and one mine under development in Appalachia, along with other coal reserves not currently in development. To finance the acquisition, we sold of 48.7 million shares of our common stock and issued $2.0 billion in aggregate principal amount of senior unsecured notes. We directly expensed costs related to the financing and acquisition of $104.2 million.

(2) In the second quarter of 2010, we exchanged 68.4 million tons of coal reserves in the Illinois Basin for an additional 9% ownership interest in Knight Hawk Holdings, LLC (Knight Hawk), increasing our ownership to 42%. We recognized a pre-tax gain of $41.6 million on the transaction, representing the difference between the fair value and net book value of the coal reserves, adjusted for our retained ownership interest in the reserves through the investment in Knight Hawk.

(3) On August 9, 2010, we issued $500.0 million in aggregate principal amount of 7.25% senior unsecured notes due in 2020 at par. We used the net proceeds from the offering and cash on hand to fund the redemption on September 8,

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2010 of $500.0 million aggregate principal amount of our outstanding 6.75% senior notes due in 2013 at a redemption price of 101.125%. We recognized a loss on the redemption of $6.8 million.

(4) On October 1, 2009, we purchased the Jacobs Ranch mining complex in the Powder River Basin from Rio Tinto Energy America for a purchase price of $768.8 million. To finance the acquisition, the Company sold 19.55 million shares of its common stock and $600.0 million in aggregate principal amount of senior unsecured notes. The net proceeds received from the issuance of common stock were $326.5 million and the net proceeds received from the issuance of the 8.75% senior unsecured notes were $570.3 million.

(5) On June 29, 2007, we sold select assets and related liabilities associated with our Mingo Logan Ben Creek mining complex in West Virginia for $43.5 million. We recognized a net gain of $8.9 million in 2007 on the sale.

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

Overview

Arch Coal is one of the world's largest coal producers by volume. We sell the majority of our coal as steam coal to power plants and industrial facilities in the U.S. and around the world. We also sell metallurgical coal used in steel production, a market that we expanded into further with the acquisition of International Coal Group, Inc. (ICG) in June 2011. On June 15, we acquired ICG's 1.1 billion ton, predominantly underground reserve base, of which nearly 30% is metallurgical-quality coal; twelve mining complexes and one development project in Appalachia, and one mining complex in Illinois. The acquisition of ICG adds low-cost, high-quality metallurgical coal to our product mix and creates substantial synergies with our existing operations, including blending opportunities, combining operations and reducing selling, general and administrative costs.

2011 was a transformative year for Arch Coal. We expanded our met coal profile with the acquisition of ICG; facilitated expansion into overseas markets with new offices in Asia and Europe; and increased our port access along the East, West and Gulf Coasts. In December, 2011 we were awarded a federal coal lease for the South Hilight tract in Wyoming that will give us the right to mine an estimated 222 million tons of coal reserves contiguous to our Black Thunder mining complex.

Coal markets weakened in the fourth quarter of 2011, as abnormally mild weather and muted economic growth caused U.S. power generation to decline slightly for the full year. Domestic coal consumption declined 5 percent in 2011, resulting from the decrease in power generation as well as fuel switching by power producers given decade-low prices for natural gas and abnormally high hydroelectric availability. As a result, coal stockpiles at U.S. generators rose to an estimated 180 million tons by year end, a seasonal build that is above historical norms. Mild weather has reduced power demand and the current oversupply in natural gas markets could induce more coal displacement in 2012.

Offsetting weak domestic coal trends is continued projected growth in global energy demand. In 2011, global cross-border hard coal trade exceeded 1.2 billion tons, and that growth is expected to continue in 2012. Roughly 470 gigawatts of new coal-fueled capacity is planned to start up by 2015, resulting in an estimated 1.6 billion tons of additional coal demand during the next three years. Since 2010, approximately 350 new coal plants have begun operating around the world. Domestic coal exports reached 108 million tons in 2011 in response to the demand.

In response to weak U.S. coal markets, we're scaling back lower-margin production in the Western Bituminous and Appalachia segments. On November 3, 2011, we announced that we plan to suspend longwall our Dugout Canyon mine in Utah operations at the end of the current panel in the first half of 2012. The next potential longwall panel at Dugout Canyon has already been developed. We expect to sell 9 to 10 million tons of metallurgical coal in 2012, but future decisions about thermal coal production will be based on market conditions. Our sales commitments for 2012 are presented in "Item 7. Quantitative and Qualitative Disclosures About Market Risk".

Items Affecting Comparability of Reported Results

The comparability of our operating results for the years ended December 31, 2011, 2010 and 2009 is affected by the following significant items:

Acquisition of ICG On June 15, 2011, we completed our acquisition of ICG, a leading coal producer, adding 12 mining complexes in Appalachia, one complex in the Illinois Basin and one mine under development in Appalachia, along with other coal reserves not currently in development. To finance the acquisition, we received net proceeds of $1.3 billion from the sale of our common stock and issued $2.0 billion in aggregate principal amount of senior unsecured notes. We directly expensed costs related to the financing and acquisition of $104.2 million.

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Dugout Canyon production suspensions We temporarily suspended production at our Dugout Canyon mine in Carbon County, Utah, on April 29, 2010 after an increase in carbon monoxide levels resulted from a heating event in a previously mined area. After permanently sealing the area, we resumed full coal production on May 21, 2010. On June 22, 2010, an ignition event at our longwall resulted in a second evacuation of all underground employees at the mine. All employees were safely evacuated in both events. The resumption of mining required us to render the mine's atmosphere inert, ventilate the longwall area, determine the cause of the ignition, implement preventive measures, and secure an MSHA-approved longwall ventilation plan. We restarted the longwall system on September 9, 2010, and resumed production at normalized levels by the end of September. As a result of the outages in the second and third quarters, the Dugout Canyon mine incurred a loss of $29.3 million for the year ended December 31, 2010. We have provided additional information about the performance of our operating segments under the heading "Operating segment results".

Gain on Knight Hawk transaction In the second quarter of 2010, we exchanged 68.4 million tons of coal reserves in the Illinois Basin for an additional 9% ownership interest in Knight Hawk, increasing our ownership to 42%. We recognized a pre-tax gain of $41.6 million on the transaction, representing the difference between the fair value and net book value of the coal reserves, adjusted for our retained ownership interest in the reserves through the investment in Knight Hawk.

Refinancing of Senior Notes On August 9, 2010, we issued $500.0 million in aggregate principal amount of 7.25% senior unsecured notes due in 2020 at par. We used the net proceeds from the offering and cash on hand to fund the redemption on September 8, 2010 of $500.0 million aggregate principal amount of our outstanding 6.75% senior notes due in 2013 at a redemption price of 101.125%. We recognized a loss on the redemption of $6.8 million, including the payment of the $5.6 million redemption premium, the write-off of $3.3 million of unamortized debt financing costs, partially offset by the write-off of $2.1 million of the original issue premium on the 6.75% senior notes.

Equity and Debt Offerings During the third quarter of 2009, we sold 19.55 million shares of our common stock at a price of $17.50 per share and issued $600.0 million in aggregate principal amount, 8.75% senior unsecured notes due 2016 at an initial issue price of 97.464%. The net proceeds received from the issuance of common stock were $326.5 million and the net proceeds received from the issuance of the 8.75% senior unsecured notes were $570.3 million. See further discussion of these transactions in "Liquidity and Capital Resources". We used the net proceeds from these transactions primarily to finance the purchase of the Jacobs Ranch mining complex.

Purchase of Jacobs Ranch mining operations On October 1, 2009, we purchased the Jacobs Ranch mining operations for a purchase price of $768.8 million. The acquired operations included approximately 345 million tons of coal reserves located adjacent to our Black Thunder mining complex. We have achieved significant operating efficiencies by combining the two operations, including operational cost savings, administrative cost reductions and coal-blending optimization.

Results of Operations

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Summary. Our results during 2011 when compared to 2010 were impacted positively by the contribution from the acquired ICG operations and higher average sales realizations as a result of improved market conditions, but these factors were offset by the acquisition, transition and financing costs necessary to complete the acquisition, as well as the impact of lower volumes from our Mountain Laurel complex and the Powder River Basin.

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Revenues. Our revenues consist of coal sales and revenues from our ADDCAR subsidiary acquired with ICG. The following table summarizes information about coal sales during the year ended December 31, 2011 and compares it with the information for the year ended December 31, 2010:

	Year Ended December 31		Increase (Decrease)	
	2011	2010	Amount	%
	(Amounts in thousands, except per ton data and percentages)			
Coal sales	$ 4,280,605	$ 3,186,268	$ 1,094,337	34.3%
Tons sold	156,897	162,763	(5,866)	(3.6)%
Coal sales realization per ton sold	$ 27.28	$ 19.58	$ 7.70	39.4%

Coal sales increased in 2011 from 2010, due to an increase in the overall average price per ton sold, the result of improved pricing on metallurgical-quality coal sold, the contribution from the ICG operations, including higher-priced metallurgical coal sales volumes, and higher steam pricing in all regions, as well as the impact of changes in regional mix on our average coal sales realization. Coal sales revenues attributed to acquired ICG operations were $601.6 million in 2011. Overall sales volumes decreased as lower sales volumes in the Powder River Basin offset the increases in the Appalachia and Western Bituminous regions. We have provided more information about the tons sold and the coal sales realizations per ton by operating segment under the heading "Operating segment results".

Costs, expenses and other. The following table summarizes costs, expenses and other components of operating income for the year ended December 31, 2011 and compares it with the information for the year ended December 31, 2010:

	Year Ended December 31		Increase (Decrease) in Net Income	
	2011	2010	Amount	%
	(Amounts in thousands, except percentages)			
Cost of sales	$ 3,267,910	$ 2,395,812	$ (872,098)	(36.4)%
Depreciation, depletion and amortization	466,587	365,066	(101,521)	(27.8)%
Amortization of acquired sales contracts, net	(22,069)	35,606	57,675	162.0%
Selling, general and administrative expenses	119,056	118,177	(879)	(0.7)%
Change in fair value of coal derivatives and coal trading activities, net	(2,907)	8,924	11,831	132.6%
Acquisition and transition costs	54,676		(54,676)	N/A
Gain on Knight Hawk transaction		(41,577)	(41,577)	100.0%
Other operating income, net	(10,934)	(19,724)	(8,790)	(44.6)%
	$ 3,872,319	$ 2,862,284	$ (1,010,035)	(35.3)%

Cost of coal sales. Our cost of sales increased in 2011 from 2010 primarily from the impact of the acquisition of the ICG operations, an increase in transportation costs as a result of the increase in export shipments, and an increase in sales-sensitive costs. We have provided more information about the performance and profitability of our operating segments under the heading "Operating segment results".

Depreciation, depletion and amortization. When compared with 2010, higher depreciation, depletion and amortization costs in 2011 resulted primarily from the acquired ICG operations, partially offset by the impact of lower depreciation and amortization on assets amortized or depleted on the basis of tons produced.

Amortization of acquired sales contracts, net. The fair values of acquired sales contracts are amortized over the tons of coal shipped during the term of the contracts. In 2011, amortization expense related to contracts we acquired in 2009 with the Jacobs Ranch operations in the PRB was offset by amortization income related to the contracts we acquired with the ICG operations. We expect net amortization income of acquired sales contracts, based upon expected shipments, to be approximately $18.0 million in 2012.

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Selling, general and administrative expenses. Selling, general and administrative expenses were essentially flat over 2010. Our growth in 2011 resulted in an increase in salaries, travel costs, and other professional service fees, and permitting, reserve acquisitions and environmental compliance resulted in higher legal costs . These were offset by a decrease in the net obligation under the deferred compensation plan of $7.7 million and a decrease in costs related to incentive compensation plans of $2.2 million. Amounts recognized under our deferred compensation plan are impacted by changes in the value of our common stock and changes in the value of the underlying investments. In addition, in 2010 we recognized the cost of a contribution to the Arch Coal Foundation of $5.0 million. We made no contributions to the Foundation in 2011.

Change in fair value of coal derivatives and coal trading activities, net. Net (gains) losses relate to the net impact of our coal trading activities and the change in fair value of other coal derivatives that have not been designated as hedge instruments in a hedging relationship. In 2011, we entered into economic hedging strategies relating to export sales that did not qualify for hedge accounting treatment, resulting in unrealized gains of approximately $12 million.

Gain on Knight Hawk Transaction. The gain was recognized on our 2010 exchange of Illinois Basin reserves for an additional ownership interest in Knight Hawk, an equity method investee operating in the Illinois Basin.

Other operating income, net. When compared with 2010, other operating income, net decreased in 2011 due to an increase in commercial-related expenses and unrealized losses on heating oil contracts entered into as economic hedges of fuel surcharges on freight agreements of $2.9 million, partially offset by approximately $9.5 million of other income generated by acquired ICG operations, primarily royalties and ash disposal income.

Operating segment results. The following table shows results by operating segment for year ended December 31, 2011 and compares it with the information for the year ended December 31, 2010:

	Year Ended December 31		Increase (Decrease)	
	2011	**2010**	**$**	**%**
Powder River Basin				
Tons sold (in thousands)	117,846	132,350	(14,504)	(11.0)%
Coal sales realization per ton sold[1]	$ 13.62	$ 12.06	$ 1.56	12.9%
Operating margin per ton sold[2]	$ 1.51	$ 1.09	$ 0.42	38.5%
Adjusted EBITDA[3] (in thousands)	$ 370,423	$ 366,375	$ 4,048	1.1%
Appalachia				
Tons sold (in thousands)	20,874	14,102	6,772	48.0%
Coal sales realization per ton sold[1]	$ 84.52	$ 68.93	$ 15.59	22.6%
Operating margin per ton sold[2]	$ 13.61	$ 13.25	$ 0.36	2.7%
Adjusted EBITDA[3] (in thousands)	$ 468,806	$ 283,787	$ 185,019	65.2%
Western Bituminous				
Tons sold (in thousands)	17,041	16,311	730	4.5%
Coal sales realization per ton sold[1]	$ 35.72	$ 32.76	$ 2.96	9.0%
Operating margin per ton sold[2]	$ 6.95	$ 3.32	$ 3.63	109.3%
Adjusted EBITDA[3] (in thousands)	$ 200,900	$ 138,579	$ 62,321	45.0%

(1) Coal sales prices per ton exclude certain transportation costs that we pass through to our customers. We use these financial measures because we believe the amounts as adjusted better represent the coal sales prices we achieved within our operating segments. Since other companies may calculate coal sales prices per ton differently, our calculation may not be comparable to similarly titled measures used by those companies. For 2011, transportation costs per ton were $0.36 for the Powder River Basin, $7.22 for Appalachia and $3.76 for the Western Bituminous region. For 2010, transportation costs per ton were $0.08 for the Powder River Basin, $4.99 for Appalachia and $0.19 for the Western Bituminous region.

(2) Operating margin per ton sold is calculated as coal sales revenues less cost of coal sales, depreciation, depletion and amortization and sales contract amortization divided by tons sold.

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(3) Adjusted EBITDA is defined as net income attributable to the Company before the effect of net interest expense, income taxes, depreciation, depletion and amortization and the amortization of acquired sales contracts. Adjusted EBITDA may also be adjusted for items that may not reflect the trend of future results. Segment Adjusted EBITDA is reconciled to net income at the end of this "Results of Operations" section.

Powder River Basin Segment Adjusted EBITDA increased in 2011 when compared to 2010, due to higher average sales prices, reflecting the improved coal markets. Partially offsetting the impact of higher selling prices were lower sales volumes in the Powder River Basin in 2011 when compared with 2010, due to the flooding in the Midwest and a market-driven approach to sales commitments earlier in the year , as well as higher per-ton production costs. Higher production costs reflected an increase in labor, maintenance and diesel costs and an increase in sales-sensitive costs, due to the increased realizations. Per-ton costs were also higher due to the lower production levels.

Appalachia Segment Adjusted EBITDA increased from 2010 primarily from an increase in the volumes and pricing of metallurgical-quality coal sold and the acquisition of ICG. Geology issues at the Mountain Laurel mine partially offset the volume contributions from the acquired ICG operations. We sold 7.5 million tons of metallurgical-quality coal in 2011 compared to 5.5 million tons in 2010. The benefit from higher per-ton realizations in 2011, net of sales sensitive costs, drove the improvement in our operating margins over 2010, partially offset by the impacts of the Mountain Laurel geology issues, and an increase in production at higher cost mines on our average per-ton production costs.

We will transition to a new seam at our Mountain Laurel mining complex in the first quarter. We expect that the longwall will begin its transition in mid-February, and start production in the new seam at the end of March. The new seam is thinner than the current seam, which will result in a loss of yield at the mine, translating into slightly higher costs; however, we anticipate more consistent quality in the new seam.

Western Bituminous Improved Segment Adjusted EBITDA reflects higher sales volumes and improved pricing resulting from increased export shipments for coal from our Colorado operations. Effective cost control in the region and slightly higher production levels reduced our per-ton operating costs, which also contributed to the improved results in 2011, when compared with 2010, when two outages affected production at the Dugout Canyon mine.

Net interest expense. The following table summarizes our net interest expense for year ended December 31, 2011 and compares it with the information for the year ended December 31, 2010:

	Year Ended December 31		**Increase (Decrease) in Net Income**	
	2011	**2010**	**$**	**%**
	(Amounts in thousands, except percentages)			
Interest expense	$ (230,186)	$ (142,549)	$ (87,637)	(61.5)%
Interest income	3,309	2,449	860	35.1%
	$ (226,877)	$ (140,100)	$ (86,777)	61.9%

The increase in interest expense during 2011 when compared with 2010 is the result of the ICG acquisition financing. See further discussion in "Liquidity and Capital Resources.

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Other non-operating expense. The following table summarizes other non-operating expense for year ended December 31, 2011 and compares it with the information for the year ended December 31, 2010:

	Year Ended December 31		Increse (Decrease) in Net Income
	2011	2010	$
	(Amounts in thousands, except percentages)		
Bridge financing costs related to ICG	$ (49,490)	$	$ (49,490)
Net loss resulting from early retirement debt	(1,958)	(6,776)	4,818
	$ (51,448)	$ (6,776)	$ (44,672)

Amounts reported as non-operating consist of income or expense resulting from our financing activities, other than interest costs. Other non-operating expenses during 2011 represent financing-related costs of the ICG acquisition, including the cost to maintain a bridge financing facility, which was not used. The loss in 2010 relates to the redemption of $500 million in principal amount of the 6.75% senior notes.

Income taxes. Our effective income tax rate is sensitive to changes in and the relationship between annual profitability and the deduction for percentage depletion. The following table summarizes our income taxes for the year ended December 31, 2011 and compares it with the information for the year ended December 31, 2010:

	Year Ended December 31		Increase in Net Income	
	2010	2009	$	%
	(Amounts in thousands, except percentages)			
Provision for (benefit from) income taxes	$ (7,589)	$ 17,714	$ 25,303	142.8%

The income tax provision in 2010 includes a tax benefit of $4.0 million related to the recognition of tax benefits based on settlements with taxing authorities.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Summary. Our improved results during 2010 when compared to 2009 were generated from increased sales volumes, including an increase in metallurgical coal volumes sold, lower production costs and the gain on the Knight Hawk transaction. Higher selling, general and administrative costs, unrealized losses on coal derivatives and higher interest and financing costs partially offset the benefit from these factors.

Revenues. The following table summarizes information about coal sales during the year ended December 31, 2010 and compares it with the information for the year ended December 31, 2009:

	Year Ended December 31		Increase (Decrease)	
	2010	2009	Amount	%
	(Amounts in thousands, except per ton data and percentages)			
Coal sales	$ 3,186,268	$ 2,576,081	$ 610,187	23.7%
Tons sold	162,763	126,116	36,647	29.1%
Coal sales realization per ton sold	$ 19.58	$ 20.43	$ (0.85)	(4.2)%

Coal sales increased in 2010 from 2009, primarily due to an increase in tons sold in the Powder River Basin region, resulting from the acquisition of the Jacobs Ranch mining complex at the beginning of the fourth quarter of 2009 and the impact of an increase in metallurgical coal sales volumes. Our average coal sales realization per ton was lower in 2010, as the impact of changes in regional mix on our average selling price and lower pricing in the Powder River Basin offset the benefit of the increase in metallurgical coal sales volumes. We have provided more information about the tons sold and the coal sales realizations per ton by operating segment under the heading "Operating segment results".

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Costs, expenses and other. The following table summarizes costs, expenses and other components of operating income for the year ended December 31, 2010 and compares it with the information for the year ended December 31, 2009:

	Year Ended December 31		Increase (Decrease) in Net Income	
	2010	2009	$	%
	(Amounts in thousands, except percentages)			
Cost of coal sales	$ 2,395,812	$ 2,070,715	$ (325,097)	(15.7)%
Depreciation, depletion and amortization	365,066	301,608	(63,458)	(21.0)
Amortization of acquired sales contracts, net	35,606	19,623	(15,983)	(81.5)
Selling, general and administrative expenses	118,177	97,787	(20,390)	(20.9)
Change in fair value of coal derivatives and coal trading activities, net	8,924	(12,056)	(20,980)	(174.0)
Gain on Knight Hawk transaction	(41,577)		41,577	N/A
Acquisition and transaction costs		13,726	13,726	100.0
Other operating income, net	(19,724)	(39,036)	(19,312)	(49.5)
	$ 2,862,284	$ 2,452,367	$ (409,917)	(16.7)%

Cost of coal sales. Our cost of coal sales increased in 2010 from 2009 primarily due to the higher sales volumes discussed above, partially offset by the impact of a lower average cost per-ton sold, due to the impact of the changes in regional mix as well as lower per-ton production costs in all regions, exclusive of transportation and sales-sensitive costs. We have provided more information about our operating segments under the heading "Operating segment results".

Depreciation, depletion and amortization. When compared with 2009, higher depreciation and amortization costs in 2010 resulted primarily from the impact of the acquisition of the Jacobs Ranch mining complex in the fourth quarter of 2009.

Amortization of acquired sales contracts, net. We acquired both above- and below-market sales contracts with a net fair value of $58.4 million with the Jacobs Ranch mining operation. The fair values of acquired sales contracts are amortized over the tons of coal shipped during the term of the contracts.

Selling, general and administrative expenses. The increase in selling, general and administrative expenses in 2010 is due primarily to compensation-related costs, an increase of legal fees of $1.9 million and a contribution to the Arch Coal Foundation of $5.0 million in 2010. In particular, our improved results were the primary driver of higher costs of approximately $5.9 million in 2010 related to our incentive compensation plans when compared to 2009. Costs related to our deferred compensation plan, where amounts recognized are impacted by changes in the value of our common stock and changes in the value of the underlying investments, also increased $5.9 million. Legal fees increased primarily as a result of costs associated with permitting, reserve acquisitions and environmental compliance.

Change in fair value of coal derivatives and coal trading activities, net. Net (gains) losses relate to the net impact of our coal trading activities and the change in fair value of other coal derivatives that have not been designated as hedge instruments in a hedging relationship. During 2010, rising coal prices resulted in losses on derivative instruments positions and trading activities, compared with weaker market conditions in 2009, which resulted in gains.

Gain on Knight Hawk Transaction. The gain was recognized on our exchange of Illinois Basin reserves for an additional ownership interest in Knight Hawk, an equity method investee operating in the Illinois Basin.

Other operating income, net. The decrease in net other operating income in 2010 from 2009 is primarily the result of a decrease in income from contract settlements and bookout transactions of $26.4 million, partially offset by an increase in income from our investment in Knight Hawk of $9.3 million.

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Operating segment results. The following table shows results by operating segment for year ended December 31, 2010 and compares it with the information for the year ended December 31, 2009:

	Year Ended December 31		Increase (Decrease)	
	2010	2009	$	%
Powder River Basin				
Tons sold (in thousands)	132,350	96,083	36,267	37.8%
Coal sales realization per ton sold(1)	$ 12.06	$ 12.43	$ (0.37)	(3.0)%
Operating margin per ton sold(2)	$ 1.09	$ 0.79	$ 0.30	38.0%
Adjusted EBITDA(31)	$ 366,375	$ 233,623	$ 132,752	56.8%
Appalachia				
Tons sold (in thousands)	14,102	13,286	816	6.1%
Coal sales realization per ton sold(1)	$ 68.93	$ 59.58	$ 9.35	15.7%
Operating margin per ton sold(2)	$ 13.25	$ 6.22	$ 7.03	113.0%
Adjusted EBITDA(3)	$ 283,787	$ 201,736	$ 82,051	40.7%
Western Bituminous				
Tons sold (in thousands)	16,311	16,747	(436)	(2.6)%
Coal sales realization per ton sold(1)	$ 29.61	$ 29.11	$ 0.50	1.7%
Operating margin per ton sold(2)	$ 3.32	$ 1.55	$ 1.77	114.2%
Adjusted EBITDA(3)	$ 138,579	$ 113,192	$ 25,387	22.4%

(1) Coal sales prices per ton exclude certain transportation costs that we pass through to our customers. We use these financial measures because we believe the amounts as adjusted better represent the coal sales prices we achieved within our operating segments. Since other companies may calculate coal sales prices per ton differently, our calculation may not be comparable to similarly titled measures used by those companies. For 2010, transportation costs per ton were $0.08 for the Powder River Basin, $4.99 for Appalachia and $0.19 for the Western Bituminous region. For 2009, transportation costs per ton were $0.11 for the Powder River Basin, $2.89 for Appalachia and $0.41 for the Western Bituminous region.

(2) Operating margin per ton sold is calculated as coal sales revenues less cost of coal sales and depreciation, depletion and amortization divided by tons sold.

(3) Adjusted EBITDA is defined as net income attributable to the Company before the effect of net interest expense, income taxes, depreciation, depletion and amortization and the amortization of acquired sales contracts. Adjusted EBITDA may also be adjusted for items that may not reflect the trend of future results. Segment Adjusted EBITDA is reconciled to net income at the end of this "Results of Operations" section.

Powder River Basin Segment Adjusted EBITDA increased 56.8% in 2010 when compared to 2009 due primarily to an increase in sales volumes in 2010 when compared with 2009. The higher sales volumes were primarily from the acquisition of the Jacobs Ranch mining operations on October 1, 2009, although improving demand for Powder River Basin coal in the second half of 2010 also had a positive impact on sales volumes. A decrease in per-ton costs during 2010 when compared with 2009 offset the effect of a lower average sales price, primarily reflecting the roll-off of contracts committed when market conditions were more favorable. The decrease in per-ton costs resulted from efficiencies achieved from combining the acquired Jacobs Ranch mining operations with our existing Black Thunder operations, as well as a decrease in hedged diesel fuel costs.

Western Bituminous In the Western Bituminous region, despite a soft steam coal market in the region and the two outages at the Dugout Canyon mine in 2010, Segment Adjusted EBITDA increased in 2010 when compared with 2009. Sales volumes decreased only slightly compared to 2009, because sales volumes in 2009 were also affected by weaker market conditions that had an impact on our ability to market coal with a high ash content, which resulted from geologic conditions at our West Elk mine, and the decision to reduce production accordingly. A preparation plant at the West Elk mine was placed into service in the fourth quarter of 2010 to address any future quality issues arising from sandstone intrusions similar to those we encountered previously. Despite the detrimental impact in 2009 on our per-ton realizations of selling coal with a higher ash content, our realizations increased only slightly in 2010, due to the soft steam coal market and an unfavorable mix of customer

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contracts. Effective cost control in the region resulted in the higher per-ton operating margins in 2010, partially offset by the impact of the two outages at the Dugout Canyon mine in 2010.

Appalachia Segment Adjusted EBITDA increased 40.8% in 2010 over 2009 on higher metallurgical coal sales volumes in 2010, resulting from the improvement in metallurgical coal demand, partially offset by weaker steam coal demand. We sold approximately 5.5 million of metallurgical-quality coal in 2010 compared to 2.1 million tons in 2009. Because metallurgical coal generally commands a higher price than steam coal, the increase had a favorable impact on our average realizations compared to 2009.

Although our sales volumes improved over 2009, production in Appalachia was less than expected in the 4th quarter due to the geologic challenges at our Mountain Laurel longwall mine in December referenced in "Items Affecting the Comparability of Reported Results".

Net interest expense. The following table summarizes our net interest expense for year ended December 31, 2010 and compares it with the information for the year ended December 31, 2009:

	Year Ended December 31		Decrease in Net Income	
	2010	**2009**	**$**	**%**
	(Amounts in thousands, except percentages)			
Interest expense	$ (142,549)	$ (105,932)	$ (36,617)	(34.6)%
Interest income	2,449	7,622	(5,173)	(67.9)
	$ (140,100)	$ (98,310)	$ (41,790)	(42.5)%

The increase in net interest expense in 2010 compared to 2009 is primarily due to an increase in outstanding senior notes due to the issuance of the 8.75% senior notes in the third quarter of 2009 to finance the acquisition of the Jacobs Ranch mining complex and the issuance of the 7.25% senior notes on August 9, 2010. The proceeds from the issuance 7.25% senior notes were used to redeem a portion of the 6.75% senior notes on September 8, 2010.

In 2009, we recorded interest income of $6.1 million related to a black lung excise tax refund that we recognized in the fourth quarter of 2008.

Other non-operating expense. The following table summarizes our other non-operating expense for year ended December 31, 2010 and compares it with the information for the year ended December 31, 2009:

	Year Ended December 31		Decrease in Net Income	
	2010	**2009**	**$**	**%**
	(Amounts in thousands, except percentages)			
Loss on early extinguishment of debt	$ (6,776)	$	$ (6,776)	(100)%

Amounts reported as non-operating consist of income or expense resulting from our financing activities, other than interest costs. The loss on early extinguishment of debt relates to the redemption of $500 million in principal amount of the 6.75% senior notes. The loss includes the payment of $5.6 million of redemption premium and the write-off of $3.3 million of unamortized debt financing costs, partially offset by the write-off of $2.1 million of the original issue premium.

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Income taxes. Our effective income tax rate is sensitive to changes in and the relationship between annual profitability and the deduction for percentage depletion. The following table summarizes our income taxes for year ended December 31, 2010 and compares it with the information for the year ended December 31, 2009:

	Year Ended December 31		Decrease in Net Income	
	2010	2009	$	%
	(Amounts in thousands, except percentages)			
Provision for (benefit from) income taxes	$ 17,714	$ (16,775)	$ (34,489)	(205.6)%

The income tax provision in 2010 includes a tax benefit of $4.0 million related to the recognition of tax benefits based on settlements with taxing authorities.

Reconciliation of Segment Adjusted EBITDA to Net Income

The discussion in "Results of Operations" in 2011, 2010 and 2009 includes references to our Adjusted EBITDA results. Adjusted EBITDA is defined as net income attributable to the Company before the effect of net interest expense, income taxes, depreciation, depletion and amortization and the amortization of acquired sales contracts. Adjusted EBITDA may also be adjusted for items that may not reflect the trend of future results. We believe that Adjusted EBITDA presents a useful measure of our ability to service and incur debt based on ongoing operations. Investors should be aware that our presentation of Adjusted EBITDA may not be comparable to similarly titled measures used by other companies. The table below shows how we calculate Adjusted EBITDA.

	Year Ended December 31,		
	2011	2010	2009
Reported Segment Adjusted EBITDA	$ 1,040,129	$ 788,741	$ 548,551
Corporate and other[(1)]	(118,991)	(64,622)	(89,890)
Adjusted EBITDA	921,138	724,119	458,661
Depreciation, depletion and amortization	(466,587)	(365,066)	(301,608)
Amortization of acquired sales contracts, net	22,069	(35,606)	(19,623)
Interest expense	(230,186)	(142,549)	(105,932)
Interest income	3,309	2,449	7,622
Acquisition and transition costs[(2)]	(64,201)		(13,726)
Bridge financing costs related to ICG	(49,490)		
Net loss resulting from early retirement of debt	(1,958)	(6,776)	
(Provision for) benefit from income taxes	7,589	(17,714)	16,775
Net income attributable to Arch Coal	$ 141,683	$ 158,857	$ 42,169

(1) Corporate and other Adjusted EBITDA includes primarily selling, general and administrative expenses, income from our equity investments, the change in fair value of coal derivatives and coal trading activities, net.

(2) Includes acquisition and transition costs as reflected on the consolidated statements of income and the pre-tax impact on cost of sales of inventory written up to fair value in the ICG acquisition.

Liquidity and Capital Resources

Our primary sources of cash are coal sales to customers, borrowings under our credit facilities and other financing arrangements, and debt and equity offerings related to significant transactions. Excluding any significant mineral reserve acquisitions, we generally satisfy our working capital requirements and fund capital expenditures and debt-service obligations with cash generated from operations or borrowings under our lines of credit. The borrowings under these arrangements are classified as current if the underlying credit facilities expire within one year or if, based on cash projections and management plans, we do not have the intent to replace them on a long-term basis. Such plans are subject to change based on our cash needs.

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We believe that cash generated from operations and borrowings under our credit facilities or other financing arrangements will be sufficient to meet working capital requirements, anticipated capital expenditures and scheduled debt payments for at least the next several years. We manage our exposure to changing commodity prices for our non-trading, long-term coal contract portfolio through the use of long-term coal supply agreements. We enter into fixed price, fixed volume supply contracts with terms greater than one year with customers with whom we have historically had limited collection issues. Our ability to satisfy debt service obligations, to fund planned capital expenditures, to make acquisitions, to repurchase our common shares and to pay dividends will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry and financial, business and other factors, some of which are beyond our control.

In June 2011, we issued equity and debt securities to finance the ICG acquisition. On June 8, 2011, we sold 48 million shares of our common stock at a public offering price of $27.00 per share pursuant to an automatically effective shelf registration statement on Form S-3, a prospectus previously filed and a related prospectus supplement filed in June 2011. On July 8, 2011, we issued an additional 0.7 million shares of our common stock under the same terms and conditions to cover underwriters' over-allotments for net proceeds of $18.4 million. On June 14, 2011, we issued $1.0 billion in aggregate principal amount of 7.0% senior unsecured notes due in 2019 at par ("2019 Notes") and $1.0 billion in aggregate principal amount of 7.25% senior unsecured notes due in 2021 at par ("2021 Notes"). We secured bridge financing to ensure that funds would be available to us, if needed, to close the transaction. While we did not draw on the line of credit, we incurred costs of $49.9 million related to the bridge financing.

Our indebtedness consisted of the following at December 31, 2011 and 2010:

	December 31,	
	2011	2010
	(In thousands)	
Commercial paper	$	$ 56,904
Indebtedness to banks under credit facilities	481,300	
6.75% senior notes ($450.0 million face value) due July 1, 2013	450,971	451,618
8.75% senior notes ($600.0 million face value) due August 1, 2016	588,974	587,126
7.00% senior notes due June 15, 2019 at par	1,000,000	
7.25% senior notes due October 1, 2020 at par	500,000	500,000
7.25% senior notes due June 15, 2021 at par	1,000,000	
Other	21,903	14,093
	4,043,148	1,609,741
Less current maturities of debt and short-term borrowings	280,851	70,997
Long-term debt	$ 3,762,297	$ 1,538,744

Senior Notes

Our subsidiary, Arch Western Finance LLC, has outstanding an aggregate principal amount of $450.0 million of 6.75% senior notes due on July 1, 2013 ("2013 Notes"), subsequent to the redemption of $500.0 million aggregate principal amount on September 8, 2010. The Company recognized a loss on the redemption of $6.8 million, including the payment of the $5.6 million redemption premium and the write-off of $3.3 million of unamortized debt financing costs, partially offset by the write-off of $2.1 million of the original issue premium. Interest is payable on the 2013 Notes on January 1 and July 1 of each year. The 2013 Notes are secured by an intercompany note from Arch Coal to Arch Western. The indenture under which the 2013 Notes were issued contains certain restrictive covenants that limit Arch Western's ability to, among other things, incur additional debt, sell or transfer assets and make certain investments. The 2013 Notes are redeemable at any time at their face value.

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We have outstanding an aggregate principal amount of $600.0 million of 8.75% senior notes due 2016 that were issued at an initial issue price of 97.464% of face amount. Interest is payable on the 8.75% senior notes on February 1 and August 1 of each year. At any time on or after August 1, 2013, we may redeem some or all of the notes. The redemption price, reflected as a percentage of the principal amount, is: 104.375% for notes redeemed between August 1, 2013 and July 31, 2014; 102.188% for notes redeemed between August 1, 2014 and July 31, 2015; and 100% for notes redeemed on or after August 1, 2015. In addition, prior to August 1, 2012, at any time and on one or more occasions, we may redeem an aggregate principal amount of senior notes not to exceed 35% of the original aggregate principal amount of the senior notes outstanding with the proceeds of one or more public equity offerings, at a redemption price equal to 108.750%.

On August 9, 2010, we issued $500.0 million in aggregate principal amount of 7.25% senior unsecured notes due in 2020 ("2020 Notes") at par. Interest is payable on the 7.25% senior unsecured notes due in 2020 ("2020 Notes") on April 1 and October 1 of each year. At any time on or after October 1, 2015, we may redeem some or all of the notes. The redemption price reflected as a percentage of the principal amount is: 103.625% for notes redeemed between October 1, 2015 and September 30, 2016; 102.417% for notes redeemed between October 1, 2016 and September 30, 2017; 101.208% for notes redeemed between October 1, 2017 and September 30, 2018; and 100% for notes redeemed on or after October 1, 2018. In addition, at any time and on one or more occasions prior to October 1, 2013, the Company may redeem an aggregate principal amount of senior notes not to exceed 35% of the original aggregate principal amount of the senior notes outstanding with the proceeds of one or more public equity offerings, at a redemption price equal to 107.250%.

Interest is payable on the 2019 Notes and 2021 Notes on June 15 and December 15 of each year, commencing December 15, 2011. At any time prior to June 15, 2014, we may redeem up to 35% of the aggregate principal amount of each of the 2019 Notes and 2021 Notes, plus accrued and unpaid interest, with the net proceeds from certain equity offerings. We may redeem the 2019 Notes prior to June 15, 2015 and the 2021 Notes prior to June 15, 2016 at the respective make-whole prices set forth in the indenture. On or after June 15, 2015, we may redeem the 2019 Notes for cash at redemption prices, reflected as a percentage of the principal amount, of: 103.5% from June 15, 2015 through June 14, 2016; 101.75% from June 15, 2016 through June 14, 2017; and 100% beginning on June 15, 2017. On or after June 15, 2016, we may redeem the 2021 Notes for cash at redemption prices, reflected as a percentage of the principal amount, of: 103.625% from June 15, 2016 through June 14, 2017; 102.417% from June 15, 2017 through June 14, 2018; 101.208% from June 15, 2018 through June 14, 2019; and 100% beginning on June 15, 2019. In each case, accrued and unpaid interest at the redemption date is due upon redemption. Upon a change in control, we are required to make a tender offer for both series of notes at a price of 101% of the principal amount.

We entered into a registration rights agreement (the "Registration Rights Agreement") in connection with the issuance and sale of the 2019 Notes and 2021 Notes. Pursuant to the Registration Rights Agreement, we agreed to file a registration statement with the Securities and Exchange Commission to register an exchange offer pursuant to which the Company will offer to exchange a like aggregate principal amount of senior notes identical in all material respects to the 2019 Notes and 2021 Notes, except for terms relating to additional interest and transfer restrictions, for any or all of the outstanding 2019 Notes and 2021 Notes. Pursuant to the Registration Rights Agreement, we must use commercially reasonable efforts to cause the registration statement to become effective as soon as practicable and to complete the exchange offer no later than June 13, 2012. Should we fail to meet these obligations within the specified time frame, the applicable interest rates on the 2019 Notes and the 2021 Notes shall be increased by one-quarter of one percent per annum for the first 90 days following the occurrence of such failure. Such interest rates will increase by an additional one-quarter of one percent per annum thereafter at the end of each subsequent 90-day period up to a maximum aggregate increase of one percent per annum. Once any of the required events occur, the interest rates will revert to the rate specified in the indenture governing the 2019 Notes and 2021 Notes.

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The 2016, the 2019, the 2020 and the 2021 unsecured senior notes are guaranteed by substantially all of our subsidiaries, including the newly acquired subsidiaries of ICG but excluding Arch Western, its subsidiaries and Arch Receivable Company, LLC and the Company's subsidiaries outside the U.S.

We have filed a universal shelf registration statement on Form S-3 with the SEC that allows us to offer and sell from time to time an unlimited amount of unsecured debt securities consisting of notes, debentures, and other debt securities, common stock, preferred stock, warrants, or units. Related proceeds could be used for general corporate purposes, including repayment of other debt, capital expenditures, possible acquisitions and any other purposes that may be stated in any related prospectus supplement.

ICG Debt

Upon the closing of the acquisition, we gave our 30-day redemption notice to the Trustee of ICG's 9.125% senior notes and legally discharged our obligation under the 9.125% senior notes by depositing $260.7 million with the Trustee to redeem the debt. On July 14, 2011, all of the outstanding 9.125% senior notes were redeemed at an aggregate price of $251.4 million, including the required make-whole premium, plus accrued interest of $5.2 million, and the remainder of the deposit was returned to us.

At the acquisition date, ICG's 4.00% convertible senior notes with a fair value of $298.5 million and 9.00% convertible senior notes with a fair value of $1.7 million ("convertible notes") became convertible into cash, pursuant to the amended indentures governing the convertible notes, at a calculated conversion rate of $2,614.6848 for each $1,000 in principal amount surrendered for conversion for the 4.00% convertible notes and $2,392.73414 for the 9.00% convertible notes for conversions occurring prior to August 17, 2011.

At the acquisition date, other ICG debt had a fair value of approximately $54.0 million and consisted mainly of equipment notes and insurance notes payable.

We recognized a net loss of $2.0 million during the year ended December 31, 2011 on the early extinguishment of ICG's debt, including the conversions of the 4.00% and 9.00% convertible notes described above. The remaining amounts outstanding of under the convertible notes and other ICG debt is included in "other" in the debt table above.

Lines of Credit and Commercial Paper

On June 14, 2011, we amended and restated our secured revolving credit facility to allow for up to $2.0 billion in borrowings. Borrowings under this credit facility bear interest at a floating rate based on a LIBOR determined by reference to our leverage ratio, as calculated in accordance with the credit agreement. The credit facility has a five-year term that expires on June 14, 2016 and is secured by substantially all of our assets as well as our ownership interests in substantially all of our subsidiaries, excluding our ownership interests in Arch Western and its subsidiaries. Commitment fees of 0.50% per annum are payable on the average unused daily balance of the revolving credit facility. The leverage ratio requires that we not permit the ratio of total net debt (as defined in the facility) at the end of any calendar quarter to EBITDA (as defined in the facility) for the four quarters then ended to exceed a specified amount. The interest coverage ratio requires that we not permit the ratio of EBITDA (as defined in the facility) at the end of any calendar quarter to interest expense for the four quarters then ended to be less than a specified amount. The senior secured leverage ratio requires that we not permit the ratio of total net senior secured debt (as defined in the facility) at the end of any calendar quarter to EBITDA (as defined in the facility) for the four quarters then ended to exceed a specified amount. We were in compliance with all financial covenants at December 31, 2011.

We are party to an accounts receivable securitization program whereby eligible trade receivables are sold, without recourse, to a multi-seller, asset-backed commercial paper conduit. We entered into an amendment to its accounts receivable program in November, 2011 to increase the eligible receivables pool, as defined by the agreement, to include receivables generated from the acquired ICG subsidiaries. On December 13, 2011, the

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Company entered into another amendment to its accounts receivable securitization program to increase the size of the program to allow for aggregate borrowings and letters of credit of up to $250.0 million from $175.0 million. The credit facility supporting the borrowings under the program is subject to renewal annually and expires December 11, 2012. Under the terms of the program, eligible trade receivables consist of trade receivables generated by our operating subsidiaries. Actual borrowing capacity is based on the allowable amounts of accounts receivable as defined under the terms of the agreement. Although the participants in the program bear the risk of non-payment of purchased receivables, we have agreed to indemnify the participants with respect to various matters. The participants under the program will be entitled to receive payments reflecting a specified discount on amounts funded under the program, including drawings under letters of credit, calculated on the basis of the base rate or commercial paper rate, as applicable. We pay facility fees, program fees and letter of credit fees (based on amounts of outstanding letters of credit) at rates that vary with our leverage ratio. Under the program, we are subject to certain affirmative, negative and financial covenants customary for financings of this type, including restrictions related to, among other things, liens, payments, merger or consolidation and amendments to the agreements underlying the receivables pool. A termination event would permit the administrator to terminate the program and enforce any and all rights, subject to cure provisions, where applicable. Additionally, the program contains cross-default provisions, which would allow the administrator to terminate the program in the event of non-payment of other material indebtedness when due and any other event which results in the acceleration of the maturity of material indebtedness.

On June 14, 2011, we terminated our commercial paper placement program and the supporting credit facility.

The Company's average borrowing level under these programs was approximately $234.2 million and $132.0 million for the years ended December 31, 2011 and 2010, respectively.

Availability

As of December 31, 2011 we had $375.0 million of borrowings outstanding under the amended and restated secured credit facility and $106.3 million of borrowings outstanding under our accounts receivable securitization program. As of December 31, 2011, we had availability of approximately $901.4 million under all lines of credit, as limited by customary financial covenants that may limit our total debt based on defined earnings measurements. We also had outstanding letters of credit of $146.6 million as of December 31, 2011.

The following is a summary of cash provided by or used in each of the indicated types of activities during the past three years:

	Year Ended December 31		
	2011	**2010**	**2009**
	(Dollars in thousands)		
Cash provided by (used in):			
Operating activities	$ 642,242	$ 697,147	$ 382,980
Investing activities	(3,496,916)	(389,129)	(1,130,382)
Financing activities	2,899,230	(275,563)	737,891

Cash provided by operating activities decreased in 2011 compared to 2010, despite higher operating income adjusted for non-cash items, driven largely by an increase in inventory costs, as well as a benefit in 2010 from the timing of payments on accounts and production taxes payable. Cash provided by operating activities increased substantially in 2010 compared to 2009, due to increased profits during the year, driven largely by higher sales volumes, as well as the benefit in 2010 from the timing of payments on accounts and production taxes payable. We used approximately $3.1 billion more cash in investing activities in 2011 compared to the amount used in 2010, primarily due to the acquisition of ICG and the related capital spending of the acquired operations. Particularly, we spent approximately $73 million since the acquisition on the development of the Tygart Valley mine, where the longwall is scheduled to start in mid-2013. We expect to spend over $200 million in 2012 on metallurgical coal growth projects, including the Tygart Valley development. We also made advances to and investments in equity-

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method investees of $61.9 million, including the investment in Millennium Bulk Terminals. See "Financial Statements and Supplementary Data, Note 8 to the consolidated financial statements" for further information regarding our equity-method investments.

Cash used in investing activities in 2010 was $741.3 million less than in 2009, due to the acquisition of the Jacobs Ranch mining operations in 2009 for $768.8 million. In 2010, we made cash advances to and investments in equity-method investees totaling $46.2 million, compared with $10.9 million in 2009. This included $26.6 million to increase our ownership interest in Knight Hawk to 49% and $9.8 million to acquire a 35% interest in Tenaska Trailblazer Partners, LLC, ("Tenaska") the developer of the Trailblazer Energy Center. The power plant, fueled by low sulfur coal, will capture and store carbon dioxide for enhanced oil recovery applications. Capital expenditures were $314.7 million during 2010, slightly less than during 2009. During 2010, we made payments of $118.2 million on our Montana leases and spent $26.0 million on a preparation plant at the West Elk mine.

Cash provided by financing activities was $2.9 billion in 2011, compared to the cash used in financing activities during 2010 of $275.6 million. The change is a result of the proceeds from the financing transactions related to the acquisition of ICG discussed previously. We paid financing costs of $114.8 million in conjunction with these transactions.

Cash used in financing activities was $275.6 million during 2010, compared to cash provided by financing activities of $737.9 million during 2009. As mentioned previously, in 2010 we used the net proceeds from the offering of the 7.25% notes and cash on hand to fund the redemption $500.0 million aggregate principal amount of our outstanding 6.75% senior notes due in 2013 at a redemption price of 101.125%. We also repaid approximately $196.6 million under our various financing arrangements during 2010. We paid financing costs of $12.7 million in 2010.

In 2009, we sold 19.55 million shares of our common stock at a public offering price of $17.50 per share and issued $600 million in aggregate principal amount of 8.750% senior unsecured notes due 2016. Total net proceeds from these transactions were $896.8 million. We used the net proceeds from these transactions primarily to finance the purchase of the Jacobs Ranch mining complex. As a result of these transactions, we were able to reduce outstanding borrowings under credit facilities, repaying approximately $85.8 million during 2009. We paid financing costs of $29.6 million in 2009.

We paid dividends of $80.7 million in 2011, $63.4 million in 2010 and $55.0 million in 2009.

Ratio of Earnings to Fixed Charges

The following table sets forth our ratios of earnings to combined fixed charges and preference dividends for the periods indicated:

	Year Ended December 31				
	2011	**2010**	**2009**	**2008**	**2007**
Ratio of earnings to combined fixed charges and preference dividends(1)	1.49x	2.17x	1.26x	4.91x	2.37x

(1) Earnings consist of income from operations before income taxes and are adjusted to include only distributed income from affiliates accounted for on the equity method and fixed charges (excluding capitalized interest). Fixed charges consist of interest incurred on indebtedness, the portion of operating lease rentals deemed representative of the interest factor and the amortization of debt expense.

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Contractual Obligations

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

	Payments Due by Period				
	2012	2013-2014	2015-2016	After 2016	Total
	(Dollars in thousands)				
Long-term debt, including related interest	$ 544,488	$ 1,150,040	$ 1,040,625	$ 3,131,250	$ 5,866,403
Operating leases	28,903	52,729	27,289	12,640	121,561
Coal lease rights	47,770	202,108	171,962	114,371	536,211
Coal purchase obligations	65,495	128,850	134,904	63,223	392,472
Unconditional purchase obligations	421,962	185,332	157,253	91,563	856,110
Total contractual obligations	$ 1,108,618	$ 1,719,059	$ 1,532,033	$ 3,413,047	$ 8,033,305

Our maturities of debt in 2011 include amounts borrowed that are supported by credit facilities that have a term of less than one year and amounts borrowed under credit facilities with terms longer than one year that we do not intend to refinance on a long-term basis, based on cash projections. The related interest on long-term debt was calculated using rates in effect at December 31, 2011 for the remaining term of outstanding borrowings.

Coal lease rights represent non-cancelable royalty lease agreements, as well as lease bonus payments due.

Our coal purchase obligations include purchase obligations in the over-the-counter market, as well as unconditional purchase obligations with coal suppliers. Additionally, they include coal purchase obligations incurred with the sale of certain Appalachia operations in 2005 to supply ongoing customer sales commitments.

Unconditional purchase obligations include open purchase orders and other purchase commitments, which have not been recognized as a liability. The commitments in the table above relate to contractual commitments for the purchase of materials and supplies, payments for services and capital expenditures.

The table above excludes our asset retirement obligations. Our consolidated balance sheet reflects a liability of $473.9 million for asset retirement obligations that arise from SMCRA and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. Asset retirement obligations are recorded at fair value when incurred and accretion expense is recognized through the expected date of settlement. Determining the fair value of asset retirement obligations involves a number of estimates, as discussed in the section entitled "Critical Accounting Policies", including the timing of payments to satisfy the obligations. The timing of payments to satisfy asset retirement obligations is based on numerous factors, including mine closure dates. You should see the notes to our consolidated financial statements for more information about our asset retirement obligations.

The table above also excludes certain other obligations reflected in our consolidated balance sheet, including estimated funding for pension and postretirement benefit plans and worker's compensation obligations. The timing of contributions to our pension plans varies based on a number of factors, including changes in the fair value of plan assets and actuarial assumptions. You should see the section entitled "Critical Accounting Policies" for more information about these assumptions. In order to achieve a desired funded status, we expect to make contributions of $24.5 million to our pension plans in 2012. You should see the notes to our consolidated financial statements for more information about the amounts we have recorded for workers' compensation and pension and postretirement benefit obligations.

The table above excludes future contingent payments of up to $74.4 million related to development financing for certain of our equity investees. Our obligation to make these payments, as well as the timing of any payments required, is contingent upon a number of factors, including project development progress, receipt of permits and the obtaining of construction financing.

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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, indemnifications, financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. Liabilities related to these arrangements are not reflected in our consolidated balance sheets, and 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.

We use a combination of surety bonds, corporate guarantees (e.g., self bonds) and letters of credit to secure our financial obligations for reclamation, workers' compensation, coal lease obligations and other obligations as follows as of December 31, 2011:

	Reclamation Obligations	Lease Obligations	Workers' Compensation Obligations	Other	Total
			(Dollars in thousands)		
Self bonding	$ 420,516	$	$	$	$ 420,516
Surety bonds	301,523	64,555	12,200	135,439	513,717
Letters of credit			47,907	16,646	64,553

We have agreed to continue to provide surety bonds and letters of credit for the reclamation and retiree healthcare obligations of the properties we sold to Magnum. If the surety bonds and letters of credit related to the reclamation obligations are not replaced by Magnum within a specified period of time, Magnum must post a letter of credit in favor of the Company in the amounts of the reclamation obligations. The surety bonding amounts are mandated by the state and are not directly related to the estimated cost to reclaim the properties. As of December 31, 2011, Patriot has replaced $48.9 million of the surety bonds and has posted letters of credit of $16.1 million in the Company's favor. At December 31, 2011, the Company had $38.5 million of surety bonds remaining related to properties sold to Magnum, which are included in the above table.

Magnum also acquired certain coal supply contracts with customers who have not consented to the assignment of the contract to Magnum. We have committed to purchase coal from Magnum to sell to those customers at the same price we are charging the customers for the sale. In addition, certain contracts have been assigned to Magnum, but we have guaranteed Magnum's performance under the contracts. The longest of the coal supply contracts extends to the year 2017. If Magnum is unable to supply the coal for these coal sales contracts then we would be required to purchase coal on the open market or supply contracts from our existing operations. At market prices effective at December 31, 2011, the cost of purchasing 9.8 million tons of coal to supply the contracts that have not been assigned over their duration would exceed the sales price under the contracts by approximately $199.4 million, and the cost of purchasing 0.7 million tons of coal to supply the assigned and guaranteed contracts over their duration would exceed the sales price under the contracts by approximately $15.3 million. We do not believe that it is probable that we would have to purchase replacement coal. If we would have to perform under these guarantees, it could potentially have a material adverse effect on our business, results of operations and financial condition.

In connection with the acquisition of the coal operations of ARCO and the simultaneous combination of the acquired ARCO operations and our Wyoming operations into the Arch Western joint venture, we agreed to indemnify the other member of Arch Western against certain tax liabilities in the event that such liabilities arise prior to June 1, 2013 as a result of certain actions taken, including the sale or other disposition of certain properties of Arch Western, the repurchase of certain equity interests in Arch Western by Arch Western or the reduction under certain circumstances of indebtedness incurred by Arch Western in connection with the acquisition. If we were to become liable, the maximum amount of potential future tax payments was $19.3 million at December 31, 2011. Since the indemnification is dependent upon the initiation of activities within our control and we do not intend to initiate such activities, it is remote that we will become liable for any obligation related to this indemnification.

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Critical Accounting Policies

We prepare our financial statements 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 amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities. Management bases our estimates and judgments on historical experience and other factors that are believed to be reasonable under the circumstances. Additionally, these estimates and judgments are discussed with our audit committee on a periodic basis. Actual results may differ from the estimates used under different assumptions or conditions. We have provided a description of all significant accounting policies in the notes to our consolidated financial statements. We believe that of these significant accounting policies, the following may involve a higher degree of judgment or complexity:

Derivative Financial Instruments

The Company generally utilizes derivative instruments to manage exposures to commodity prices. Additionally, the Company may hold certain coal derivative instruments for trading purposes. Derivative financial instruments are recognized in the balance sheet at fair value. Certain coal contracts may meet the definition of a derivative instrument, but because they provide for the physical purchase or sale of coal in quantities expected to be used or sold by the Company over a reasonable period in the normal course of business, they are not recognized on the balance sheet.

Certain derivative instruments are designated as the hedge instrument in a hedging relationship. In a fair value hedge, we hedge the risk of changes in the fair value of a firm commitment, typically a fixed-price coal sales contract. Changes in both the hedged firm commitment and the fair value of a derivative used as a hedge instrument in a fair value hedge are recorded in earnings. In a cash flow hedge, we hedge the risk of changes in future cash flows related to a forecasted purchase or sale. Changes in the fair value of the derivative instrument used as a hedge instrument in a cash flow hedge are recorded in other comprehensive income. Amounts in other comprehensive income are reclassified to earnings when the hedged transaction affects earnings and are classified in a manner consistent with the transaction being hedged.

Any ineffective portion of a hedge is recognized immediately in earnings. Ineffectiveness was insignificant for the years ended December 31, 2011 2010 and 2009.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives for undertaking various hedge transactions. We evaluate the effectiveness of our hedging relationships both at the hedge inception and on an ongoing basis.

Asset Retirement Obligations

Our asset retirement obligations arise from SMCRA 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. Our asset retirement obligations are initially recorded at fair value, or the amount at which the obligations could be settled in a current transaction between willing parties. This involves determining the present value of estimated future cash flows on a mine-by-mine basis based upon current permit requirements and various estimates and assumptions, including estimates of disturbed acreage, reclamation costs and assumptions regarding equipment productivity. We estimate disturbed acreage based on approved mining plans and related engineering data. Since we plan to use internal resources to perform the majority of our reclamation activities, our estimate of reclamation costs involves estimating third-party profit margins, which we base on our historical experience with contractors that perform certain types of reclamation activities. We base productivity assumptions on historical experience with the equipment that we expect to utilize in the reclamation activities. In

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order to determine fair value, we discount our estimates of cash flows to their present value. We base our discount rate on the rates of treasury bonds with maturities similar to expected mine lives, adjusted for our credit standing.

Accretion expense is recognized on the obligation through the expected settlement date. On at least an annual basis, we review our entire reclamation liability and make necessary adjustments for permit changes as granted by state authorities, changes in the timing of reclamation activities, and revisions to cost estimates and productivity assumptions, to reflect current experience. Any difference between the recorded amount of the liability and the actual cost of reclamation will be recognized as a gain or loss when the obligation is settled. We expect our actual cost to reclaim our properties will be less than the expected cash flows used to determine the asset retirement obligation. At December 31, 2011, our balance sheet reflected asset retirement obligation liabilities of $473.9 million, including amounts classified as a current liability. As of December 31, 2011, we estimate the aggregate undiscounted cost of final mine closures to be approximately $941.0 million.

See the rollforward of the asset retirement obligation liability in "Financial Statements and Supplementary Data, Note 14 to the consolidated financial statements."

Goodwill

In a business combination, goodwill represents the excess of the purchase price over the fair value assigned to the net tangible and identifiable intangible assets acquired. We test goodwill for impairment annually as of the beginning of the fourth quarter, or when circumstances indicate a possible impairment may exist. If the results of the testing indicate that the carrying amount of a reporting unit exceeds the fair value of the reporting unit, the fair value of goodwill must be calculated. An impairment loss generally would be recognized when the carrying amount of goodwill exceeds the implied fair value of goodwill, determined by subtracting the fair value of the other assets and liabilities associated with the reporting unit from the total fair value of the reporting unit. The fair value of a reporting unit is determined using a discounted cash flow ("DCF") technique. A number of significant assumptions and estimates are involved in the application of the DCF analysis to forecast operating cash flows, including the discount rate and projections of selling prices and costs to produce. The goodwill generated in the acquisition of ICG of $480.3 million was allocated to ICG properties with high quality metallurgical coal reserves. As such, the forecasted cash operating flows used to test this goodwill balance for impairment are sensitive to changes in metallurgical coal prices, in addition to the factors named previously.

Employee Benefit Plans

We have non-contributory defined benefit pension plans covering certain of our salaried and hourly employees. Benefits are generally based on the employee's age and compensation. The actuarially-determined funded status of the defined benefit plans is reflected in the balance sheet.

The calculation of our net periodic benefit costs (pension expense) and benefit obligation (pension liability) associated with our defined benefit pension plans requires the use of a number of assumptions. Changes in these assumptions can result in different pension expense and liability amounts, and actual experience can differ from the assumptions.

The expected long-term rate of return on plan assets is an assumption reflecting the average rate of earnings expected on the funds invested or to be invested to provide for the benefits included in the projected benefit obligation. We establish the expected long-term rate of return at the beginning of each fiscal year based upon historical returns and projected returns on the underlying mix of invested assets. The pension plan's investment targets are 65% equity, 30% fixed income securities and 5% cash. Investments are rebalanced on a periodic basis to approximate these targeted guidelines. The long-term rate of return assumption used to determine pension expense was 8.5% for 2011and 2010. The long-term rate of return assumptions are less than the plan's actual life-to-date returns. Any difference between the actual experience and the assumed experience is recorded in other comprehensive income and amortized into earnings in the future. The impact

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of lowering the expected long-term rate of return on plan assets 0.5% for 2011 would have been an increase in expense of approximately $1.3 million.

The discount rate represents our estimate of the interest rate at which pension benefits could be effectively settled. Assumed discount rates are used in the measurement of the projected, accumulated and vested benefit obligations and the service and interest cost components of the net periodic pension cost. In estimating that rate, rates of return on high-quality fixed-income debt instruments are required. We utilize a bond portfolio model that includes bonds that are rated "AA" or higher with maturities that match the expected benefit payments under the plan. The discount rate used to determine pension expense was 5.71% for 2011 and 5.97% for 2010. The impact of lowering the discount rate 0.5% for 2011 would have been an increase in expense of approximately $3.3 million.

The differences generated from changes in assumed discount rates and returns on plan assets are amortized into earnings over a five-year period, which represents the average amount of time before participants vest in their benefits.

For the measurement of our 2011 year-end pension obligation and pension expense for 2012, we used a discount rate of 4.91%.

We also currently provide certain postretirement medical and life insurance coverage for eligible employees. Generally, covered employees who terminate employment after meeting eligibility requirements are eligible for postretirement coverage for themselves and their dependents. The salaried employee postretirement benefit plans are contributory, with retiree contributions adjusted periodically, and contain other cost-sharing features such as deductibles and coinsurance.

Actuarial assumptions are required to determine the amounts reported as obligations and costs related to the postretirement benefit plan. The discount rate assumption reflects the rates available on high-quality fixed-income debt instruments at year-end and is calculated in the same manner as discussed above for the pension plan. The discount rate used to calculate the postretirement benefit expense was 5.23% and 5.67% for 2011 and 2010, respectively.

Had the discount rate been lowered by 0.5% in 2011, we would have incurred additional expense of $0.2 million.

For the measurement of our 2011 year-end other postretirement benefits obligation and postretirement expense for 2012, we used a discount rate of 4.52%.

Income Taxes

We provide for deferred income taxes for temporary differences arising from differences between the financial statement and tax basis of assets and liabilities existing at each balance sheet date using enacted tax rates expected to be in effect when the related taxes are expected to be paid or recovered. We initially recognize the effects of a tax position when it is more than 50 percent likely, based on the technical merits, that the position will be sustained upon examination, including resolution of the related appeals or litigation processes, if any. Our determination of whether or not a tax position has met the recognition threshold considers the facts, circumstances, and information available at the reporting date. A valuation allowance may be recorded to reflect the amount of future tax benefits that management believes are not likely to be realized. We reassess our ability to realize our deferred tax assets annually in the fourth quarter or when circumstances indicate that the ability to realize deferred tax assets has changed. In determining the appropriate valuation allowance, we take into account expected 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 additional valuation allowance through income tax expense in the period such determination is made.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We manage our commodity price risk for our non-trading, long-term coal contract portfolio through the use of long-term coal supply agreements, and to a limited extent, through the use of derivative instruments. At December 31, 2011, our commitments for 2012 and 2013 are as follows:

	2012		2013	
	Tons	Price	Tons	Price
Powder River Basin				
Committed, Priced	97.8	$ 14.40	45.8	$ 14.97
Committed, Unpriced	6.5		11.5	
Appalachia				
Committed, Priced (Metallurgical)	4.9	$ 135.7		
Committed, Unpriced (Metallurgical)	0.2		0.1	
Committed, Priced (Thermal)	8.9	$ 70.48	4.2	$ 63.30
Committed, Unpriced (Thermal)	0.5			
Western Bituminous Region				
Committed, Priced	12.9	$ 38.7	11.5	$ 39.01
Committed, Unpriced	0.2			
Illinois Basin				
Committed, Priced	2.0	$ 39.66	1.5	$ 42.25

We are exposed to commodity price risk in our coal trading activities, which represents the potential future loss that could be caused by an adverse change in the market value of coal. Our coal trading portfolio included forward, swap and put and call option contracts at December 31, 2011. With respect to our coal trading portfolio at December 31, 2011, the potential for loss of future earnings resulting from changing coal prices was insignificant. The estimated future realization of the value of the trading portfolio is $2.6 million of losses in 2012 and $1.8 million of losses in 2013.

We monitor and manage market price risk for our trading activities with a variety of tools, including Value at Risk (VaR), position limits, management alerts for mark to market monitoring and loss limits, scenario analysis, sensitivity analysis and review of daily changes in market dynamics. Management believes that presenting high, low, end of year and average VaR is the best available method to give investors insight into the level of commodity risk of our trading positions. Illiquid positions, such as long-dated trades that are not quoted by brokers or exchanges, are not included in VaR.

VaR is a statistical one-tail confidence interval and down side risk estimate that relies on recent history to estimate how the value of the portfolio of positions will change if markets behave in the same way as they have in the recent past. While presenting VaR will provide a similar framework for discussing risk across companies, VaR estimates from two independent sources are rarely calculated in the same way. Without a thorough understanding of how each VaR model was calculated, it would be difficult to compare two different VaR calculations from different sources. The level of confidence is 95%. The time across which these possible value changes are being estimated is through the end of the next business day. A closed-form delta-neutral method used throughout the finance and energy sectors is employed to calculate this VaR. VaR is back tested to verify usefulness.

On average, portfolio value should not fall more than VaR on 95 out of 100 business days. Conversely, portfolio value declines of more than VaR should be expected, on average, 5 out of 100 business days. When more value than VaR is lost due to market price changes, VaR is not representative of how much value beyond VaR will be lost.

During the year ended December 31, 2011, VaR for our trading portfolio ranged from under $0.5 million to $2.1 million. The linear mean of each daily VaR was $1.2 million. The final VaR at December 31, 2011 was

$0.6 million. We have also entered into positions for risk management purposes for which we could not elect hedge accounting. The VaR at December 31, 2011 for these positions was $1.9 million

We are also exposed to the risk of fluctuations in cash flows related to our purchase of diesel fuel. We expect to use approximately 80 million to 90 million gallons of diesel fuel annually in our operations. We enter into forward physical purchase contracts, as well as heating oil swaps and options, to reduce volatility in the price of diesel fuel for our operations. At December 31, 2011, the Company had protected the price of approximately 82% of its expected purchases for fiscal year 2012, mostly through the use of the derivative instruments noted above. Since the changes in the price of heating oil are highly correlated to changes in the price of the hedged diesel fuel purchases, the heating oil swaps and purchased call options qualify for cash flow hedge accounting. Accordingly, changes in the fair value of the derivatives are recorded through other comprehensive income, with any ineffectiveness recognized immediately in income. At December 31, 2011, a $0.25 per gallon decrease in the price of heating oil would not result in an increase in our expense related to the heating oil derivatives.

We are exposed to market risk associated with interest rates due to our existing level of indebtedness. At December 31, 2011, of our $4.0 billion principal amount of debt outstanding, $481.3 million of outstanding borrowings have interest rates that fluctuate based on changes in the market rates. An increase in the interest rates related to these borrowings of 25 basis points would result in an annualized increase in interest expense of $1.2 million, based on borrowing levels at December 31, 2011.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The consolidated financial statements and consolidated financial statement schedule of Arch Coal, Inc. and subsidiaries are included in this Annual Report on Form 10-K beginning on page F-1.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

We performed an evaluation under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2011. Based on that evaluation, our management, including our chief executive officer and chief financial officer, concluded that the disclosure controls and procedures were effective as of such date. As permitted by guidance issued by the SEC, we have excluded from this assessment the disclosure controls and procedures of International Coal Group, Inc. (ICG) which was acquired in the year ended December 31, 2011. ICG and its subsidiaries represent approximately 14% and 37% of our consolidated assets as of December 31, 2011 and consolidated revenues for the year ended December 31, 2011, respectively. As permitted by guidance issued by the SEC, we have also excluded ICG from our management's assessment of the effectiveness of our internal control over financial reporting for the year ended December 31, 2011.

There were no significant changes in our internal control over financial reporting during our fiscal quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

We incorporate by reference the report of independent registered public accounting firm and management's report on internal control over financial reporting included on pages F-3 and F-4, respectively, of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 401 of Regulation S-K is included under the caption "Director Qualifications, Diversity and Biographies" in our 2011 Proxy Statement and in Part I of this report under the caption "Executive Officers." The information required by Items 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K is included under the captions "Section 16(a) Beneficial Ownership Reporting Compliance," "Code of Conduct" and "Board Meetings and Committees" in our 2011 Proxy Statement. Such information is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Items 402 and 407(e)(4) and (e)(5) of Regulation S-K is included under the captions "Executive Compensation," "Director Compensation," "Compensation Committee Interlocks and Insider Participation" and "Personnel and Compensation Committee Report" (which is furnished) in our 2011 Proxy Statement and is incorporated herein by reference.

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

The information required by Items 201(d) and 403 of Regulation S-K is included under the captions "Equity Compensation Plan Information," "Security Ownership of Directors and Executive Officers" and "Security Ownership of Certain Beneficial Owners" in our 2011 Proxy Statement and is incorporated herein by reference.

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

The information required by Items 404 and 407(a) of Regulation S-K is included under the caption "Directors and Corporate Governance Practices" in our 2011 Proxy Statement and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 9(e) of Regulation S-K is included under the caption "Fees Paid to Auditors" in our 2011 Proxy Statement and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

Financial Statements

Reference is made to the index set forth on page F-1 of this report.

Financial Statement Schedules

Financial statement schedules listed under SEC rules but not included in this report are omitted because they are not applicable or the required information is provided in the notes to our consolidated financial statements.

Exhibits

Reference is made to the Exhibit Index beginning on page 88 of this report.

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Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Arch Coal, Inc.

Steven F. Leer
Chairman and Chief Executive Officer
February 29, 2012

Signatures	**Capacity**	**Date**
Steven F. Leer	Chairman and Chief Executive Officer (Principal Executive Officer)	February 29, 2012
John T. Drexler	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 29, 2012
John W. Lorson	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 29, 2012
* James R. Boyd	Director	February 29, 2012
	President, Chief Operating Officer and Director	February 29, 2012

John W. Eaves		
*	Director	February 29, 2012
David D. Freudenthal		

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Signatures	Capacity	Date
* Patricia F. Godley	Director	February 29, 2012
* Douglas H. Hunt	Director	February 29, 2012
* Brian J. Jennings	Director	February 29, 2012
* J. Thomas Jones	Director	February 29, 2012
* A. Michael Perry	Director	February 29, 2012
* Robert G. Potter	Director	February 29, 2012
* Theodore D. Sands	Director	February 29, 2012
* Wesley M. Taylor	Director	February 29, 2012
* Peter I. Wold	Director	February 29, 2012

*By:

Robert G. Jones,
Attorney-in-Fact

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Exhibit Index

Exhibit	Description
2.1	Purchase and Sale Agreement, dated as of December 31, 2005, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated herein by reference to Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 6, 2006).
2.2	Amendment No. 1 to the Purchase and Sale Agreement, dated as of February 7, 2006, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated by reference to Exhibit 2.1 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2005).
2.3	Amendment No. 2 to the Purchase and Sale Agreement, dated as of April 27, 2006, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated herein by reference to Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2006).
2.4	Amendment No. 3 to the Purchase and Sale Agreement, dated as of August 29, 2007, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated herein by reference to Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q for the period ended September 30, 2007).
2.5	Agreement, dated as of March 27, 2008, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated herein by reference to Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2008).
2.6	Amendment No. 1 to Agreement, dated as of February 5, 2009, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated herein by reference to Exhibit 2.6 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2008).
2.7	Agreement and Plan of Merger, dated as of May 2, 2011, by and among Arch Coal, Inc., Atlas Acquisition Corp. and International Coal Group, Inc. (incorporated herein by reference to Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on May 3, 2011).
2.8	Amendment to Agreement and Plan of Merger, dated as of May 26, 2011 among Arch Coal, Inc., Atlas Acquisition Corp. and International Coal Group, Inc.
3.1	Restated Certificate of Incorporation of Arch Coal, Inc. (incorporated herein by reference to Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on May 5, 2006).
3.2	Arch Coal, Inc. Bylaws, as amended effective as of December 5, 2008 (incorporated herein by reference to Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on December 10, 2008).
4.1	Indenture, dated as of June 25, 2003, by and among Arch Western Finance, LLC, Arch Coal, Inc., Arch Western Resources, LLC, Arch of Wyoming, LLC, Mountain Coal Company, L.L.C., Thunder Basin Coal Company, L.L.C. and The Bank of New York, as trustee (incorporated herein by reference to Exhibit 4.1 to the Registration Statement on Form S-4 (Reg. No. 333-107569) filed by Arch Western Finance, LLC on August 1, 2003).
4.2	First Supplemental Indenture dated October 22, 2004 among Arch Western Finance, LLC, Arch Western Resources, LLC, Arch of Wyoming, LLC, Arch Western Bituminous Group, LLC, Mountain Coal Company, L.L.C., Thunder Basin Coal Company, L.L.C., Triton Coal Company, LLC, and The Bank of New York, as trustee (incorporated herein by reference to Exhibit 4.4 to the registrant's Current Report on Form 8-K filed on October 28, 2004).
4.3	Indenture, dated as of July 31, 2009 by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on July 31, 2009).
4.4	First Supplemental Indenture, dated as of February 8, 2010, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2010).

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Exhibit	Description
4.5	Second Supplemental Indenture, dated as of March 12, 2010, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.5 to the registrant's Registration Statement on Form S-4 filed on April 7, 2010)
4.6	Third Supplemental Indenture, dated as of May 7, 2010, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.3 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2010)
4.7	Fourth Supplemental Indenture, dated December 16, 2010, by and among Arch Coal West, LLC, Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.7 to the registrant's Annual Report on Form 10-K for the period ended December 31, 2010).
4.8	Fifth Supplemental Indenture, dated as of June 24, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee.
4.9	Sixth Supplemental Indenture, dated as of October 7, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee.
4.10	Indenture, dated as of August 9, 2010, by and between Arch Coal, Inc. and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on August 9, 2010)
4.11	First Supplemental Indenture, dated as of August 9, 2010, by and among Arch Coal, Inc., the subsidiary guarantors named therein, and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on August 9, 2010)
4.12	Second Supplemental Indenture, dated as of December 16, 2010, by and among Arch Coal West, LLC, Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.7 to the registrant's Annual Report on Form 10-K for the period ended December 31, 2010).
4.13	Third Supplemental Indenture, dated as of June 24, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee.
4.14	Fourth Supplemental Indenture, dated as of October 7, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee.
4.15	Indenture, dated as of June 14, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on June 14, 2011).
4.16	First Supplemental Indenture, dated as of July 5, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee.
4.17	Second Supplemental Indenture, dated as of October 7, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee.
4.18	Registration Rights Agreement, dated as of June 14, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein, Morgan Stanley & Co. LLC, PNC Capital Markets LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBS Securities Inc. and Citigroup Global Markets Inc. as representatives of the initial purchasers named therein (incorporated herein by reference to Exhibit 4.4 to the registrant's Current Report on Form 8-K filed on June 14, 2011).
10.1	Amended and Restated Credit Agreement, dated as of June 14, 2011, by and among the Company, the lenders party thereto, PNC Bank, National Association, as administrative agent and Bank of America, N.A., The Royal Bank of Scotland PLC and Citibank, N.A., as co-documentation agents (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by the registrant on June 17, 2011).

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Exhibit	Description
10.2*	Employment Agreement, dated November 10, 2006, between Arch Coal, Inc. and Steven F. Leer (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by the registrant on November 16, 2006).
10.3*	Form of Employment Agreement for Executive Officers of Arch Coal, Inc. (other than Steven F. Leer) (for employment agreements entered into up to 2011) (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by the registrant on November 16, 2006).
10.4*	Form of Employment Agreement for Executive Officers of Arch Coal, Inc. (other than Steven F. Leer) (for employment agreements entered into beginning in 2011).
10.5	Coal Lease Agreement dated as of March 31, 1992, among Allegheny Land Company, as lessee, and UAC and Phoenix Coal Corporation, as lessors, and related guarantee (incorporated herein by reference to the Current Report on Form 8-K filed by Ashland Coal, Inc. on April 6, 1992).
10.6	Federal Coal Lease dated as of June 24, 1993 between the U.S. Department of the Interior and Southern Utah Fuel Company (incorporated herein by reference to Exhibit 10.17 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.7	Federal Coal Lease between the U.S. Department of the Interior and Utah Fuel Company (incorporated herein by reference to Exhibit 10.18 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.8	Federal Coal Lease dated as of July 19, 1997 between the U.S. Department of the Interior and Canyon Fuel Company, LLC (incorporated herein by reference to Exhibit 10.19 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.9	Federal Coal Lease dated as of January 24, 1996 between the U.S. Department of the Interior and the Thunder Basin Coal Company (incorporated herein by reference to Exhibit 10.20 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.10	Federal Coal Lease Readjustment dated as of November 1, 1967 between the U.S. Department of the Interior and the Thunder Basin Coal Company (incorporated herein by reference to Exhibit 10.21 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.11	Federal Coal Lease effective as of May 1, 1995 between the U.S. Department of the Interior and Mountain Coal Company (incorporated herein by reference to Exhibit 10.22 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.12	Federal Coal Lease dated as of January 1, 1999 between the Department of the Interior and Ark Land Company (incorporated herein by reference to Exhibit 10.23 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.13	Federal Coal Lease dated as of October 1, 1999 between the U.S. Department of the Interior and Canyon Fuel Company, LLC (incorporated herein by reference to Exhibit 10 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1999).
10.14	Federal Coal Lease effective as of March 1, 2005 by and between the United States of America and Ark Land LT, Inc. covering the tract of land known as "Little Thunder" in Campbell County, Wyoming (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by the registrant on February 10, 2005).
10.15	Modified Coal Lease (WYW71692) executed January 1, 2003 by and between the United States of America, through the Bureau of Land Management, as lessor, and Triton Coal Company, LLC, as lessee, covering a tract of land known as "North Rochelle" in Campbell County, Wyoming (incorporated by reference to Exhibit 10.24 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2004).
10.16	Coal Lease (WYW127221) executed January 1, 1998 by and between the United States of America, through the Bureau of Land Management, as lessor, and Triton Coal Company, LLC, as lessee, covering a tract of land known as "North Roundup" in Campbell County, Wyoming (incorporated by reference to Exhibit 10.24 to the registrant's Annual Report on Form 10-K for the

year ended December 31, 2004).

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Exhibit	Description
10.17	State Coal Lease executed October 1, 2004 by and between The State of Utah, Thru School & Institutional Trust Lands Admin, as lessor, and Ark Land Company and Arch Coal, Inc., as lessees, covering a tract of land located in Seiever County, Utah (incorporated by reference to Exhibit 10.20 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2006).
10.18	State Coal Lease executed September 1, 2000 by and between The State of Utah, Thru School & Institutional Trust Lands Admin, as lessor, and Canyon Fuel Company, LLC, as lessee, for lands located in Carbon County, Utah (incorporated by reference to Exhibit 10.21 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2006).
10.19	Federal Coal Lease executed September 1, 1996 by and between the Bureau of Land Management, as lessor, and Canyon Fuel Company, LLC, as lessee, covering a tract of land known as "The North Lease" in Carbon County, Utah (incorporated by reference to Exhibit 10.22 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2006).
10.20	State Coal Lease executed January 18, 2008 by and between The State of Utah, Thru School & Institutional Trust Lands Admin, as lessor, and Ark Land Company, as lessee, for lands located in Emery County, Utah (incorporated by reference to Exhibit 10.21 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2008).
10.21	Form of Indemnity Agreement between Arch Coal, Inc. and Indemnitee (as defined therein) (incorporated herein by reference to Exhibit 10.15 to the Registration Statement on Form S-4 (Registration No. 333-28149) filed by the registrant on May 30, 1997).
10.22*	Arch Coal, Inc. Incentive Compensation Plan For Executive Officers (incorporated herein by reference to Appendix B to the proxy statement on Schedule 14A filed by the registrant on March 22, 2010).
10.23*	Arch Coal, Inc. Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on December 11, 2008).
10.24*	Arch Coal, Inc. 1997 Stock Incentive Plan (as amended and restated on October 21, 2010) (incorporated herein by reference to Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on October 27, 2010).
10.25*	Arch Mineral Corporation 1996 ERISA Forfeiture Plan (incorporated herein by reference to Exhibit 10.20 to the Registration Statement on Form S-4 (Registration No. 333-28149) filed by the registrant on May 30, 1997).
10.26*	Arch Coal, Inc. Outside Directors' Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.4 of the registrant's Current Report on Form 8-K filed on December 11, 2008).
10.27*	Arch Coal, Inc. Supplemental Retirement Plan (as amended on December 5, 2008) (incorporated herein by reference to Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on December 11, 2008).
10.28*	Form of Restricted Stock Unit Contract (incorporated herein by reference to Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on February 24, 2006).
10.29*	Form of Non-Qualified Stock Option Agreement (for stock options granted prior to February 21, 2008) (incorporated herein by reference to Exhibit 10.35 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2006).
10.30*	Form of 2008 Restricted Stock Unit Contract for Messrs. Leer and Eaves (incorporated herein by reference to Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on February 27, 2008).
10.31*	Form of 2008 Non-Qualified Stock Option Agreement for Messrs. Leer and Eaves (incorporated herein by reference to Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on February 27, 2008).
10.32*	Form of Non-Qualified Stock Option Agreement (for stock options granted on or after February 21, 2008) (incorporated herein by reference to Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on February 27, 2008).
10.33*	Form of Performance Unit Contract (incorporated herein by reference to Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on February 23, 2009).

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Exhibit	Description
10.34*	Form of Director Indemnity Agreement (incorporated herein by reference to Exhibit 10.40 to the registrant's Annual Report on Form 10-K for the period ended December 31, 2010).
10.35	Amended and Restated Receivables Purchase Agreement, dated as of February 24, 2020, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc., Market Street Funding LLC, as issuer, the financial institutions from time to time party thereto, as LC Participants, and PNC Bank, National Association, as Administrator on behalf of the Purchasers and as LC Bank (incorporated herein by reference to Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2010).
10.36	First Amendment to Amended and Restated Receivables Purchase Agreement, dated January 31, 2011, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc. and the other parties thereto (incorporated by reference to Exhibit 10.41 to the registrant's Annual Report on Form 10-K for the period ended December 31, 2010).
10.37	Second Amendment to Amended and Restated Receivables Purchase Agreement dated June 15, 2011 (incorporated by reference to Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2011).
10.38	Third Amendment to Amended and Restated Receivables Purchase Agreement dated November 21, 2011, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc. and the other parties thereto.
10.39	Fourth Amendment to Amended and Restated Receivables Purchase Agreement dated December 13, 2011, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc. and the other parties thereto.
12.1	Computation of ratio of earnings to combined fixed charges and preference dividends.
21.1	Subsidiaries of the registrant.
23.1	Consent of Ernst & Young LLP.
23.2	Consent of Weir International, Inc.
24.1	Power of Attorney.
31.1	Rule 13a-14(a)/15d-14(a) Certification of Steven F. Leer.
31.2	Rule 13a-14(a)/15d-14(a) Certification of John T. Drexler.
32.1	Section 1350 Certification of Steven F. Leer.
32.2	Section 1350 Certification of John T. Drexler.
95	Mine Safety Disclosure Exhibit.
101	Interactive Data File (Form 10-K for the year ended December 31, 2011 furnished in XBRL).

* Denotes management contract or compensatory plan arrangements.

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FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial statements of Arch Coal, Inc. and subsidiaries and reports of independent registered public accounting firm follow.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Arch Coal, Inc.

We have audited the accompanying consolidated balance sheets of Arch Coal, Inc. (the Company) as of December 31, 2011 and 2010, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Arch Coal, Inc. at December 31, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Arch Coal, Inc.'s internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 29, 2012, expressed an unqualified opinion thereon.

St. Louis, Missouri
February 29, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Arch Coal, Inc.

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

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

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

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

As indicated in the accompanying Report of Management and Management's Report on Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of International Coal Group, Inc. which is included in the 2011 consolidated financial statements of Arch Coal, Inc. and constituted $3.8 billion and $3.1 billion of total and net assets, respectively, as of December 31, 2011 and $606.9 million and $14.6 million of revenues and net income, respectively, for the year then ended. Our audit of internal control over financial reporting of Arch Coal, Inc. also did not include an evaluation of the internal control over financial reporting of International Coal Group, Inc.

In our opinion, Arch Coal, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Arch Coal, Inc. as of December 31, 2011 and 2010, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2011, and our report dated February 29, 2011, expressed an unqualified opinion thereon.

St. Louis, Missouri
February 29, 2012

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REPORT OF MANAGEMENT

The management of Arch Coal, Inc. (the "Company") is responsible for the preparation of the consolidated financial statements and related financial information in this annual report. The financial statements are prepared in accordance with accounting principles generally accepted in the United States and necessarily include some amounts that are based on management's informed estimates and judgments, with appropriate consideration given to materiality.

The Company maintains a system of internal accounting controls designed to provide reasonable assurance that financial records are reliable for purposes of preparing financial statements and that assets are properly accounted for and safeguarded. The concept of reasonable assurance is based on the recognition that the cost of a system of internal accounting controls should not exceed the value of the benefits derived. The Company has a professional staff of internal auditors who monitor compliance with and assess the effectiveness of the system of internal accounting controls.

The Audit Committee of the Board of Directors, comprised of independent directors, meets regularly with management, the internal auditors, and the independent auditors to discuss matters relating to financial reporting, internal accounting control, and the nature, extent and results of the audit effort. The independent auditors and internal auditors have full and free access to the Audit Committee, with and without management present.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Arch Coal, Inc. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Securities Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including its principal executive officer and principal financial officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the criteria set forth in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, management concluded that the Company's internal control over financial reporting is effective as of December 31, 2011. On June 15, 2011, the Company acquired International Coal Group, Inc. (ICG), whose total assets and revenues constitute approximately 14% and 37%, respectively, of the amounts reflected in the accompanying consolidated financial statements for the year ended December 31, 2011. As permitted by the guidance the SEC, we have excluded ICG from our annual assessment of the effectiveness of internal control over financial reporting for the year ended December 31, 2011, the year of acquisition.

The Company's independent registered public accounting firm, Ernst & Young LLP, has issued an audit report on the Company's internal control over financial reporting.

Steven F. Leer	John T. Drexler
Chairman and Chief Executive Officer	*Senior Vice President and Chief Financial Officer*

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CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31		
	2011	2010	2009
	(In thousands, except per share data)		
REVENUES	$ 4,285,895	$ 3,186,268	$ 2,576,081
COSTS, EXPENSES AND OTHER			
Cost of sales	3,267,910	2,395,812	2,070,715
Depreciation, depletion and amortization	466,587	365,066	301,608
Amortization of acquired sales contracts, net	(22,069)	35,606	19,623
Selling, general and administrative expenses	119,056	118,177	97,787
Change in fair value of coal derivatives and coal trading activities, net	(2,907)	8,924	(12,056)
Acquisition and transition costs	54,676		13,726
Gain on Knight Hawk transaction		(41,577)	
Other operating income, net	(10,934)	(19,724)	(39,036)
	3,872,319	2,862,284	2,452,367
Income from operations	413,576	323,984	123,714
Interest expense, net:			
Interest expense	(230,186)	(142,549)	(105,932)
Interest income	3,309	2,449	7,622
	(226,877)	(140,100)	(98,310)
Other non-operating expense:			
Bridge financing costs related to ICG	(49,490)		
Net loss resulting from early retirement of debt	(1,958)	(6,776)	
	(51,448)	(6,776)	
Income before income taxes	135,251	177,108	25,404
Provision for (benefit from) income taxes	(7,589)	17,714	(16,775)
Net income	142,840	159,394	42,179
Less: Net income attributable to noncontrolling interest	(1,157)	(537)	(10)
Net income attributable to Arch Coal, Inc.	$ 141,683	$ 158,857	$ 42,169
EARNINGS PER COMMON SHARE			
Basic earnings per common share	$ 0.75	$ 0.98	$ 0.28
Diluted earnings per common share	$ 0.74	$ 0.97	$ 0.28
Basic weighted average shares outstanding	190,086	162,398	150,963
Diluted weighted average shares outstanding	190,905	163,210	151,272
Dividends declared per common share	$ 0.43	$ 0.39	$ 0.36

The accompanying notes are an integral part of the consolidated financial statements.

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CONSOLIDATED BALANCE SHEETS

	December 31	
	2011	2010
	(In thousands, except per share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 138,149	$ 93,593
Restricted cash	10,322	
Trade accounts receivable	380,595	208,060
Other receivables	88,584	44,260
Inventories	377,490	235,616
Prepaid royalties	21,944	33,932
Deferred income taxes	42,051	
Coal derivative assets	13,335	15,191
Other	110,304	104,262
Total current assets	1,182,774	734,914
Property, plant and equipment:		
Coal lands and mineral rights	6,578,430	2,523,172
Plant and equipment	3,225,985	2,397,444
Deferred mine development	1,064,279	872,329
	10,868,694	5,792,945
Less accumulated depreciation, depletion and amortization	(2,919,544)	(2,484,053)
Property, plant and equipment, net	7,949,150	3,308,892
Other assets:		
Prepaid royalties	86,626	66,525
Goodwill	596,103	114,963
Deferred income taxes		361,556
Equity investments	225,605	177,451
Other	173,701	116,468
Total other assets	1,082,035	836,963
Total assets	$ 10,213,959	$ 4,880,769
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 383,782	$ 198,216
Coal derivative liabilities	7,828	4,947
Deferred income taxes		7,775
Accrued expenses and other current liabilities	348,207	245,411
Current maturities of debt and short-term borrowings	280,851	70,997
Total current liabilities	1,020,668	527,346
Long-term debt	3,762,297	1,538,744
Asset retirement obligations	446,784	334,257
Accrued pension benefits	48,244	49,154
Accrued postretirement benefits other than pension	42,309	37,793
Accrued workers' compensation	71,948	35,290
Deferred income taxes	976,753	
Other noncurrent liabilities	255,382	110,234
Total liabilities	6,624,385	2,632,818

Redeemable noncontrolling interest		11,534		10,444
Stockholders' equity:				
Common stock, $0.01 par value, authorized 260,000 shares, issued 213,183 and 164,117 shares at December 31, 2011 and 2010, respectively		2,136		1,645
Paid-in capital		3,015,349		1,734,709
Treasury stock, 1,512 shares at December 31, 2011 and 2010, at cost		(53,848)		(53,848)
Retained earnings		622,353		561,418
Accumulated other comprehensive loss		(7,950)		(6,417)
Total stockholders' equity		3,578,040		2,237,507
Total liabilities and stockholders' equity	$	10,213,959	$	4,880,769

The accompanying notes are an integral part of the consolidated financial statements.

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CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Three Years Ended December 31, 2011

	Common Stock	Paid-In Capital	Treasury Stock, at Cost	Retained Earnings	Accumulated Other Comprehensive Loss	Total
	(In thousands, except per share data)					
BALANCE AT JANUARY 1, 2009	$ 1,447	$ 1,381,496	$ (53,848)	$ 478,734	$ (79,096)	$ 1,728,733
Comprehensive income:						
Net income attributable to Arch Coal, Inc.				42,169		42,169
Pension, postretirement and other post-employment benefits					12,176	12,176
Net amount reclassified to income					718	718
Unrealized losses on available-for- sale securities					(86)	(86)
Unrealized gains on derivatives					2,436	2,436
Net amount reclassified to income					43,999	43,999
Total comprehensive income						101,412
Dividends on common shares ($0.36 per share)				(54,969)		(54,969)
Issuance of 19,550 common shares	196	326,256				326,452
Issuance of 45 shares of common stock under the stock incentive plan restricted stock and restricted stock units	0	0				0
Issuance of 13 shares of common stock under the stock incentive plan stock options including income tax benefits	0	84				84
Employee stock-based compensation expense		13,394				13,394
BALANCE AT DECEMBER 31, 2009	1,643	1,721,230	(53,848)	465,934	(19,853)	2,115,106
Comprehensive income:						
Net income attributable to Arch Coal, Inc.				158,857		158,857
Pension, postretirement and other post-employment benefits					9,750	9,750
Net amount reclassified to income					110	110
Unrealized gains on available-for- sale securities					1,841	1,841
Unrealized gains on derivatives					221	221
Net amount reclassified to income					1,514	1,514
Total comprehensive income						172,293
Dividends on common shares ($0.39 per share)				(63,373)		(63,373)
Issuance of 9 shares of common stock under the stock incentive plan restricted stock and restricted stock units, net of forfeitures	0	0				0
Issuance of 155 shares of common stock under the stock incentive plan stock options including income tax benefits	2	1,762				1,764
Employee stock-based compensation expense		11,717				11,717
BALANCE AT DECEMBER 31, 2010	1,645	1,734,709	(53,848)	561,418	(6,417)	2,237,507
Comprehensive income:						
Net income attributable to Arch Coal, Inc.				141,683		141,683
Pension, postretirement and other post-employment benefits					4,331	4,331
Net amount reclassified to income					1,672	1,672
Unrealized gains on available-for- sale securities					114	114
Unrealized gains on derivatives					2,913	2,913
Net amount reclassified to income					(10,563)	(10,563)
Total comprehensive income						140,150
Dividends on common shares ($0.43 per share)				(80,748)		(80,748)
Issuance of 48,705 common shares	487	1,267,446				1,267,933
Issuance of 162 shares of common stock under the stock incentive plan restricted stock and restricted stock units, net of forfeitures	2	(2)				0

Issuance of 199 shares of common stock under the stock incentive plan stock options including income tax benefits	2	2,314				2,316
Employee stock-based compensation expense		10,882				10,882
BALANCE AT DECEMBER 31, 2011	$ 2,136	$ 3,015,349	$ (53,848)	$ 622,353	$ (7,950)	$ 3,578,040

The accompanying notes are an integral part of the consolidated financial statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31		
	2011	2010	2009
		(In thousands)	
OPERATING ACTIVITIES			
Net income	$ 142,840	$ 159,394	$ 42,179
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	466,587	365,066	301,608
Amortization of acquired sales contracts, net	(22,069)	35,606	19,623
Bridge financing costs related to ICG	49,490		
Write down of assets acquired from ICG	7,316		
Prepaid royalties expensed	34,842	34,605	29,746
Employee stock-based compensation	10,882	11,717	13,394
Amortization relating to financing activities	14,067	10,398	6,741
Gain on Knight Hawk transaction		(41,577)	
Net loss resulting from early retirement of debt	1,958	6,776	
Changes in operating assets and liabilities:			
Receivables	(74,914)	(7,287)	47,794
Inventories	(50,900)	5,160	(28,518)
Coal derivative assets and liabilities	6,079	9,554	32,266
Accounts payable, accrued expenses and other current liabilities	52,191	87,807	(44,764)
Income taxes payable/receivable	(21,759)	(1,364)	2,100
Deferred income taxes	10,519	(12,405)	(34,668)
Asset retirement obligations	3,868	23,997	18,741
Other	11,245	9,700	(23,262)
Cash provided by operating activities	642,242	697,147	382,980
INVESTING ACTIVITIES			
Acquisitions of businesses, net of cash acquired	(2,894,339)		(768,819)
Decrease in restricted cash	5,167		
Capital expenditures	(540,936)	(314,657)	(323,150)
Proceeds from dispositions of property, plant and equipment	25,887	330	825
Additions to prepaid royalties	(29,957)	(27,355)	(26,755)
Purchases of investments and advances to affiliates	(61,909)	(46,185)	(10,925)
Consideration paid related to prior business acquisitions	(829)	(1,262)	(4,767)
Reimbursement of deposits on equipment			3,209
Cash used in investing activities	(3,496,916)	(389,129)	(1,130,382)
FINANCING ACTIVITIES			
Proceeds from the issuance of senior notes	2,000,000	500,000	584,784
Proceeds from the issuance of common stock, net	1,267,933		326,452
Payments to retire debt	(605,178)	(505,627)	
Net increase (decrease) in borrowings under lines of credit and commercial paper program	424,396	(196,549)	(85,815)
Net proceeds from (payments on) other debt	5,334	82	(2,986)
Debt financing costs	(114,823)	(12,751)	(29,659)
Dividends paid	(80,748)	(63,373)	(54,969)
Issuance of common stock under incentive plans	2,316	1,764	84
Contribution from noncontrolling interest		891	
Cash provided by (used in) financing activities	2,899,230	(275,563)	737,891
Increase (decrease) in cash and cash equivalents	44,556	32,455	(9,511)
Cash and cash equivalents, beginning of year	93,593	61,138	70,649
Cash and cash equivalents, end of year	$ 138,149	$ 93,593	$ 61,138

SUPPLEMENTAL CASH FLOW INFORMATION:						
Cash paid during the year for interest	$	213,697	$	134,866	$	76,801
Cash paid during the year for income taxes	$	7,094	$	36,765	$	17,482

The accompanying notes are an integral part of the consolidated financial statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of Arch Coal, Inc. and its subsidiaries and controlled entities ("the Company"). The Company produces coal from surface and underground mines located throughout the United States for sale to domestic and international customers as steam coal to power plants and industrial facilities and metallurgical coal used in steel production. The Company expanded further into metallurgical coal markets with the acquisition of International Coal Group, Inc. ("ICG") on June 15, 2011, as described in Note 3, "Business Combinations." The Company operates 23 mining complexes in West Virginia, Kentucky, Maryland, Virginia, Illinois, Wyoming, Colorado and Utah. All subsidiaries (except as noted below) are wholly-owned. Intercompany transactions and accounts have been eliminated in consolidation.

The Company owns a 99% membership interest in a joint venture named Arch Western Resources, LLC ("Arch Western"), which operates coal mines in Wyoming, Colorado and Utah. The Company also acts as the managing member of Arch Western.

Accounting Pronouncements

There were no accounting pronouncements whose adoption had, or is expected to have, a material impact on the Company's consolidated financial statements.

Accounting Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and revenues and expenses in the accompanying consolidated financial statements and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost. Cash equivalents consist of highly-liquid investments with an original maturity of three months or less when purchased. At December 31, 2011 and 2010, the carrying amounts of cash and cash equivalents approximate their fair value.

Allowance for Uncollectible Receivables

The Company establishes an allowance for uncollectible receivables for the amounts of trade accounts receivable and other receivables that are not expected to be collected, based on past collection history, the economic environment and specified risks identified in the receivables portfolio. Receivables are considered past due if the full payment is not received by the contractual due date. At December 31, 2011 and 2010, there was either no allowance or an insignificant allowance for uncollectible receivables.

Inventories

Coal and supplies inventories are valued at the lower of average cost or market. Coal inventory costs include labor, supplies, equipment costs, transportation costs incurred prior to the transfer of title to customers and operating overhead. The costs of removing overburden, called stripping costs, incurred during the production phase of the mine are considered variable production costs and are included in the cost of the coal extracted during the period the stripping costs are incurred.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Investments and Membership Interests in Joint Ventures

Investments and membership interests in joint ventures are accounted for under the equity method of accounting if the Company has the ability to exercise significant influence, but not control, over the entity. The Company's share of the entity's income is reflected in other operating income, net in the consolidated statements of income. Information about investment activity is provided in Note 8, "Equity Investments and Membership Interests in Joint Ventures."

Marketable equity securities held by the Company that do not qualify for equity method accounting are classified as available-for-sale and are recorded at their fair value on the balance sheet. Unrealized gains and losses on these investments are recorded in other comprehensive income. A decline in the value of an investment that is considered other-than-temporary is recognized in income.

Prepaid Royalties

Leased mineral rights are often acquired through royalty payments. When royalty payments represent prepayments recoupable against future production, they are recorded as a prepaid asset, with amounts expected to be recouped within one year classified as current. When the coal is mined under these leases the royalties are recouped and the prepayment is charged to cost of sales.

Acquired Sales Contracts

Coal supply agreements (sales contracts) acquired in a business combination are capitalized at their fair value and amortized over the tons of coal shipped during the term of the contract. The fair value of a sales contract is determined by discounting the cash flows attributable to the difference between the contract price and the prevailing forward prices for the tons under contract at the date of acquisition. See Note 6, "Acquired Sales Contracts" for further information related to the Company's acquired sales contracts.

Exploration Costs

Costs to acquire permits for exploration activities are capitalized. Drilling and other costs related to locating coal deposits and evaluating the economic viability of such deposits are expensed as incurred.

Property, Plant and Equipment

Plant and Equipment

Plant and equipment are recorded at cost. Interest costs incurred during the construction period for major asset additions are capitalized. Expenditures that extend the useful lives of existing plant and equipment or increase the productivity of the asset are capitalized. The cost of maintenance and repairs that do not extend the useful life or increase the productivity of the asset are expensed as incurred.

Preparation plants and loadouts are depreciated using the units-of-production method over the estimated recoverable reserves, subject to a minimum level of depreciation. Other plant and equipment are depreciated principally using the straight-line method over the estimated useful lives of the assets, limited by the remaining life of the mine. The useful lives of mining equipment, including longwalls, draglines and shovels, range from 5 to 32 years. The useful lives of buildings and leasehold improvements generally range from 10 to 30 years.

Deferred Mine Development

Costs of developing new mines or significantly expanding the capacity of existing mines are capitalized and amortized using the units-of-production method over the estimated recoverable reserves that are associated with the property being benefited. Costs may include construction permits and licenses; mine design; construction of access roads, shafts, slopes and main entries; and removing overburden to access reserves in a new pit. Additionally, deferred mine development includes the asset cost associated with asset retirement obligations.

Coal Lands and Mineral Rights

Rights to coal reserves may be acquired directly through governmental or private entities. A significant portion of the Company's coal reserves are controlled through leasing arrangements. The net book value of the Company's leased coal interests was $1.6 billion at December 31, 2011 and 2010. Payments to acquire royalty lease agreements and lease bonus payments are capitalized as a cost of the underlying mineral reserves and depleted over the life of proven and probable reserves. Coal lease rights are depleted using the units-of-production method, and the rights are assumed to have no residual value. Lease agreements are generally long-term in nature (original terms range from 10 to 50 years), and substantially all of the leases contain provisions that allow for automatic extension of the lease term providing certain requirements are met. See Note 2, "Property Transactions" for further disclosures on coal lease agreements.

Impairment

If facts and circumstances suggest that the carrying value of a long-lived asset or asset group may not be recoverable, the asset or asset group is reviewed for potential impairment. If this review indicates that the carrying amount of the asset will not be recoverable through projected undiscounted cash flows generated by the asset and its related asset group over its remaining life, then an impairment loss is recognized by reducing the carrying value of the asset to its fair value. The Company may, under certain circumstances, idle mining operations in response to market conditions or other factors. Because an idling is not a permanent closure, it is not considered an automatic indicator of impairment.

Goodwill

In a business combination, goodwill represents the excess of the purchase price over the fair value assigned to the net tangible and identifiable intangible assets acquired. The Company tests goodwill for impairment annually as of the beginning of the fourth quarter, or when circumstances indicate a possible impairment may exist. If the results of the testing indicate that the carrying amount of a reporting unit exceeds the fair value of the reporting unit, the fair value of goodwill must be calculated. An impairment loss generally would be recognized when the carrying amount of goodwill exceeds the implied fair value of goodwill, determined by subtracting the fair value of the other assets and liabilities associated with the reporting unit from the total fair value of the reporting unit. The fair value of a reporting unit is determined using a discounted cash flow ("DCF") technique. A number of significant assumptions and estimates are involved in the application of the DCF analysis to forecast operating cash flows, including the discount rate and projections of selling prices and costs to produce.

Deferred Financing Costs

The Company capitalizes costs incurred in connection with new borrowings, the establishment or enhancement of credit facilities and the issuance of debt securities. These costs are amortized as an adjustment to interest expense over the life of the borrowing or term of the credit facility using the interest method. The unamortized balance of deferred financing costs was $90.5 million and $37.6 million at December 31, 2011 and 2010, respectively. Amounts classified as current were $15.8 million and $9.6 million at December 31, 2011 and 2010, respectively. Current amounts are recorded in other current assets and noncurrent amounts are recorded in other assets in the accompanying consolidated balance sheets.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Revenue Recognition

Revenues include sales to customers of coal produced at Company operations and coal purchased from third parties. The Company recognizes revenue at the time risk of loss passes to the customer at contracted amounts. Transportation costs are included in cost of sales and amounts billed by the Company to its customers for transportation are included in revenues.

Other Operating Income, Net

Other operating income, net in the accompanying consolidated statements of income reflects income and expense from sources other than physical coal sales, including: bookouts, the practice of offsetting purchase and sale contracts for shipping convenience purposes, and contract settlements; royalties earned from properties leased to third parties; income from equity investments; gains and losses from dispositions of assets; and realized gains and losses on derivatives that do not qualify for hedge accounting and are not held for trading purposes.

Asset Retirement Obligations

The Company's legal obligations associated with the retirement of long-lived assets are recognized at fair value at the time the obligations are incurred. Accretion expense is recognized through the expected settlement date of the obligation. Obligations are incurred at the time development of a mine commences for underground and surface mines or construction begins for support facilities, refuse areas and slurry ponds. The obligation's fair value is determined using a DCF technique and is based upon permit requirements and various estimates and assumptions that would be used by market participants, including estimates of disturbed acreage, reclamation costs and assumptions regarding equipment productivity. Upon initial recognition of a liability, a corresponding amount is capitalized as part of the carrying value of the related long-lived asset.

The Company reviews its asset retirement obligation at least annually and makes necessary adjustments for permit changes as granted by state authorities and for revisions of estimates of the amount and timing of costs. For ongoing operations, adjustments to the liability result in an adjustment to the corresponding asset. For idle operations, adjustments to the liability are recognized as income or expense in the period the adjustment is recorded. Any difference between the recorded obligation and the actual cost of reclamation is recorded in profit or loss in the period the obligation is settled. See additional discussion in Note 14, "Asset Retirement Obligations."

Derivative Instruments

The Company generally utilizes derivative instruments to manage exposures to commodity prices. Additionally, the Company may hold certain coal derivative instruments for trading purposes. Derivative financial instruments are recognized in the balance sheet at fair value. Certain coal contracts may meet the definition of a derivative instrument, but because they provide for the physical purchase or sale of coal in quantities expected to be used or sold by the Company over a reasonable period in the normal course of business, they are not recognized on the balance sheet.

Certain derivative instruments are designated as the hedge instrument in a hedging relationship. In a fair value hedge, the Company hedges the risk of changes in the fair value of a firm commitment, typically a fixed-price coal sales contract. Changes in both the hedged firm commitment and the fair value of a derivative used as a hedge instrument in a fair value hedge are recorded in earnings. In a cash flow hedge, the Company hedges the risk of changes in future cash flows related to a forecasted purchase or sale. Changes in the fair value of the derivative instrument used as a hedge instrument in a cash flow hedge are recorded in other comprehensive income. Amounts in other comprehensive income are reclassified to earnings when the hedged transaction affects earnings and are classified in a manner consistent with the transaction being hedged. The Company formally documents the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

relationships between hedging instruments and the respective hedged items, as well as its risk management objectives for hedge transactions.

The Company evaluates the effectiveness of its hedging relationships both at the hedge's inception and on an ongoing basis. Any ineffective portion of the change in fair value of a derivative instrument used as a hedge instrument in a fair value or cash flow hedge is recognized immediately in earnings. The ineffective portion is based on the extent to which exact offset is not achieved between the change in fair value of the hedge instrument and the cumulative change in expected future cash flows on the hedged transaction from inception of the hedge in a cash flow hedge or the change in the fair value. Ineffectiveness was insignificant for the years ended December 31, 2011, 2010 and 2009. See Note 10, "Derivative Instruments" for further disclosures related to the Company's derivative instruments.

Fair Value

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly hypothetical transaction between market participants at a given measurement date. Valuation techniques used must maximize the use of observable inputs and minimize the use of unobservable inputs. See Note 13, "Fair Values of Financial Instruments" for further disclosures related to the Company's fair value estimates.

Income Taxes

Deferred income taxes are provided for temporary differences arising from differences between the financial statement amount and tax basis of assets and liabilities existing at each balance sheet date using enacted tax rates anticipated to be in effect when the related taxes are expected to be paid or recovered. A valuation allowance is established if it is more likely than not that a deferred tax asset will not be realized. In determining the need for a valuation allowance, the Company considers projected realization of tax benefits based on expected levels of future taxable income, available tax planning strategies and its overall deferred tax position. See Note 12, "Taxes" for further disclosures about income taxes.

Benefit Plans

The Company has non-contributory defined benefit pension plans covering most of its salaried and hourly employees. Benefits are generally based on the employee's age and compensation. The Company also currently provides certain postretirement medical and life insurance coverage for eligible employees. The cost of providing these benefits are determined on an actuarial basis and accrued over the employee's period of active service.

The Company recognizes the overfunded or underfunded status of these plans as determined on an actuarial basis on the balance sheet and the changes in the funded status are recognized in other comprehensive income. See Note 16, "Employee Benefit Plans" for additional disclosures relating to these obligations.

Stock-Based Compensation

The compensation cost of all stock-based awards is determined based on the grant-date fair value of the award, and is recognized in income over the requisite service period. The grant-date fair value of option awards is determined using a Black-Scholes option pricing model. Compensation cost for an award with performance conditions is accrued if it is probable that the conditions will be met. See further discussion in Note 18, "Stock Based Compensation and Other Incentive Plans."

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Property Transactions

On December 14, 2011, the Company was awarded a federal coal lease for the South Hilight tract in Wyoming for a price of $300.0 million. The bid price will be paid in five equal installments, with the first one made in December 2011. The coal lease will give the Company the right to mine an estimated 222 million tons of coal reserves. The South Hilight tract is contiguous to the Company's Black Thunder mining complex.

On November 12, 2009, the Company entered into a lease of coal reserves and other coal resources from Great Northern Properties Limited Partnership in Montana for $73.1 million. On March 18, 2010, the Company was awarded a Montana state coal lease for the Otter Creek tracts for a price of $85.8 million. These two transactions gave the Company the right to mine approximately 1.4 billion tons of coal reserves in the Montana's Otter Creek area.

The total of the Company's future lease bonus payments due are $23.4 million in 2012, $83.4 million in 2013, $67.3 million in 2014, $60.0 million in 2015 and $60.0 million in 2016.

3. Business Combinations

On June 15, 2011, the Company completed its acquisition of ICG, a leading coal producer, adding 12 mining complexes in Appalachia, one complex in the Illinois Basin and one mine under development in Appalachia, along with other coal reserves not currently in development. The Company acquired all of ICG's outstanding shares of common stock. The acquisition was financed with the proceeds from the Company's sale of common stock and issuance of senior notes. See Note 5, "Debt and Financing Arrangements" and Note 17, "Capital Stock" for further information about these transactions.

The following table summarizes the consideration paid for ICG and the recognized amounts of assets acquired and liabilities assumed at the acquisition date:

	(In millions)
Consideration paid, net of cash acquired	$ 2,894.4
Recognized amounts of net tangible and intangible assets acquired and liabilities assumed:	
Restricted cash	15.5
Receivables	113.2
Inventories	91.0
Net property, plant and equipment, including mineral rights	4,582.6
Goodwill	480.3
Other assets	35.9
Accounts payable	(86.0)
Other accrued expenses and current liabilities	(59.1)
Debt	(604.8)
Litigation accrual	(108.9)
Accrued postretirement benefits	(47.7)
Asset retirement obligation	(112.7)
Coal supply agreements, net	(91.0)
Deferred income taxes, net	(1,278.9)
Other	(35.0)
Net tangible and intangible assets acquired	$ 2,894.4

The Company is awaiting the receipt of the final valuation report from a third party valuation services firm. As a result the fair values for mineral rights, goodwill and deferred taxes may not be final.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The revenues and income before income taxes related to the acquired operations reflected in the consolidated statements of income since the date of acquisition were $606.9 million and $14.6 million, respectively.

The following unaudited pro forma information has been prepared for illustrative purposes and assumes that the business combination occurred on January 1, 2010. The unaudited pro forma results have been prepared based upon ICG's historical results and estimates of the ongoing effects of the transactions that the Company believes are reasonable and supportable. The results are not necessarily reflective of the consolidated results of operations had the acquisition actually occurred on January 1, 2010, nor are they indicative of future operating results.

The unaudited supplemental pro forma financial information of the combined entity follows:

	Year Ended December 31,	
	2011	2010
	(In millions)	
Total revenues		
As reported	$ 4,285.9	$ 3,186.3
Pro forma	$ 4,825.6	$ 4,299.9
Net income attributable to Arch Coal		
As reported	$ 141.7	$ 158.9
Pro forma	$ 113.5	$ (1.2)

The pro forma income before income taxes includes adjustments to operating costs to reflect the new basis in assets acquired and interest expense to reflect the debt incurred to finance the acquisition. In addition, the following pre-tax costs and expenses reflected in the accompanying consolidated statement of income for the year ended December 31, 2011 are reflected in the pro forma results above as of January 1, 2010.

	(In millions)
Costs of completing the acquisition	$ 31.6
Severance costs	15.8
Write off of acquired assets	7.3
Bridge financing fees	49.5
	$ 104.2

Severance costs represent both change in control payments to executives and severance for employees terminated after the acquisition. The acquired asset write-off relates to a preparation plant and loadout of an acquired ICG mining operation. The acquired operation was combined with an existing operation of the Company, and utilizes an existing facility.

Synergies from the acquisition are not reflected in the pro forma results.

In conjunction with the acquisition, the Company had $10.3 million of restricted cash at December 31, 2011 to fund change in control payments for executives.

On October 1, 2009 the Company purchased the Jacobs Ranch mining operations for a purchase price of $768.8 million. The acquired operations included approximately 345 million tons of coal reserves. The acquired mining operations were integrated into the Company's Black Thunder mining operations in its Powder River Basin segment. To finance the acquisition, the Company sold shares of its common stock and issued senior notes. See Note 5, "Debt and Financing Arrangements" and Note 17 "Capital Stock" for further information about these transactions.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Goodwill

Changes in the carrying value of goodwill for the years ended December 31, 2011, 2010 and 2009 are as follows:

	(In thousands)
Balance at January 1, 2009	$ 46,832
Consideration paid related to prior business acquisitions	4,767
Acquisition of Jacobs Ranch	62,102
Balance at December 31, 2009	113,701
Consideration paid related to prior business acquisitions	1,262
Balance at December 31, 2010	114,963
Consideration paid related to prior business acquisitions	829
Acquisition of ICG	480,311
Balance at December 31, 2011	$ 596,103

Goodwill of $115.8 million has been allocated to the Company's Powder River Basin segment and goodwill of $480.3 million has allocated to the Company's Appalachia segment for impairment testing purposes. The goodwill recognized in the ICG acquisition relates to the impact of volatility in the pricing for metallurgical coal and geological and technical efforts prior to the acquisition relating to the mine development project in progress. The goodwill related to the acquisition of ICG is not expected to be deductible for income tax purposes; however, the remaining goodwill is expected to be deductible. The consideration paid related to prior business acquisitions represents ongoing adjustments to the purchase price of a previous acquisition resulting from a 2008 tax settlement.

5. Debt and Financing Arrangements

Debt consists of the following:

	December 31, 2011	December 31, 2010
	(In thousands)	
Commercial paper	$	$ 56,904
Indebtedness to banks under credit facilities	481,300	
6.75% senior notes ($450.0 million face value) due July 1, 2013	450,971	451,618
8.75% senior notes ($600.0 million face value) due August 1, 2016	588,974	587,126
7.00% senior notes due June 15, 2019 at par	1,000,000	
7.25% senior notes due October 1, 2020 at par	500,000	500,000
7.25% senior notes due June 15, 2021 at par	1,000,000	
Other	21,903	14,093
	4,043,148	1,609,741
Less current maturities of debt and short-term borrowings	280,851	70,997
Long-term debt	$ 3,762,297	$ 1,538,744

The current maturities of debt include contractual maturities, as well as amounts borrowed that are supported by credit facilities that have a term of less than one year and amounts borrowed under credit facilities with terms longer than one year that the Company does not intend to refinance on a long-term basis, based on cash projections and management's plans.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ICG Debt

Upon the closing of the ICG acquisition, the Company gave a 30-day redemption notice to the Trustee of ICG's 9.125% senior notes and legally discharged its obligation under the 9.125% senior notes by depositing $260.7 million with the Trustee to redeem the debt. On July 14, 2011, all of the outstanding 9.125% senior notes were redeemed at an aggregate price of $251.4 million, including the required make-whole premium, plus accrued interest of $5.2 million, and the remainder of the deposit was returned to the Company.

At the acquisition date, ICG's 4.00% convertible senior notes with a fair value of $298.5 million and 9.00% convertible senior notes with a fair value of $1.7 million ("convertible notes") became convertible into cash, pursuant to the amended indentures governing the convertible notes, at a calculated conversion rate of $2,614.6848 for each $1,000 in principal amount surrendered for conversion for the 4.00% convertible notes and $2,392.73414 for the 9.00% convertible notes for conversions occurring prior to August 17, 2011.

At the acquisition date, other ICG debt had a fair value of approximately $54.0 million and consisted mainly of equipment notes and insurance notes payable.

The Company recognized a net loss of $2.0 million during the year ended December 31, 2011 on the early extinguishment of ICG's debt, including the conversions of the 4.00% and 9.00% convertible notes described above. The remaining amounts outstanding under the convertible notes and other ICG debt is included in "other" in the debt table above.

Credit Facilities

On June 14, 2011, the Company amended and restated its secured credit facility to allow for up to $2.0 billion in borrowings. The Company paid and deferred $21.1 million in financing fees related to the amendment of this agreement. Borrowings under this credit facility bear interest at a floating rate based on LIBOR determined by reference to the Company's leverage ratio, as calculated in accordance with the credit agreement. The credit facility has a five-year term that expires on June 14, 2016 and is secured by substantially all of the Company's assets as well as its ownership interests in substantially all of its subsidiaries, excluding its ownership interests in Arch Western and its subsidiaries. Commitment fees of 0.50% per annum are payable on the average unused daily balance of the revolving credit facility. The weighted-average interest rate of the Company's outstanding borrowings under the credit facility was 3.04% at December 31, 2011. Financial covenant requirements may restrict the amount of unused capacity available to the Company for borrowings and letters of credit.

The Company maintains an accounts receivable securitization program under which eligible trade receivables are sold, without recourse, to a multi-seller, asset-backed commercial paper conduit. The entity through which these receivables are sold is consolidated into the Company's financial statements. The Company may borrow and draw letters of credit against the facility, and pays facility fees, program fees and letter of credit fees (based on amounts of outstanding letters of credit) at rates that vary with its leverage ratio, as defined under the program. The Company entered into an amendment to its accounts receivable program in November of 2011 to increase the eligible receivables pool, as defined by the agreement, to include receivables generated from the acquired ICG subsidiaries. On December 13, 2011, the Company entered into another amendment to its accounts receivable securitization program to increase the size of the program to allow for aggregate borrowings and letters of credit of up to $250.0 million from $175.0 million. The total aggregate borrowings and letters of credit are limited by eligible accounts receivable, as defined under the terms of the agreement. The credit facility supporting the borrowings under the program is subject to renewal annually, and expires on December 11, 2012. The interest rate in effect as of December 31, 2011 was 0.73%.

On June 14, 2011, the Company terminated its commercial paper placement program and the supporting credit facility.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company's average borrowing level under these programs was approximately $234.2 million and $132.0 million for the years ended December 31, 2011 and 2010, respectively.

Availability

As of December 31, 2011, the Company had $375.0 million of borrowings outstanding under the amended and restated secured credit facility and $106.3 million of borrowings outstanding under its accounts receivable securitization program. The Company also had $146.6 million of outstanding letters of credit at December 31, 2011. As of December 31, 2011, the Company had availability of $901.4 million under all lines of credit, as limited by customary financial covenants that may limit the Company's total debt based on defined earnings measurements.

2013 Senior Notes

The 6.75% senior notes due in 2013 ("2013 Notes") were issued by the Company's subsidiary, Arch Western Finance LLC ("Arch Western Finance"), under an indenture dated June 25, 2003. The Company redeemed $500.0 million aggregate principal amount of the 2013 Notes on September 8, 2010. The Company recognized a loss on the redemption of $6.8 million, including the payment of the $5.6 million redemption premium and the write-off of $3.3 million of unamortized debt financing costs, partially offset by the write-off of $2.1 million of the original issue premium. The senior notes are guaranteed by Arch Western and certain of its subsidiaries and are secured by an intercompany note from Arch Coal, Inc. to Arch Western. The terms of the senior notes contain restrictive covenants that limit Arch Western's ability to, among other things, incur additional debt, sell or transfer assets, and make certain investments. Of the aggregate principal outstanding at December 31, 2011 and 2010, $118.4 million of the 2013 Notes were issued at a premium of 104.75% of par. The premium is amortized over the term of the notes. Interest is payable on the notes on January 1 and July 1 of each year. The notes are redeemable at any time at their face value.

2016 Senior Notes

On July 31, 2009, the Company issued $600.0 million in aggregate principal amount of 8.75% senior unsecured notes due 2016 ("2016 Notes") at an initial issue price of 97.464% of the face amount. The Company incurred issue costs of $14.5 million in association with the 2016 Notes. Interest is payable on the notes on February 1 and August 1 of each year. At any time on or after August 1, 2013, the Company may redeem some or all of the notes. The redemption price, reflected as a percentage of the principal amount, is: 104.375% for notes redeemed between August 1, 2013 and July 31, 2014; 102.188% for notes redeemed between August 1, 2014 and July 31, 2015; and 100% for notes redeemed on or after August 1, 2015. In addition, at any time and on one or more occasions prior to August 1, 2012, the Company may redeem an aggregate principal amount of senior notes not to exceed 35% of the original aggregate principal amount of the senior notes outstanding with the proceeds of one or more public equity offerings, at a redemption price equal to 108.750%.

2020 Senior Notes

On August 9, 2010, we issued $500.0 million in aggregate principal amount of 7.25% senior unsecured notes due in 2020 ("2020 Notes") at par. Interest is payable on the 2020 Notes on April 1 and October 1 of each year. At any time on or after October 1, 2015, the Company may redeem some or all of the notes. The redemption price reflected as a percentage of the principal amount is: 103.625% for notes redeemed between October 1, 2015 and September 30, 2016; 102.417% for notes redeemed between October 1, 2016 and September 30, 2017; 101.208% for notes redeemed between October 1, 2017 and September 30, 2018; and 100% for notes redeemed on or after October 1, 2018. In addition, at any time and on one or more occasions prior to October 1, 2013, the Company may redeem an aggregate principal amount of senior notes not to exceed 35% of the original aggregate principal

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

amount of the senior notes outstanding with the proceeds of one or more public equity offerings, at a redemption price equal to 107.250%.

2019 and 2021 Senior Notes

On June 14, 2011, the Company entered into an indenture in conjunction with the issuance of the 7.00% unsecured senior notes due 2019 ("2019 Notes") and the 7.25% unsecured senior notes due 2021 ("2021 Notes") as discussed in Note 3, "Business Combinations." Interest is payable on the 2019 Notes and 2021 Notes on June 15 and December 15 of each year.

At any time prior to June 15, 2014, the Company may redeem up to 35% of the original aggregate principal amount of each of the 2019 Notes and 2021 Notes, plus accrued and unpaid interest, with the net proceeds from certain equity offerings, at a redemption price, reflected as a percentage of the principal amount, equal to 107.0% and 107.25%, respectively. The Company may redeem the 2019 Notes prior to June 15, 2015 and the 2021 Notes prior to June 15, 2016 at the respective make-whole prices set forth in the indenture. On or after June 15, 2015, the Company may redeem the 2019 Notes at redemption prices, reflected as a percentage of the principal amount, of: 103.5% from June 15, 2015 through June 14, 2016; 101.75% from June 15, 2016 through June 14, 2017; and 100% beginning on June 15, 2017. On or after June 15, 2016, the Company may redeem the 2021 Notes at redemption prices, reflected as a percentage of the principal amount, of: 103.625% from June 15, 2016 through June 14, 2017; 102.417% from June 15, 2017 through June 14, 2018; 101.208% from June 15, 2018 through June 14, 2019 and 100% beginning on June 15, 2019. In each case, accrued and unpaid interest at the redemption date is due upon redemption. Upon a change in control, the Company is required to make a tender offer for both series of notes at a price of 101% of the principal amount. The Company incurred issue costs of $44.2 million related to the issuance of these notes.

The Company and the guarantor subsidiaries entered into a registration rights agreement (the "Registration Rights Agreement") in connection with the issuance and sale of the 2019 Notes and 2021 Notes. Pursuant to the Registration Rights Agreement, the Company and the guarantor subsidiaries agreed to file a registration statement with the Securities and Exchange Commission to register an exchange offer pursuant to which the Company will offer to exchange a like aggregate principal amount of senior notes identical in all material respects to the 2019 Notes and 2021 Notes, except for terms relating to additional interest and transfer restrictions, for any or all of the outstanding 2019 Notes and 2021 Notes. Pursuant to the Registration Rights Agreement, the Company must use commercially reasonable efforts to cause the registration statement to become effective as soon as practicable and to complete the exchange offer no later than June 13, 2012. Should those events not occur within the specified time frame, the applicable interest rates on the 2019 Notes and the 2021 Notes shall be increased by one-quarter of one percent per annum for the first 90 days following the occurrence of such failure. Such interest rate will increase by an additional one-quarter of one percent per annum thereafter at the end of each subsequent 90-day period up to a maximum aggregate increase of one percent per annum. Once any of the required events occur, the interest rates will revert to the rate specified in the indenture governing the 2019 Notes and 2021 Notes.

The 2016, the 2019, the 2020 and the 2021 unsecured senior notes are guaranteed by substantially all of the Company's subsidiaries, including the newly acquired subsidiaries of ICG and excluding Arch Western, its subsidiaries and Arch Receivable Company, LLC and the Company's subsidiaries outside the U.S.

Expected aggregate maturities of debt for the next five years are $280.9 million in 2012, $672.4 in 2013, $0 in 2014, $0 in 2015 and $600.0 million in 2016.

Terms of the Company's credit facilities and leases contain financial and other covenants that limit the ability of the Company to, among other things, acquire, dispose, merge or consolidate assets; incur additional debt; pay dividends and make distributions or repurchase stock; make investments; create liens; issue and sell capital stock of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

subsidiaries; enter into restrictions affecting the ability of restricted subsidiaries to make distributions, loans or advances to the Company; engage in transactions with affiliates and enter into sale and leaseback transactions. The terms also require the Company to, among other things, maintain various financial ratios and comply with various other financial covenants, including an interest coverage ratio test, as defined in the indentures. In addition, the covenants require the Company to pledge assets to collateralize the revolving credit facility. The assets pledged include equity interests in wholly-owned subsidiaries, certain real property interests, accounts receivable and inventory of the Company. Failure by the Company to comply with such covenants could result in an event of default, which, if not cured or waived, could have a material adverse effect on the Company. The Company complied with all financial covenants at December 31, 2011.

6. Acquired Sales Contracts

The acquired sales contracts reflected in the consolidated balance sheets are as follows:

	December 31, 2011		December 31, 2010	
	Assets	Liabilities	Assets	Liabilities
	(In thousands)		(In thousands)	
Acquired fair value	$ 149,457	$ 166,697	$ 114,453	$ 40,654
Accumulated amortization	(115,322)	(69,699)	(82,376)	(14,613)
Total	$ 34,135	$ 96,998	$ 32,077	$ 26,041
Net total		$ (62,863)	$ 6,036	
Balance Sheet classification:				
Other current	$ 18,929	$ 38,441	$ 25,063	$ 5,615
Other noncurrent	$ 15,206	$ 58,557	$ 7,014	$ 20,426

Above-market contracts with a fair value of $35.0 million and below-market contracts with a fair value of $126.0 million were acquired from ICG. See Note 3, "Business Combinations" for discussion of purchase price adjustments.

The Company anticipates amortization income of all acquired sales contracts, based upon expected shipments in the next five years, to be approximately $18.5 million in 2012, $5.2 million in 2013, $3.3 million in 2014, $12.7 million in 2015 and $7.7 million in 2016.

7. Accumulated Other Comprehensive Income (Loss)

Other comprehensive income (loss) includes transactions recorded in stockholders' equity during the year, excluding net income and transactions with stockholders. Following are the items included in accumulated other comprehensive income (loss):

	Derivative Instruments	Pension, Postretirement and Other Post-Employment Benefits	Available-for-Sale Securities	Accumulated Other Comprehensive Loss
	(In thousands)			
Balance at January 1, 2009	$ (45,249)	$ (33,433)	$ (414)	$ (79,096)
2009 activity, before tax	72,553	20,124	(136)	92,541
2009 activity, tax effect	(26,118)	(7,230)	50	(33,298)
Balance at December 31, 2009	1,186	(20,539)	(500)	(19,853)
2010 activity, before tax	2,711	15,406	2,877	20,994
2010 activity, tax effect	(976)	(5,546)	(1,036)	(7,558)
Balance at December 31, 2010	2,921	(10,679)	1,341	(6,417)
2011 activity, before tax	(11,951)	9,345	176	(2,430)
2011 activity, tax effect	4,301	(3,342)	(62)	897

Balance at December 31, 2011	$	(4,729)	$	(4,676)	$	1,455	$	(7,950)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Equity Investments and Membership Interests in Joint Ventures

Below are the equity method investments reflected in the consolidated balance sheets:

	Knight Hawk	DKRW	DTA	Tenaska	Millennium	Tongue River	Total
				(In thousands)			
Balance at January 1 , 2009	$ 48,093	$ 25,124	$ 14,544	$	$	$	$ 87,761
Advances to (distributions from) affiliates, net	(5,164)		2,925				(2,239)
Equity in comprehensive income (loss)	6,674	(1,535)	(3,393)				1,746
Balance at December 31, 2009	49,603	23,589	14,076				87,268
Investments in affiliates	77,637			9,768			87,405
Advances to (distributions from) affiliates, net	(12,639)		4,264				(8,375)
Equity in comprehensive income (loss)	16,649	(1,628)	(3,868)				11,153
Balance at December 31, 2010	$ 131,250	$ 21,961	$ 14,472	$ 9,768	$	$	$ 177,451
Investments in affiliates				5,500	25,000	12,989	43,489
Advances to (distributions from) affiliates, net	(16,621)		6,498		3,477		(6,646)
Equity in comprehensive income (loss)	20,596	(2,246)	(4,884)	(2)	(2,153)		11,311
Balance at December 31, 2011	$ 135,225	$ 19,715	$ 16,086	$ 15,266	$ 26,324	$ 12,989	$ 225,605
Notes receivable from investees:							
Balance at December 31, 2010	$ 1,700	$ 18,100	$	$ 4,100	$	$	$ 23,900
Balance at December 31, 2011		30,751		5,059			35,810

The Company holds an equity interest in Knight Hawk Holdings, LLC ("Knight Hawk"), a coal producer in the Illinois Basin. In June 2010, the Company exchanged 68.4 million tons of coal reserves in the Illinois Basin for an additional 9% ownership interest, increasing the Company's ownership in Knight Hawk to 42% from $33\frac{1}{3}$%. The Company recognized a gain of $41.6 million on the transaction, representing the difference between the fair value and the $12.1 million net book value of the coal reserves, adjusted for the Company's retained ownership interest in the reserves through its investment in Knight Hawk. In December 2010, the Company increased its ownership interest in Knight Hawk to 49% for $26.6 million in cash.

The Company holds a 24% equity interest in DKRW Advanced Fuels LLC ("DKRW"), a company engaged in developing coal-to-liquids facilities. Under a coal reserve purchase option with DKRW, DKRW could purchase reserves from the Company, which the Company would then mine on a contract basis for DKRW. DKRW may borrow funds from the Company under a convertible secured promissory note. Amounts borrowed are due and payable in cash or in additional equity interests on the earlier of April 15, 2012 or upon the closing of DKRW's next financing, bear interest at the rate of 1.25% per month, and are secured by DKRW's equity interests in Medicine Bow Fuel & Power LLC. As of December 31, 2011, DKRW had borrowed the maximum amount allowed under the note. The note balances above are reflected in other receivables on the consolidated balance sheets.

The Company holds a general partnership interest of 21.875% in Dominion Terminal Associates ("DTA"), which is accounted for under the equity method. DTA operates a ground storage-to-vessel coal transloading facility in Newport News, Virginia for use by the partners. Under the terms of a throughput and handling agreement with DTA, each partner is charged its share of cash operating and debt-service costs in exchange for the right to use the facility's loading capacity and is required to make periodic cash advances to DTA to fund such costs.

The Company holds a 35% ownership interest in Tenaska Trailblazer Partners, LLC ("Tenaska"), the developer of the Trailblazer Energy Center, a fossil-fuel-based electric power plant near Sweetwater, Texas. The plant, fueled by low sulfur coal, will capture and store carbon dioxide for enhanced oil recovery applications. Additional future payments are due upon the achievement of project milestones to maintain the Company's interest. The Company made a milestone payment of $5.5 million in 2011. The Company will also pay 35% of the future development

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

costs of the project, not to exceed $12.5 million without prior approval from the Company. The receivables for these development costs, shown above, are reflected in the consolidated balance sheets in other noncurrent assets, as the development costs will either be reimbursed when the project receives construction financing, or they will be considered an additional capital contribution, with ownership percentages adjusted accordingly.

In January 2011, the Company purchased a 38% ownership interest in Millennium Bulk Terminals-Longview, LLC ("Millennium"), the owner of a brownfield bulk commodity terminal on the Columbia River near Longview, Washington, for $25.0 million, plus additional future consideration upon the completion of certain project milestones. Millennium continues to work on obtaining the required approvals and necessary permits to complete dredging and other upgrades to enable coal, alumina and cementitious material shipments through the terminal. The Company will control 38% of the terminal's throughput and storage capacity, in order to facilitate export shipments of coal off the west coast of the United States.

In July 2011, the Company purchased a 33% membership interest in the Tongue River Holding Company, LLC ("Tongue River") joint venture. Tongue River will develop and construct a railway line near Miles City, Montana and the Company's Otter Creek reserves. The Company has the right, upon the receipt of permits and approval for construction or under other prescribed circumstances, to require the other investors to purchase all of the Company's units in the venture at an amount equal to the capital contributions made by the Company at that time, less any distributions received.

Under development financing agreements with certain investees, the Company may be required to make future contingent payments of up to $74.4 million, including milestone payments. The Company's obligation to make these payments, as well as the timing of any payments required, is contingent upon a number of factors, including project development progress, receipt of permits and construction financing.

Summarized financial information of the Company's equity method investees follows:

	December 31		
	2011	2010	2009
	(In thousands)		
Condensed combined income statement information:			
Revenues	$ 184,358	$ 172,933	$ 166,152
Gross profit	19,495	25,203	15,426
Income from operations	13,180	20,243	1,611
Net income (loss)	6,788	16,015	(1,797)
Condensed combined balance sheet information:			
Current assets	$ 94,644	$ 48,202	
Noncurrent assets	331,848	276,125	
Total assets	$ 426,492	$ 324,327	
Current liabilities	$ 51,674	$ 39,237	
Noncurrent liabilities	120,494	99,350	
Equity	254,163	185,639	
Noncontrolling interest	161	101	
Total liabilities and equity	$ 426,492	$ 324,327	

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Inventories

Inventories consist of the following:

	December 31	
	2011	2010
	(In thousands)	
Coal	$ 206,517	$ 115,647
Repair parts and supplies	163,527	119,969
Work-in-process	7,446	
	$ 377,490	$ 235,616

The work-in-process is related to the Company's ADDCAR subsidiary acquired with ICG, which manufactures and sells its patented highwall mining system. The repair parts and supplies are stated net of an allowance for slow-moving and obsolete inventories of $13.1 million and $12.7 million at December 31, 2011 and 2010, respectively.

10. Derivative Instruments

Diesel fuel price risk management

The Company is exposed to price risk with respect to diesel fuel purchased for use in its operations. The Company anticipates purchasing approximately 80 to 90 million gallons of diesel fuel for use in its operations during 2012. To reduce the volatility in the price of diesel fuel for its operations, the Company uses forward physical diesel purchase contracts, as well as heating oil swaps and purchased call options. At December 31, 2011, the Company had protected the price of approximately 82% of its expected purchases for fiscal year 2012.

At December 31 2011, the Company held heating oil swaps and purchased call options for approximately 69 million gallons for the purpose of managing the price risk associated with future diesel purchases. Since the changes in the price of heating oil highly correlate to changes in the price of the hedged diesel fuel purchases, the heating oil swaps and purchased call options qualify for cash flow hedge accounting.

The Company also purchased heating oil call options to hedge the fuel surcharges on its barge and rail shipments that cover increases in diesel fuel prices. These positions reduce the Company's risk of cash flow fluctuations related to these surcharges but the positions are not accounted for as hedges. At December 31, 2011, Company held purchased call options for approximately 19.1 million gallons for the purpose of managing the fluctuations in cash flows associated with fuel surcharges on future shipments.

Coal risk management positions

The Company may sell or purchase forward contracts, swaps and options in the over-the-counter coal market in order to manage its exposure to coal prices. The Company has exposure to the risk of fluctuating coal prices related to forecasted sales or purchases of coal or to the risk of changes in the fair value of a fixed price physical sales contract. Certain derivative contracts may be designated as hedges of these risks.

At December 31, 2011, the Company held derivatives for risk management purposes that are expected to settle in the following years :

	2012	2013	2014	2015
(Tons in thousands)				
Coal sales	2,416	1,117	1,440	720
Coal purchases	254			

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Coal trading positions

The Company may sell or purchase forward contracts, swaps and options in the over-the-counter coal market for trading purposes. The Company is exposed to the risk of changes in coal prices on the value of its coal trading portfolio. The estimated future realization of the value of the trading portfolio is $2.6 million of losses in 2012 and $1.8 million of losses in 2013.

Tabular derivatives disclosures

The Company's contracts with certain of its counterparties allow for the settlement of contracts in an asset position with contracts in a liability position in the event of default or termination. Such netting arrangements reduce the Company's credit exposure related to these counterparties. For classification purposes, the Company records the net fair value of all the positions with a given counterparty as a net asset or liability in the consolidated balance sheets. The amounts shown in the table below represent the fair value position of individual contracts, regardless of the net position presented in the accompanying consolidated balance sheets. The fair value and location of derivatives reflected in the accompanying consolidated balance sheets are as follows:

Fair Value of Derivatives (In thousands)	December 31, 2011 Asset Derivative	December 31, 2011 Liability Derivative		December 31, 2010 Asset Derivative	December 31, 2010 Liability Derivative	
Derivatives Designated as Hedging Instruments						
Heating oil diesel purchases	$ 8,997	$		$ 13,475	$	
Coal	1,109			2,009	(2,350)	
Total	10,106			15,484	(2,350)	
Derivatives Not Designated as Hedging Instruments						
Heating oil fuel surcharges	1,797					
Coal held for trading purposes	15,505	(19,927)		34,445	(24,087)	
Coal	14,855	(6,035)		1,139	(912)	
Total	32,157	(25,962)		35,584	(24,999)	
Total derivatives	42,263	(25,962)		51,068	(27,349)	
Effect of counterparty netting	(18,134)	18,134		(22,402)	22,402	
Net derivatives as classified in the balance sheets	**$ 24,129**	**$ (7,828)**	**$ 16,301**	**$ 28,666**	**$ (4,947)**	**$ 23,719**

		December 31 2011	December 31 2010
Net derivatives as reflected on the balance sheets			
Heating oil	Other current assets	$ 10,794	$ 13,475
Coal	Coal derivative assets	13,335	15,191
	Coal derivative liabilities	(7,828)	(4,947)
		$ 16,301	$ 23,719

The Company had a current asset for the right to reclaim cash collateral of $12.4 million and $10.3 million at December 31, 2011 and December 31, 2010, respectively. These amounts are not included with the derivatives

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

presented in the table above and are included in "other current assets" in the accompanying consolidated balance sheets.

The effects of derivatives on measures of financial performance are as follows:

Year Ended December 31,
(In thousands)

Derivatives used in Fair Value Hedging Relationships	Gain on Derivatives Used in Fair Value Hedge Relationships			Hedged Items in Fair Value Hedge Relationships	Loss on Hedged Items In Fair Value Hedge Relationships		
	2011	2010	2009		2011	2010	2009
	(In thousands)				(In thousands)		
Coal	$ (3)	$ (3)	$ 2,586(3)	Firm commitments	$ (3)	$ (3)	$ (2,586)(3)

Derivatives used in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI (Effective Portion)			Gains (Losses) Reclassified from OCI into Income (Effective Portion)		
	2011	2010	2009	2011	2010	2009
Heating oil diesel purchases	$ 1,294	$ (149)	$ 10,309	$ 14,866(2)	$ 437(2)	$ (49,055)(2)
Coal sales	4,923	(4,714)	(7,441)	1,572(1)	(1,602)(1)	(6,999)(1)
Coal purchases	(2,009)	5,145	1,089	(2)	(1,202)(2)	(13,181)(2)
Totals	$ 4,208	$ 282	$ 3,957	$ 16,438	$ (2,367)	$ (69,235)

Derivatives used in Cash Flow Hedging Relationships	Gain (Loss) Recognized in Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)		
	2011	2010	2009
Heating oil diesel purchases	$	$	$
Coal sales			
Coal purchases			
Totals	$	$	$

Derivatives Not Designated as Hedging Instruments	Gain (Loss)		
	2011	2010	2009
Coal unrealized	$ 6,438(3)	$ (10,991)(3)	$ 9,673(3)
Coal realized	$ (7)(4)	$ 4,542(4)	$ (4)
Heating oil fuel surcharges unrealized	$ (2,906)(4)	$ (4)	$ (4)

Location in Statement of Income:

(1) Revenues

(2) Cost of sales

(3) Change in fair value of coal derivatives and coal trading activities, net

(4) Other operating income, net

The Company recognized net unrealized and realized losses of $3.5 million during the year ended December 31, 2011 and net unrealized and realized gains of $2.1 million and $2.4 million, during the years ended December 31, 2010 and 2009, respectively, related to its trading portfolio (including derivative and non-derivative contracts). These balances are included in the caption "Change in fair value of coal derivatives and coal trading activities, net" in the accompanying consolidated statements of income and are not included in the previous table.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During the next twelve months, based on fair values at December 31, 2011, gains on derivative contracts designated as hedge instruments in cash flow hedges of approximately $9.2 million are expected to be reclassified from other comprehensive income into earnings.

11. Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities consist of the following:

	December 31	
	2011	2010
	(In thousands)	
Payroll and employee benefits	$ 65,323	$ 51,327
Taxes other than income taxes	133,331	107,969
Interest	55,266	52,843
Acquired sales contracts (see Note 6)	38,441	5,615
Workers' compensation (see Note 15)	11,666	6,659
Asset retirement obligations (see Note 14)	27,119	8,862
Other	17,061	12,136
	$ 348,207	$ 245,411

12. Taxes

The Company is subject to U.S. federal income tax as well as income tax in multiple state jurisdictions. The tax years 2005 through 2011 remain open to examination for U.S. federal income tax matters and 1998 through 2011 remain open to examination for various state income tax matters.

Significant components of the provision for (benefit from) income taxes are as follows:

	Year Ended December 31		
	2011	2010	2009
		(In thousands)	
Current:			
Federal	$ (20,164)	$ 34,304	$ 21,295
State	1,212	2,283	864
Total current	(18,952)	36,587	22,159
Deferred:			
Federal	13,214	(18,506)	(39,492)
State	(1,851)	(367)	558
Total deferred	11,363	(18,873)	(38,934)
	$ (7,589)	$ 17,714	$ (16,775)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A reconciliation of the statutory federal income tax expense on the Company's pretax income to the actual provision for (benefit from) income taxes follows: